General Order 166
Emergency Response
Plan Compliance Report
(PUBLIC)

April 28, 2023

GENERAL ORDER 166
2022 COMPLIANCE REPORT

Purpose: The Annual Report and Emergency Response Plan ("Report") is to ensure SDG&E's processes and procedures are established for emergencies and disasters in order to minimize response times and provide for service restoration and communications for the public during those emergencies and disasters. This Report has been developed, updated, and maintained in compliance with CPUC General Order (G.O.) 166 as modified by Decisions (D.) 98-07-097, D.00-05-022, D.12-01-032, D.14-05-020 and D.21-05-019. The period of compliance for this Report is the previous twelve months, ending December 31, 2022.

This Report has been updated and incorporates the requirements of the November 1, 2012, Memorandum of Emergency Reporting Guidelines from the Deputy Director of Safety and Enforcement Division (which revoked the previously applicable October 28, 2009, CPUC Energy Division Memorandum of Emergency Reporting Guidelines).

The Report is provided in compliance with Standard 11 of G.O. 166 and page 7 of D.98-07-097, which states: "We have adopted rules that require the utilities to provide us with general plans for responding to emergencies but do not implicitly require the utilities to present us with detailed procedural manuals."

GENERAL ORDER 166
STANDARDS 1–14

STANDARD 1

PREPARE AN EMERGENCY RESPONSE PLAN

AND

UPDATE THE PLAN ANNUALLY

Standard 1. Emergency Response Plan

SDG&E's Compliance with Standard 1

SDG&E's Emergency and Disaster Preparedness Plan (CEADPP) is provided as a separate document from the GO 166 Annual Compliance Report, as required by the November 1, 2012, Memorandum from the CPUC's Safety and Enforcement Division (SED; formerly Consumer Protection and Safety Division).

In compliance with Standard 1, SDG&E's Emergency and Disaster Preparedness Plan has been annually updated; changes from the prior year's Emergency and Disaster Preparedness Plan include updates to contact information, and updates to Standards 4, 6, and 8.

A. Internal Coordination:

When an emergency event occurs, SDG&E's Emergency Management (EM) department is responsible for determining the level of emergency, activating SDG&E's Emergency Operations Center (EOC), and notifying EOC responders of the emergency and EOC activation. Activation of an emergency event at Level IV through I initiates notifications to key departments and personnel that a major event is forecast or is in progress that may significantly affect the gas and electric system. At every Event Level, each department has specific responsibilities that allow SDG&E to prepare for and respond to such an event in an organized manner.

When an Event Level III is activated, the impacted Commodity Operations Department Operating Center will be opened. This position(s) is staffed by the Deputy Operations Chief. Its purpose is to help coordinate the movement of crews, equipment and material between districts, and to provide system-wide information to various groups. It provides resource coordination and prioritization of resources allocated to the event.

The Customer Care Center ensures adequate staffing is in place to manage increased call volume.

B. ISO/TO Coordination:

SDG&E deals directly with the California Independent System Operator (CAISO). This procedure is under the overall jurisdiction of the CAISO. Proper and timely communication with the CAISO is required. See ISO Operating Procedure 4610.

C. Public Information Coordination:

SDG&E's Marketing and Communications team serves as Public Information Officer upon the activation of the Emergency Operations Center (EOC) and is responsible for providing timely and accurate information to customers, broadcast media, and employees. Information is disseminated through TV and radio news *outlets, social media channels, SDG&E's website and mobile app, SDG&E NewsCenter website, stakeholders and community partners, and internal communication platforms. SDG&E uses a "OneVoice" communications strategy for all communications to internal and external stakeholders to ensure consistent messaging.*

D. External and Government Coordination:

Guidelines have been developed for SDG&E's Emergency Management to report major electric and gas outage information for regulatory compliance and to support proactive communication links. Essential Customers, Public Safety Partners, and appropriate state and local government agencies receive updates regarding emergency events and progress of restoration through Emergency Operations Services.

SDG&E maintains lists of all partners, which is updated quarterly to ensure accuracy. The updates are conducted as part of an annual functional notifications group exercise as well as an annual meeting of the regional partners. Additionally, a live link is provided to partners where they can update real-time as changes are made in their organization.

Consistent with Standardized Emergency Management System (SEMS) and Federal Emergency Management Agency (FEMA National Incident Management System (NIMS) which includes the Incident Command System (ICS) Framework, SDG&E's Company Emergency and Disaster Preparedness Plan addresses how they are applied to our planning documents to include, but not limited to the following ICS principles:

- *Common terminology*
- *Establishment and transfer of command*
- *Chain and unity of command*
- *Unified command*
- *Management by objectives*
- *Modular organization*
- *Incident action planning*
- *Manageable span of control*
- *Incident locations and facilities*
- *Comprehensive resource management*
- *Integrated communications*
- *Information and intelligence management*
- *Effective accountability*
- *Dispatch/deployment*

REPORTING PROCEDURES

During Normal Business Hours
Notification to Emergency Management could come from an Operational Department Director or their designee, District Manager, Media Communications, the Customer Care Center, or First Responder Agencies.

The on-duty Emergency Management employee is responsible for: obtaining accurate internal information and contacting each of the organizational emergency contacts on the agency listing; providing follow up information at a reasonable frequency throughout the event to those agencies on the agency listing; and developing a record of initial contact and each subsequent contact and making a recommendation whether the EOC should be activated.

During Non-Business Hours
Emergency Management has a rotational employee that staffs one-week on-duty shifts. An Emergency Management on-duty phone number, text page, and email provides the mechanism for alerting the Emergency Management team. The on-duty Emergency Management employee will contact the notifying party within 30 minutes, obtain relevant information and contact the Emergency Operations Services Manager, who will instruct the on-duty Emergency Management employee of what notifications and/or actions to take.

The on-duty Emergency Management employee is responsible for obtaining accurate internal information and contacting the organizational emergency contacts on the agency listing, as appropriate. The exception is the CPUC, who is contacted by SDG&E's Claims Department when reporting criteria are met. An Emergency Management On-Duty employee is responsible for providing follow-up information at a reasonable frequency throughout the event to the appropriate agencies on the agency listing. Developing a record from the initial contact and each subsequent contact is necessary.

Agency Listing

- *California Energy Commission (CEC) 916-654-4287*
- *California Public Utilities Commission (CPUC) 800-235-1076*
- *CalOES California State Warning Center (CSWC) 916-845-8911*
- *California Utilities Emergency Association (CUEA) Executive Director 916-845-8518*
- *County of San Diego Office of Emergency Services 858-565-3490*
- *County of Orange Office of Emergency Services 714-628-7050*

E. Fire Prevention Plan:

Those electric utilities identified below shall have a Fire Prevention Plan that: lists and describes the measures the electric utility intends to implement, both in the short run and in the long run, to mitigate the threat of power line fire ignitions in *situations that meet all of the following criteria: (i) The force of 3-second wind gusts or other threat that exceeds the maximum working stress specified in G.O. 95, Section IV, for installed overhead electric facilities; (ii) the installed overhead electric facilities affected by these 3-second wind gusts* or other threat *are located in geographic areas designated as the first or second highest fire threat area on a fire- threat map adopted by the CPUC in Rulemaking (R.) 08-11-005; and (iii) the 3- second wind gusts occur at the time and place of a Red Flag Warning issued by United States National Weather Service or other emergency situations. The requirement to prepare a fire prevention plan applies to: (1) Electric utilities in Imperial, Los Angeles, Orange, Riverside, Santa Barbara, San Bernardino, San Diego, and Ventura counties; and (2) Electric utilities in all other counties with overhead electric facilities located in areas of high fire risk as determined by such utilities in accordance with Decision (D.)12-01-032 issued in Phase 2 of R.08-11-005. GO 166, Standard 1.E. See also D.12-01-032, pg. B-25.*

Standard 1.E was added to GO 166 in January 2012 by D.12-01-032 and was modified by D.14-05-020 (May 15, 2014). Standard 1.E requires SDG&E to prepare and submit plans to prevent power line fires during extreme fire-weather conditions or other emergencies*. As ordered by D.12-01-032, SDG&E submitted its first Fire Prevention Plan (FPP) by Advice Letter (AL) 2429-E on December31, 2012. Resolution E-4576 (issued May 23, 2013) required SDG&E to make minor modifications to its FPP; these modifications were incorporated by SDG&E's supplemental Advice Letter filing 2429-E-A. The supplemental AL 2429-E-A was approved by a disposition letter from the Director of the CPUC's Energy Division on June 18, 2013, with an effective date of May 23, 2013.*

In October 2018, the CPUC opened R.18-10-007 to implement the provisions of Senate Bill 901 related to electric utility Wildfire Mitigation Plans. Through that proceeding and guidance from the CPUC's Wildfire Safety Division (WSD), SDG&E submits its Wildfire Mitigation Plan (WMP) on a triennial basis, with annual updates on progress and performance. The WSD transitioned from the CPUC to the Office of Energy Infrastructure Safety (OEIS) in July, 2021. In July 2022, OEIS approved SDG&E's 2022 WMP Update by and the CPUC subsequently ratified OEIS's decision in August per Public Utilities Code Section 8386(a) by Resolution SPD-1. SDG&E's WMP addresses the requirements of the FPP, as prescribed by the above-referenced GO and Decisions. As such, SDG&E is attaching its 2022 WMP to this report as Appendix 1.

F. Safety Considerations:

SDG&E Construction & Operations (C&O) Centers are responsible for the repair and restoration of service in their district, damage assessment, coordination with the Electric Distribution Emergency Operations Desk, and the management of resources and equipment necessary to restore service as quickly and safely as possible.

The C&O Center Manager is responsible for the repair and restoration of service within their district boundary.

The District Assessment Coordinator is responsible for:

- *Assessment of overall damage to the district;*
- *Call out for primary and secondary assessors (a.k.a. fielders);*
- *Assigning personnel to assess damage;*
- *Prioritizing emergencies; and*
- *Making sure expectations are clear to fielders and ensuring fielders are briefed on safety. Fielders are to understand that wires down or exposed conductors are to be considered energized unless identified, isolated, tested dead, and grounded. They should be informed that downed or exposed conductors could become energized without warning in storm conditions or other emergencies. Fielders should ensure that the public does not go near downed or exposed power lines or equipment.*

Additionally, SDG&E has developed a Field Safety Officer program which is responsible for safety at field incidents. Those certified as Field Safety Officers must complete training equivalent to FEMA's L0954: NIMS ICS All-Hazards Safety Officer course.

G. Damage Assessment:

System-wide damage assessment at the onset of the emergency or disaster is extremely important and the information can be difficult to collect. A network software application called Oracle Utilities Network Management System is being utilized to assist with this process and to provide estimated restoration times. The District Assessment Coordinator is responsible for immediately assigning resources to the damage assessment process. Personnel may include, but are not limited to; Electric Troubleshooter, Working Foremen, Linemen, Construction Supervisor, Project Coordinators, and Planners.

Once the assessment is completed, the assessment is updated on either the Oracle Utilities Network Management System or the Service Order Routing Technology (SORT) application. The updated information is passed to the Oracle Storm Management application within the Oracle Utilities Network Management System and Oracle Utility Analytics. The purpose of utilizing these systems is to provide data on current and completed backlog to the Distribution Electric Emergency Operations Desk so that assessment of system-wide damage can be accomplished, and staffing levels can be adjusted accordingly.

H. Restoration Priority Guidelines:

Restoration guidelines include consideration of the following:

- *Emergencies (life threatening);*
- *Special cases and critical facilities (as defined by Operations Manager) to include;*
    - *Critical Customers*
    - *Customers who self-identity as Access and Functional Needs populations*
    - *Essential Customers*
    - *Public Safety Partners*
- *Primary Electric Outages: Generally, set assessment and restoration priorities to restore service first to critical and essential customers, and so the largest number of customers receive service in the shortest amount of time;*
- *Non-Primary Electric Outages: Emergency Agencies standing by and equipment damage not related to primary outages;*
- *Transformer Outages; and*
- *Single-No-Light outages.*

I. Mutual Assistance:

The Electric Distribution Electric Emergency Operations Desk Manager or Emergency Operations Center Company Officer-in-Charge (OIC) will:

- *Notify Emergency Services that mutual assistance is being considered and request that informal inquiries to other utilities be made;*
- *Determine resource needs from discussions with the districts, the outage forecast data, the weather/storm forecast, and resource shortages; and*
- *Hold discussions with SDG&E's Vice President of Electric System Operations, Senior Vice President of Electric Operations, the Director(s) of Electric Operations, the Director of Construction Management, the Manager of Emergency Services and the Director of Emergency Management to determine the need for mutual assistance and obtain approval to request.*

Conditions triggering these discussions include, but are not limited to:

- *Concurrent outage impacts nearing ten percent of SDG&E's electric customers;*
- *When forecasted outage duration exceeds 24 hours, discussion for mutual assistance is initiated and decisions are documented;*
- *Storm impact intensity is forecasted to last another 48 hours;*
- *All SDG&E crew resources have been or will be committed;*
- *All local contract crews have been or will be committed.*

J. Plan Update:

This general plan has been adjusted for changes made since the last submittal and addresses the requirements of D.98-07-097, D.00-05-022, and D.12-01-032, as well as the latest CPUC reporting guidelines from the November 1, 2012 SED (formerly CPSD) Memorandum. Procedural manuals are updated as required to conform to this general plan.

The plan is reviewed annually to meet changes in regulatory requirements and recommendations resulting from training, exercises, and After-action reports. Every 3 years a full document review with stakeholder input is conducted. The plan development also follows FEMA Comprehensive Guide 101 (CPG 101). As such, SDG&E is attaching its 2022 Company Emergency and Disaster Preparedness Plan to this report as Appendix 2.

<u>STANDARD 2</u>

ENTER INTO

MUTUAL ASSISTANCE AGREEMENTS

WITH OTHER UTILITIES

Standard 2. Mutual Assistance Agreement(s)

SDG&E's Compliance with Standard 2

SDG&E has three Mutual Assistance Agreements for the following areas/regions:

(1) California: See Appendix 4 for Mutual Assistance Agreement Among Members of the California Utilities Emergency Association (CUEA)

(2) Western U.S.: See Appendix 5 for Western Region Mutual Assistance Agreement for Electric and Natural Gas Utilities

(3) Nationwide: See Appendix 6 for Edison Electric Institute Mutual Assistance Agreement

During the reporting period, SDG&E did not request or receive mutual assistance.

<u>STANDARD 3</u>

CONDUCT ANNUAL EMERGENCY TRAINING

AND EXERCISES USING THE UTILITY’S

EMERGENCY RESPONSE PLAN

Standard 3. <u>Emergency Training and Exercise</u>

The utility shall conduct an exercise annually using the procedures set forth in the utility's emergency plan. If the utility uses the plan during the twelve-month period in responding to an event or major outage, the utility is not required to conduct an exercise for that period.

<u>SDG&E's Compliance with Standard 3</u>

SDG&E activated its plan for the following incidents in 2022

- *COVID - 19 1/1/2022*
- *PG&E Mutual Assistance 1/4/2022*
- *IID Mutual Assistance 8/11/2022*
- *Border Fire 32 8/31/2022*
- *Labor Day Extreme Heat 9/5/2022*
- *Tropical Storm Kay 9/9/2022*
- *PG&E Mutual Assistance 12/21/2022*

SDG&E conducted PSPS Tabletop and Functional training exercises on 5/24/2022, 6/27/2022, and 8/16/2022-8/18/2022 which were attended by representatives from the San Diego County Office of Emergency Services (SD County OES), CalOES, and the CPUC.

SDG&E requires all EOC responders to complete basic ICS, NIMS, and SEMS training and has set a target to have EOC Command and General staff achieve Utility Representative EOC Position Credentialling from CalOES. See table below for training requirements. Additionally, SDG&E trains all responders in Summer Readiness, (including review of PSPS and Load Curtailment protocols) in company-specific courses and briefings.

EOC Role Type	Required G Series & SEMS Training	Required ICS Training	Required NIMS Training
All Responders	SEMS G606	IS Intro to ICS IS 200 Basic ICS for Initial Response	IS 700 NIMS
EOC Command & General Staff	SEMS 606 G 611 EOC Section Overview (L,M,O,P,F) G 626E EOC Action Planning G 775 EOC Mgmt & Ops	IS 100 Intro to ICS IS 200 Basic ICS for Initial Response G 191 ICS/EOC Interface	IS 230 Fundamentals of Emergency Management G 197 Integrating AFN into Emergency Management (or IS 368) IS 700 NIMS IS 706 NIMS Intrastate MA IS 800 National Response Framework, an Intro.

STANDARD 4

DEVELOP A STRATEGY FOR INFORMING THE PUBLIC AND RELEVANT AGENCIES OF A MAJOR OUTAGE

Standard 4. <u>Communications Strategy</u>

<u>SDG&E's Compliance with Standard 4</u>

SDG&E's Communications Strategy is set forth below:

A. Customer Communications: Public Information Office (PIO) and Customer Care Center

SDG&E's Public Information Office owns and manages a Crisis Communications Plan, outlining public-facing communications strategies before, during and after a major outage or emergency Some tactics are listed below; however, for additional information, please see Appendix 3 for the Crisis Communication Plan.

The Customer Care Center starts to obtain emergency damage data during the Event Level III alert and continues through the completion of the emergency. During Events Level II or I, the Customer Care Center will dispatch a representative to the Electric Distribution Emergency Operations Desk to coordinate outage data for the Care Center.

SDG&E has several communications tools to expedite the delivery of emergency information to media and customers, including:

- *SDG&E partners with the local emergency broadcast radio station, KOGO-AM, to place emergency ads, which can air within 2–3 hours of a request. Additionally, the radio station is prepared to provide news coverage, as merited by the situation.*
- *The PIO will issue media advisories and/or press releases, as appropriate, post situation updates on SDG&E's Newscenter website, and respond to media inquiries, including any received through SDG&E's 24-hour media hotline. Additionally, when appropriate, proactive calls will be made to local television, radio, and print news outlets with situation updates.*
- *The Customer Care team provides situation updates on SDG&E social media channels, including Twitter, Facebook, Instagram, and Nextdoor. This responsibility is transferred to the PIO Section upon the activation of SDG&E's Emergency Operations Center.*
- *An outage map is accessible via SDGE.com. The outage map provides information related to active outages on SDG&E's electric system. The outage map includes details on the affected communities, outage cause, number of impacted customers, and estimated time of restoration. The outage map and similar information can also be accessed through SDG&E's mobile app, Alerts by SDGE.*
- *SDG&E partners with the network of local government agencies responsible for alert and warning in communities and coordinates with Public Safety Partners to maximize outreach efforts.*

SDG&E's communication strategy leverages the Public Safety Power Shut-off (PSPS) Guidelines where it is feasible and appropriate. For example, in a major outage caused by an earthquake or other no-notice disaster or emergency type, it is not possible to provide advanced notice per the PSPS Guidelines.

B. External and Government:

Guidelines for Emergency Operations Services exist to report major electric and gas outage information for regulatory compliance and to support proactive communication links. Local and state agencies may initiate the California Standardized Emergency Management System (SEMS) during an emergency, which will coordinate the agencies' activities.

<u>REPORTING PROCEDURES</u>

During Normal Business Hours

Notification to Emergency Management could come from an Operational Department Director or their designee, District Manager, Media Communications, the Customer Care Center, or First Responder Agencies.

The on-duty Emergency Management employee is responsible for: obtaining accurate internal information and contacting each of the organizational emergency contacts on the agency listing; providing follow up information at a reasonable frequency throughout the event to those agencies on the agency listing; and developing a record of initial contact and each subsequent contact and making a recommendation whether the EOC should be activated.

During Non-Business Hours

Emergency Management has a rotational employee that staffs one-week on-duty shifts. An Emergency Management on-duty phone number, text page, and email provides the mechanism for alerting the Emergency Management team. The on-duty Emergency Management employee will contact the notifying party within 30 minutes, obtain relevant information and contact the Emergency Operations Services Manager, who will instruct the on-duty Emergency Management employee of what notifications and/or actions to take.

The on-duty Emergency Management employee is responsible for obtaining accurate internal information and contacting the organizational emergency contacts on the agency listing, as appropriate. The exception is the CPUC, who is contacted by SDG&E's Claims Department when reporting criteria are met. An Emergency Management On-Duty employee is responsible for providing follow-up information at a reasonable frequency throughout the event to the appropriate agencies on the agency listing. Developing a record from the initial contact and each subsequent contact is necessary.

Agency Listing

- *California Energy Commission (CEC) 916-654-4287*
- *California Public Utilities Commission (CPUC) 415-703-1366*
- *CalOES California State Warning Center Warning Center (CSWC) 916-845-8911*
- *California Utilities Emergency Association (CUEA) Executive Director 916-845-8518*
- *County of San Diego Office of Emergency Services 858-565-3490*
- *County of Orange Office of Emergency Services 714-628-7050*

C. Independent System Operator (ISO) / Transmission Owner:

SDG&E deals directly with the California ISO (CAISO). This procedure is under the overall jurisdiction of the CAISO. Proper and timely communication with the CAISO is required. See ISO Operating Procedure 5110.

STANDARD 5

COORDINATE INTERNAL ACTIVITIES

DURING A MAJOR OUTAGE

IN A TIMELY MANNER

Standard 5. Activation Standard

SDG&E's Compliance with Standard 5

SDG&E's Activation Standard is set forth below for the Emergency Operating Center (EOC) to be activated within one hour.

The criteria used to define the severity of an incident for SDG&E include hazard-specific conditions and impact conditions such as:

- *Number of customers affected*
- *Resources deployed to address the incident*
- *Estimated time of restoration*
- *Facilities or systems impacted*
- *Workforce impact*
- *Financial impact*
- *The extent of media and political external interest*
- *Company reputational issues*

The incident types and the descriptors for each are intended to be used as guidelines for preparedness and response planning. There is a difference in how we classify an incident or event type on its impact to the company and the EOC activation, staffing and authority skill-level of activation required to resolve the situation.

The incident or event is evaluated to define how significant of a disruptive impact to the company's capability to safely provide its commodity services to our customers, proper workforce environment, infrastructure-facility- resources and meet our regulatory obligations. The larger the negative impact to these functions or disruption of services, the greater the resources required to repair or restore those services. The company response may range from a simple executive notification the incident, which usually can be accommodated within a couple days by field crews, to an EOC activation level-one which is catastrophic and may need external mutual assistance and months to restore.

In other words, a type-one incident classification has the potential to exceed the SDG&E company's authority and or financial capability to resolve. As the severity of an incident increases, the financial impact to the company expands accordingly and can extend to the Sempra Enterprise stake holder where we would coordinate with the Sempra Crisis Management Center (CMC) through the SDG&E Executive Management Team (EMT) leadership decision process.

NIMS incidents are categorized by the severity of their impact on a community, human suffering, disruption of life sustaining capability, infrastructure damage that can affect community viability and financial impact that affects resiliency of people to recover from the disaster. They are classified in the FEMA National Incident Management System Incident Complexity Guide Planning, Preparedness and Training document Jan 2021 as five-classification types. SDG&E uses the same basic incident types, but *they are modified to meet the impact of the incident on a Utility Company operational capability.*

These incident types are sufficiently important to understand that they are also referenced in the ICS-NIMS training courses of ICS-300, Intermediate ICS for Expanding Incidents and ICS-400, Advanced ICS Command and General Staff-Complex Incidents for crisis management. The value of this typing is for personnel to understand that an incident can be simple or complex and the resulting skills, management authority and manpower scale up or down accordingly. SDG&E utilizes the NIMS incident type and management scaling to configure the ICS response structure of Area Command, Utility Field Command (UFC's), Unified Commands, EMT and Sempra CMC as appropriate.

The EOC activation levels are determined by the authority, skill-level, and company resources required to effectively manage the incidents or events impacting the company. It is how the crisis management leadership group, and its staff, will expand to meet the response situation as follows:

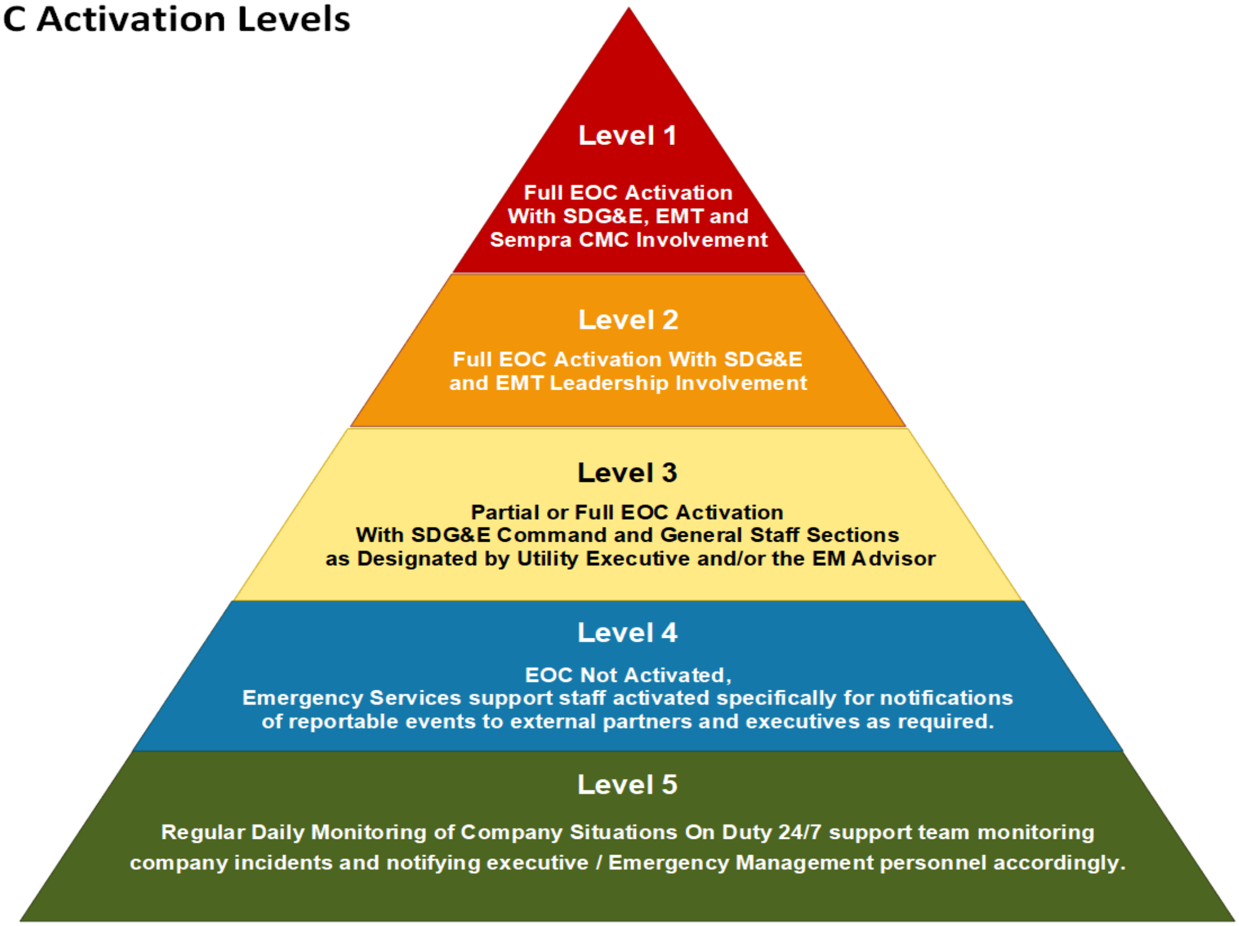
- ***Executive Notification (Green, EOC not activated)** – An incident that is common and does not disrupt daily business operations. Local incident involving a relatively small number of customers, such as those managed during routine operations. Does not require activation of EOC. There is no expectation of reputational or financial exposure from this incident. First level that requires any type of Emergency Services activity.*
- ***Level 4: Active Monitoring, Blue, EOC activated with minimal targeted responders** – An incident or operating condition, active or transpired, that has the potential to limit the ability to meet customer demand, to cause damage to company assets, or to disrupt business processes. The number of customers affected, or systems issues to be addressed likely exceeds the ability of local resources to respond; however, it is likely that the incident can be addressed within company resources. There will be an actual or potential non- routine effect on employees. The incident may draw media and government and regulatory interest, potentially some notifications that an event has occurred, but there is no expectation of reputational damage or financial exposure.*
- ***Level 3: Serious, Yellow, Partial or Full EOC activation with the affected emergency responders and Notification Process Team** – An incident that decreases the ability to meet customer demand or carry-out critical business processes. An area-wide or higher profile incident involving a significant number of customers, affecting multiple company businesses, and/or resolution may require more resources than available within the company. The incident will draw media, regulatory and governmental interest, and questions. Reputational damage could potentially occur if the response is not addressed in an effective and timely manner. Financial exposure will be limited. EOC positions are partially staffed, fully staffed, or*

virtual as necessary to support affected DOC's, Electric DOC-E, Gas DOC-G, Cyber SOC, and Security CSOC as required.

- ***Level 2: Severe, Orange, Full SDG&E EOC Activation including the Executive Management Team- EMT** – Incident that creates such severe impact that resources from across the company will be required to restore service or maintain operations and additional non-company resources may be required to support the recovery effort. Typically involve large numbers of customers and may result in significant customer inquiry volume. Employees' families may be affected. Facilities may be evacuated. There will be increased and on-going media attention. Government entities and regulators will want on-going reports regarding the status of company preparedness, response, and recovery conditions. There may be reputational and financial exposure. The EOC response positions are fully staffed, or virtual, appropriate DOCs are activated, and Senior leadership (EMT) involvement could be required. Usually necessary when multiple companywide departments are or could be affected or commodity service disruptions are involved but does not meet catastrophic loss or damage to company assets criteria. It is at this level the authority and leadership experience level are elevated to implement the resource and financial commitments necessary to resolve the issues including mutual aid. The EOC staff is fully involved with its senior leadership and corresponding team staff, but the severity of the events is within the SDG&E company area of responsibility and resources to resolve.*
- ***Level 1: Catastrophic, Red, Full SDG&E EOC activation and Sempra executive Crisis Management Center Coordination** – An incident that is significantly disruptive to a wide range of operational and business processes both within the company and the communities it serves. Resources will be drawn from outside the region and likely from outside the state, depending on the impact to neighboring regions. May require coordination of the company's response across the service territory. There will be significant financial exposure and significant potential for reputational damage. The incident will draw national media attention and likely will involve or draw scrutiny from State and Federal agencies, regulators, and political leaders. Fully manned EOC staff for support, appropriate DOCs are activated and Senior Leadership (EMT) and potential or real involvement coordinating with Sempra CMC will be required. This will involve the most qualified experienced EOC and Senior leadership roles in the management positions and will be managing the response across the company.*

The following EOC activation level diagram in this section illustrates the criteria that SDG&E will use to characterize the response management requirements.

EOC Activation Levels



STANDARD 6

NOTIFY RELEVANT INDIVIDUALS

AND AGENCIES

OF AN EMERGENCY OR MAJOR OUTAGE

IN A TIMELY MANNER

Standard 6. Initial Notification Standard

SDG&E's Compliance with Standard 6

Within one hour of the identification of a major outage or other newsworthy event, the utility shall notify the CPUC and the CalOES Warning Center of the location, possible cause and expected duration of the outage. The CalOES Warning Center is expected to notify other state agencies of the outage. SDG&E will notify SD County OES, who will notify other local agencies. Subsequent contacts between state and local agencies and the utility shall be conducted between personnel identified in advance, as set forth in Standard 4.B. From time to time, CPUC staff may issue instructions or guidelines regarding reporting.

SDG&E's Initial Notification Standard is set forth below:

Guidelines for Emergency Services exist to report major electric and gas outages for regulatory compliance and to support proactive communication links. Within one hour of the identification of a major outage or other newsworthy event, the CPUC, the CalOES Warning Center and the SD County OES shall be notified of the location, possible cause and expected duration of the outage.

REPORTING PROCEDURES

During Normal Business Hours
Notification to Emergency Services could come from a Company Utility Commander, Electric Distribution Operations, a District Manager or their designee, Media Communications, the Customer Care Center or First Responder Agencies.

The on-duty Emergency Management employee is responsible for obtaining accurate internal information and then contacting the organizational emergency contacts on the agency listing as appropriate. The exception is the CPUC who is contacted by SDG&E's Claims Department when reporting criteria is met. The on-duty Emergency Management employee is responsible for providing follow up information at a reasonable frequency throughout the event to the appropriate agencies on the agency listing. Developing a record from the initial contact and each subsequent contact is necessary.

During Non-Business Hours
Emergency Management has a rotational employee that stands one-week on duty shifts. An Emergency Management on-duty telephone number, text page, and e-mail provide the notification mechanism for alerting the Emergency Management team. The on-duty Emergency Management employee will contact the notifying party within 30 minutes, obtain information and call the Manager of Emergency Operations Services, who will instruct the Emergency Management on-call on what notifications and/or action to take.

The on-duty Emergency Management employee is responsible for obtaining accurate internal information and then contacting the organizational emergency contacts on the agency listing as appropriate. The exception is the CPUC who is contacted by SDG&E's Claims Department when reporting criteria is met. Emergency Management employee is responsible for providing follow up information at a reasonable frequency throughout the event to the appropriate agencies on the agency listing. Developing a record from the initial contact and each subsequent contact is necessary.

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Guidelines for Notification to the CPUC of Emergency or Urgent Events

I. References

G.O. 166: Standards for Operation, Reliability, and Safety during (Electric) Emergencies and Disasters. This report has been updated and incorporates the requirements of the November 1, 2012 CPUC SED (formerly CPSD) Memorandum of Emergency Reporting Guidelines, as well as Standard 1.E, as required by D.12-01-032.

This Plan is to ensure SDG&E's processes and procedures for emergencies and disasters are established to minimize response times and provide for service restoration and communications for the public. This report has been developed, updated, and maintained in compliance with G.O. 166 and the November 1, 2012 SED Memorandum. The period for this report is the previous twelve months ending December 31, 2022.

II. How to Report Emergency Reporting

Electric and gas incidents, emergencies, and power plant safety-related incidents are reported via the CPUC online form:

- *https://ia.cpuc.ca.gov/safetyevents/*

Electric utilities report major electric outages via the CPUC online form:

- *https://ia.cpuc.ca.gov/electricincidents/*

If the online form is unavailable, but internet access is available, electric and gas incidents, *emergencies, and major outages should be reported via email to the following CPUC staff:*

- *Safety Enforcement and Policy Division Deputy Executive Director, Forest Kaser, at Forest.Kaser@cpuc.ca.gov*
- *SED Director, Leslie "Lee" Palmer, at leslie.palmer@cpuc.ca.gov*
- *SED Program and Project Supervisor, Fadi Daye, at fadi.daye@cpuc.ca.gov*

If internet access is unavailable, notify the CPUC via the telephone hotlines:

- *Gas or Electric Incidents: 800-235-1076*
- *Power Plants: 415-355-5503*

If the hotlines' voicemail systems are not in service, notification will be made to the following SED personnel:

- *Lee Palmer at 415-703-2369, or Fadi Daye at 213-598-7439*

Notification of Significant Grid Events

The CAISO will continue its current practice to notify CPUC Offices, Directors and key staff of significant grid events (Alerts, Warnings, and Emergencies) by email.

If SDG&E is directed by CAISO to shed load due to an Emergency event, SDG&E will provide notification via the online form and by email to the following general mailbox and CPUC Energy Division (ED) personnel:

- *Electric Safety & Reliability Branch at ESRB_ComplianceFilings@cpuc.ca.gov*
- *Executive Director, Rachel Peterson, at rachel.peterson@cpuc.ca.gov*
- *Director for Procurement, Efficiency, and Electrification, Pete Skala, at pete.skala@cpuc.ca.gov*
- *Program Manager, Electric Planning and Market Design Branch, Molly Sterkel, at meredith.sterkel@cpuc.ca.gov*

SDG&E will notify CPUC Offices, Directors and key staff of imminent or planned curtailment of interruptible customer load and rotating outages of firm load, whether ordered by the CAISO (Emergency Stages 2 or 3) or made necessary by other emergencies. Notification will be made via the online form and by email to the following:

- *Electric Safety & Reliability Branch at ESRB_ComplianceFilings@cpuc.ca.gov*
- *Executive Director, Rachel Peterson, at rachel.peterson@cpuc.ca.gov*
- *Director for Procurement, Efficiency, and Electrification, Pete Skala, at pete.skala@cpuc.ca.gov*
- *ED Analyst, Michele Kito, at michele.kito@cpuc.ca.gov*

Notifications should specify the start time, anticipated duration, and impacted areas (city/county or community).

III. What to Report and When

Major Utility Reporting Requirements

(GO 166) Definitions:
<u>Emergency or Disaster</u>: *An event which is the proximate cause of a major outage, including but not limited to storms, lightning strikes, fires, floods, hurricanes, volcanic activity, landslides, earthquakes, windstorms, tidal waves, terrorist attacks, riots, civil disobedience, wars, chemical spills, explosions, and airplane or train wrecks.*

<u>Major Outage:</u> *Consistent with Public Utilities Code Section 364, a major outage occurs when 10 percent of the electric utility's serviceable customers experience a simultaneous, non-momentary interruption of service. For utilities with less than 150,000 customers within California, a major outage occurs when 50 percent of the electric utility's serviceable customers experience a simultaneous, non-momentary interruption of service.*

Follow the guidelines below for initial reports of Electric System Emergencies and Urgent Events. For emergencies that last more than 24 hours, please provide an update by 9 am each business day until the emergency is resolved. For reports required within one hour, please provide follow up reports as practicable, but at least once every four hours, during the business day.

ELECTRIC EMERGENCIES AND URGENT EVENTS

1. *Imminent or planned implementation of interruptible electric load curtailments or rotating outages of firm electric load by your utility, either ordered by the CAISO (Stage 2or 3 Alert) or necessitated by other emergencies.*

   Notify the CPUC as soon as possible <u>every time you interrupt new blocks of circuits.</u> Notification should include:

   - *Start time and anticipated duration of curtailments or rotating outages;*
   - *Interruptible load or firm load rotating outage blocks/groups and sub blocks/groups to be interrupted;*
   - *Total amount of interruptible load curtailments or firm load outages and major locations (counties and cities) of firm load to be interrupted;*
   - *Contact person for the emergency, with contact numbers.*

2. *Outage of electric service expected to accrue to over 300,000 customer hours, or exceeding 300 megawatts of interrupted load, or affecting more than 10% of your electric customers. (For utilities with fewer than 150,000 customers in California (small utilities), report when 50% of your customers are affected or 30,000 customer hours of interruption are expected to accrue.)*

   Notify us within <u>one hour</u>. Please report:

- *Possible cause of the outage, time and location of the initiating event;*
- *Approximate number and location (by county/city) of customers affected;*
- *Work necessary to restore service;*
- *Estimated time of service restoration;*
- *Your contact person for this emergency, with contact numbers.*

3. *An emergency, involving your facilities or personnel, likely to be reported statewide or in more than one major media market.*

   Notify the CPUC within <u>one hour</u>. Notification should include:

- *What happened, where, when, and how;*
- *Any impacts on electric service;*
- *Any injuries, hospitalizations, or casualties;*
- *Any property damage;*
- *Steps being taken to resolve the emergency;*
- *Time the situation is expected to return to normal;*
- *Your contact person for this emergency, with contact numbers.*

4. *Interruptions to bulk power supply (generators, transmission lines, or other equipment controlled by you) that are likely to lead to a CAISO declared Stage 2 or 3 Alert on or before the next business day.*

   Notify the CPUC within <u>one hour</u>. Notification should include:

- *The cause of the interruption, time and location of initiating event;*
- *Factors that would mitigate or worsen the emergency;*
- *Location and number of customers potentially affected;*
- *The expected duration of the low capacity situation;*
- *Your contact person for this event, with contact numbers.*

5. *An electric outage affecting more than 30,000 customers, or lasting over 24 hours for 2,500 customers, or expected to total over 60,000 customer hours, or a situation (such as floodwaters threatening a substation) likely to lead to such an outage. (Small utilities shall report outages affecting 3,000 customers or lasting over 24 hours for more than 250 customers or are expected to accrue to more than 6,000 customer hours.)*

   Notify the CPUC by <u>9 a.m. the next business day</u>. Notification should include:

- *The cause and time of the interruption;*
- *Name and location of facilities affected;*
- *Starting and end times of the outage;*
- *Location (by county and city) and number of customers affected;*
- *Number of customers for whom the outage exceeded four hours;*
- *If the outage is ongoing, when service will be restored;*
- *Your contact person for this event, with contact numbers.*

6. Electric outages associated with OES declared states of emergency, not otherwise reportable under above criteria.

Notify the CPUC ***as soon as possible.*** *Notification should include:*

- *Cause of the outage;*
- *Starting and end times of the outage;*
- *Location (by county and city) and number of customers affected;*
- *Number of customers for whom the outage exceeded four hours;*
- *If the outage is ongoing, when service will be restored;*
- *Movements of emergency crews between regions;*
- *Mutual assistance requests to other utilities;*
- *Your contact person for this event, with contact numbers.*

STANDARD 7

EVALUATE THE NEED

FOR MUTUAL ASSISTANCE

DURING A MAJOR OUTAGE

Standard 7. <u>Mutual Assistance Evaluation</u>

<u>SDG&E's Compliance with Standard 7</u>

No more than 4 hours after the onset of a major outage, SDG&E will begin the process of evaluating and documenting the need for mutual assistance.

The Electric Distribution Emergency Operations Desk Manager or Emergency Operations Center Company Utility Commander will:

- *Notify Emergency Operations Services that mutual assistance is being considered and request informal inquiries to other utilities be made;*
- *Determine resource needs from discussions with the districts, the outage forecast data, the storm forecast and resource shortages;*
- *Hold discussions with the Vice President of Electric System Operations, the Senior Vice President of Electric Operations, Director of Electric Operations, Director of Construction Services, Manager of Emergency Services and the Emergency Operations Services' Representative regarding the need for mutual assistance and obtain approval to request.*

Conditions triggering these discussions include, but are not limited to:

- *All SDG&E crew resources have been or will be committed;*
- *All local contract crews have been or will be committed;*
- *The restoration times for primary outages are forecast for 24 to 36 hours;*
- *Storm intensity is forecast to last another 48 hours;*
- *Concurrent outage impacts nearing ten percent of SDG&E's electric customers;*

It is the standard procedure during an EOC activation for a major event to evaluate as soon as possible if there would be a need for mutual assistance.

During the reporting period SDG&E did provide Mutual Assistance to other utilities, Pacific Gas & Electric (PG&E) on January 4, 2022 and December 21, 2022; and flooding situations with the Imperial Irrigation District (IID) on August 11, 2022.

STANDARD 8

INFORM THE PUBLIC

AND

RELEVANT PUBLIC SAFETY AGENCIES

OF THE ESTIMATED TIME

FOR RESTORING POWER

DURING A MAJOR OUTAGE

Standard 8. <u>Major Outage and Restoration Estimate Communication Standard</u>

<u>SDG&E's Compliance with Standard 8</u>

SDG&E's major outage and restoration estimate communication plan is set forth below.

A. *During regular operations, SDG&E leverages automated estimated restoration times based on historical restoration averages on a per circuit basis. During storms, PSPS or any other major event, automated restoration times are disabled and a manual estimated restoration time is created based on the best information available at the start of the event. This includes, but is not limited to, size, scope and type of event, meteorological forecasts, and any other relevant information obtained from community partners and/or first responder agencies.*

System-wide damage assessment at the onset of the emergency is extremely important and the information can be difficult to collect. The Damage Assessment program has been developed to assist this process and provide estimated restoration times.

The Customer Care Center starts to obtain emergency damage data during the Event Level II and continues through the completion of the emergency. During Event Level III or IV, the Customer Care Center (CCC) will work with Electric Distribution Emergency Operations to coordinate outage data for the Customer Care Center. This ensures data availability well in advance of the G.O. 166 requirement of within four hours of the identification of the major outage.

SDG&E has several communications tools to expedite the delivery of emergency information to media and customers, including:

- *SDG&E partners with the local emergency broadcast radio station, KOGO- AM, to place emergency ads, which can air within 2–3 hours of a request. Additionally, the radio station is prepared to provide news coverage, as merited by the situation.*
- *The PIO Section will issue media advisories and/or press releases, as appropriate, posts situation updates on SDG&E's Newscenter website and respond to media inquiries, including any received through SDG&E's 24-hour media hotline. Additionally, when appropriate, proactive calls will be made to local television, radio, and print news outlets with situation updates.*
- *The Customer Care Center provides situation updates on SDG&E digital/social media channels, including Twitter, Facebook, Instagram and Nextdoor. This responsibility is transferred to the PIO Section upon the activation of SDG&E's Emergency Operations Center.*
- *All outages and estimated restoration times are communicated through SDG&E's website and mobile app. An outage map is accessible via SDGE.com. The outage map provides information related to active outages on SDG&E's electric system. The outage map includes details on the affected communities, outage cause, number of impacted customers, and estimated time of restoration. The outage map and similar information can also be accessed on SDG&E's mobile app. All estimated restoration times are updated when new relevant information is obtained, such as the*

determination of the outage cause, or the repair crews arriving on scene.

B. *The Customer Care Center starts to obtain emergency damage data, including restoration estimates, during the Event Level III and continues through the completion of the emergency. During Event Levels II or I, the Customer Care Center will work closely with Electric Distribution Emergency Operations to coordinate outage data, including estimated restoration times. This ensures data availability well in advance of the GO 166 requirement of within four hours of the initial damage assessment and the establishment of priorities for restoring service.*

C. *As restoration estimates are updated based on repair work in the field, those updates are communicated with the customers primarily on the SDG&E outage website.*

D. *SDG&E leverages different methodologies for creating initial estimated restoration time estimates based on the size, scope and type of event, meteorological forecasts, and any other relevant information obtained from community partners and/or first responder agencies. In storms and PSPS, given these are both weather related, meteorological forecasts are leveraged for the initial estimated restoration time. If there is a fire or earthquake, SDG&E would leverage its partnerships with first responders to know when it was safe to begin assessment in the impacted areas and build ERT's from that information. For PSPS specifically, initial ERT's are created by taking the estimated weather event end time plus 12 hours of daylight patrol and restoration time.*

To evaluate the accuracy of the estimated restoration times, SDG&E measures the accuracy as the absolute value of (actual restoration time – estimated restoration time) divided by actual restoration time.

E. *SDG&E's communication strategy leverages the Public Safety Power Shut-off (PSPS) Guidelines where it is feasible and appropriate. For example, in a major outage caused by an earthquake or other no-notice disaster or emergency type, it is not possible to provide advanced notice per the PSPS Guidelines.*

STANDARD 9

TRAIN ADDITIONAL PERSONNEL

TO ASSIST WITH

EMERGENCY ACTIVITIES

Standard 9. <u>Personnel Redeployment Planning Standard</u>

<u>SDG&E's Compliance with Standard 9</u>

SDG&E's Training and Redeployment Plans for performing safety standby activities and assessing damage during a major outage are as follows:

Redeployment Plan: The District Operations and Engineering Manager is responsible for immediately assigning resources to the damage assessment process. Personnel may include, but is not limited to electric troubleshooter, working foremen, linemen, helpers, general foremen, project coordinators, and planners. In a major event, it may become necessary to draw on additional company personnel. Each district not yet involved in the emergency (storm) should be prepared to assist other districts. Requests for additional personnel should go through the Resource Coordination Desk at Distribution Operations so that effective control and allocation of resources is assured. Resource Coordination will contact the Trouble Dispatch department if assistance is needed to recruit personnel. Trouble Dispatch will provide a callout list similar to the district callout lists for this purpose.

Training: Assessor and safety standby training is performed on an annual basis. Formal classes are provided to ensure public and worker safety. Drills for specific areas of the plan are performed during the year as practical training and a formal drill, using the entire plan is performed yearly. In addition, the O&E Manager in each district is to brief assessors and safety stand-by personnel prior to their deployment. Fielders are to understand that wires down or exposed conductors are to be considered energized unless identified, isolated, tested dead, and grounded. They are to be aware that downed or exposed conductors could become energized without warning in storm conditions.

During the reporting period, SDG&E did not activate its Personnel Redeployment Planning Standard.

STANDARD 10

COORDINATE EMERGENCY PLANS

WITH

STATE AND LOCAL PUBLIC SAFETY AGENCIES

Standard 10. Annual Pre-Event Coordination Standard

SDG&E's Compliance with Standard 10

During the reporting period, SDG&E hosted agencies for training exercises focused on PSPS. Representatives from SD County OES, CalOES and the CPUC attended the exercises on May 24, 2022, June 27, 2022 and August 16-18, 2022.

Additionally, SDG&E follows all PSPS regulations for pre-event coordination which includes:

- *Meeting with public safety partners several times throughout the year*
- *Updating partner contact information*
- *Participating in joint training & exercises*
- *Briefing local Senior and elected officials*
- *Coordination with local tribal partners*
- *Coordination with critical infrastructure partners*

SDG&E also participates in regional planning efforts such as:

- *Critical Lifelines*
- *Southern California Catastrophic Earthquake Plan*
- *Southern Region Mutual Aid Regional Advisory Council Meetings*
- *California Emergency Services Association membership*
- *Regional Emergency Managers Working Group*
- *Regional AFN Working Group*

STANDARD 11

FILE AN ANNUAL REPORT

DESCRIBING COMPLIANCE

WITH THESE STANDARDS

Standard 11. Annual Report

SDG&E's Compliance with Standard 11

This document includes SDG&E's annual report for the 12-month period ending December 31, 2022 and describes SDG&E's compliance with the GO 166 standards. In addition, SDG&E's repair and maintenance personnel are listed below (by county) for 2021 and 2022

2021 REPAIR AND MAINTENANCE PERSONNEL
BY CLASSIFICATION
IN EACH COUNTY

Personnel Classification	*San Diego County*	*Orange County*
Electric Supervisor (General & Administrative)	*43*	*2*
Working Foreman	*37*	*3*
Fault Finding Specialist	*5*	*1*
Lineman	*141*	*12*
Apprentice Lineman	*60*	*6*
Line Checker	*1*	*0*
Troubleshooter	*39*	*3*
Line Assistant	*50*	*2*
Total	*376*	*29*

2022 REPAIR AND MAINTENANCE PERSONNEL
BY CLASSIFICATION
IN EACH COUNTY

Personnel Classification	*San Diego County*	*Orange County*
Electric Supervisor (General & Administrative)	*36*	*3*
Working Foreman	*29*	*4*
Fault Finding Specialist	*5*	*1*
Lineman	*142*	*13*
Apprentice Lineman	*65*	*7*
Line Checker	*1*	*0*
Troubleshooter	*38*	*3*
Line Assistant	*22*	*1*
Total	*338*	*32*

STANDARD 12

RESTORATION PERFORMANCE BENCHMARK

FOR A MEASURED EVENT

Standard 12. <u>Restoration Performance Benchmark for a Measured Event</u>

<u>SDG&E's Compliance with Standard 12</u>

SDG&E did not have any Measured Events during the twelve-month time period ending December 31, 2022, that caused SDG&E to implement Standard 12. SDG&E's benchmarks are set forth below.

A. Benchmark

The CPUC will review SDG&E's restoration performance following a Measured Event[1] based on the Customer Average Interruption Duration Index (CAIDI).

B. CAIDI

A CAIDI of 570 or below is presumed reasonable. A CAIDI above 570 is presumed unreasonable; however, the presumptions are rebuttable. Each sustained interruption experienced by a single customer shall count as a separate customer interruption. CAIDI will be measured from the beginning of the Measured Event until all customers experiencing interruptions during the Measured Event have been restored.

C. Transmission Outages

Customer minutes of interruption caused by outages on the transmission system are included in the calculation of CAIDI. Transmission outage minutes attributable to compliance with ISO directives that preclude SDG&E from restoring service are excluded from the CAIDI calculation.

[1] Measured Event: A Measured Event is a Major Outage (as defined herein), resulting from non-earthquake, weather-related causes, affecting between 10% (simultaneous) and 40% (cumulative) of a utility's electric customer base. A Measured Event is deemed to begin at 12:00 a.m. on the day when more than one percent (simultaneous) of the utility's electric customers experience sustained interruptions. A Measured Event is deemed to end when fewer than one percent (simultaneous) of the utility's customers experience sustained interruptions in two consecutive 24-hour periods (12:00 a.m. to 11:59 p.m.); and the end of the Measured Event in 11:59 p.m. of that 48-hour period.

STANDARD 13

CUSTOMER CONTACT CENTER

BENCHMARK FOR A MEASURED EVENT

Standard 13. <u>Customer Contact Center Benchmark for a Measured Event</u>

<u>SDG&E's Compliance with Standard 13</u>

SDG&E did not have any Measured Events during the twelve-month time period ending December 31, 2022 that caused SDG&E to implement Standard 13. SDG&E's benchmarks are set forth below.

A. Benchmark:

The CPUC will perform a review of SDG&E's Customer Care Center performance following a Measured Event based on percent busies.

B. Percent Busies:

SDG&E's Contact Center performance will be presumed reasonable if the percent busies calculation is lower than Level-1 and presumed to be unreasonable if the percent busies calculation is greater that Level-2. The presumptions are rebuttable. Performance equal to or between Level-1 and Level-2 is subject to no presumption.

Percent busies calculation measures the levels of busy signals encountered by customers at SDG&E's switch and that of its contractors. Percent busies indicator is measured on a 24-hour basis for outage-related calls (on energy outage and general call lines) from the time the Measured Event begins (12:00 a.m. to 11:59 p.m.) and separately for each 24-hour period until the Measured Event ends.

Percent busies may be calculated as either:

- *a. Percent of call attempts reaching the Customer Care Center that receive a busy signal.*
- *b. Percent of time that trunk line capacity is exhausted.*

Level-1 and Level-2 are defined as follows:

- *Level-1 is defined as 30% busies over the day of the outage (12:00 a.m. to 11:59 p.m.);*
- *Level-2 is defined as 50% busies over the day of the outage plus at least 50% busies in each of six one-hour increments (increments need not be consecutive).*

C. Other Call Center Metrics:

SDGE tracks metrics which measures availability of agents, to provide customers with information during an emergency or disaster. Theses metrics are reviewed and managed with focus on continuous improvement. Additionally, the company's external website, SDGE.com is hosted on "The Cloud" via Amazon Web Services (AWS). The company has a 99.99999 uptime service level agreement (SLA) which includes auto-scaling of web servers and regions, as well as advanced Disaster Recovery plans to mitigate downtime.

STANDARD 14

PLAN DEVELOPMENT COORDINATION

AND PUBLIC MEETING

Standard 14. Plan Development Coordination and Public Meeting

SDG&E's Compliance with Standard 14

SDG&E invites every city, county, state, and tribal partners to an annual meeting to review and provide input to the Company Emergency and Disaster Preparedness Plan (CEADPP).

- *Orange County: April 12, 2022*
- *San Diego County: May 25, 2022*
- *Tribal Partners: July 22, 2022*

In addition to the agencies listed above, SDG&E also provides opportunities to provide input at the following regional stakeholder meetings:

- *Public Safety Partners*
- *San Diego County Unified Disaster Council*
- *Regional AFN Working Group*
- *SDG&E Wildfire Advisory Council*
- *SDG&E Community Advisory Council*
- *Regional Emergency Managers Working Group*
- *Regional Tribal Leaders Group*

In accordance with the standard, every two years the meetings are publicly noticed. All documentation for the biennial meetings is submitted to the appropriate persons of contact at the commission.

BEFORE THE PUBLIC UTILITIES
COMMISSION OF THE STATE OF CALIFORNIA

DECLARATION OF BRIAN D'AGOSTINO
REGARDING CONFIDENTIALITY OF CERTAIN DATA/DOCUMENTS
PURSUANT TO D.17-09-023

I, Brian D'Agostino, do declare as follows:

1. I am the Vice President of Wildfire and Climate Science for San Diego Gas & Electric Company ("SDG&E"). I have reviewed the confidential information included within the General Order 166 Emergency Response Plan Compliance Report, submitted concurrently herewith (the "2022 G.O. 166 Compliance Report"). I am personally familiar with the facts in this Declaration and, if called upon to testify, I could and would testify to the following based upon my personal knowledge and/or information and belief.

2. I hereby provide this Declaration in accordance with Decision ("D.") 17-09-023 and General Order ("GO") 66-D Revision 1[1] to demonstrate that the confidential information ("Protected Information") provided in the "2022 G.O. 166 Compliance Report" is within the scope of data protected as confidential under applicable law.

3. In accordance with the narrative justification described in Attachment A, the Protected Information should be protected from public disclosure.

I declare under penalty of perjury under the laws of the State of California that the foregoing is true and correct to the best of my knowledge.

Executed this 26th day of April, 2023, at San Diego.

Brian D'Agostino
Vice President of Wildfire and Climate Science

[1]GO 66-D was modified by D. 19-01-028 to create GO 66-D Revision 1 which became effective February 1, 2019.

ATTACHMENT A

SDG&E Request for Confidentiality on the following information in its 2022 G.O. 166 Compliance Report

Location of Protected Information	**Legal Citations**	**Narrative Justification**
Grey highlighted portion in Appendix 2, Company Disaster and Emergency Preparedness Plan, pages: • v • 4 • 56	Other categories where disclosure would be against the public interest (Govt. Code § 6255(a): Due to sensitivity around names, LAN IDs and phone numbers for individual employees, the public interest in maintaining the confidentiality of this information outweighs the public interest in disclosure.	Disclosing staff names in conjunction with other identifying information such as e-mail addresses, home addresses, and telephone numbers could pose a risk to staff safety. Additionally, disclosure of such information increases the risks of cyber-attacks, incessant robo-calls, and malicious emails. Disclosure could result in information security concerns. Personnel and medical records are sensitive information and if misused could cause discrimination, loss of opportunities, or potential safety concerns. Protection should be afforded for utility employees' information, similar to Civil Code §§ 1798.80 et seq.'s protection of such information for customers.
Grey highlighted portion in Appendix 2, Company Disaster and Emergency Preparedness Plan, page 36, section 4.6	CPRA Exemption, Gov't Code § 6254.15 (disclosure not required for "corporate financial records, corporate proprietary information including ROI, and information relating to siting within the state furnished to a government agency by a private company for the purpose of permitting the agency to work with the company in retaining, locating, or expanding a facility within California").	Public disclosure of internal audits would discourage companies from conducting self-critical assessments that identify and mitigate issues. The protected information also represents corporate financial records and corporate proprietary information, including trade secrets.

Location of Protected Information	Legal Citations	Narrative Justification
	CPRA Exemption, Gov't Code § 6254(k) ("Records, the disclosure of which is exempted or prohibited pursuant to federal or state law") • Cal. Evid. Code § 1060 • Cal. Civil Code §§ 3426 *et seq.* (relating to trade secrets) [2] • *TMX Funding Inc. v. Impero Technologies, Inc.*, 2010 WL 2745484 at *4 (N.D. Cal. 2010) (defining trade secret in an injunction to include "business plans and strategies") • *Whyte v. Schlage Lock Co.*, 101 Cal. App. 4th 1443, 1453, 1456 (2002) (giving a list of what may be trade secret and holding that "[t]he ultimate determination of trade secret status is subject to proof presented at trial") • *Morton v. Rank America, Inc., 812 F. Supp.* 1062,	

[2] Civil Code Section 3426.1 defines "trade secret" as "information, including a formula, pattern, compilation, program, device, method, technique, or process, that:
(1) Derives independent economic value, actual or potential, from not being generally known to the public or to other persons who can obtain economic value from its disclosure or use; and
(2) Is the subject of efforts that are reasonable under the circumstances to maintain its secrecy."

Location of Protected Information	Legal Citations	Narrative Justification
	1073 (1993) (denying motion to dismiss because "actual or probable income, expenses and capital needs of [a company], the financial, operational, marketing and other business strategies and methods" could constitute trade secret) • 5 U.S.C. § 552(b)(4) (Exemption 4 of FOIA protecting "trade secrets and commercial or financial information obtained from a person and privileged or confidential")	

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

DECLARATION OF SCOTT CRIDER REGARDING CONFIDENTIALITY OF CERTAIN DATA/DOCUMENTS PURSUANT TO D.17-09-023

I, Scott Crider, do declare as follows:

1. I am, Scott Crider, Senior Vice President of External & Operations Support, for San Diego Gas & Electric Company ("SDG&E"). I have reviewed the confidential information included within 2022 SDG&E General Order 166 Annual Emergency Response Plan Compliance Report, submitted concurrently herewith (the "2022 G.O.166 Compliance Report"). I am personally familiar with the facts in this Declaration and, if called upon to testify, I could and would testify to the following based upon my personal knowledge and/or information and belief.

2. I hereby provide this Declaration in accordance with Decision ("D.") 17-09-023 and General Order ("GO") 66-D Revision 1[1] to demonstrate that the confidential information ("Protected Information") provided in "2022 G.O.166 Compliance Report" is within the scope of data protected as confidential under applicable law.

3. In accordance with the narrative justification described in Attachment A, the Protected Information should be protected from public disclosure.

[1] GO 66-D was modified by D. 19-01-028 to create GO 66-D Revision 1 which became effective February 1, 2019.

I declare under penalty of perjury under the laws of the State of California that the foregoing is true and correct to the best of my knowledge.

Executed this 20th day of April 2023.

Scott B. Crider

Senior Vice President, External & Ops Support

ATTACHMENT A

SDG&E Request for Confidentiality on the following information in its response to 2021 G.O. 166 Compliance Report

Location of Protected Information	Legal Citations	Narrative Justification
Gray shaded portion(s) in Appendix 3, 2022 SDG&E Crisis Communications Plan, at pages 15 and 17.	Other categories where disclosure would be against the public interest (Govt. Code § 6255(a): Due to sensitivity around names, LAN IDs and phone numbers for individual employees, the public interest in maintaining the confidentiality of this information outweighs the public interest in disclosure.	Disclosing staff names in conjunction with other identifying information such as e-mail addresses, home addresses, and telephone numbers could pose a risk to staff safety. Additionally, disclosure of such information increases the risks of cyber-attacks, incessant robo-calls, and malicious emails. E-mail Addresses: Disclosure could result in information security concerns. Personnel and medical records are sensitive information and if misused could cause discrimination, loss of opportunities, or potential safety concerns. Protection should be afforded for utility employees' information, similar to Civil Code§§ 1798.80 *et seq.* 's protection of such information for customers.

Appendix 1:
SDG&E's 2022 Wildfire Mitigation Plan

2020-2022 WILDFIRE MITIGATION PLAN UPDATE

San Diego Gas & Electric Company

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List of Abbreviations

Abbreviation	Name
2022 WMP Update	2022 Wildfire Mitigation Plan Update
AAR	After-Action Review
ABI	Advanced Baseline Imager
ADA	Americans with Disabilities Act
AFN	Access and Functional Needs
AFUDC	Allowance of Funds Used During Construction
AI	Artificial intelligence
AMI	Advanced Metering Infrastructure
API	Application Programming Interface
APP	Advanced Protection Program
AQI	Air Quality Index
ASC	Arc Suppression Coil
ASTM	American Society for Testing and Materials
AVL	Automatic Vehicle Location
BLF	Building Loss Factor
CAED	College of Architecture & Environmental Design
CAFES	College of Agriculture, Food & Environmental Sciences
CAISO	California Independent System Operator
CAL FIRE	California Department of Forestry and Fire Protection
Cal Poly	California Polytechnic State University, San Luis Obispo
Cal/OSHA	Division of Occupational Safety and Health
CalOES	California Office of Emergency Services
Caltrans	California Department of Transportation
CARE	California Alternative Rates for Energy
CAISO	California Independent System Operator
CBO	Community Based Organization
CBU	Capacitor Balancing Unit
CCC	California Conservation Corps
CENG	College of Engineering
CEQA	California Environmental Quality Act
CERP	Company Emergency Response Plan
CERT	Community Emergency Response Teams
CforAT	Center for Accessible Technology
CFR	Contract Fire Resources
CHI	Circuit Health Index
CI	Customers Impacted
CLA	College of Liberal Arts
CMI	Customer Minutes Interrupted
CMP	Corrective Maintenance Program
CNF	Cleveland National Forest
CoRE	Consequence of Risk Event
COSAM	College of Science & Mathematics
County OES	County Office of Emergency Services
CPUC	California Public Utilities Commission
CR	Central Repository

CRC	Community Resource Center
CRI	Circuit Risk Index
CUEA	California Utilities Emergency Association
DAC	Disadvantaged Communities
DCRI	Distribution Communications Reliability Improvements
DFM	Dead Fuel Moisture
DGF	Data Governance Framework
DIAR	Drone Investigation, Assessment and Repair
DINS	Damage Inspection Specialists
DL	Dryness Level
DMS	
DMV	Department of Motor Vehicles
DOE	Department of Energy
DOT	Department of Transportation
DPG	Design Preference Guide
EAMP	Enterprise Asset Management Platform
EFD	Early Fault Detection
ENS	Enterprise Notification System
EOC	Emergency Operations Center
EPA	Environmental Protection Agency
ERA	
ERC	Energy Release Component
ERR	enterprise risk registry
ESA	Energy Savings Assistance
ESCMP	Environmental & Safety Compliance Management Program
ESH	Electrical System Hardening
ESP	Electric Standard Practice
ESS	Energy Service Specialist
ETS	Electric Troubleshooters
EVM	enhanced vegetation management
FACT	Facilitating Access to Coordinated Transportation
FB	Fire Behavior
FBI	Fire Behavior Index
FBO	Fire Behavior Officer
FBP	Fixed Backup Power
FCA	Field Construction Advisor
FCP	Falling Conductor Protection
FDC	Fire Detection and Characterization
FERA	Family Electric Rate Assistance
FERC	Federal Energy Regulatory Commission
FiRM	Fire Risk Mitigation
FMC	fuel moisture component
FPI	Fire Potential Index
FRAP	Fire and Resource Assessment Program
FRMMA	Fire Risk Mitigation Memorandum Account
FRP	Fire Radiative Power
FS&CA	Fire Science and Climate Adaptation
FSD	Field Service Delivery

FSI	Fire Science and Innovation
FTE	Full time employee
FWI	Fire Weather Index
Gag	Annual Grasses
GAP	Generator Assistance Program
GEV PDF	Generalized Extreme Value Probability Distribution Function
GFN	Ground Fault Neutralizer
GGP	Generator Grant Program
GIS	Geographic Information System
GO	General Order
GOES	Geostationary Operational Environmental Satellite
GRC	General Rate Case
GSOB	Gold Spotted Oak Borer
HDD	Horizontal Directional Drilling
HFE	Human Factors Engineering
HFTD	High Fire Threat District
HIF	High Impedance Fault
HLC	Hotline Clamp
HMI	Human Machine Interface
HPCC	High Performance Computing Clusters
HRFA	High Fire Risk Areas
HVRA	Highly Valued Resources and Asset
IBEW	International Brotherhood of Electrical Workers
ICS	Incident Command System
IEEE	Institute of Electrical and Electronics Engineering
IIP	Intelligent Image Processing
IMP	Ignition Management Program
IOU	Investor-Owned Utility
IPC	insulation piercing connector
ISA	International Society of Arboriculture
ISO	International Organization for Standardization
IUCRC	Industry-University Cooperative Research Center
IWRMC	International Wildfire Risk Mitigation Consortium
Km	kilometer
kV	kilovolt
kVA	Kilovolt-Amps
kWh	Kilowatt-hour
LEP	Limited English Proficiency
LFM	Live Fuel Moisture
LFMC	Live Fuel Moisture Content
LFP	Large Fire Potential
LiDAR	Light detection and ranging
LMS	Learning Management System
LoRE	Likelihood of Risk Event
LTE	Long-Term Evolution
Maturity Model	Utility Wildfire Mitigation Maturity Model
MAVF	Multi-Attribute Value Function
MBL	Medical Baseline

MCA	management corrective action
MDT	mobile data terminals
MOU	memorandum of understandings
Mph	Miles per hour
MSUP	Master Special Use Permit
NCCP	Natural Communities Conservation Plan
NDVI	Normalized Difference Vegetation Index
NEETRAC	National Electric Energy Testing, Research, and Applications Center
NERC	North American Electric Reliability Corporation
NEPA	National Environmental Protection Act
NIMS	National Incident Management System
NMS	Network Management System
NUITF	National Utility Industry Training Fund
O&M	Operations and Maintenance
OEIS	Office of Energy Infrastructure Safety
OFER Div	Operational Field & Emergency Readiness Division
ORNL	Oak Ridge National Laboratory
OSHA	Occupational Safety and Health Administration
OUA	Oracle Utility Analytics
PEV	post enrollment verification
PG&E	Pacific Gas & Electric
PLS-CADD	Power Line Systems – Computer Aided Drafting and Design
$PM_{2.5}$	Particulate matter 2.5 microns or smaller in diameter
PMU	phasor measurement unit
PoC	Proof of Concept
PoF	Probability of Failure
PoI	Probability of Ignition
PoI_F	conditional probability model
PPE	personal protective equipment
PRiME	Pole Risk Mitigation Engineering
PSE	Pacific Science & Engineering
Psf	Pounds per square foot
PSPS	Public Safety Power Shutoff
QA/QC	Quality assurance/quality control
QDR	Quarterly Data Report
QEW	qualified electrical worker
QIU	Quarterly Initiative Update
QNL	Quarterly Notification Letter
RAMP	Risk Assessment Mitigation Phase
RAWS	Remote Automated Weather Stations
RCC	Residual Current Compensation
RCIP	Regional Computer-Aided Dispatch Interoperability Project
REFCL	Rapid Earth Fault Current Limiter
RETS	Relief Trouble Shooter
RFF	Relief Fault Finder
RFW	Red Flag Warning
RMAG	Regional Mutual Assistance Group
ROS	Rate of Spread

ROW	Right of way
RSE	Risk Spend Efficiencies
RTLS	real time location system
RTU	Remote Terminal Unit
S-MAP	Safety Model and Assessment Proceeding
SA	Settlement Agreement
SAIDI	System Average Duration Index
SAIDIDAT	System Average Duration Index Data
SAIFI	System Average Interruption Frequency Index
SAWTI	Santa Ana Wind Threat Index
SBIR	Small Business Innovation Research
SCADA	supervisory control and data acquisition
SCE	Southern California Edison
SDG&E	San Diego Gas & Electric
SDSC	San Diego Supercomputer Center
SEMS	Standardized Emergency Management System
SGF	Sensitive Ground Fault
SIF	Serious Injuries and Fatalities
S-MAP	Safety Model and Assessment Proceeding
SME	Subject matter expert
SMS	Safety Management System
SRA	State Responsibility Area
SRP	Sensitive Relay Profile
SSEC	Space Science and Engineering Center
STC	Skills Training Center
TFCP	Transmission Falling Conductor Protection
TRAQ	Tree Risk Assessment Qualification
TWRS	Total Wildfire Risk Score
UCLA	University of California Los Angeles
UICS	Utility Incident Command System
μm	micrometer
VMA	Vegetation Management Area
VRI	Vegetation Risk Index
WASA	Wide Area Situational Awareness
WCAG	Web Content Accessibility Guidelines
WDD	Wire Down Detection
WECC	Western Energy Coordinating Council
WFA-E	Wildfire Analyst-Enterprise
WFABBA	Wildfire Automated Biomass Burning Algorithm
WFI	Wireless fault indicator
WiNGS-Planning	Wildfire Next Generation System Planning
WiNGS-Ops	Wildfire Next Generation System for Operations
WIRC	Wildfire Interdisciplinary Research Center
WiSE	Wire Safety Enhancement
WMPMA	Wildfire Mitigation Plan Memorandum Account
WRF	Weather Forecasting and Research
WRRM	Wildfire Risk Reduction Model
WRRM-Ops	Wildfire Risk Reduction Model for Operations

WSCAC	Wildfire Safety Community Advisory Counci
WSD	Wildfire Safety Division
WUI	Wildland Urban Interface

Executive Summary

Safety is SDG&E's top value, and virtually no activity implicates safety more than wildfire prevention and mitigation. SDG&E has focused on wildfire prevention and mitigation activities for more than a decade, continually striving to be the industry leader in this area. In the aftermath of the catastrophic October 2007 wildfires in SDG&E's service territory and across Southern California, SDG&E dedicated itself to revamping and enhancing its wildfire prevention and mitigation measures across a wide spectrum of disciplines and activities. Many of those initiatives were undertaken without any precedent or road map for SDG&E to follow. Building on expertise developed over a decade, several of the initiatives described in this 2022 Wildfire Mitigation Plan (WMP) Update, such as hardening the overhead electric system, are an outgrowth of the efforts that began after the October 2007 wildfires.

The COVID-19 pandemic and associated issues with the global supply chain and resource constraints continued to present significant societal challenges in 2021. At the same time, catastrophic wildfires continued to threaten communities and the environment. The 2021 Dixie Fire was the second largest wildfire and largest single (non-complex) wildfire in California's history, surpassed only by 2020's August Complex Fire. In total, 2021 saw over 2.5 million acres burned across California. Unfortunately, these tragic wildfires caused deaths and the destruction of property and natural resources.

In San Diego Gas & Electric Company's (SDG&E's) service territory, the most significant fire of 2021 was the Southern Fire, burning 5,366 acres and leading to the destruction of four structures. While the ignition of the Southern Fire was not linked to utility equipment, the consequences of any wildfire reinforce the continued importance of increased efforts to mitigate the risk of climate-change-driven catastrophic wildfires in California, including potential utility-caused wildfires.

SDG&E's wildfire mitigation efforts build upon its initial foundation of initiatives developed after the 2007 wildfires and in response to the evolving wildfire risk presented by climate change. For instance, SDG&E developed an in-house meteorology team to enable the Company to undertake advanced preparations for severe weather events, building the first of its kind network of dense, utility-owned weather stations to provide detailed weather data across the service territory, which informs day-to-day operational decision-making at all levels. Additionally—and as a last resort when conditions warrant—SDG&E pioneered the use of de-energization (i.e., Public Safety Power Shutoffs or PSPS) to protect the public from major wildfires. SDG&E openly shared its experience, lessons learned, and technological advancements in weather and wildfire mitigation with other investor-owned utilities (IOUs), state agencies, and stakeholders in the fire community, with the objective of improving wildfire prevention across California and the West.

An effective wildfire mitigation program includes a safe and hardened electrical grid that is rigorously inspected and maintained. Informed by meteorological data, SDG&E developed design standards by considering the localized wind conditions for grid hardening. While SDG&E already utilized Power Line Systems – Computer Aided Drafting and Design (PLS-CADD) design tools for its transmission line designs, it began applying this tool to its grid hardening work for its distribution system, which improved modeling and designs.

SDG&E also developed the Wildfire Risk Reduction Model (WRRM) to enable risk assessment and prioritize its distribution grid hardening approach. SDG&E has shared this work with other utilities, leading to a similar statewide approach. The WRRM Operations (WRRM-Ops) tool continued to advance the use of the WRRM model to understand fire propagation and is used during live fire incidents. And SDG&E developed the WiNGS-Planning model to help provide an understanding of the fire risk at a more granular level across the service territory and aid in informing which mitigations should be applied in which areas. In the last two years, and to reduce Public Safety Power Shutoff impacts to SDG&E's customers, grid hardening efforts have incorporated strategic undergrounding of the distribution system in the High Fire Threat District (HFTD) and instituted generator programs for some of the customers experiencing PSPS events.

Wildfire mitigation and fire safety are community endeavors, thus SDG&E partners with stakeholders in public safety, academia, and the private sector to collaborate on safety efforts and promote community outreach. SDG&E has continued its culture of engagement with the communities who live in the HFTD through Wildfire Safety Fairs and community meetings. Outreach and collaboration with community safety partners led to the development of robust communications and a camera network to assist fire agencies serving in the HFTD areas. Among the many stakeholder collaboration activities, SDG&E established a Wildfire Safety Community Advisory Council (WSCAC) comprised of leaders from the following groups in the San Diego region: public safety partners, communications and water service providers, local and tribal government officials, business groups and non-profits, Access and Functional Needs (AFN) and vulnerable communities, and academic organizations. These meetings are held quarterly and are highly regarded as an effective means to discuss wildfire issues and receive input from WSCAC members on relevant emerging community issues on wildfire safety and preparedness.

A main driver for SDG&E's continued advancement in wildfire mitigation is its cultural commitment to wildfire safety. Wildfire safety is woven into the way SDG&E performs risk assessment, continues to evaluate different methods to improve situational awareness, collaborates with community safety partners, and seeks input from various stakeholders and employees. SDG&E's 2021 Safety Culture Assessment highlighted this culture as shown by the positive results. SDG&E continues to implement the recommendations of the Safety Culture Assessment and recommendations for improvement. And the Company seeks continuous improvements in wildfire safety culture to better develop methods by which to gather input and implement ideas, especially from employees directly working on wildfire mitigation work.

As highlighted below, SDG&E will continue to innovate and improve wildfire mitigation initiatives to promote community safety through situational awareness, prevention, communication, and collaboration.

Risk Assessment and Mapping

SDG&E continues to advance its maturity in risk modeling to better understand the probability and consequence of ignition along its infrastructure. The Probability of Ignition (PoI) models were developed to increase the accuracy and granularity of data available. The WiNGS-Planning model was operationalized as WiNGS-Ops to support and quantify decision-making during PSPS events. SDG&E has begun the process of automating and transitioning models to the cloud. This transition will allow for the connection of multiple data sets and more granular models to be run on an hourly basis during high-risk situations such as Red Flag Warnings (RFWs)or PSPS events.

Situational Awareness and Forecasting

The fire season in 2021 seemed to pick up right where the record-setting year of 2020 had left off. Winter rainfall across the region was well below normal (approximately 50 percent), which further exacerbated drought conditions, setting the stage for another highly active wildfire season. And as expected, well above normal wildfire activity developed again in 2021. SDG&E was well prepared for the fire conditions due to the continuous enhancements made to its situational awareness and forecasting capabilities before the start of the season. Looking ahead to 2022, SDG&E is preparing for another active wildfire year. Despite recent improvements to the drought severity across California due to the significant rainfall in December 2021, official National Weather Service outlooks are still calling for an overall warm and dry start to 2022.

SDG&E’s Weather Station Network, the world’s first utility-owned network of its kind, is foundational to SDG&E’s ability to understand and predict the potential impact of extreme fire weather events and the localized impacts on communities in the service territory. The additional information generated by this equipment, which is shared with first responders and academia, enables SDG&E to further sectionalize circuits and decrease the footprint of PSPS events when weather conditions permit. In 2021, SDG&E upgraded 43 additional weather stations to enable wind speed reporting every 30 seconds rather than every 10 minutes. This additional data demonstrated that in many cases high wind gusts were brief and isolated in nature such that de-energizations were not necessary, decreasing the total customers impacted by PSPS during those weather events.

In 2021, SDG&E expanded upon the lessons learned in 2020 and integrated its artificial intelligence (AI) forecasting system across 190 weather stations, providing the latest available forecasting technology to help serve communities in the highest risk fire areas. SDG&E’s ability to implement this technology stems from recording weather observations every 10 minutes for over 10 years, collecting one billion observations to train AI. Additionally, as more data is collected each year, more data can be integrated back into the forecasting system to improve the model. These new predictive technology models help increase the accuracy of weather forecasts, which are shared with the public and fire agencies. Due to the continued success and performance of this forecasting methodology in 2021, SDG&E will continue to build and expand this program moving forward.

The Artificial Intelligence (AI) smoke detection algorithm was implemented in 2021. This information is critical to identifying fires soon after ignition by operationalizing satellite fire detection coupled with mountaintop cameras. These space-based fire alerts are sent to the San Diego Supercomputing Center (SDSC) in real time where they are processed for relevance within established boundary conditions and filtered for false positives. The ignition data is then sent to SDG&E within 5 minutes as an email that includes a link to a web-based map of the area and camera images auto triangulated on the fire.

2021 also saw the development of an initiative to install particulate sensors measuring the Air Quality Index (AQI). Particulates contained in wildfire smoke are hazardous to employees and the public. SDG&E’s AQI Program will install particulate sensors and an automatic notification system built on the backbone of SDG&E’s existing best-in-class Weather Station Network. Real-time AQI values for townships in San Diego County will be available on the Fire Science and Climate Adaptation (FS&CA) App. The app will also have the option of sending poor air quality alerts to personnel once dangerous levels are detected.

Grid Design and System Hardening

SDG&E's grid hardening initiatives first began after the 2007 fires in its service territory. Since then, SDG&E has completed hardening over 400 miles of transmission lines and over 900 miles of distribution lines. With a focus on wildfire risk and reducing PSPS impacts, several grid hardening milestones were achieved in 2021. SDG&E continues to transition its distribution hardening from bare conductor hardening towards covered conductor and undergrounding. SDG&E completed 100 miles of bare conductor hardening, 20 miles of covered conductor, and 25 miles of strategic undergrounding, meeting the targets set forth in the 2021 WMP Update.

SDG&E also implemented initiatives to reduce the impacts of PSPS impacts on customers. In 2021, the Generator Grant Program (GGP) provided over 2,300 portable battery-powered backup generators to customers enrolled in Medical Baseline (MBL). The Generator Assistance Program provided the opportunity for over 55,000 customers in Tiers 2 and 3 of the HFTD to download an instant rebate coupon to aid in the purchase of an off-the-shelf portable backup generator. Over 700 customers benefitted from the coupons and ultimately made a purchase in 2021. The final component of SDG&E's backup generator strategy focuses on permanent backup generation for customers who reside in areas most prone to PSPS events and least likely to benefit from other, more costly, grid-hardening initiatives. In 2021, SDG&E installed over 350 permanent propane-powered backup generators for customers in Tier 3 of the HFTD that seamlessly transition from grid power to generator power through an automatic transfer switch. Additionally, SDG&E's four microgrid locations were upgraded in 2021, removing the temporary generators and installing renewable power solutions. New solutions such as a mobile battery storage unit and box power units were also deployed to aid in mitigating the impacts of PSPS events for critical customers.

Asset Management and Inspections

To prevent wildfires and safely operate its grid, SDG&E conducts various mandatory and discretionary asset management and inspection programs to enable identification and repair of equipment conditions. These programs include detailed cyclical inspections, infrared inspections, intrusive wood pole inspections, light detection and ranging (LiDAR) surveys, additional HFTD Tier 3 focused inspections, drone inspections, annual aerial and ground patrols, and quality assurance of inspections. 2021 saw the expansion of drone inspections on the distribution system into Tier 2. In 2021 SDG&E completed drone inspections on approximately 1,000 transmission structures and over 21,000 distribution structures. SDG&E also completed infrared inspections for approximately 17,000 distribution structures.

SDG&E also began to collect updated LiDAR data across the HFTD in 2021. The project is expected to capture updated data for over 4,000 miles of distribution circuits. This data will be leveraged to provide detailed power line analysis for pre-construction design and post-construction survey, increasing both system reliability and safety. SDG&E will also utilize the LiDAR data to perform vegetation analysis, identifying trees with strike potential and areas of high-risk due to clearance from power lines.

Vegetation Management and Inspections

SDG&E continues to enhance its vegetation management activities to address wildfire risk. In 2021, the Vegetation Management program continued its success by conducting the activities of tracking and maintaining its inventory tree database, completing routing and enhanced patrols, pruning and removing hazardous trees, replacing unsafe trees with species compatible with powerlines, and pole brushing. This resulted in inspections of over 500,000 trees, trimming over 175,000 trees, and removing over 5,000 trees. Enhanced clearances from greater than 12 feet and up to 25 feet where possible were achieved for targeted species, leading to over 12,000 targeted trees trimmed to greater than 12 feet within the HFTD. Pole brushing was completed on over 35,000 poles.

To build upon its existing program promoting the planting of trees compatible with wildfire safety and powerlines, SDG&E expanded its Right Tree Right Place Program and began implementation of a 10,000 tree-planting goal in conjunction with the Company's overall sustainability initiative. This included collaboration and partnership with agencies, municipalities, tribal lands, and private landowners to provide trees to enhance environmental quality, combat climate change, enrich customer relationships, and help cities reach climate action goals. SDG&E also engaged a new certified vendor that processes 100 percent of vegetation-management-related material received into recyclable streams, resulting in an increase in the amount of material diverted from landfills and a further reduction of the carbon footprint related to tree trimming efforts. Current percentage of total green waste diverted to recycling facilities is now approximately 46 percent.

Grid Operations and Protocols

When elevated or extreme fire weather conditions are forecasted, SDG&E remotely enables Sensitive Relay Profile (SRP) on its system, which is designed to make dynamic protective devices such as reclosers and circuit breakers more sensitive to faults on the overhead distribution system so they can activate quickly to interrupt power. SDG&E pre-identifies and maintains a list of these devices and can quickly communicate with its distribution operations control center to enable SRP when conditions warrant and in observance of wildfire safety efforts. SDG&E has an existing a tool that supports a yearly analysis of every device in Tier 2 or Tier 3 of the HFTD to flag SRP setpoints that need to be verified due to changing load in the region. In 2021, reviews and updates were completed for approximately 250 devices including approximately 60 new devices, improving sectionalization and maintaining optimal operational logic for SRP. Improvements were also made to address offline SCADA switches with 33 devices identified and repaired prior to peak PSPS-event season.

SDG&E's Aviation Firefighting Program incorporated several improvements in 2021, including a partnership with CAL FIRE for night firefighting. While the demands and requirements are determined by CAL FIRE, SDG&E began night currency and proficiency flights for pilots to gain confidence and familiarity with night operations. SDG&E took ownership of a Sikorsky S-70M (Firehawk), which will serve as a lead aerial firefighting resource once it is outfitted with firefighting capability. Operations with the Firehawk will be more capable and safer compared to the current Blackhawk due to advanced safety systems and enhanced performance characteristics. The Firehawk will have a 1,000-gallon water drop capacity.

Data Governance

SDG&E's data governance initiatives encompass both its enterprise-wide efforts and efforts specific to wildfire mitigation and prevention. The enterprise-wide initiative seeks to build a central data repository and establish an asset data foundation integrating key asset-related attributes to enable predictive health analyses and risk modeling and improve inspection/assessment strategies and prioritization. In 2021 a central repository reporting strategy was developed which leverages common data sources to meet the requirements of Energy Safety's non-spatial and GIS spatial reporting requirements. Additional progress was also made to automate the data collection for the Quarterly Data Reports (QDRs).

With respect to wildfire mitigation, SDG&E established a data governance structure in 2020, creating the Mitigation, Measures, and Metrics area within its Wildfire Mitigation department. This group developed a weekly electronic dashboard that depicts the wildfire-related metrics established by Energy Safety as a measure of effectiveness of the WMP; summarizes the progress of programs and initiatives under the WMP; details the capital and O&M spend on the WMP programs; provides trending on the overall effectiveness of the WMP; and includes numerous statistics on SDG&E's wildfire-related programs.

In 2021, SDG&E also improved the Ignition Management Program (IMP) which gathers information on ignitions and near-ignitions. Work continued on the automation and collection of the data, which was also used to inform the newly developed PoI models to gain better understanding of the wildfire risk in the service territory.

Resource Allocation Methodology

SDG&E's resource allocation process is best described in terms of an enterprise-level methodology and a program-level methodology. Both complement each other and use the same frameworks to evaluate projects. The enterprise-level methodology includes the Investment Prioritization tool that is being developed by SDG&E's Asset Management business unit to aid with the allocation of capital resources across SDG&E's electric asset classes, while WiNGS-Planning, the program-level methodology developed by SDG&E's Wildfire Mitigation department, applies a more granular approach to targeting the implementation of programs such as grid hardening. Accomplishments in risk assessment models go hand in hand with improving resource allocation methodologies—as better risk models are built and more information about risks become available, the approach to targeting mitigations can be further refined to address the areas of highest concern.

In 2021, SDG&E continued programming the Investment Prioritization tool as a full software solution. Sample entries for transmission and substation portfolios were performed and development began on the electric distribution value framework. Additionally, WiNGS-Planning was expanded to create WiNGS-Ops to quantify PSPS risks and assist with real-time decision making during PSPS events. WiNGS-Planning continues to be used to scope and prioritize future covered conductor and undergrounding projects. Additional enhancements were made to begin automation of WiNGS-Planning elements and develop lifecycle cost analysis for these projects.

Emergency Planning and Preparedness

SDG&E's Emergency Management business unit coordinates safe and effective emergency preparedness for the Company, customers, and emergency response personnel. In 2021, to respond appropriately to any incident while adhering to COVID-19 protocols, SDG&E's Emergency Operations Center (EOC) continued to consist of tiered staffing plans with a largely virtual response.

The EOC was activated for all 365 days in 2021 due to COVID-19 and 27 days for the following events:

- Fire-related and PSPS incidents – 8 days
- Mutual Assistance to other utilities – 15 days
- Other – 4 days

Each of these events was followed by a comprehensive After-Action Review (AAR) process, which included workshops with both internal and external stakeholders to gather lessons learned to inform any corrective actions.

When a potential PSPS event is identified, SDG&E follows customer notification cadences mandated by the CPUC, notifying public safety partners and critical facility operators prior to impacted customers and communities. These communications begin up to 72 hours prior to a potential de-energization and are sent using SDG&E's Enterprise Notification System via email, text, and phone call to customers for whom the utility has contact information. SDG&E takes additional measures to ensure all MBL customers are notified prior to an interruption in power. This process involves calls from live agents in the Customer Care Center and subsequent "door knocks," in which a Customer Service Field employee will visit the place of residence and personally inform the MBL residents regarding the potential for a PSPS.

In 2021, SDG&E improved its communication efforts by partnering with and expanding its Tribal and AFN campaigns to communicate with a greater number of hard-to-reach vulnerable populations. SDG&E worked with the Indian Health Council and Southern Indian Health Council to identify needs during PSPS events, and partnered with these organizations to address those needs (e.g., generators, resiliency items, etc.). SDG&E also continued holding drive-through Wildfire Safety Fairs that attracted over 2,400 HFTD residents. PSPS event notifications were improved to be more accessible by including a video with American Sign Language interpretation and an audio read-out. Additionally, to expand reach into under-represented communities, SDG&E conducts its public education efforts in the prevalent languages in its service territory.

Stakeholder Cooperation and Community Engagement

SDG&E recognizes that collaboration, the sharing of best practices, and the exchange of lessons learned is of the utmost importance to protect public safety. SDG&E regularly solicits feedback from communities it serves in an effort to identify gaps in processes, communications, and partnerships. This feedback is analyzed as part of an iterative improvement process.

To date, SDG&E has established a Community Based Organization (CBO) network comprised of over 400 organizations, each serving a critical role in connecting SDG&E with its constituencies. This includes the County of San Diego Office of Emergency Services (County OES) AFN Working Group and the Partner Relay Network. In 2021, SDG&E continued to build on the 2020 education efforts for customers with AFN and launched an enhanced a dedicated campaign in April. This campaign promoted available solutions to customers via SDG&E's partnerships with entities such as 211, Facilitating Access to Coordinated Transportation (FACT), and the Salvation Army to provide access to resources such as transportation, hotel stays, and meals.

1 Persons Responsible for Executing the WMP

Instructions:[1] *Provide an accounting of the responsibilities of the responsible person(s) executing the plan, including:*
1. *Executive level with overall responsibility*
2. *Program owners specific to each component of the plan*

Title, credentials and components of responsible person(s) must be released publicly, but other contact information may be provided in a redacted file attached to the WMP submission.

Wildfire mitigation at San Diego Gas & Electric (SDG&E) is a Company-wide, inter-departmental effort involving resources and programs across utility functions. Consistent with the instructions, SDG&E provides the names and titles of the program owners specific to each component of this 2022 Wildfire Mitigation Plan Update (2022 WMP Update). This information is accurate as of February 11, 2022, and may change due to employee movement and attrition.

Executive-level owner with overall responsibility

Name, Title	John D. Jenkins, Vice President-Electric System Operations
Email	JJenkins@sdge.com
Phone	(858)654-8627

Program owners specific to each section of the plan

Table 1-1 provides the program owner for each section of the 2022 WMP Update. For any questions related to this WMP Update or the activities described herein, SDG&E's designated single point of contact is Kellen Gill, Regulatory Business Manager (kgill@sdge.com, (619) 696-2972).

Table 1-1: WMP Section Program Owners

Name	Title	Email	Phone Number	Component
Section 1: Persons responsible for executing the plan				
Jonathan Woldemariam	Director – Wildfire Mitigation and Vegetation Management	JWoldemariam@sdge.com	(858) 650-4084	Entire Section
Section 2: Adherence to statutory requirements				
Kellen Gill	Regulatory Business Manager	KGill@sdge.com	(619) 696-2972	Entire Section
Section 3: Actuals and planned spending				
Shaun Gahagan	Wildfire Mitigation Program Manager	SGahagan@sdge.com	(858) 503-5124	Entire Section
Section 4: Lessons learned and risk trends				
Nisha Menon	Wildfire Mitigation Regulatory Analytics Team Lead	NMenon@sdge.com	(858) 654-8237	Entire Section

[1] Text in orange text boxes are instructions, prompts, and clarifications from Resolution WSD-011, Attachment 2.2 – 2021 Wildfire Mitigation Plan Guidelines Template (November 2020), as modified by the WSD on January 5, 2021, January 22, 2021, and January 25, 2021.

Name	Title	Email	Phone Number	Component
Section 5: Inputs to the Plan and Directional Vision				
Nisha Menon	Wildfire Mitigation Regulatory Analytics Team Lead	NMenon@sdge.com	(858) 654-8237	Entire Section
Section 6: Metrics and Underlying Data				
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Section 7: Mitigation Initiatives				
Jonathan Woldemariam	Director – Wildfire Mitigation and Vegetation Management	JWoldemariam@sdge.com	(858) 650-4084	Section 7.1 Section 7.2 Section 7.3.5 Section 7.3.6 Section 7.3.7
Shaun Gahagan	Wildfire Mitigation Program Manager	SGahagan@sdge.com	(858) 503-5124	Section 7.3.3 Section 7.3.4
Nisha Menon	Wildfire Mitigation Regulatory Analytics Team Lead	NMenon@sdge.com	(858) 654-8237	Section 7.3.1 Section 7.3.8
Brian DAgostino	Director – Fire Science and Climate Adaptation	BDAgostino@sdge.com	(858) 650-4084	Section 7.3.2 Section 7.3.10
Thom Porter	Director – Emergency Management	TPorter@sdge.com	(619) 676-4286	Section 7.3.9
Section 8: Public Safety Power Shutoff				
Jonathan Woldemariam	Director – Wildfire Mitigation and Vegetation Management	JWoldemariam@sdge.com	(858) 650-4084	Entire Section
Section 9: Appendix				
Jonathan Woldemariam	Director – Wildfire Mitigation and Vegetation Management	JWoldemariam@sdge.com	(858) 650-4084	Entire Section

1.1 Verification

I am an officer of the applicant corporation herein, and am authorized to make this verification on its behalf. The statements in the foregoing document are true of my own knowledge, except as to matters which are therein stated on information or belief, and as to those matters I believe them to be true.

I declare under penalty of perjury that the foregoing is true and correct.

Executed on February 11, 2022 at San Diego, California.

____

John D. Jenkins
Vice President – Electric System Operations
San Diego Gas & Electric Company

2 Adherence to Statutory Requirements

***Instructions:** Section 2 comprises a "check list" of the Pub. Util. Code § 8386 © requirements and subparts. The utility is required to both affirm that the WMP addresses each requirement AND cite the section and page number where statutory compliance is demonstrated fully. Citations are required to use cross-referencing with hyperlinks.*

Note: Energy Safety reserves the right to automatically reject a WMP that does not provide substantiation for statutory compliance or does not provide citations to appropriate sections of the WMP.

Table 2-1: Statutory Requirements Checklist

Requirement	Description	WMP Section and Page Number
1	An accounting of the responsibilities of person(s) responsible for executing the plan	Section 1, pg. 8
2	The objectives of the plan	Section 5.2, pg. 144
3	A description of the preventive strategies and programs to be adopted by the electrical corporation to minimize the risk of its electrical lines and equipment causing catastrophic wildfires, including consideration of dynamic climate change risks	Section 7.3, pg. 195
4	A description of the metrics the electrical corporation plans to use to evaluate the plan's performance and the assumptions that underlie the use of those metrics	Section 5.3, pg. 150
5	A discussion of how the application of previously identified metrics to previous plan performances has informed the plan	Section 4.1, pg. 18
6	Protocols for disabling reclosers and deenergizing portions of the electrical distribution system that consider the associated impacts on public safety. As part of these protocols, each electrical corporation shall include protocols related to mitigating the public safety impacts of disabling reclosers and deenergizing portions of the electrical distribution system that consider the impacts on all of the aspects listed in PU Code 8386c	Section 7.3.6.1, pg. 305 Section 8.2, pg. 354
7	Appropriate and feasible procedures for notifying a customer who may be impacted by the de-energizing of electrical lines, including procedures for those customers receiving a medical baseline allowance as described in paragraph (6). The procedures shall direct notification to all public safety offices, critical first responders, health care facilities, and operators of telecommunications infrastructure with premises within the footprint of potential de-energization for a given event	Section 7.3.10.1.1
8	Identification of circuits that have frequently been de-energized pursuant to a de-energization event to mitigate the risk of wildfire and the measures taken, or planned to be taken, by the electrical corporation to reduce the need for, and	Section 8.3, pg.364 Section 8.6, pg. 369

Requirement	Description	WMP Section and Page Number
	impact of, future de-energization of those circuits, including, but not limited to, the estimated annual decline in circuit de-energization and de-energization impact on customers, and replacing, hardening, or undergrounding any portion of the circuit or of upstream transmission or distribution lines	
9	Plans for vegetation management	Section 7.3.5, pg. 273
10	Plans for inspections of the electrical corporation's electrical infrastructure	Section 7.3.4, pg. 244
11	Protocols for the de-energization of the electrical corporation's transmission infrastructure, for instances when the de-energization may impact customers who, or entities that, are dependent upon the infrastructure	Section 8.2, pg. 354
12	A list that identifies, describes, and prioritizes all wildfire risks, and drivers for those risks, throughout the electrical corporation's service territory, including all relevant wildfire risk and risk mitigation information that is part of the Safety Model Assessment Proceeding and the Risk Assessment Mitigation Phase filings	Section 4.3, pg. 45
13	A description of how the plan accounts for the wildfire risk identified in the electrical corporation's Risk Assessment Mitigation Phase filing	Section 4.2, pg. 26 Section 7.1.1, pg. 182 Section 7.1.2, pg. 183
14	A description of the actions the electrical corporation will take to ensure its system will achieve the highest level of safety, reliability, and resiliency, and to ensure that its system is prepared for a major event, including hardening and modernizing its infrastructure with improved engineering, system design, standards, equipment, and facilities, such as undergrounding, insulation of distribution wires, and pole replacement	Section 5.2, pg. 144
15	A description of where and how the electrical corporation considered undergrounding electrical distribution lines within those areas of its service territory identified to have the highest wildfire risk in a commission fire threat map	Section 7.3.3.16, pg. 230
16	A showing that the electrical corporation has an adequately sized and trained workforce to promptly restore service after a major event, taking into account employees of other utilities pursuant to mutual aid agreements and employees of entities that have entered into contracts with the electrical corporation	Section 5.4, pg. 158 Section 7.3.9.1, pg. 325 Section 7.3.9.5, pg. 336
17	Identification of any geographic area in the electrical corporation's service territory that is a higher wildfire threat than is currently identified in a commission fire threat map, and where the commission must consider expanding the high fire threat district based on new information or changes in the environment	Section 4.2.1, pg. 42

Requirement	Description	WMP Section and Page Number
18	A methodology for identifying and presenting enterprise-wide safety risk and wildfire-related risk that is consistent with the methodology used by other electrical corporations unless the commission determines otherwise	Section 4.2, pg. 26
19	A description of how the plan is consistent with the electrical corporation's disaster and emergency preparedness plan prepared pursuant to Section 768.6, including plans to restore service and community outreach	Section 7.3.9.4, pg. 335
20	A statement of how the electrical corporation will restore service after a wildfire	Section 7.3.9.5, pg. 336 Section 8.2, pg. 354
21	Protocols for compliance with requirements adopted by the commission regarding activities to support customers during and after a wildfire, outage reporting, support for low-income customers, billing adjustments, deposit waivers, extended payment plans, suspension of disconnection and nonpayment fees, repair processing and timing, access to electrical corporation representatives, and emergency communications	Section 7.3.9.3, pg. 331
22	A description of the processes and procedures the electrical corporation will use to do the following: A. Monitor and audit the implementation of the plan. B. Identify any deficiencies in the plan or the plan's implementation and correct those deficiencies. C. Monitor and audit the effectiveness of electrical line and equipment inspections, including inspections performed by contractors, carried out under the plan and other applicable statutes and commission rules.	Section 7.2.1, pg. 192 Section 7.2.2, pg. 193 Section 7.2.3, pg. 194 Section 7.3.4.14, pg. 272 Section 7.3.5.13, pg. 293

3 Actuals and Planned Spending for Mitigation Plan

3.1 Summary of WMP Initiative Expenditures

***Instructions:** In the Table 3-1, summarize the projected costs (in thousands of US $) per year over the three-year WMP cycle, including actual expenditures for past years. In Table 3.1-2, break out projected costs per category of mitigations, over the three-year WMP plan cycle. In reporting "planned" expenditure, use data from the corresponding year's WMP or WMP Update (i.e., 2020 planned expenditure must use 2020 WMP data). The financials represented in the summary tables below equal the aggregate spending listed in the mitigations financial tables reported quarterly. Nothing in this document is required to be construed as a statement that costs listed are approved or deemed reasonable if the WMP is approved, denied, or otherwise acted upon.*

Table 3-1.1: Summary of WMP Expenditures - Total

Year	Spend in thousands of $USD
2020 Planned	$444,544
2020 Actual	$569,237
2020 Difference	$124,693
2021 Planned	$646,466
2021 Actual	$543,912
2021 Difference	($102,554)
2022 Planned	$770,393
2020-22 Planned (With 2020 and 2021 Actual)	$1,883,542

Table 3-2: Summary of WMP Expenditures by Category[2]

WMP Category	2020			2021			2022	2020-2022 Planned (w/ 2020 and 2021 Actuals)
	Planned	Actual	Change	Planned	Actual	Change	Planned	
Risk and Mapping	$1,400	$1,191	($209)	$1,539	$1,446	($93)	$4,554	$7,191
Situational Awareness	$6,845	$5,890	($955)	$7,914	$4,345	($3,569)	$10,652	$20,887
Grid Design and System Hardening	$265,972	$343,782	$77,810	$415,358	$333,476	$(81,882)	$476,390	$1,153,649
Asset Management and Inspections	$56,790	$81,591	$24,801	$68,357	$65,486	($2,871)	$95,402	$242,479
Vegetation Management	$62,322	$79,264	$16,942	$71,639	$61,877	($9,762)	$68,877	$210,018
Grid Operations	$20,167	$17,110	($3,057)	$20,731	$23,557	$2,826	$36,227	$76,894
Data Governance	$315	$7,480	$7,165	$22,693	$10,614	($12,079)	$22,259	$40,353
Resource Allocation	$11,985	$5,342	($6,643)	$7,387	$5,299	($2,088)	$4,786	$15,427
Emergency Planning	$13,821	$14,353	$532	$17,626	$21,839	$4,213	$34,221	$70,412
Stakeholder Cooperation and Community Engagement	$4,928	$13,234	$8,307	$13,222	$15,973	$2,751	$17,026	$46,233
Total	**$444,544**	**$569,237**	**$124,693**	**$646,466**	**$543,912**	**($102,554)**	**$770,393**	**$1,883,542**

[2] This table is numbered 3.1-2 in the 2022 WMP Guidelines.

3.2 Summary of Ratepayer Impact

Instructions: *For each of the years in Table 3.2-1, report the actual and projected cost increases to ratepayers due to utility-related ignitions and wildfire mitigation activities engaged. For past years, account for all expenditures incurred in that year due to utility-related ignitions and wildfire mitigation activities. Below the table, describe the methodology behind the calculations.*

SDG&E has not incurred costs due to a utility-ignited wildfire during the 2016-2021 timeframe. SDG&E's wildfire mitigation activities forecasted prior to 2019 are currently recovered through its 2019 General Rate Case (GRC).[3] Since the passage of Senate Bill 901 and Assembly Bill 1054, SDG&E has recorded wildfire mitigation expenditures incremental to its authorized revenue requirement in CPUC-authorized memorandum accounts, including its Wildfire Mitigation Plan Memorandum Account (WMPMA), the Fire Risk Mitigation Memorandum Account (FRMMA), and other cost recovery mechanisms. SDG&E anticipates that, consistent with the direction of AB 1054, cost recovery for expenditures related to the WMP will be addressed in its next GRC.

Pending its next GRC, in 2021, SDG&E requested that the CPUC review and approve an interim rate relief mechanism by which SDG&E might begin to collect 50% of the balances recorded in its WMPMA, subject to refund after a final reasonableness determination by the CPUC. That Application, (A).21-07-07, is pending and a decision is anticipated sometime in 2022. If approved, SDG&E expects to implement the interim rate relief mechanism sometime in 2022. To that end, SDG&E has included the forecasted rate impacts of interim relief, consistent with those initially provided to the CPUC with its Application, in the chart below. These forecasted impacts are subject to change depending on many factors, including but not limited to CPUC approval of the interim rate relief mechanism and the form thereof, and the final recorded balances in the WMPMA.

Unless otherwise indicated, the bill impact is an estimate for a residential customer on basic service with a consumption of 400 kilowatt-hours (kWh)/month.

[3] D.19-09-051. SDG&E's GRC also authorized two-way balancing, subject to certain regulatory approval, for SDG&E's Tree Trimming Balancing Account (TTBA), which covers SDG&E's vegetation management activities.

Table 3-3: WMP Electricity Cost Increase to Ratepayers[4]

Outcome metric name	Annual Performance						Unit(s)
	Actual					Projected	
	2017	2018	2019	2020	2021	2022	
Increase in electric costs to ratepayer due to utility-related ignitions (total)	0	0	0	0	0	0	Dollar value of average monthly rate increase attributable to utility-related ignitions per year (e.g., $3/month on average across customers for utility-related ignitions occurring in 20XX)
Increase in electric costs to ratepayer due to wildfire mitigation activities (total)	0	0	1.32	2.26	0.00	1.92[5]	Dollar value of average monthly rate increase attributable to WMPs per year

[4] This table is numbered 3.2-1 in the 2022 WMP Guidelines.

[5] The projected 2022 increase in electric costs is related SDG&E's Interim Relief Mechanism, which remains subject to CPUC approval. For more information, see https://www.sdge.com/sites/default/files/regulatory/Wildfire%20Recover_Bill%20Insert.pdf

4 Lessons Learned and Risk Trends

4.1 Lessons Learned: How Tracking Metrics on the 2020 and 2021 Plans Informed the 2022 Plan Update

Instructions: *Describe how the utility's plan has evolved since the 2020 WMP and 2021 WMP Update submissions. Outline any major themes and lessons learned from the 2020 and 2021 plans, and subsequent implementation of the initiatives. In particular, focus on how utility performance against the metrics used has informed the 2022 WMP Update. Include an overview map of the utility's service territory. If any of the lessons learned are derived from data, include visual/graphical representations of this/these lesson(s) learned.*

SDG&E's wildfire mitigation efforts have continued to develop and evolve across all categories since the submission of the 2021 WMP Update. Areas of focus include the continuous enhancement of data analytics and modeling capabilities, continued evaluation of technologies and efficacy studies to assess various strategies for mitigating wildfire and PSPS risk, and enhancement of preparedness for Public Safety Power Shutoff (PSPS) events.

During 2021, SDG&E executives demonstrated their commitment to wildfire safety by creating a "double down" challenge to all Company leadership to identify and complete additional preparedness activities. This "double down" initiative yielded an additional 53 ideas. Key lessons learned from ongoing WMP initiatives as well as the "double down" challenge are included below.

4.1.1 Risk Assessment and Mapping

SDG&E continues to develop and mature models to better understand ignition probability, conductor risk, and estimations of wildfire consequences along electric lines and equipment. This enhanced understanding and more predictive modeling methods better inform operational decision making at SDG&E. As examples, during 2021, SDG&E learned:

- Developing Probability of Ignition (PoI) models with increasing granularity and accuracy is needed to continue to advance risk modeling capabilities.
- The Wildfire Next Generation System Planning (WiNGS-Planning) model can be operationalized, with the creation of Wildfire Next Generation System for Operations (WiNGS-Ops), to support decision making during PSPS events (refer to Section 4.5.1.8 Wildfire Next Generation System-Operations for visual aid reference).
- Wildfire Risk Reduction Model for Operations (WRRM-Ops) can be updated to generate consequence values that are incorporated directly into wildfire risk modeling efforts.
- Transitioning models to the cloud and upgrading high-performance computing infrastructure is needed to run granular models on an hourly basis. Additionally, the models need intensive computing power of cloud resources to run on-demand forecasts for the same assets and temporally, triggered by, but not limited to 72 hours prior to Red Flag Warning (RFW) notifications.
- Risk modeling automation will enable more real-time updates and facilitate what-if scenario planning.

- Circuit connectivity and conductor risk models support ongoing modeling of PSPS consequences, but more dynamic modeling is needed.

Refer to Section 7.3.1 Risk Assessment and Mapping for additional details on risk assessment and mapping initiatives.

4.1.2 Situational Awareness

Utilization of situational awareness tools such as weather stations, cameras, wireless fault indicators, and the Fire Potential Index (FPI) has proven beneficial to system planning, emergency operations, and the safe implementation of PSPS. During 2021, SDG&E learned:

- The Artificial Intelligence (AI) smoke detection algorithm is critical to identifying fires soon after ignition by operationalizing satellite fire detection coupled with mountaintop cameras. See Figure 4-1 for an example of a smoke detection image identified by the AI smoke detection algorithm from a mountaintop camera.
- The Machine Learning Wind Gust model for all High Fire Threat Districts (HFTDs) (189 out of 220 weather stations) is vital for situational awareness 72 hours prior to a RFW event. The circuit forecast is generated twice daily with updated weather models and the output is a 3-day forecast for each circuit associated weather station, delineating max gust and time for each day.
- There is a need for a technology strategy to support scalable complex modeling that performs dynamically in supporting operational decisions.

Figure 4-1: Smoke Detection Image identified by AI Smoke Detection Algorithm

Refer to Section 7.3.2 Situational Awareness and Forecasting for additional details on situational awareness initiatives.

4.1.3 Grid Design and System Hardening

SDG&E continues to analyze its electric system to develop longer-term strategies that consider the changing climate and increasing wildfire risk, with a continued focus on mitigating PSPS impacts to customers. During 2021, SDG&E learned:

- Grid Design and System Hardening research studies (see Section 4.4.2 Research Findings) showed that system faults were reduced over time due to hardening measures
- Accelerated remedies for 230kV infrastructure issues were implemented in the HFTD.
- Ability to underground certain areas can be heavily contingent upon effective alignment with telecommunication companies. Ongoing discussions with stakeholders are important to continue to pave the path for future mitigation efforts.
- Undergrounding can be implemented effectively at shallower depths, resulting in improved cost effectiveness.

Refer to Section 7.3.3 Grid Design and System Hardening for additional details on grid design and hardening initiatives.

4.1.4 Asset Management Inspections

SDG&E will continue to enhance its distribution and transmission inspection programs to identify potential issues not visible by traditional ground inspections, where terrain or other constraints may limit the ability to perform a detailed ground inspection or where the high-resolution imagery captured by drones provides better visibility of a potential fire hazard. In 2021, SDG&E learned:

- The use of drones for level 3 image capture (shots) could be eliminated as the shots captured were less effective for inspections, allowing the program to focus on the more effective level 1 and level 2 image types. The three types of drone shots are: Above the pole (level 1), At equipment/attachment height (level 2), and Below equipment/attachment (level 3). This change created more efficiency in the field, as the level 3 shot presented the highest level of difficulty in collection. After inspections were completed for the Tier 3 HFTD on approximately 39,000 poles, the data was analyzed to determine which shot was used by the inspectors to identify each issue type. Figure 4-2 shows Issues Found by Shot Type; Figure 4-3 shows Higher Threat Issues by Shot Type.
- The effectiveness of the Drone Investigation, Assessment and Repair (DIAR) Program, where a 62 percent reduction was observed in issues found during Corrective Maintenance Program (CMP) inspections in 2021 in the Tier 3 HFTD, despite a 20 percent increase in inspection of distribution poles.
- Distribution inspections using infrared technology found more circuit heat-risk issues in Tier 2 compared to the Tier 3. This is likely due to higher energy usage in increased population density areas that result in larger temperature differentials when issues were present.
- The Laguna Fire scar area was identified as an area of concern due to the terrain and available fuels. Additional distribution and transmission inspection patrols were completed and findings addressed.

- The Circuit Ownership platform created for field personnel to identify circuit vulnerabilities was proven obsolete due to the same data being captured by extensive existing and ongoing inspections including the DIAR program, QA/QC inspections, enhanced infrared inspections in HFTD, and pre- and post-PSPS-event patrols.

Figure 4-2: Issues Found by Shot Type

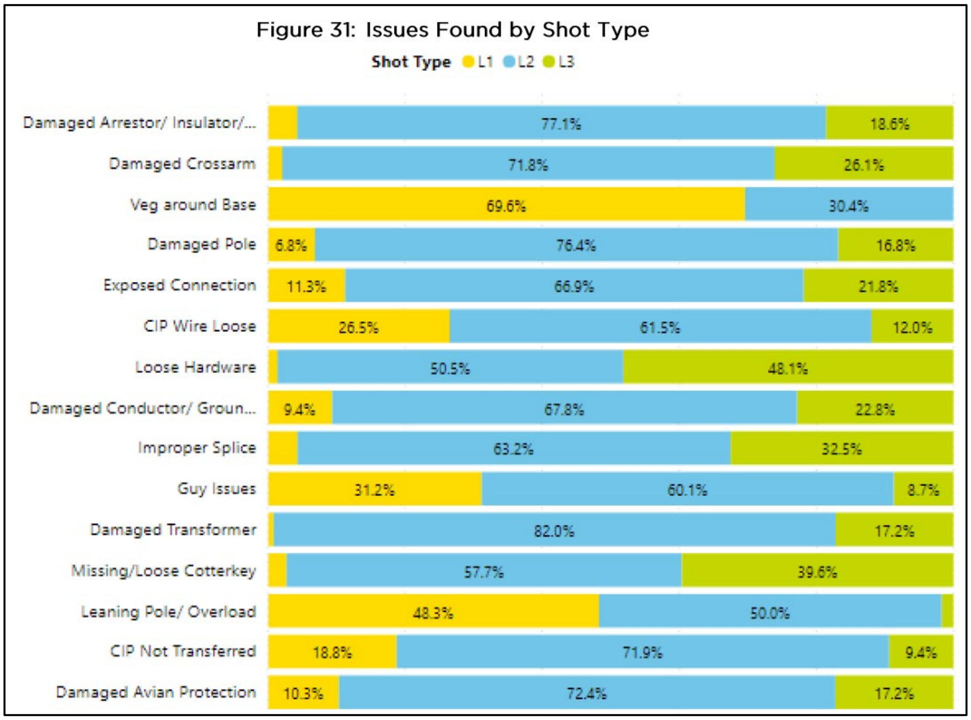
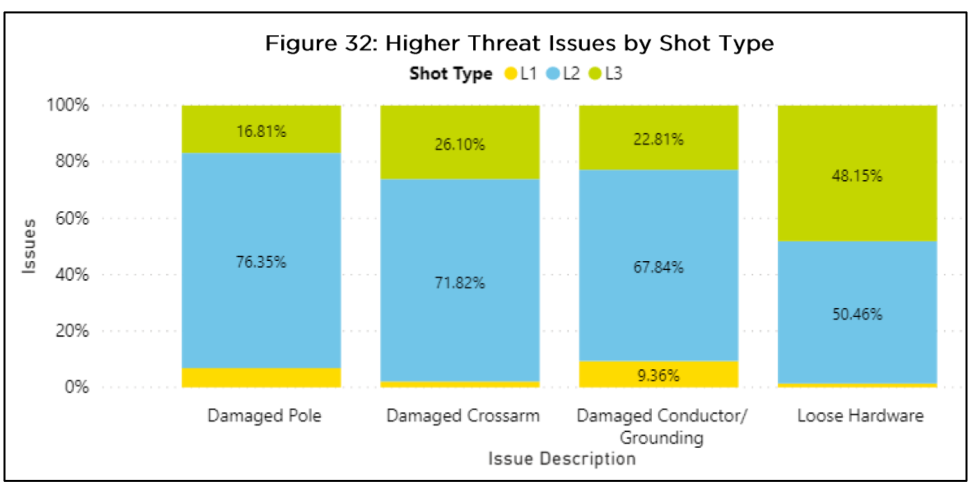


Figure 4-3: Higher Threat Issues by Shot Type



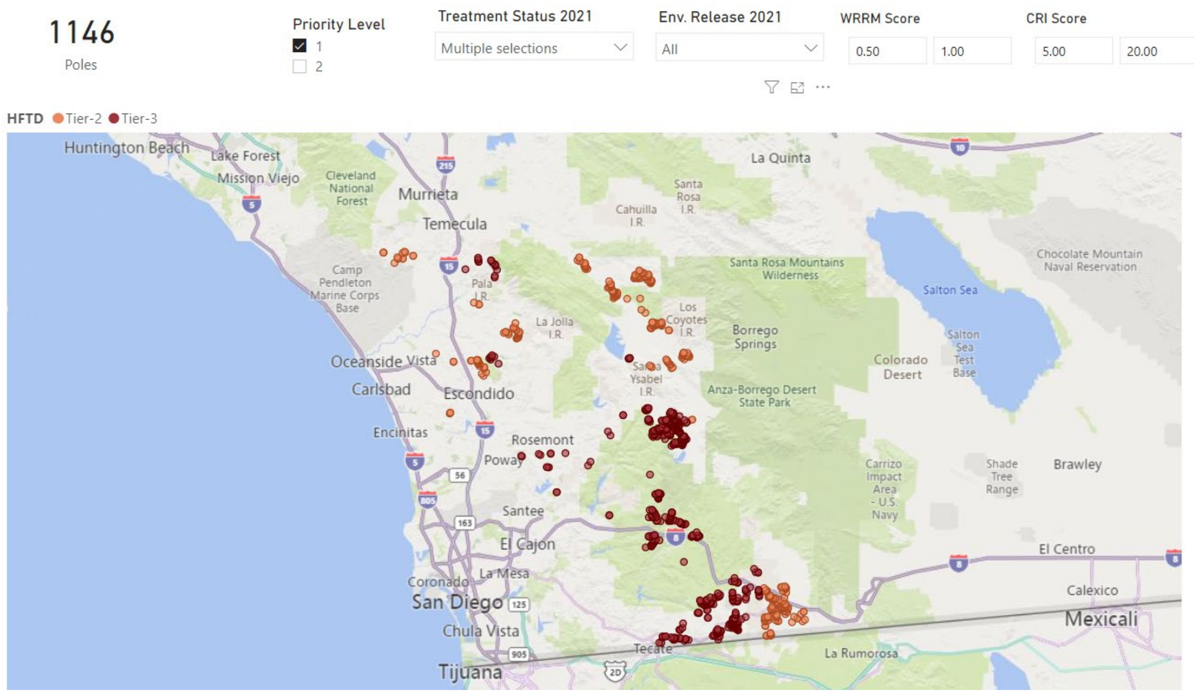
Refer to Section 7.3.4 Asset Management and Inspections for additional details on asset management inspection initiatives.

4.1.5 Vegetation Management and Inspections

The Fuels Management Program involves three activities: fuels modification, vegetation abatement, and fuels reduction grants. In 2021, SDG&E learned:

- The fuels modification involves the mechanical thinning of vegetation in a 50-foot radius surrounding the poles. In 2021 the Circuit Risk Index (CRI) and Wildfire Risk Reduction Model (WRRM) score were leveraged to identify relative higher risk areas within the HFTD. A methodology was created to integrate the CRI and WRRM scores, poles with lower environmental impact, and poles that carry non-exempt hardware as the basis for where the activity would be performed. The initial analysis identified over 1100 poles that met the criteria. The number of actual poles cleared was dependent on customer authorization, site inspection, and environmental constraints.
- To create synergy where ignition risk associated with pole-mounted hardware is relatively higher, the methodology for fuels modification was revised in 2021 to target poles where brush clearing for Public Resources Code Section 4292 is also required.
- Environmental desktop pre-screening was performed to reduce site inspections and create efficiencies for the fuels modification program.
- Customer engagement and the notification process for fuels modification was streamlined to schedule and execute operations. However, the customer notification process should begin earlier prior to peak fire season to secure a steady volume of authorizations and work.
- Prescribed goat grazing for brush abatement was initially successful and the plan is to expanded the program to sections of the transmission corridor.
- The fuels modification program needs further analysis to determine the most cost effective and effectual alternatives to current activities (e.g., fire retardant)
- Geographic Information System (GIS) data needs to be analyzed for new overhead construction to provide an opportunity to perform fuels abatement prior to construction.

Figure 4-4: Fuels Modification Sites Using CRI and WRRM



Refer to Section 7.3.5 Vegetation Management and Inspections for additional details on vegetation management and inspection initiatives.

4.1.6 Grid Operations and Protocols

SDG&E continued to leverage fire suppression resources to accompany crews performing work in the HFTD during elevated FPI. In 2021, SDG&E learned:

- Transmission outage procedures at higher voltages could be adapted to support PSPS events where necessary.
- Smart meter usage data could be utilized to identify potentially overloaded equipment posing a possible fire risk.

Refer to Section 7.3.6 Grid Operations and Protocols for additional details on grid operations and protocols initiatives.

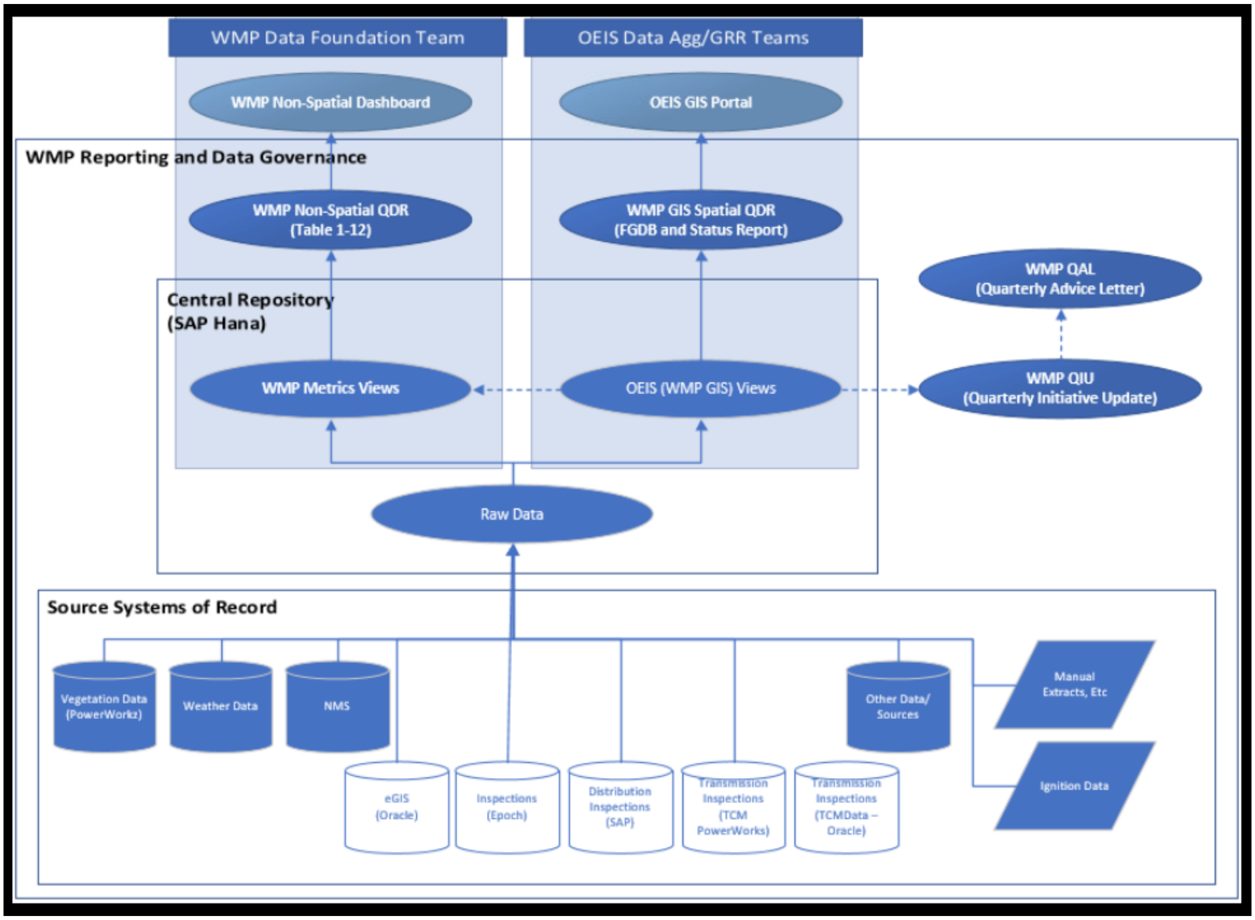
4.1.7 Data Governance

SDG&E continued to build out and integrate the central repository supporting the WMP metrics tables and the GIS schema with the source systems of record. In 2021, SDG&E learned:

- Collaboration across multiple internal stakeholders can optimize enterprise data governance awareness, policies, processes, and training.
- Development of documentation standards for metric and GIS schema logic promotes auditability of the data.

- A Central Repository (CR) reporting strategy (shown in Figure 4-5) will leverage common data sources to meet WMP non-spatial and GIS spatial reporting requirements.

Figure 4-5: Central Repository Reporting Strategy



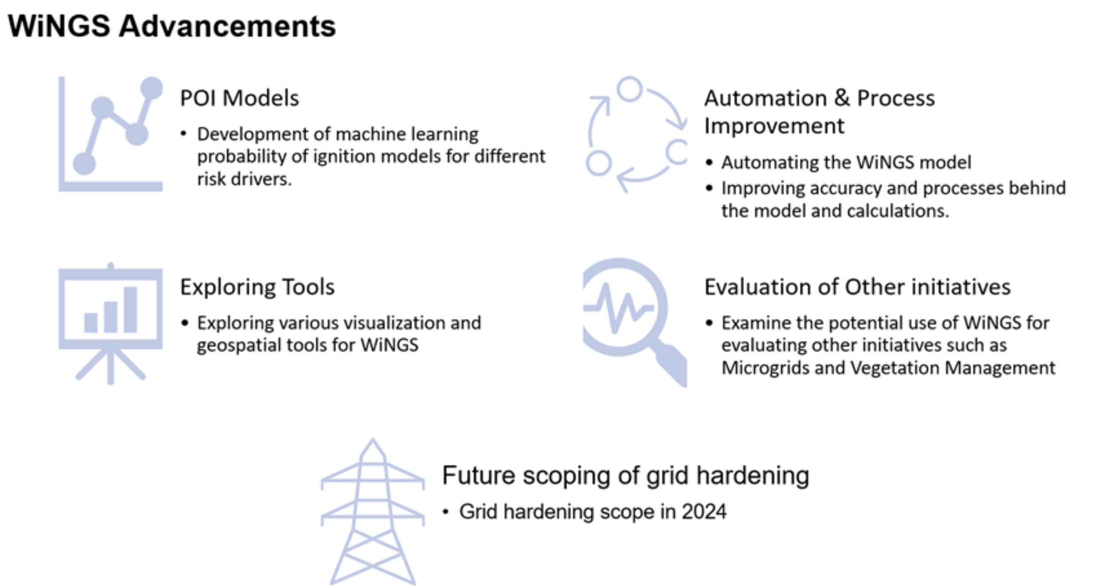
Refer to Section 7.3.7 Data Governance for additional details on data governance initiatives.

4.1.8 Resource Allocation Methodology

SDG&E has worked to develop programs and tools to assist in resource allocation across business units and asset classes for various risks, including the Asset Integrity Management program and the WiNGS-Planning model. In 2021, SDG&E learned:

- A specific asset investment planning and risk valuation tool is needed to complement other resource allocation models already implemented to support asset investment decisions.
- Evaluation of other initiatives should be incorporated into the WiNGS-Planning model to account for asset health, circuit connectivity, and vegetation risk. (See Figure 4-6).
- Operations and planning models will be updated and transitioned to the cloud and python script will be updated to enhance data processing capabilities, expedite real-time data refreshing, and ensure model reproducibility by limiting human input errors.

Figure 4-6: WiNGS Advancements



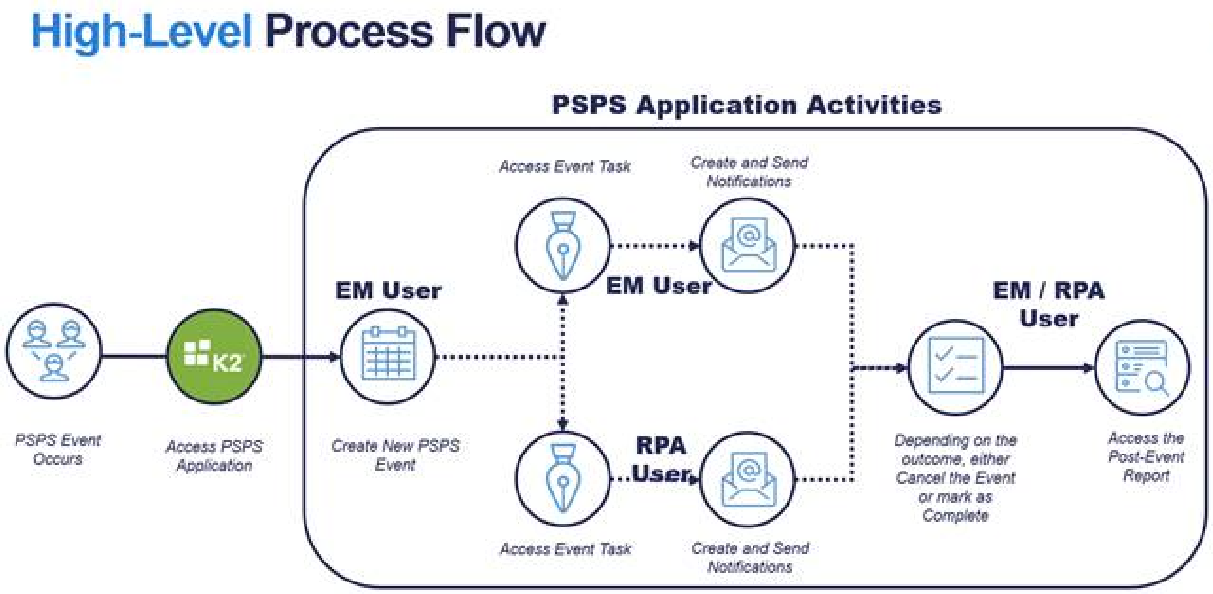
Refer to Section 7.3.8 Resource Allocation Methodology for additional details on resource allocation methodology initiatives.

4.1.9 Emergency Planning and Preparedness

SDG&E enhanced its emergency preparedness plan in collaboration with key internal business units and external public safety partners. In 2021, SDG&E learned:

- Implementation of workflow process tools is necessary to improve the efficiency of notifications with public safety and other state partners. (See Figure 4-7).
- Through coordination with other Investor-Owned Utilities (IOUs), preregistering public safety partners information on a secure website was important to improve completeness of data.
- Safety stand-downs at all operating centers were key to enhancing preparedness.

Figure 4-7: PSPS Notification Process Flow



Refer to Section 7.3.9 Emergency Planning and Preparedness for additional details on emergency planning and preparedness initiatives.

4.1.10 Stakeholder Cooperation and Community Engagement

SDG&E understands the important role all stakeholders play in achieving wildfire prevention and mitigation. In 2021, SDG&E increased its lines of communication and learned:

- Food support for Access and Functional Needs (AFN) customers can be very limited on major holidays such as Thanksgiving. SDG&E intends to increase the number of contracted vendors to streamline such support in the future.
- Direct engagement with tribal leaders is needed to target generators to tribal members with the most need.

Refer to Section 7.3.10 Stakeholder Cooperation and Community Engagement for additional details on stakeholder cooperation and community engagement initiatives.

4.2 Understanding Major Trends Impacting Ignition Probability and Wildfire Consequence

Instructions: *Describe how the utility assesses wildfire risk in terms of ignition probability and estimated wildfire consequence, including use of Multi-Attribute Risk Score (MARS) and Multi-Attribute Value Function (MAVF) as in the*

Safety Model and Assessment Proceeding (S-MAP)[6] and Risk Assessment Mitigation Phase (RAMP), highlighting changes since the 2020 WMP and 2021 Update. Include description of how the utility distinguishes between these risks and the risks to safety and reliability. List and describe each "known local condition" that the utility monitors per GO 95, Rule 31.1, including how the condition is monitored and evaluated.

Enterprise Risk Management

Risk Framework

SDG&E's risk framework is modeled after an internationally recognized risk management standard, ISO 31000.[7] This framework consists of an enterprise risk management governance structure, which addresses the roles of employees at various levels ranging up to SDG&E's Board of Directors, as well as various risk processes and tools.

One such process is SDG&E's 6-step enterprise risk management process. Figure 4-8 describes SDG&E's enterprise risk management process, whereby SDG&E identifies, manages, and mitigates enterprise risks and aims to provide consistent, transparent, and repeatable results.

Figure 4-8: Enterprise Risk Management Process

This 6-step process is aligned with the Cycla Corporation's 10-Step Evaluation Method, which was adopted by the California Public Utilities Commission (CPUC) "as a common yardstick for evaluating

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[6] Updates to S-MAP are currently in deliberation under proceeding R. 20-07-013 – Order Instituting Rulemaking to Further Develop a Risk-Based Decision-Making Framework for Electric and Gas Utilities (July 16, 2020).

[7] ISO 31000 is a family of standards relating to risk management codified by the International Organization for Standardization.

maturity, robustness, and thoroughness of utility Risk Assessment and Mitigation Models and risk management frameworks."[8] While the lexicon used by Cycla differs slightly from that of SDG&E, the content is largely aligned. SDG&E performs its enterprise risk management process annually, resulting in an Enterprise Risk Registry (ERR). The CPUC defines an ERR as "[a]n inventory of enterprise risks at a snapshot in time that summarizes (for a utility's management and/or stakeholders such as the CPUC) risks that a utility may face. The ERR must be refreshed on a regular basis and can reflect the changing nature of a risk; for example, risks that were consolidated together may be separated, new risks may be added, and the level of risks may change over time."[9]

Accordingly, SDG&E's identified enterprise-level risks, including safety-related and wildfire-related risks, are presented in its ERR. Each risk has one or more risk owner(s), a member of the senior management team who is ultimately responsible and accountable for the risk, and one or more risk manager(s) responsible for ongoing risk assessments and overseeing implementation of risk management plans.

SDG&E uses input from the risk managers and the risk owners to ultimately finalize its ERR. Therefore, SDG&E's enterprise risk management process is both a "bottom-up" and "top-down" approach.

In addition, each risk in the ERR has an associated set of mitigations (i.e., projects or programs that reduce the likelihood of the risk and/or negative consequences should the risk occur). Notwithstanding these risk management and mitigation efforts, however, adverse events will occur. When that happens, SDG&E's efforts, including implementation of response plans, development of role and responsibility descriptions and checklists, and facilitation of training and exercises, are designed to prepare the Company to respond safely and effectively to those adverse events that occurred despite mitigation efforts.

Risk Identification and Evaluation

In SDG&E's enterprise risk management process, as explained in the 2021 Risk Assessment Mitigation Phase (RAMP),[10] risk identification is the process of finding, recognizing, and describing risks. As the first step in the enterprise risk management process, the Enterprise Risk Management organization works with various business units to update existing risk information and identify enterprise-level risks that have emerged or accelerated since the prior assessment. This part of the process also includes the identification of risk events, their causes, and potential consequences, which is summarized in a Risk Bow Tie. The Risk Bow Tie is "[a] tool that consists of a Risk Event in the center, a listing of drivers on the left side that potentially lead to the Risk Event occurring, and a listing of Consequences on the right side that show the potential outcomes if the Risk Event occurs."[11]

Risk evaluation is also included in SDG&E's enterprise risk management process[12] and results in a pre-mitigation risk score. The methodology or framework utilized by SDG&E to calculate risk scores, including for the Wildfire risk, was adopted in the Safety Model and Assessment Proceeding (S-MAP) (D.18-12-014) and presented in SDG&E's 2021 RAMP filing.

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[8] D.16-08-018 at 195, Ordering Paragraph 4.

[9] D.18-12-014 at 16-17.

[10] Application 21-05-011, Application of SDG&E to Submit its 2021 RAMP Report (May 17, 2021) (2021 RAMP), Chapter RAMP-B at B-3.

[11] D.18-12-014 at 16.

[12] See 2019 RAMP, Chapter RAMP-B at B-6.

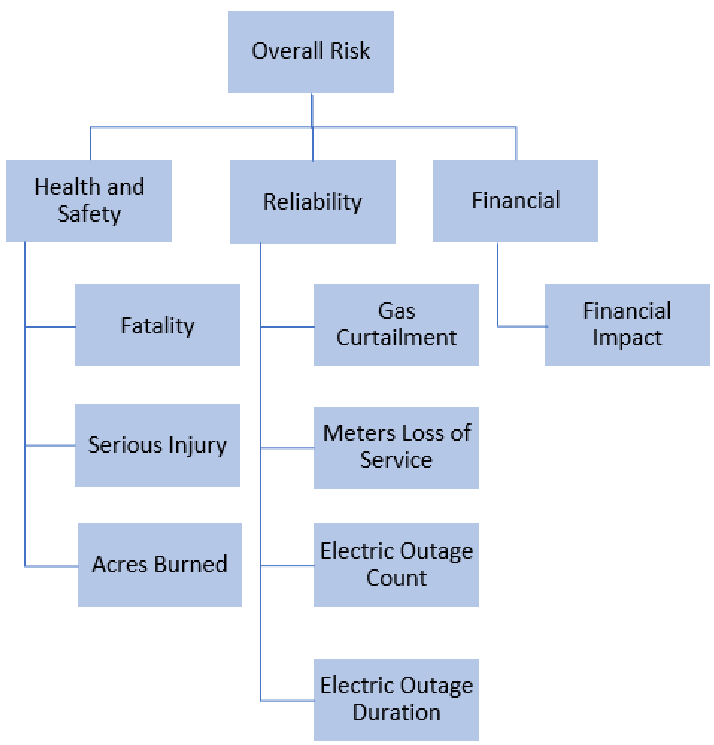
The S-MAP puts forth a consistent framework to be applied in future RAMP and GRC filings for identifying and evaluating risk across all California utilities. Thus, SDG&E's approach generally follows a consistent framework with the other utilities. It is important to note that SDG&E was the first utility to apply the new quantitative risk methodology adopted in the S-MAP and is continuing to review opportunities for improvement and lessons learned from the new approach including the feedback received in the open RAMP review process.

Multi Attribute Value Function

SDG&E refers to its Multi-Attribute Value Function (MAVF) as its Risk Quantification Framework. This is an evolving framework that SDG&E uses as a tool to discuss and inform quantitative risk assessments, and remains subject to ongoing changes and development. The Risk Quantification Framework depicted and discussed below was used in SDG&E's 2021 RAMP filing, which was filed on May 17, 2021. What is presented in this WMP is the most up to date information at the time of the writing of this document but is subject to change.

SDG&E continues to enhance its Risk Quantification Framework from the version initially used in its 2019 RAMP. For example, an "Acres Burned" sub-attribute was added. The changes from 2019 are due to the evolving nature of risk frameworks. In particular, the inclusion of Acres Burned was introduced to more fully measure the potential impact from a wildfire. The burning of vegetation and pollution impacts of wildfire are also a serious health concern, and SDG&E has utilized academic and government work to understand and estimate those impacts.

Figure 4-9: 2021 Risk Quantification Framework



Attribute	Unit	Range	Weight
Health & Safety	Index	0-20	60%
Reliability	Index	0-1	23%
Financial	$M	0-500M	17%

Health & Safety is measured by indexes, has a range of 0 - 20, and a weight of 60%. Sub-attributes:

- Fatality has a value of 1
- Serious Injury has a value of 0.25
- Acres Burned has a value of 0.00005

Reliability is measured by indexes, has a range of 0-1, and a weight of 23 percent. Sub-attributes:

- Gas Curtailment is measured by the number of million cubic feet, has a range of 0-250 for SDG&E, and a weight of 25 percent
- Meters Loss of Service is measured by the number of meters, has a range of 0-50,000 (SDG&E), and a weight of 25 percent (SDG&E)
- Electric Outage Count is measured by the System Average Interruption Frequency Index (SAIFI) outages, has a range of 0-1, and a weight of 25 percent
- Electric Outage Duration is measured by the System Average Duration Index (SAIDI) minutes, has a range of 0-100, and a weight of 25 percent

Financial is measured in millions of dollars, has a range of $0-500 million, and a weight of 17 percent.

Approach for determining probability of ignitions and consequences

SDG&E continually evaluates its wildfire risk assessments regarding the probability of ignitions and the consequences of a potential wildfire. This wildfire risk assessment is an on-going effort which is updated as new data is collected and when new studies are undertaken. The general approach to wildfire risk is a hybrid “top down” approach coupled with a “bottoms up” approach. The “top down” approach refers to the assessment of entire risk, namely the total wildfire risk across the entire service territory, using global concepts of ignitions, relevant outages, potential damage, etc. The “bottoms up” approach is undertaken by analyzing granular aspects of wildfire risk such as the amount of risk (likelihood of ignition and consequence if an ignition occurs) from specific assets or locations. Together these two methods help calibrate each other to provide a more robust risk picture.

The global “top down” assessment is based on a model that was built using stochastic methods (e.g., Monte Carlo) which allows for uncertainty to be incorporated into the modeling. The inputs related to the likelihood of ignition involve information related to historical large fires, annual ignitions, accommodations to climate change, accommodations to system hardening, and accommodations from operational changes such as system protection settings and PSPS events. The inputs related to the consequence of ignitions involve information related to wildfire behavior modeling, accommodations due to climate change, and application of financial treatments to consequences to adjust to the current year’s financial considerations (e.g., real estate prices, Consumer Price Index). The model output consists of two probability distributions, one for ignition likelihoods and another for financial consequence.

Currently, the financial consequence is used as a proxy for human safety due to the strong connection between safety and homes destroyed and because large fires are rare, resulting in a small sample size to find correlations between location and safety implications. Future versions of risk modeling will include refinements on how to include safety impacts into modeling, including such notions as density, egress, and specific customer types affected. Together, the financial and safety consequences are used in SDG&E's Risk Quantification Framework.

The granular "bottoms up" approach attempts to find failure and ignition rates for specific scenarios, starting with equipment types and sub-types and including location and environmentally-focused conditions such as vegetation and wind. Because the sample size of ignitions is relatively small from a statistical standpoint when considering all of the situational characteristics, some information is generalized.

An important notion regarding wildfire risk is the connection between ignitions and risk of those ignitions developing into a catastrophic wildfire. SDG&E has chosen to use ignitions largely as a rule-of-thumb indicator of risk reduction, while understanding that prevented ignitions might not necessarily result in a catastrophic wildfire. SDG&E's global modeling suggests that approximately one in 500 ignitions could be catastrophic (e.g., damage resulting in over $100 million; significant damage and potential safety consequences), and therefore, if a mitigation prevents one ignition it is preventing 1/500th of a catastrophic wildfire.

Together, the "top down" and "bottoms up" methods are used to provide an overall view of wildfire risk and assist in determining which mitigations make the most sense to perform. Currently, the "bottoms up" approach helps allocate the amount of risk that has been identified by the "top down" approach.

Incorporation of PSPS Impacts in the Evaluation of Wildfire Risk

SDG&E recognizes that PSPS events, while effective at reducing the risk of a utility ignited wildfire, have impacts to customers that are subjected to outages. While PSPS events could be considered a separate risk, they are directly tied to wildfire mitigation and would not exist otherwise. SDG&E attempts to balance between wildfire risk and the impacts of PSPS to optimally promote public safety.

When evaluating the current level of wildfire risk, SDG&E takes into account the current implementation of PSPS. In Risk Management, the terms "inherent" and "residual" refer to the levels of risk before and after a risk-reducing activity has been undertaken. In the case of PSPS events, the inherent wildfire risk can be thought of as the risk level without a PSPS program, and the residual wildfire risk is the risk level with a PSPS program in place.

In this WMP, SDG&E continues to include the impacts of PSPS events in the overall risk evaluation. There are two separate risk scores that SDG&E measures: (1) wildfire risk, and (2) PSPS impacts. The overall risk evaluation is the sum of the risk scores for wildfire risk and PSPS impact. In this section, the sum of these risk scores is referred to as the Total Wildfire Risk Score (TWRS). Both wildfire risk and PSPS impacts are evaluated using the Risk Quantification Framework described above. All Risk Spend Efficiencies (RSEs) presented in this WMP use the TWRS as their basis. Some mitigations in the WMP reduce wildfire risk, other mitigations reduce PSPS impacts, and others lower the risk for both wildfire risk and PSPS impacts.

Without a PSPS program, the TWRS would be comprised solely from inherent wildfire risk. SDG&E's PSPS Program works to reduce total wildfire risk to the community. PSPS impact evaluation remains in the early stages of development, and SDG&E's WiNGS-Ops framework will continue to evolve in quantifying and understanding the impacts of PSPS events to inform strategies for wildfire mitigation.

PSPS Customer Impacts Valuation

To mitigate PSPS impacts, SDG&E considers the probability and consequences of PSPS events on an annual basis at a segment level. A segment is multiple spans and structures between two electrical isolation points that are used for PSPS activities. These segments range from approximately one mile to several miles and are the basis on which SDG&E implements PSPS. Each segment has an associated weather station that acts as a proxy for weather conditions impacting that segment.

The individual probability of a segment undergoing a PSPS event is assessed in a given year by examining historical weather events and by applying SME guidelines on how often each segment would experience a PSPS event.

Although this analysis is performed at the segment level, there are interdependencies with other segments. For example, if a distribution circuit is comprised of two PSPS segments, the "upstream" segment that starts at the substation and goes half the length of the circuit and the "downstream" segment goes from that halfway point to the end of the circuit and the "upstream" segment has a PSPS event, the "downstream" segment would also experience a PSPS event due to the loss of power that emanated from the "upstream" segment. SDG&E considers these upstream/downstream effects of PSPS events when analyzing the true impact to the customers.

To calculate the PSPS impact portion of the TWRS, recent data such as the number of PSPS activations, the number of customers affected, and duration of the outages for each customer was used. SDG&E recognizes that the impact of a PSPS is not the same on all customer types and that there are certain customer groups that may suffer higher consequences in a PSPS event. Therefore, three categories are used to represent different types of customers as follows:

- Critical Facilities and Infrastructure: Urgent customers whose mission supports regional emergency response (e.g., police, fire department, hospitals) as well as essential customers who are essential to public health, safety, and security as defined by the CPUC (e.g., public utilities, communications providers, water service providers, transportation)
- Medical Baseline: Residential and other customers with a qualifying medical condition or medical device usage (e.g., dialysis machine)
- Other: All other customers that do not fall in either the critical or medical baseline categories

Each customer group is evaluated on risk attribute categories similar to those defined in the MAVF (i.e., safety, financial, reliability). The key difference is that unlike the definition of reliability used in RAMP (e.g., gas meters out, curtailment, SAIDI, SAIFI), reliability is measured as the number of customers losing access to key services (e.g., utilities, healthcare). Since the critical categorization represents a spectrum of different customer types, specific customer types are used as proxies. For example, the impact on "urgent" customers is estimated by using an outage on a communications tower as a proxy.

A combination of industry research and subject matter expertise is used, by attribute, to group the range of impact values and correspond them to an attribute consequence weighting. As shown in Table 4-1, each customer category is evaluated using reasonable worst-case consequence conditions and assigned a consequence multiplier for each risk attribute.

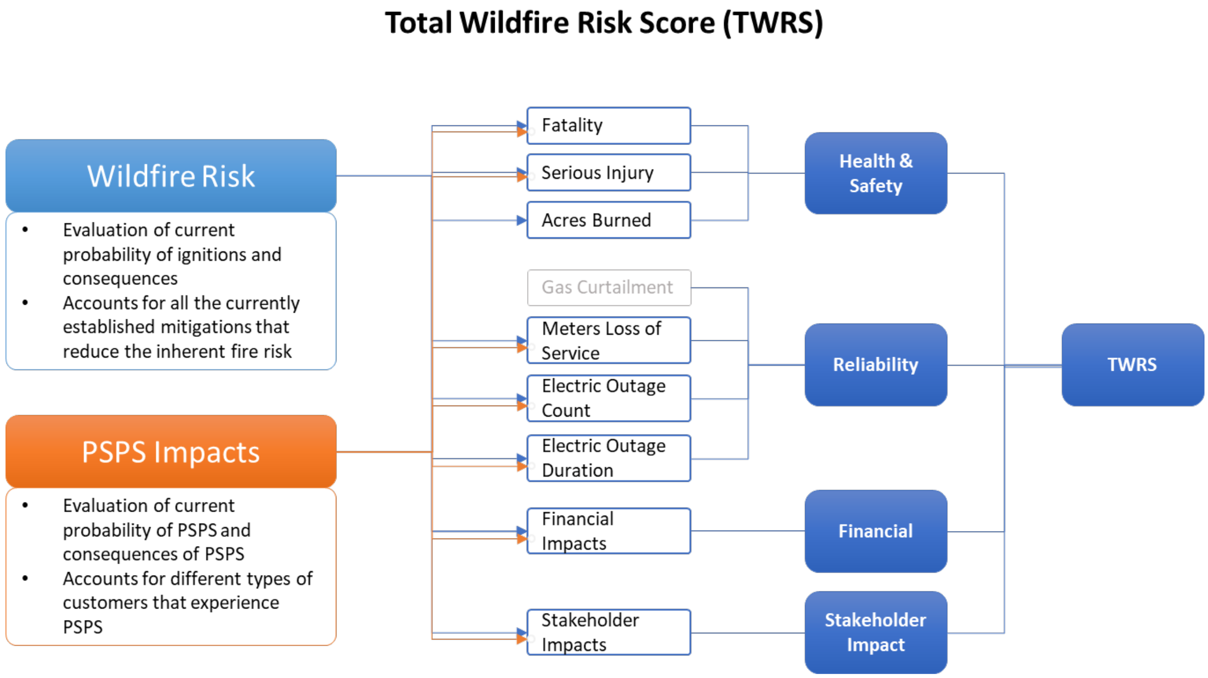
Table 4-1: Customer Impacts by Type

Customer Type	Data Assumptions/ Proxys	Safety			Financial			Reliability		
		Initial Score	Impact Multiplier	Total Impact	Initial Score	Impact Multiplier	Total Impact	Initial Score	Impact Multiplier	Total Impact
Critical Facilities and Infrastructure	***Proxy***: Communications Tower	20	1	20	10	1	10	30	1	30
Medical Baseline		5	1	5	1	1	1	1	1	1
Other	***Assumption***: 80% Residential, 10% Commercial, 10% Industrial	1	1	1	1	1	1	1	1	1

The baseline PSPS impact, per attribute, is calculated using the total number of downstream customers. The per attribute customer value is determined by multiplying the downstream customer count of each customer category by its value and then taking the sum. For each attribute, the baseline risk value is multiplied by the ratio of customer impact to the total number of customers.

The framework of valuing the varying PSPS impacts on different customer types is still in early development and will continue to be iterated and improved upon with input from both internal and external stakeholders. Figure 4-10 is a visual representation showing how the wildfire risk and PSPS impact are evaluated using the common Risk Quantification Framework described above.

Figure 4-10: Evaluation of Wildfire Risk and PSPS impact Using RQF



Risk Evaluation and RSE Estimation

Risk Scope and Methodology

This section provides an overview of the scope and methodologies applied for the purpose of risk quantification. The Risk Quantification Framework is based on the Settlement Agreement (SA) that the IOUs and intervenors reached in the S-MAP proceeding and which was adopted by the CPUC as the guiding framework for conducting risk assessments for RAMP.

The Settlement Decision requires a pre- and post-mitigation risk calculation[13]. Chapter SCG/SDG&E RAMP-C of RAMP 2021 Report[14] explains the Risk Quantitative Framework, including how the pre-mitigation risk score, Likelihood of Risk Event (LoRE), and Consequence of Risk Event (CoRE) are calculated. SDG&E continually evaluates its wildfire risk assessments regarding the probability of ignitions and the consequences of wildfires. This wildfire risk assessment is an ongoing effort that is updated as new data is collected and when new studies are undertaken. In accordance with the Settlement Decision,[15] Table 4-2 and Table 4-3 provide risk scores that take into account the benefits of any mitigations that have been implemented as of the end of 2020. They also provide the risk score for the wildfire risk, PSPS impact and TWRS. Table 4-4 provides definitions for in scope and out of scope wildfires.

[13] D.18-12-014 at Attachment A, A-11 (“Calculation of Risk”)

[14] 2021 RAMP, Chapter RAMP C Risk Quantification Framework and Risk Spend Efficiency

[15] D.18-12-014 at Attachment A, A-8 – A-9 (“Identification of Potential Consequences of Risk Event” and “Identification of the Frequency of the Risk Event”)

Table 4-2: Pre-Mitigation Analysis Risk Quantification Scores[16]

	Wildfire Risk	PSPS Impact	TWRS
Pre-Mitigation Risk Score	11,768	4,691	16,459
LoRE	21.2	4	n/a
CoRE*	556	1,173	n/a

* The CoRE is the aggregated weighted average

Table 4-3: Pre-Mitigation Analysis Risk Quantification Scores by Non-HFTD and HFTD Tiers

	Wildfire Risk Score			PSPS Impact		
	Non-HFTD	**Tier 2**	**Tier 3**	**Non-HFTD**	**Tier 2**	**Tier 3**
Pre-Mitigation Risk Score	278	4,261	7,230	0	1407	3,283
LoRE	9.2	6.8	5.1	0	4	4
CoRE	30.2	622.9	1,409.30	N/A	351.8	820.9

Table 4-4: Risk Quantification Scope

In-Scope for purposes of risk quantification	The risk of wildfires that meet the CPUC Fire Incident Data Collection requirements for reporting.[17] A wildfire must be reported if all three of the following criteria are met: • A self-propagating fire of material other than electrical and/or communication facilities • The resulting fire traveled greater than one linear meter from the ignition point • The utility has knowledge that the fire occurred The impacts of PSPS to customers are also included in the scope of the risk quantification.
Out-of-Scope for purposes of risk quantification	Wildfires that do not meet the CPUC Fire Incident Data Collection requirement for reporting are excluded from this analysis.

Sources of Input

SDG&E's safety risk assessment primarily utilized historical data provided by the California Department of Forestry and Fire Protection (CAL FIRE), which has various resources useful for analysis. A notable resource used from CAL FIRE is known as the "Redbook." These are published annually and provide name, cause of fire, acres burned, structures burned, and human safety information for each fire. The data is also summarized by County and Region. CAL FIRE also provides maps and GIS data at their Fire

[16] The term "pre-mitigation analysis," in the language of the Settlement Decision refers to required preactivity analysis conducted prior to implementing control or mitigation activity, see D.18-12-014 at Attachment A, A-12 ("Determination of Pre-Mitigation LoRE by Tranche," "Determination of PreMitigation CoRE," "Measurement of Pre-Mitigation Risk Score").

[17] D.14-02-015, Appendix C.

and Resource Assessment Program (FRAP) website.[18] GIS files provide the key element of the geographic location of each fire in CAL FIRE's records and therefore can be used to analyze fires based on location-specific characteristics such as vegetation class or weather patterns. CAL FIRE's incident reports are also valuable because they provide additional facts about events. For example, CAL FIRE's incident page discussing the Sawday Fire, which occurred in San Diego in 2019, has information regarding the ignition location and links to situational updates.[19]

Other data sources used to estimate wildfire risks are web-based news articles that discuss the facts surrounding wildfire events. Although CAL FIRE Redbooks have fire-related facts, web-based news articles can help explain the events in greater detail, providing information such as the type of structures destroyed, the extent of injuries, or the estimated cost of the event. Regarding financial losses, it is difficult to determine the precise cost of wildfire events, given the many considerations in play. Wildfire events primarily have costs related to property damage, personal injury or fatality, suppression costs, environmental damage and remediation, lost economic output for various reasons (including work closures and employee unavailability), and personal relocation. There is no single source to assess all financial impacts from wildfire. SDG&E used available data to approximate financial impacts.

Approach for Estimating Likelihoods and Consequences

The following provides an explanation of how wildfire risk likelihoods and consequences were estimated. Wildfire risk is unique among other enterprise risks because it has an extremely wide range of impacts (i.e., some fires have no impact while others can cause catastrophic devastation), it is situationally dependent on many changing variables (i.e., climate change, weather, vegetation), drivers to the risk are frequently outside a utility's control (e.g., man-made debris, animal, human, and vegetation contacts), and significant impacts are rare, leading to low-confidence estimations regarding future risk.

SDG&E continually evaluates its wildfire risk assessments regarding the probability of ignitions and the consequences of wildfires. This wildfire risk assessment is an ongoing effort that is updated as new data is collected and when new studies are undertaken. An outline of how wildfire risk was modeled and used for developing the WMP is outlined in the following steps:

- Data Gathering:
  - Wildfire Risk: Historical data was used as a starting point for consideration of likelihoods. Data was considered from both reportable ignitions (since 2014) and from large fire history (since 1970) reported (as described in detail in Sources of Input).
  - PSPS impact: Historical data ranging from 2017 onwards was pulled from SDG&E's reporting database Oracle Utility Analytics (OUA) and its source system Network Management System (NMS).
- Changes from Historic Likelihood:
  - Wildfire Risk: Changes were considered from the historic likelihood of fires. Changes from historic likelihoods are primarily due to system hardening programs, including PSPS, that have been undertaken during the timeframe used, climate change, increased

[18] [18] CA.Gov, CAL FIRE, FRAP, available at: https://frap.fire.ca.gov/.

[19] CA.Gov, CAL FIRE, Status Updates, available at: https://www.fire.ca.gov/incidents/2019/10/25/sawday-fire/.

overhead miles relative to previous timeframes, and change in vegetation relative to previous timeframes. Because each of these changes are not precisely known, models were used to estimate the actual range of current likelihoods, with 10,000 estimates stored for use in determining Wildfire and PSPS impact.

    - PSPS impact: Historical PSPS events are being analyzed to estimate likelihood and impact of PSPS events. SDG&E is aware that the number of PSPS events has a large variance from year to year depending on the weather and the occurrence of wildfires. Additional reasons for changes in likelihood may be due to updated notions of when to perform PSPS based on analysis of the relationship between wildfire risk and PSPS impacts.

- Modeling of Consequences:
    - Wildfire Risk: Consequences were also modeled using historical fires to create or "fit" a probability distribution from large fires considering financial loss. The probability distribution is SDG&E's estimation of the extent of financial losses that may occur if a large utility-associated wildfire occurs. The probability distribution is not a precise statistical forecast, but it is a useful estimation for wildfire risk discussions. The probability distribution currently used is not permanent and will continue to be modified as new information becomes available.
    - PSPS impact: Consequences of PSPS activations is discussed in PSPS Customer Impacts Valuation. In short, SDG&E has assigned consequence values for safety, reliability and finance and those values span three different customer classes. SDG&E is aware that valuing the consequences of PSPS is an important piece of analysis and will continue to evolve its approach to reflect the impacts to customers.
- Monte Carlo Simulation:
    - Wildfire Risk: In Microsoft Excel, Monte Carlo modeling was performed to identify the likelihood and consequence of large fires, using the following approach:
        - 10,000 runs, which simulate individual years, were performed. 10,000 probabilities, one for each run, were created based upon the likelihood of information addressed above. During each run, a random number was generated and used to compare between it and the likelihood stored for that run. If the random number was smaller than the likelihood value, the model assumed that a large wildfire occurred during that run. The model also considers the possibility of having multiple large wildfires in the same year. As an average, the total number of large wildfires that the model produced was 935 over 10,000 runs.
        - If a large wildfire was modeled to occur, a method to determine the number of wildfires that occurred during that run was undertaken. That method created a random value drawn from the Poisson distribution with the parameter of 1 [i.e., $\lambda(1)$]. The maximum value between the random draw and the number 1 was then used to represent the number of large wildfires that occurred during that run.

        - Depending on the number of wildfires to run (as determined in the previous step) the consequence probability distribution was then used for sampling. The sum of the sampled values was used for the financial consequence for the run and stored for further analysis.
        - Most runs returned $0 due to the fact that large fires are modeled to occur approximately once every 15-20 years
        - The output from the Monte Carlo modeling was then tabulated and put into a format to be analyzed.
    - PSPS impact: There are currently no Monte Carlo simulations performed for PSPS impacts. SDG&E is currently working to enhance the PSPS model to properly quantify the impact of PSPS decisions.
- The following steps were undertaken to meet the SA's requirements:
    - Because the scope of Wildfire risk includes all CPUC-reportable fires and not solely large destructive fires, an internal modeling adjustment was made. For purposes of the analysis, LoRE is set to the recent history (a 5-year rolling average) of SDG&E's CPUC reportable fires, approximately 22, as indicated in Table 4-2. Because the total number of modeled large fires was 935 out of 10,000 runs, and 22 reportable fires of all sizes occur each year, this data estimates that one out of every approximately 235 reportable wildfires could result in a large destructive fire.
    - CoRE was partially calculated from the Monte Carlo modeling by extracting the expected values of the output consequences. This was done differently for each attribute:
        - Financial: The expected value of all Monte Carlo outputs was determined to be $225 million.
        - Reliability: Data was extracted from SDG&E's internal reliability database for fire-related outages to determine reliability impacts.
        - Safety: Safety impacts during a fire vary and are difficult to quantify, therefore a rule of thumb was applied to the financial data. Based on subject matter interpretation of historical data, for each $1 billion loss due to wildfire, it was assumed that 4.25 safety units would occur. This ratio was applied to the Monte Carlo output, producing an expected value of 0.96 safety units per year.
        - CoRE Output: These obtained values were then used as inputs the Risk Quantification Framework to determine a CoRE value of 556, as indicated in Table 4-2.

This analysis sets the foundational starting point for evaluating the effectiveness of mitigations and for calculating RSE scores. If an initiative reduces wildfire risk but does not reduce PSPS impact, an estimate of reduction for either LoRE or CoRE for wildfire risk was undertaken, and a post-mitigation wildfire risk score was calculated. If an initiative reduces PSPS impact but does not reduce wildfire risk, an estimate of reduction for LoRE or CoRE for PSPS impact was completed, and a post-mitigation PSPS impact score was calculated. If an initiative reduces both wildfire risk and PSPS impact, an estimate of reduction for LoRE or CoRE for both wildfire and PSPS impacts was completed, and a post-mitigation wildfire and PSPS impact was calculated. Figure 4-11 provides an overview of the risk quantification initiative assessment.

The difference between the pre-mitigation and post-mitigation risk levels was then used to calculate the RSEs by dividing the change in risk level by the total cost of the initiative, taking into account the life of the project which determines how long benefits would be realized. For example, grid hardening projects typically have a long duration for benefits because benefits of new poles can be realized over the lifetime of the new asset, or approximately 40 years. Initiatives such as inspections that occur on a more cyclical basis (e.g., every three years) will have benefits that span the duration of the cycles. These durations do not reflect the time taken to implement projects, they merely reflect the duration of the benefits.

Figure 4-11: Risk Quantification Initiative Assessment

*Note: depending on the initiative and available data, risk reductions will either be calculated based on estimated reduction in likelihood or estimated reduction in consequence.

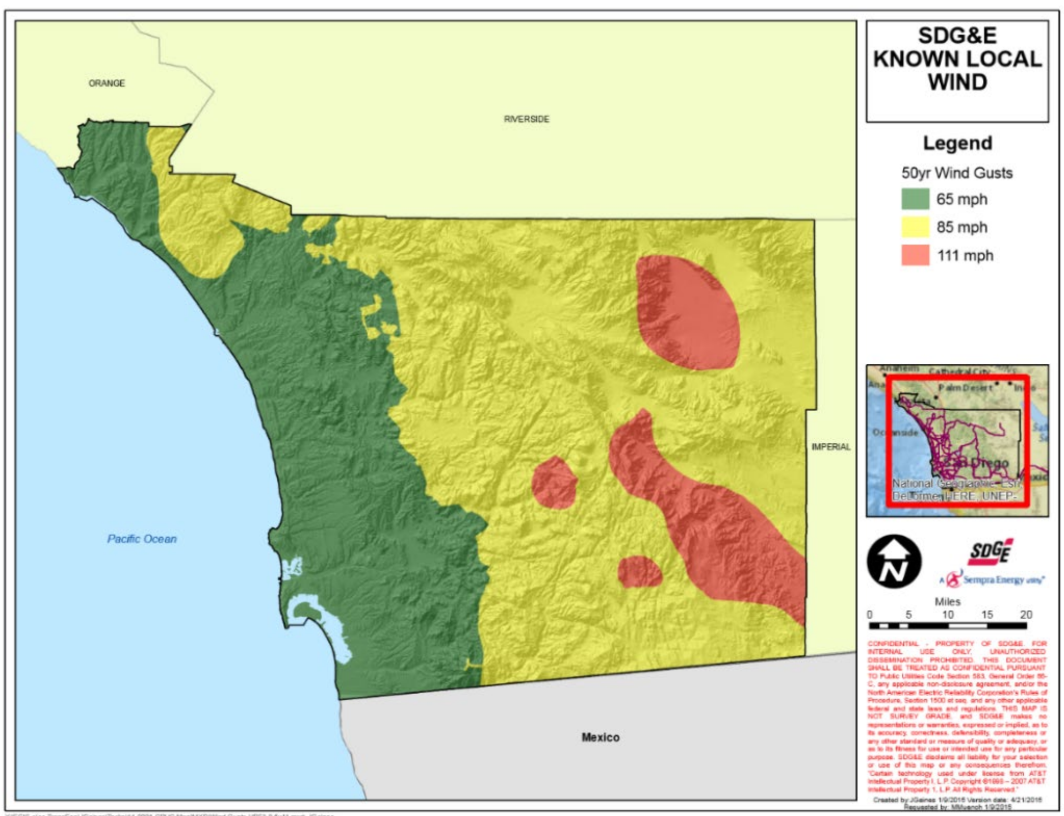
Known Local Conditions

SDG&E leverages its Weather Station Network to closely monitor winds throughout its service territory and integrates this information into local known conditions per CPUC General Order (GO) 95, Rule 31.1. SDG&E has also conducted a detailed analysis of potential wind gusts across its service territory to support wildfire hardening efforts. This section explains how these known local conditions were created and evaluated.

In an effort to create the most accurate known local wind conditions map possible, Meteorology uses a Weather Forecasting and Research (WRF) Atmospheric Model to recreate hourly weather conditions from the last 30 years on a 3-kilometer (km) grid. This is possible using government datasets to initialize WRF and create what is known as a reanalysis dataset. Thirty years of data was used because this was the extent of available computer power and data quality degraded beyond 30 years. The reanalysis dataset took approximately 1 million compute core hours on Meteorology's computing cluster. Once the dataset was created, the highest projected wind gusts were determined for each point on the 3 km grid for each year going back to 1984. This provided preliminary values, but SDG&E wanted to add a bias correction based on the real-time data received from the Weather Station Network.

To achieve this, 2 years of data from every station in the Weather Station Network was compared to the output from the WRF Model over the same 2-year period. Model biases were then determined for every grid cell on the map, which were then applied to the entire 30-year dataset. Once the full 30 years of bias-corrected data was compiled, the data was extended to create a 50-year wind model for each grid cell on the map. This was achieved by determining the peak wind gusts for each year going back to 1984 and then applying a Generalized Extreme Value Probability Distribution Function (GEV PDF) to the data. Once complete, the map was analyzed and refinements were made based upon Meteorology's subject matter expertise. With an understanding of the model's tendencies in resolving winds around certain terrain features, the subject matter experts (SMEs) were able to refine details of the wind map to bring added value and accuracy to the final version which exists today. Figure 4-12 figure depicts SDG&E's known local wind conditions.

Figure 4-12: SDG&E Known Local Wind Conditions Map



A. Describe how the utility monitors and accounts for the contribution of weather to ignition probability and estimated wildfire consequence in its decision-making, including describing any utility-generated Fire Potential Index or other measure (including input variables, equations, the scale or rating system, an explanation of how uncertainties are accounted for, an explanation of how this index is used to inform operational decisions, and an explanation of how trends in index ratings impact medium-term decisions such as maintenance and longer-term decisions such as capital investments, etc.).

SDG&E monitors and accounts for the contribution of weather to ignition probability and estimated wildfire consequence in its decision-making by integrating weather data and forecast modeling into its fire behavior and fire potential tools. WRRM-Ops, SDG&E's fire behavior modeling tool, was developed using 30 years of historical weather data. The FPI, another fire modeling tool, leverages weather data into the fire potential that is updated daily. These tools provide forecasters with information on the probability of ignition and the potential for wildfire to grow rapidly.

When specifically looking at the PoI, major contributing factors are atmospheric vapor pressures and the resulting dead fuel moistures of the finer fuels. These factors are incorporated into the FPI through fuel moisture and weather components and contribute to the daily index ranking which ranges from Normal to Extreme and carries increasing levels of work restrictions. Updated local known weather conditions are also incorporated into system hardening projects and construction standards to assist with forecasting of longer-term investments.

B. Describe how the utility monitors and accounts for the contribution of fuel conditions to ignition probability and estimated wildfire consequence in its decision-making, including describing any proprietary fuel condition index (or other measures tracked), the outputs of said index or other measures, and the methodology used for projecting future fuel conditions. Include discussion of measurements and units for live fuel moisture content, dead fuel moisture content, density of each fuel type, and any other variables tracked. Describe the measures and thresholds the utility uses to determine extreme fuel conditions, including what fuel moisture measurements and threshold values the utility considers "extreme" and its strategy for how fuel conditions inform operational decision-making.

SDG&E monitors and accounts for the contribution of fuel conditions to ignition probability and estimated wildfire consequence in its decision-making by integrating all collected weather data and forecast modeling into its fire behavior and fire potential tools. Fuel conditions are not projected outside of the 7-day forecast period of the FPI. Fuel moisture data available from the Remote Automated Weather Stations (RAWS) and fire agencies is closely monitored, including the Energy Release Components, Live Fuel Moisture Percentages through the National Fuels Database, and the number of grams of water that are measured in the 1-, 10-, 100- and 1000-hour fuels across the region. Live Fuel Moisture values are considered extreme when the reading falls below 60 percent.

This information is also modeled daily on SDG&E computers for integration into fire behavior and fire potential tools. When incorporating dead fuel moistures into the FPI, 10-hour fuel moistures are integrated because this number best represents the dead fuel component of the chaparral that drives the most extreme wildfires. The dead fuel component is considered extreme when the measurements fall below 6 grams. Dead fuels are wildland fuels whose moisture contents are controlled exclusively by changing weather conditions. Examples include dead herbaceous fuels, dead roundwood, fallen dead leaves and needles, and the litter of the forest floor. Dead fuels are divided into four "timelag" categories: 1-hour, 10-hour, 100-hour, and 1000-hour fuels. The shorter the timelag, the more responsive the fuel is to changing weather conditions. For example, 1-hour fuels only take on the order of one hour to respond to changing weather conditions, which explains why fire danger can be very high even right after a heavy rain if the subsequent weather conditions allow the 1-hour fuels to dry out. Samples are taken from standing dead trees, shrubs, or grasses. Dead fuel moisture can also be calculated from observed or forecast weather data. Model calculations of 1-hour, 10-hour, 100-hour, and 1000-hour fuel moisture are routinely made at SDG&E. The FPI uses 10-hour Dead Fuel Moisture inputs and the values can range from 1 percent to 60 percent. Ten-hour fuels are smaller diameter dead fuels in the 0.25 inch to 1 inch diameter range.

4.2.1 Service Territory Fire-Threat Evaluation and Ignition Risk Trends

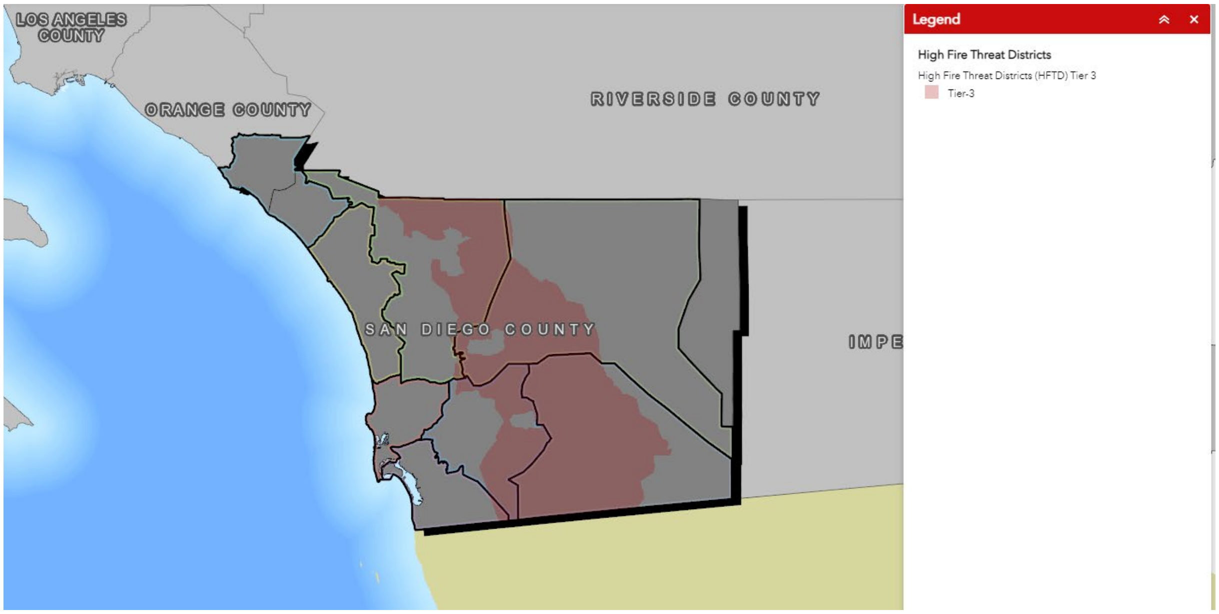
Instructions: *Present a map of the highest risk areas identified within the current High Fire Threat District (HFTD) tiers of the utility's service territory as a figure in the WMP. Discuss fire threat evaluation of the service territory to determine whether a modification to the HFTD is warranted (i.e., expansion beyond existing Tier 2 and Tier 3 areas). If the utility believes there are areas in its service territory that are not currently included in the HFTD but require prioritization for mitigation efforts, then the utility is required to provide a process outlining the formal steps necessary to have those areas considered for recognition in the CPUC-defined HFTD.[20] Include a discussion of any fire threat assessment of its service territory performed by the electrical corporation, highlighting any changes since prior WMP submissions. In the event that the utility's assessment determines the fire threat rating for any part of its service territory is insufficient (i.e., the actual fire threat is greater than what is indicated by the CPUC's Fire Threat Map and High Fire Threat District designations), the utility is required to identify those areas for potential HFTD modification, based on the new information or environmental changes, showing the differences on a map in the WMP. To the extent this identification relies upon a meteorological or climatological study, a thorough explanation and copy of the study must be included as an Appendix to the WMP.*

List, describe, and map geospatially (where geospatial mapping is applicable) any macro trends impacting ignition probability and estimated wildfire consequence within utility service territory, highlighting any changes since the 2021 WMP Update:

SDG&E closely examines its entire service territory on a regular basis and has identified areas where there is a potential increase in fire potential due to the presence of vegetation outside of the HFTD, though the risk does not elevate to the level of a Tier 2 designation in the HFTD. As circumstances evolve, SDG&E will continue to assess areas of its service territory for potential inclusion in the HFTD or non-HFTD Wildland Urban Interface (WUI) areas. The highest risk area is HFTD Tier-3, as noted in Figure 4-13.

[20] As there is no formal or standard process for modifying the HFTD maps defined by the CPUC, Utilities may utilize a similar approach adopted by SCE during the 2019 WMP review process described in D.19-05-038, p. 53. For this process, in August 2019 SCE submitted a petition to modify D.17-12-024 to recognize SCE-identified HFRA as HFTD Tier 2 areas.

Figure 4-13: HFTD Tier 3 in SDG&E Service Territory



1. *Change in ignition probability and estimated wildfire consequence due to climate change*

The data collected in 2021 shows that rainfall totals for the water year (year ending September 30, 2021) measured roughly 50 percent of normal across much of the HFTD within the service territory, which led to critically low fuel moistures region-wide through the summer and early fall. Below-normal rainfall totals and significant drought conditions were seen statewide in 2021, which contributed to an increased wildfire consequence that can be, in part, attributed to climate change.

Refer to Section 7.3.1 Risk Assessment and Mapping for a map of medium and long-term climate trends.

2. *Change in ignition probability and estimated wildfire consequence due to relevant invasive species, such as bark beetles*

Invasive pests are a natural component of the urban and rural forest ecosystem, and tree mortality can be an expected result of pest activity. Consequently, ignition probability may be expected to increase if the scale of tree mortality were to increase, and if the affected trees were located within the strike zone of overhead electrical facilities.

The most significant invasive pest that continues to impact trees within the service territory is the Gold Spotted Oak Borer (GSOB), *Agrilus auroguttatus*. The potential suitable habitat for GSOB is fairly widespread throughout San Diego County and the pest is estimated to have killed approximately 80,000 trees since its introduction in 2004. Most of the host trees for GSOB and the suitable habitat for this pest species are located within the HFTD.

Rancho Santa Fe is an enclave within San Diego County located east of Del Mar that includes a high volume of eucalyptus trees first introduced in the nineteenth century for possible use in the making of railroad ties. In much of this area, eucalyptus is a monoculture which presents a high risk to property if a wildland fire were to burn through the tree crowns. A few significant pests pose a threat to the eucalyptus, and episodically may cause relatively widespread tree mortality. These pests include the Eucalyptus Longhorned Borer (*Phoracantha recurva*) and the Lerp-Psyllid *(Glycaspis brimblecombei).*

Though the challenges with invasive pest species will likely persist for years to come, through its routine inspection activities and enhanced hazard tree inspections within the HFTD, SDG&E has been able to identify and mitigate trees infected by invasive pests that could pose a threat to the power lines.

3. Change in ignition probability and estimated wildfire consequence due to other drivers of change in fuel density and moisture

During 2021, the lack of rainfall during the late winter and early spring months combined with above average temperatures to exacerbate drought conditions, which ultimately had an impact on the fuel moistures across the service territory, increasing wildfire probability and potential consequence. SDG&E did not observe any major change in fuel density in 2021.

4. Population changes (including Access and Functional Needs population) that could be impacted by utility ignition

Since the 2021 WMP was submitted, the number of new customer accounts opened in the HFTD has increased by approximately 3 percent. Additionally, the number of customers in the HFTD identified as having AFN has increased by approximately 5 percent (see Table 4-5).

Table 4-5: 2022 HFTD Population Trends

2022 HFTD Population Trends	
New customer accounts opened in HFTD	Increased by approximately 3%
Number of customers in individuals with AFN identified in HFTD	Increased by approximately 5%

Customers in the following categories within SDG&E's database(s) are considered to be AFN:

- Customers enrolled in the following programs: California Alternative Rates for Energy (CARE), Family Electric Rate Assistance (FERA), Medical Baseline (MBL), Temperature Sensitive
- Customers who receive their utility bill in an alternate format: Braille, Large Font Bill
- Customers whose preferred language is a language other than English
- Customers who self-identify to receive an in-person visit prior to disconnection for nonpayment or self-identify as having a person with a disability in the household: disabled deaf/hearing impaired; disabled blind/vision impaired; disability – not defined
- Customers who self-identify as having an AFN (new in 2021)

5. Population changes in HFTD that could be impacted by utility ignition

As shown in Table 4-5, there was an approximate 3 percent increase in new customer accounts from 2021 through 2022 in the HFTD. For population data, SDG&E references census data. Census data is only collected once every 10 years, so true population increases are measured infrequently, however, they will be provided as census information is updated.

6. Population changes in WUI that could be impacted by utility ignition

Based on census information, there was no change for 2021.

7. Utility infrastructure location in HFTD vs non-HFTD

See Table 8 in Attachment B.

8. Utility infrastructure location in urban vs rural vs highly rural areas

See Table 8 in Attachment B.

4.3 Change in Ignition Probability Drivers

Instructions: *Based on the implementation of the above wildfire mitigation initiatives, explain how the utility sees its ignition probability drivers evolving over the 3-year term of the WMP, highlighting any changes since the 2021 WMP Update. Focus on ignition probability and estimated wildfire consequence reduction by ignition probability driver, detailed risk driver, and include a description of how the utility expects to see incidents evolve over the same period, both in total number (of occurrence of a given incident type, whether resulting in an ignition or not) and in likelihood of causing an ignition by type. Outline methodology for determining ignition probability from events, including data used to determine likelihood of ignition probability, such as past ignition events, number of risk events, and description of events (including vegetation and equipment condition).*

Over the past year, climate science has indicated an ongoing trend towards the continuation of warmer and drier conditions which leads to the possibility of a greater number of large fires. This, in turn, leads to an increase in ignitions from all sources. SDG&E's wildfire mitigation initiatives continue to address both the likelihood of an ignition and the reduction of the consequences of an ignition should one occur. SDG&E will continue to analyze data gathered through its mitigation initiatives to identify increased areas of risk and inform mitigation activities.

In the study performed in Section 4.4.2.1 Determination of Average Distribution Ignition Percentages by Location and Operating Risk Condition, the calculation of ignition probability from risk events is detailed. At a high level, a 5-year history of risk event data and ignition data was used by HFTD tiers and FPI ratings to demonstrate the impacts of location and weather on ignition probability. The study shows that ignitions are more likely to occur in the HFTD than in the non-HFTD, that ignitions are more likely to occur on days with an FPI rating of Extreme days than days with an FPI rating of Elevated, and more likely to occur on days with an FPI rating of Elevated compared to days with an FPI rating of Normal.

Tables 7.1 and 7.2 in Attachment B highlight SDG&E's forecasted change in probability drivers. To create these tables, a Risk Reduction Estimation Methodology was developed for every mitigation that directly mitigates wildfire risk in the WMP in order to calculate risk events and ignitions reduced per year. Mitigations and the list of drivers were then analyzed to determine all drivers that apply. For example, undergrounding impacts all drivers including equipment failures, foreign object in line contacts, and vehicle contacts, whereas covered conductor mitigates all those drivers with the exception of vehicle contacts. Other mitigations such as enhanced vegetation management only impact the vegetation contact driver.

Once the mitigations were allocated to the drivers, the reduction of risk events (and eventually ignitions) were applied mitigation-by-mitigation as a proportion of the risk events by driver over total risk events mitigated. See Figure 4-14 for the risk reduction estimation calculation.

Figure 4-14: Risk Reduction Estimation Calculation

For Example, SDG&E has 78 risk events per year for animal contact and a total of 1,048 risk events per year overall (based on a 5-year average of historical risk events from 2015-2019). Overhead fire hardening work completed in 2020 is estimated to result in 8.7 fewer risk events in 2021 and beyond. Using this data, the risk reduction estimation calculation can be used to find the contribution of fire hardening in 2020 towards the forecasted reduction for animal contacts.

$$\frac{78 \times 8.7}{1048} = 0.647$$

The calculation shows that there will be an estimated 0.647 fewer risk events from animal contacts after the fire-hardening work completed in 2020.

This exercise was completed for forecasted ignitions in a similar manner, converting risk events reduced to ignitions reduced leveraging the study in Section 4.4.2.1, breaking down the ignitions reduced into HFTD Tiers as required by Table 7.2 in Attachment B and providing RSE results by HFTD Tier.

Table 4-6 shows the prioritization of various risk drivers. Prioritization rationale is based on historical ignition and outage counts associated to each risk driver over a specified span of time. Average outage counts over the span of time are multiplied by the average ignition rate to find the adjusted risk score for each risk driver. Average ignition rate is found by dividing ignition counts by outage counts. The ranking of this adjusted risk score from highest to lowest is utilized to create a prioritized list among the various risk drivers.

Table 4-6: Prioritized List of Wildfire Risks and Drivers

Cause category (final)	Sub-cause category (final)	Average Outage (2015-2019)	Average Ignition rate (Sum of Ignitions ÷ Sum of Outages)	Adjusted Risk (Avg. Outage x Ignition Rate)	Risk Ranking
Contact from object	Vehicle contact	96.4	3.73%	3.60	1
Contact from object	Balloon contact	95.8	3.76%	3.60	1
Contact from object	Veg. contact	43.8	7.31%	3.20	2
Contact from object	Other contact from object	46.0	3.48%	1.60	3
Equipment / facility failure	Other	14.2	11.27%	1.60	3
Equipment / facility failure	Conductor damage or failure	59.6	2.01%	1.20	4
Contact from object	Animal Contact	78.0	1.28%	1.00	5
Equipment / facility failure	Transformer damage or failure	54.2	1.48%	0.80	6
Equipment / facility failure	Lightning arrestor damage or failure	24.8	2.42%	0.60	7
Equipment / facility failure	Switch damage or failure	13.4	4.48%	0.60	7
Equipment / facility failure	Wire-to-wire contact / contamination	4.6	13.04%	0.60	7
Equipment / facility failure	Unknown	0.1.8	0.20%	0.60	7
Equipment / facility failure	Fuse damage or failure	70.8	0.56%	0.40	8
Equipment / facility failure	Anchor / guy damage or failure	1.8	22.22%	0.40	8
Equipment / facility failure	Vandalism / Theft	2.4	16.67%	0.40	8
Vandalism / Theft	Capacitor bank damage or failure	8.8	2.27%	0.20	9
Equipment / facility failure	Crossarm damage or failure	20.2	0.99%	0.20	9
Equipment / facility failure	Pole damage or failure	40.8	0.00%	0.00	10
Equipment / facility failure	Insulator and brushing damage or failure	7	0.00%	0.00	10
Equipment / facility failure	Recloser damage or failure	1.4	0.00%	0.00	10
Equipment / facility failure	Voltage regulator / booster damage or failure	0.4	0.00%	0.00	10
Contamination	Contamination	0.6	0.00%	0.00	10

Cause category (final)	Sub-cause category (final)	Average Outage (2015-2019)	Average Ignition rate (Sum of Ignitions ÷ Sum of Outages)	Adjusted Risk (Avg. Outage x Ignition Rate)	Risk Ranking
Utility work / Operation	Utility work	7.6	0.00%	0.00	10
Other	All Other	0.4	0.00%	0.00	10

4.4 Research Proposals and Findings

Instructions: *Report all utility-sponsored research proposals, findings from ongoing studies and findings from studies completed in 2020 and 2021 relevant to wildfire and Public Safety Power Shutoff (PSPS) mitigations.*

4.4.1 Research Proposals

Instructions: *Report proposals for future utility-sponsored studies relevant to wildfire and PSPS mitigation. Organize proposals under the following structure:*

1. ***Purpose of research*** *– brief summary of context and goals of research*
2. ***Relevant terms*** *- Definitions of relevant terms (e.g., defining "enhanced vegetation management" for research on enhanced vegetation management)*
3. ***Data elements*** *- Details of data elements used for analysis, including scope and granularity of data in time and location (i.e., date range, reporting frequency and spatial granularity for each data element, see example table below)*
4. ***Methodology*** *- Methodology for analysis, including list of analyses to perform; section must include statistical models, equations, etc. behind analyses*
5. ***Timeline*** *- Project timeline and reporting frequency to the Office of Energy Infrastructure Safety*

Academic Partnerships

<u>Cal Poly WUI FIRE Institute</u>

To mitigate the consequences of WUI fires on life, property, infrastructure, economy, and the social fabric of California, SDG&E partnered with the California Polytechnic State University, San Luis Obispo (Cal Poly) WUI FIRE Institute. This institute studies the relationship between wildfires and the WUI. It has the goal of becoming a center of excellence that makes significant contributions to solving the WUI fire problem through research and education that innovates; informs policy; disseminates information; and educates students, professionals, and stakeholders to reduce WUI fire consequences, costs, and losses.

The WUI FIRE Institute will use a multi-discipline, systems-based approach that focuses on education and research factors influencing WUI fire. The Institute seeks to connect multiple public and private stakeholders to establish Statewide research priorities, collect and disseminate information, convene stakeholder dialogues, guide workforce education and training, and inform policy.

<u>Fire Science Innovation Lab</u>

The Fire Science Innovation (FSI) lab is being developed in collaboration with San Jose State University to foster an environment that supports collaborative research with academia to help scientists focus on issues specific to the utility industry, preparing them for future employment in wildfire mitigation-related work.

In 2021, SDG&E and the FSI lab team successfully competed for a grant from the National Science Foundation to match industry funding and create the Wildfire Interdisciplinary Research Center (WIRC). This new center is now an official National Science Foundation Industry-University Cooperative Research Center (IUCRC) and will focus on all aspects of wildfire science and management to better understand fire in California and around the world with a core mission of conducting high-impact wildfire research so that improved tools and policies can be provided to the community and industry stakeholders.

4.4.1.1 Environmental Impacts of Wildfires vs Wildfire Mitigation Measures

1. Purpose of research

To comply with all applicable regulatory requirements, Operations and Maintenance (O&M) and WMP projects many times will require implementation in areas under the purview of state agencies. Regulatory oversight of these activities can vary by agency and regional office. Agencies such as California State Parks often require multiple step reviews under complex O&M plans. For WMP projects such as overhead electric facility hardening or undergrounding, state agencies, including the California Department of Transportation (Caltrans), will often take issue with applicable California Environmental Quality Act (CEQA) Categorical Exemptions due to the potential for triggering environmental impacts that would indicate an exception to their use.

Additionally, preventative and post-fire vegetation and fuel management must occasionally occur outside of designated Rights of Way (ROWs) and easements within agency lands. This includes tree fall mitigation and access road maintenance. This work can trigger agency discretionary review due to the need to widen easements or the issuance of temporary encroachment permits. These discretionary actions on state lands trigger additional CEQA review processes, resulting in long review times and sometimes significant environmental impact analyses.

There is a CEQA Statutory Emergency Exemption in place, adopted in the revised CEQA Guidelines in 2018, that could potentially exempt CEQA review for WMP and O&M projects that reduce fire risk in certain circumstances:

This research proposal from the IOUs and the Cal Poly WUI FIRE institute aims to answer the question:

- Where existing information is available from environmental documentation, are localized impacts from IOU vegetation and fuels management within and adjacent to easements/ROWs, hardening of existing electric lines, and undergrounding of electric lines within existing roadways and other linear features nominal relative to catastrophic wildfire impacts?

The information can provide justification and confidence that the use of the Statutory Emergency Exemption, given the applicability of the WMP activities and catastrophic wildfire impacts to be avoided, is appropriate and significantly protective of the environment from a big picture perspective.

2. Relevant terms

WUI FIRE Institute	Academic Research Entity under Cal Poly State University San Luis Obispo
CEQA	State of California Environmental law requiring state and local agencies consider environmental impact and obtain public input of projects that trigger discretionary agency approval
CEQA Categorical Exemptions	An exemption to completing full environmental review of projects triggering discretionary environmental review that meet certain project description criteria and is can be shown that there is no potential for adverse environmental impacts

Statutory Emergency Exemption	An exemption to triggering any CEQA review that meet the definition of the exemption regardless of whether there is a potential for adverse environmental impacts

3. Data elements

Environmental effects of averaged catastrophic fire events by major vegetation type relative to impacts from WMP activities that mitigate wildfire risk as defined by the CEQA Statutory Emergency Exemption.

Data Element	Collection Period	Collection Frequency	Spatial Granularity	Temporal Granularity	Comment
Representative Fire Events Data and Modeling by Major Veg Type within IOU Service Territories	Approx. one month from research initiation	As required	Defined by catastrophic fire event samples by major veg type within IOU service territories	Fire events over the past 10 years	
Short term greenhouse gas and toxic air quality impacts	Initial Document Research after fire events averaged and identified	As required	By Major Veg Type within IOU Service Territories	Documentation over the past 10 years	
Long term GHG and toxic air quality impacts	Initial Document Research after fire events averaged and identified	As required	By Major Veg Type within IOU Service Territories	Documentation over the past 10 years	
Loss of wildlife including Threatened & Endangered species	Initial Document Research after fire events averaged and identified	As required	By Major Veg Type within IOU Service Territories	Documentation over the past 10 years	
Habitat type-change	Initial Document Research after fire events averaged and identified	As required	By Major Veg Type within IOU Service Territories	Documentation over the past 10 years	
Land use and development impacts	Initial Document Research after fire events averaged and identified	As required	By Major Veg Type within IOU Service Territories	Documentation over the past 10 years	
Societal impacts	Initial Document Research after fire events averaged and identified	As required	By Major Veg Type within IOU Service Territories	Documentation over the past 10 years	

4. Methodology

1. Identify representative past catastrophic fire events for each IOU in representative vegetation and land development settings to include potentially inland coastal sage and chaparral, coastal canyon, open space urban interface, and dense forest urban interface.

2. Use existing fire extent documentation, fire modeling, and GIS analysis to develop baseline information to estimate environmental impacts from several representative catastrophic wildfire events. Utilize existing estimates and data when available to develop impacts.

3. Use existing environmental review documentation prepared under National Environmental Protection Act (NEPA) and CEQA that document impacts from WMP utility activities including fire hardening, undergrounding, vegetation, and fuels management occurring within the representative vegetation and land development settings for the IOUs and provide averaged comparative environmental impacts from these activities.

5. Timeline

Draft results by Quarter 1 of 2022 with a final report completed by Quarter 2 of 2022.

4.4.2 Research Findings

Instructions: *Report findings from ongoing and completed studies relevant to wildfire and PSPS mitigation. Organize findings reports under the following structure:*

1. ***Purpose of research*** *– Brief summary of context and goals of research*
2. ***Relevant terms*** *- Definitions of relevant terms (e.g., defining "enhanced vegetation management" for research on enhanced vegetation management)*
3. ***Data elements*** *- Details of data elements used for analysis, including scope and granularity of data in time and location (i.e., date range, reporting frequency and spatial granularity for each data element, see example table above)*
4. ***Methodology*** *- Methodology for analysis, including list of analyses to perform; section must include statistical models, equations, etc. behind analyses*
5. ***Timeline*** *- Project timeline and reporting frequency to the Office of Energy Infrastructure Safety. Include any changes to timeline since last update*
6. ***Results and discussion*** *– Findings and discussion based on findings, highlighting new results and changes to conclusions since last update*
7. ***Follow-up planned*** *– Follow up research or action planned as a result of the research*

4.4.2.1 Determination of Average Distribution Ignition Percentages by Location and Operating Risk Condition

1. Purpose of Research

The purpose of this study was to determine the average distribution ignition percentages by location (e.g., non-HFTD, Tier 2 of HFTD, and Tier 3 of HFTD) and by operating risk condition (e.g., when the FPI rating is Normal, Elevated, or Extreme). The risk of ignition is greater in the HFTD and in elevated and extreme operating conditions. By comparing the risk events to ignitions tranched by different locations and operating conditions, the difference in risk in terms of ignition probability can be quantified. This also has the additional benefit of providing ignition percentage values for the purposes of improved RSE calculations and improved risk modeling.

2. Relevant Terms

Tier 3 HFTD	Per the CPUC Fire-Threat Map, the "Tier 3 fire-threat areas depict areas where there is an extreme risk (including likelihood and potential impacts on people

	and property) from utility associated wildfires.[21]" For the purposes of this study, Tier 3 represents all of the Tier 3 HFTD area within the service territory.
Tier 2 HFTD	Per the CPUC Fire-Threat Map, the "Tier 2 fire-threat areas depict areas where there is an elevated risk (including likelihood and potential impacts on people and property) from utility associated wildfires.[22]" For the purposes of this study, Tier 2 represents all of the Tier 2 HFTD area within the service territory.
Locations outside the HFTD	All other areas within the service territory that are not part of the Tier 2 or Tier 3 HFTD.
Normal FPI	An FPI value of 11 or less represents a normal fire potential based upon combined green-up, fuels, and weather measurements.
Elevated FPI	An FPI value of 12 to 14 represents an elevated risk of fire potential based upon combined green-up, fuels, and weather measurements.
Extreme FPI	An FPI value of 15 or greater represents an extreme risk of fire potential based upon combined green-up, fuels, and weather measurements.
Risk Event	All overhead system faults, meaning any overhead electrical fault caused by foreign object in line, equipment failure, other or of undetermined cause that impacts the primary electric distribution system (12kV and 4kV systems). An electrical fault includes an electrical system short that results in energy created in the form of heat.
Ignition	CPUC reportable ignitions (as defined by D.14-02-015).[23]

3. Data Elements

Data Element	Collection Period	Collection Frequency	Spatial Granularity	Temporal Granularity	Comment
Risk Events	2016-2020 Updated Annually as a running 6-year average	Per risk event	Lat/long per risk event, filtered by Tier 3, Tier 2, or non-HFTD	Date of risk event filtered by FPI rating of Extreme, Elevated, or Normal	
Ignition	2016-2020 Updated Annually as a running 6-year average	Per risk event	Lat/long per risk event, filtered by Tier 3, Tier 2, or non-HFTD	Date of risk event filtered by FPI rating of Extreme, Elevated, or Normal	

4. Methodology

1. The 5-year reliability dataset, including all outages, was converted into risk events.
2. An overhead outage filter was created.

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[21] See https://www.arcgis.com/apps/webappviewer/index.html?id=5bdb921d747a46929d9f00dbdb6d0fa2

[22] Ibid

[23] Per D.14-02-015, Appendix C at C-3, a reportable ignition is "[a] self-propagation fire of material other than electrical and/or communication facilities, … [t]he resulting fire traveled greater than one linear meter from the ignition point, and … [t]he utility has knowledge that the fire occurred."

3. Using the to and from structure fields which represents the outage/fault location, data was filtered to only include structures that represented overhead facilities.
4. A small subset of data did not use a facility ID in the to or from structure fields but instead utilized an equipment ID. The equipment ID was queried to find the facility ID associated with the equipment, and then applied the overhead filter to those structures.
5. If the to and from structure fields were blank (which always will be the case for undetermined outages), the lead system device location was used if the downstream system is overhead.[24]
6. Once the overhead filter was applied, additional cause code filters were applied to remove any additional underground outages the overhead filter may have missed and to remove any outages that were not faults from the risk event data set. This includes codes like “de-energized for safety” which is an outage to customers but not a fault on the system, and “faulted cables” which are underground only.
7. To apply the HFTD Tier 3 and Tier 2 filter, the to and from structure fields were used to identify the structure where the risk event occurred by querying the GIS HFTD layer to determine whether the structure was in the Tier 3 HFTD, the Tier 2 HFTD, or the non-HFTD.
8. For the small set of data that did not have data in the to and from structure fields, the isolating device structure was used as an approximation for the risk event location. If the isolating device was a circuit breaker, the HFTD location of the associated substation was applied.
9. If the HFTD location of a risk event could not be identified based on the from structure, to structure, or isolation device fields, then a circuit approximation was used. The circuit approximation assumed that if 50 percent or more circuit miles were non-HFTD, then the risk event was non-HFTD. If the circuit was 50 percent or more within the HFTD, then the majority of the circuit mileage would determine if it was classified as Tier 2 or Tier 3.
10. To apply the normal, elevated, and extreme filter, FPI data was applied per district-to-district location within the risk event data set to organize the faults into the appropriate categories.

5. Timeline

This study will be updated annually and reported to WSD during all WMP filings and annual updates. The data will use a rolling 6-year average to keep the ignition percentages relevant with current mitigations.

6. Results and discussion

The results of this study validate certain assumptions about the PoI (see Table 4-7). Over the last 5 years:

- A fault in the HFTD was twice as likely to cause to an ignition as a fault in the non HFTD.
- A fault in the HFTD during a day with an FPI of Extreme was 5 times more likely to cause an ignition than on a day with an FPI of Normal.

While ignition probability has historically been higher in Tier 2 than Tier 3, this does not take into account the risk of an ignition to develop into a fire of consequence. Even though the ignition probability

[24] This is an adjustment to the previously used methodology to provide more accurate data.

is shown to be higher in Tier 2, the risk of wildfire is higher in Tier 3 due to the impact of the risk equation.

Table 4-7: Five-Year Average Ignition Rate

Location	Normal FPI	Elevated FPI	Extreme FPI	All FPI
Non-HFTD	1.10%	2.31%	0.00%	1.32%
Tier 2	1.60%	4.95%	12.12%	3.08%
Tier 3	1.76%	4.90%	9.52%	3.09%
System	1.30%	3.78%	6.32%	2.03%
HFTD (Tier 2 and Tier 3)	1.67%	4.92%	11.11%	3.08%

7. Follow-up planned

SDG&E plans to utilize these results to estimate ignition reductions in the HFTD Tiers so that RSEs can be calculated for various mitigations per Office of Energy Infrastructure Safety (OEIS) guidance in WMP Table 12.

4.4.2.2 Understanding the Effectiveness of Recloser Protocols

1. Purpose of Research

Prior to 2017, SDG&E was disabling reclosing in the HFTD on days with an FPI of Elevated and Extreme. After 2017, reclosing is disabled in the HFTD all year regardless of the FPI rating to further reduce the risk of ignitions from risk events. This study reviewed historical risk events that were isolated by reclosers to measure the effectiveness of disabling reclosing at reducing faults and ignitions over the last 6 years.

2. Relevant Terms

Tier 3 HFTD	Per the CPUC Fire-Threat Map, the "Tier 3 fire-threat areas depict areas where there is an extreme risk (including likelihood and potential impacts on people and property) from utility associated wildfires." For the purposes of this study, Tier 3 represents all of the Tier 3 HFTD area within the service territory.
Tier 2 HFTD	Per the CPUC Fire-Threat Map, the "Tier 2 fire-threat areas depict areas where there is an elevated risk (including likelihood and potential impacts on people and property) from utility associated wildfires." For the purposes of this study, Tier 2 represents all of the Tier 2 HFTD area within the service territory.
Locations outside the HFTD	All other areas within the service territory that are not part of the Tier 2 or Tier 3 HFTD.
Normal FPI	An FPI value of 11 or less represents a normal fire potential based upon combined green-up, fuels, and weather measurements.
Elevated FPI	An FPI value of 12 to 14 represents an elevated risk of fire potential based upon combined green-up, fuels, and weather measurements.

Extreme FPI	An FPI value of 15 or greater represents an extreme risk of fire potential based upon combined green-up, fuels, and weather measurements.
Risk Event	All overhead system faults, meaning any overhead electrical fault caused by foreign object in line, equipment failure, other or of undetermined cause that impacts the primary electric distribution system (12kV and 4kV systems). An electrical fault includes an electrical system short that results in energy created in the form of heat.

3. Data Elements

Data Element	Collection Period	Collection Frequency	Spatial Granularity	Temporal Granularity	Comment
Risk Events	2016-2020 Updated Annually as a running 5-year average	Per risk event	Lat/long per risk event, filtered by Tier 3, Tier 2, or non-HFTD	Date of risk event filtered by Extreme, elevated, or normal	

4. Methodology

1. The 5-year reliability data set was converted into the 5-year risk event data set and was filtered into HFTD Tiers and FPI days as described in the Methodology Section of 4.4.2.1 Determination of Average Distribution Ignition Percentages by Location and Operating Risk Condition.
2. Data formatting pertaining to the FPI attributes were corrected and the data was refreshed.
3. The resulting data set was then filtered by isolating device to identify risk events that were isolated by reclosers. When automatic reclosing is enabled, a fault will close two additional times to see if it has cleared itself before the device locks out, leaving the sustained outage. It is assumed in this study that every time a fault occurred when reclosing is disabled, two additional faults were avoided.
4. The ignition percentage results from Section 4.4.2.1 were utilized to calculate the average annual ignitions avoided through this control.
5. An overhead/underground filter was applied to exclude downstream underground facilities which resulted in an upward driver of the 5-year ignition rates and a downward driver for estimated ignitions avoided.

5. Timeline

This study will be updated annually and report to the Wildfire Safety Division (WSD) during all WMP filings and annual updates. The data will use a rolling 5-year average to keep the ignition percentages relevant with current mitigations.

6. Results and discussion

The results of this study show that disabling reclosing reduces an average of 5.0 ignitions per year in Tier 2 of the HFTD and 4.5 ignitions per year in Tier 3 of the HFTD (see Figure 4-15).

Figure 4-15: Results of Reclosure Protocols in Ignition Avoidance

Recloser Protocol		Faults By Tier And Weather Condition								
		Non-HFTD			Tier 2			Tier 3		
	Year	Normal	Elevated	Extreme	Normal	Elevated	Extreme	Normal	Elevated	Extreme
Faults isolated by reclosers	2016	216	22	1	80	20	3	55	28	0
	2017	169	44	5	52	32	4	42	20	2
	2018	144	39	9	37	30	5	43	36	2
	2019	155	23	0	59	39	2	45	43	1
	2020	89	35	3	34	34	1	24	44	0
	5 yr Avg	154.6	32.6	3.6	52.4	31.0	3.0	41.8	34.2	1.0

5 yr avg. Ignition Rate					
Tier 2			Tier 3		
Normal	Elevated	Extreme	Normal	Elevated	Extreme
1.60%	4.95%	12.12%	1.76%	4.90%	9.52%

Adjusted for application of mitigation to calculate faults		Estimated Faults Avoided						Estimated Ignition Avoided		
		Tier 2			Tier 3			Tier 2	Tier 3	Total
	Year	Normal	Elevated	Extreme	Normal	Elevated	Extreme			
Applied DOP 3027 as written	2016		40	6		56	0	2.7	2.7	5.5
	2017		64	8		40	4	4.1	2.3	6.5
All reclosing left off in the HFTD year around, above and beyond policy requirements	2018	74	60	10	86	72	4	5.4	5.4	10.8
	2019	118	78	4	90	86	2	6.2	6.0	12.2
	2020	66	68	2	48	88	0	4.7	5.2	9.8
	5 yr Avg	86.0	62.0	6.0	74.7	68.4	2.0	4.6	4.3	9.0

7. Follow-up planned

The results of this study will be utilized as the PoI component of the RSE calculations for the 2022 WMP Update. Next year the study will refine the assumption that all recloser operations would be closing into sustained faults. Not all faults are sustained, and a fault that clears itself would result in a re-energization with no fault.

Over the same data set period, the number of momentary outages that occur downstream of reclosures will be compared to how many result in sustained outages. This will develop a metric called % sustained. The new faults avoided algorithm would be faults downstream of disabled reclosing devices multiplied by two (reclosing operations) and multiplied by % sustained. The stated effectiveness of this program would be reduced by the resulting factor but would provide a more accurate result.

4.4.2.3 Impact of Overhead Distribution Hardening at Reducing Overhead Faults

1. Purpose of Research

The goal of this research is to determine the measured effectiveness of overhead distribution hardening on the distribution system in the unique conditions of San Diego County.

2. Relevant Terms

Project ID	Overhead hardening was broken down into projects that varied in size from one structure to many structures. Structures in these projects were utilized to evaluate the reliability performance of these segments before and after the hardening project was completed.
Unhardened Risk Events	Risk events that occurred on the segments before overhead system hardening was completed.

Unhardened Years	The number of years the circuit segments associated with the project ID operated before hardening based on a 20-year reliability data set from 2000-2020.
Hardened Risk Events	Risk events that occurred on segments after overhead system hardening was completed.
Hardened Years	The number of years the circuit segments associated with the project ID operated after hardening based on a 21-year reliability data set from 2000-2020.
Miles	Number of circuit miles per project ID.

3. Data Elements

Data Element	Collection Period	Collection Frequency	Spatial Granularity	Temporal Granularity	Comment
Unhardened Risk Events	2000-2020	Per risk event	To/from structure	Date and time	
Hardened Risk Events	2000-2020	Per risk event	To/from structure	Date and time	

4. Methodology

1. A list was compiled of completed overhead hardening projects from the Fire Risk Mitigation (FiRM) Program that began hardening work in 2014, including 214 projects representing 227 miles of overhead hardening. This dataset also included the structure number for every hardened structure and the completion date for each project.
2. Reliability data was compiled from 2000 through 2020 for the projects on their respective circuits. Additional improvements were made in streamlining the project data acquisition, applying an improved overhead/underground filter, and creating additional cause codes for the reliability data set. The risk event data included the location where the risk event occurred in the to and from structure fields.
3. To and from fields in the risk event data set were compared to the project structure field in the project data set. When the structures matched, the risk event date was checked against the project completion date to determine if the risk event occurred before or after the overhead hardening project was completed.
4. For each project, the number of risk events that occurred before and after the hardening project were totaled. Operating years before and after the hardening were also calculated, as well as project miles for the purposes of normalizing the dataset.
5. Averages for the number of unhardened risk events per project were, the number of unhardened operating years per project, the number of hardened risk events per project, the number of hardened operating years per project, and the number of miles per project were calculated.
6. The average risk event per operating year per 100 miles before hardening was calculated and compared to the average risk event per operating year per 100 miles after hardening.

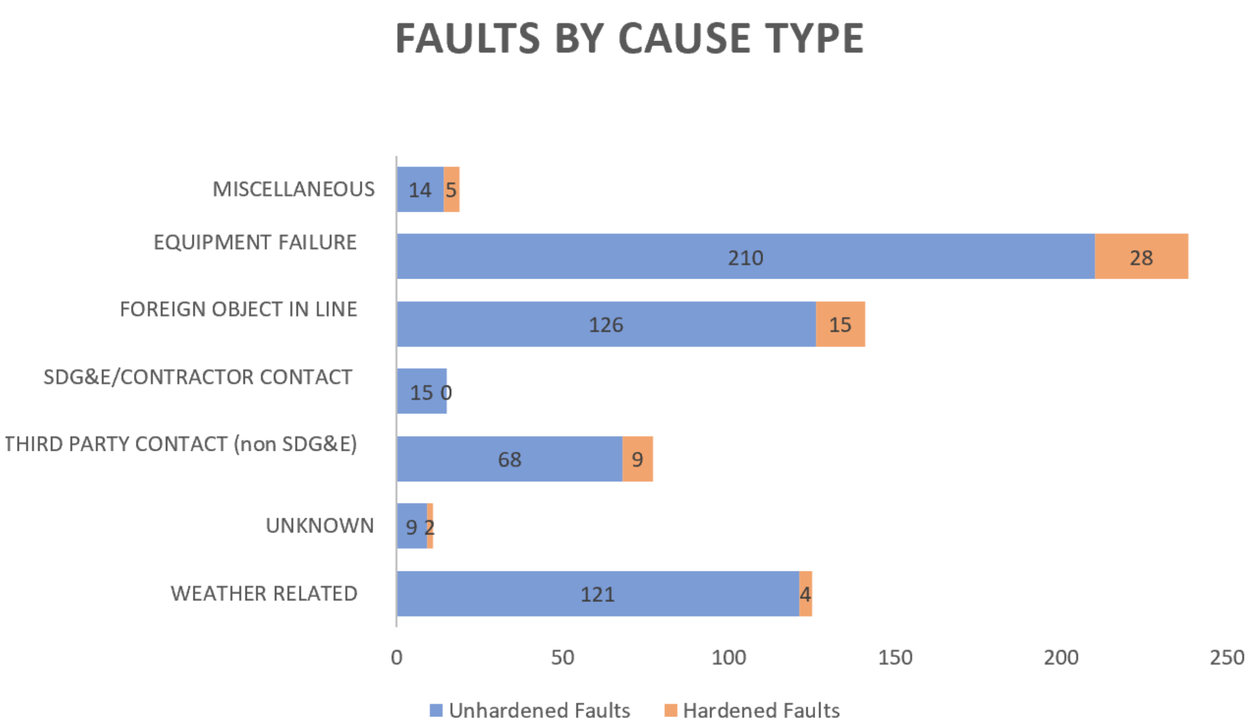
5. Timeline

This research was initially completed in 2020 and will be updated on an annual basis with additional data for further refinement.

6. Results and discussion

On average, the unhardened system saw an average of 13.50 risk events per 100 miles per operating year while the hardened system saw an average of 7.49 risk events per 100 miles per operating year.[25] This represents a 45-percent reduction in risk in hardened system areas. Utilizing the ignition percentages from the study in Section 4.5.1.1 POI Model, this represents an estimated 0.20 less ignitions per year per 100 circuit miles in Tier 2 of the HFTD, and 0.16 less ignition per year per 100 circuit miles in Tier 3 of the HFTD. Figure 4-16 shows unhardened versus hardened faults by cause type.

Figure 4-16: Unhardened vs. Hardened Faults by Cause Type



7. Follow-up planned

SDG&E continues to update its risk models with the measured effectiveness calculations.

[25] Risk events that were of underdetermined cause and had no specific risk event structure ID were omitted from this study by necessity.

4.4.2.4 CAL FIRE Approved Expulsion Fuses vs Other Expulsion Fuses

1. Purpose of Research

The Expulsion Fuse Replacement Program's goal is to replace all expulsion fuses within the HFTD with new CAL FIRE approved fuses. CAL FIRE-approved fuses are designed to capture hot particles and debris that normally exit an expulsion fuse during a normal fuse operation. Therefore, the ignition rate of the new fuse should be less than the ignition rate of traditional expulsion fuses. This study was created to test that hypothesis.

2. Relevant Terms

Expulsion Fuse Operation	An expulsion fuse operating to isolate a fault on the electric distribution system
Ignition caused by Expulsion Fuse Operation	CPUC reportable ignition caused by the normal operation of an expulsion fuse operating to isolate a fault
CAL FIRE approved fuse operation	A CAL FIRE-approved fuse operating to isolate a fault on the electric distribution system
Ignition caused by CAL FIRE approved fuse operation	CPUC reportable ignition caused by the normal operation of a CAL FIRE-approved fuse operating to isolate a fault

3. Data Elements

Data Element	Collection Period	Collection Frequency	Spatial Granularity	Temporal Granularity	Comment
Risk event isolated by overhead expulsion fuse	2015-2020	Per Risk Event	Structure/lat long	Date and time	
Risk event isolated by overhead CAL FIRE approved fuse	2015-2020	Per Risk Event	Structure/lat long	Date and time	
Ignition caused by expulsion fuse operation	2015-2020	Per Ignition	Structure/lat long	Date and time	
Ignition Caused by CAL FIRE approved fuse	2015-2020	Per Ignition	Structure/lat long	Date and time	

4. Methodology

1. The GIS database was utilized to identify the locations and installation dates of new CAL FIRE approved fuses.
2. Risk event data from 2015 through 2020 was reviewed to identify all risk events isolated by overhead fuses, including counting separate events when multiple fuses operated (more than single phase) and if, during testing, the fuse operated.

3. The risk event isolating device structure and the risk event date was compared to the GIS database to determine if the risk event was isolated by a non-CAL FIRE-approved expulsion fuse or a CAL FIRE-approved expulsion fuse.

4. Fuse operation data was compared to the ignition database data to determine which fuse operations had led to an ignition.

5. Timeline

This study was completed in 2021. SDG&E plans to update this study annually, to quantify the effectiveness over time.

6. Results and discussion

When CAL FIRE-approved fuses were used, there was a reduction in ignition percentage from 0.10 percent to 0 percent (see Figure 4-16). Currently, there are not enough samples for the data to show a statistically significant reduction, however, the early results are promising.

Figure 4-17: Ignition Reduction using CAL FIRE-Approved Fuses

Cal-Fire Approved Fuse Operation 2015-2020	
Number of times Cal-fire fuse operated to isolate the fault	293
Ignition with Cal-Fire Fuse	0
Ignition Rate	0

Expulsion Fuse Operation 2015-2020	
Number of times expulsion fuse operated to isolate the fault	4110
Ignition with Expulsion Fuse	4
Ignition Rate	0.10%

Cal-Fire Fuse	Fuse Operation	Ignition	Ignition rate	**Expulsion Fuse**	Fuse Operation	Ignition	Ignition rate
Non-HFTD	24	0	0.00%	Non-HFTD	3040	3	0.10%
Tier 2	116	0	0.00%	Tier 2	627	0	0.00%
Tier 3	153	0	0.00%	Tier 3	443	1	0.23%

7. Follow-up planned

This study will be updated as more CAL FIRE approved fuses are installed. The data will be leveraged for the purposes of RSE calculations on the expulsion fuse replacement program.

4.4.2.5 Impact of Sensitive Relay Settings at Reducing Ignitions from Risk Events

1. Purpose of Research

During days with an FPI rating of Extreme or during RFWs, sensitive relay settings are enabled on reclosers within the HFTD and coastal circuits with fire risk. The sensitive relay settings should improve the sensitivity of fault detection, the speed at which faults are cleared, and reduces the energy of the fault as much as possible, which reduces the heat generated by a fault, which should lead to fewer ignitions. This study was created to test that hypothesis.

2. Relevant Terms

Recloser	A switching device designed to detect and interrupt faults.
Sensitive relay settings	May be referred to as 'Profile 3', is a setting applied to reclosers to improve the sensitivity of fault detection and the speed at which faults are cleared.
Extreme FPI	An FPI value of 15 or greater that represents an extreme risk of fire potential based upon combined green-up, fuels, and weather measurements.
RFW	A warning issued by the National Weather Service when warm temperatures, very low humidity, and stronger winds are expected to produce an increased risk of fire danger.
Risk Event	All overhead system faults, defined as an overhead electrical fault caused by foreign object in line, equipment failure, or of undetermined cause that impacts the primary electric distribution system (12kV and 4kV systems). An electrical fault includes an electrical system short that results in energy created in the form of heat.

3. Data Elements

Data Element	Collection Period	Collection Frequency	Spatial Granularity	Temporal Granularity	Comment
Risk event downstream of a device with sensitive relay settings enabled	2015-2020	Per Risk Event	Structure/lat long	Date and time	
Risk event downstream of device operating under normal conditions	2015-2020	Per Risk Event	Structure/lat long	Date and time	
Ignition downstream of a device with sensitive relay settings enabled	2015-2020	Per Ignition	Structure/lat long	Date and time	
Ignition downstream of device operating under normal conditions	2015-2020	Per Ignition	Structure/lat long	Date and time	

4. Methodology

1. The reliability data set was filtered to convert it to a risk event dataset that included the overhead filtering discussed in Section 4.4.2.1 Determination of Average Distribution Ignition Percentages by Location and Operating Risk Condition.
2. The data was further filtered to only include risk events that occurred downstream of devices with sensitive relay settings enabled.

3. The date, time, and location of these risks events were compared to ignition data to identify which ignitions occurred as a result of the filtered risk events.
4. An ignition rate was calculated from faults and ignitions that occurred downstream of reclosers with sensitive settings enabled.
5. This sensitive setting ignition rate was compared to the ignition rate of all other risk events and related ignitions downstream of recloser devices without sensitive settings enabled to determine the effectiveness of sensitive settings at reducing ignitions.

5. Timeline

This study was completed in 2020 and the research will be updated on an annual basis with additional data for further refinement.

6. Results and discussion

The study demonstrated a reduction in ignition percentage from 3.24 percent to 0 percent (see Table 4-8). During the last 6 years, there were zero ignitions by primary faults downstream of devices with sensitive relay settings enabled. While there are not enough samples for the data to show a statistically significant reduction, the early results are promising.

Table 4-8: Ignition Rate with Sensitive Relay Protection

Sensitive Relay Protection Analysis		System Analysis	
Total Risk Events	80	Total Risk Events	2468
Tier 2	45		
Tier 3	35		
Total Ignitions	0	Total Ignitions	80
Percent Ignition	0%	Percent Ignition	3.24%
		Percent decrease in ignition after SRP enabled	100%

7. Follow-up planned

This study will be updated as more data becomes available Results will be utilized as the PoI component of the RSE calculations for the 2021 WMP update.

4.4.2.6 Impact of Inspection Programs at Finding and Repairing Equipment Issues

1. Purpose of Research

The purpose of this study was to measure the effectiveness of repair timeframes at preventing equipment failures and to provide baseline data for the estimation of the effectiveness of inspection programs at preventing risk events and ignitions.

2. Relevant Terms

Infraction	GO 95 issues that were identified through SDG&E inspection programs.
Risk Event	All overhead system faults, defined as an overhead electrical fault caused by foreign object in line, equipment failure, or of undetermined cause that impacts the primary electric distribution system (12kV and 4kV systems). An electrical fault includes an electrical system short that results in energy created in the form of heat.

3. Data Elements

Data Element	Collection Period	Collection Frequency	Spatial Granularity	Temporal Granularity	Comment
Equipment related Risk Event	2015-2019	Per Risk Event	To/from structure	Date and time	
Equipment related Risk Event with a pending infraction	2015-2019	Per Risk Event	To/from structure	Date and time	
Structures with Pending Infractions	2015-2019	Per Structure	Lat/long	Date and time	

4. Methodology

1. Five years of reliability data and corrective maintenance data were queried.
2. The reliability data set was filtered into Risk Events as described in Section 4.4.2.1 Determination of Average Distribution Ignition Percentages by Location and Operating Risk Condition.
3. The data set was further filtered to look at equipment failures only which are the primary target of the corrective maintenance programs.
4. CMP data was queried to identify all infractions associated with structures and when those infractions were repaired.
5. To and from fields of the risk data set were used to identify structures that had risk events associated with structures that had pending corrective maintenance infractions.

5. Timeline

SDG&E will update this study on an annual basis and report out at the annual updates.

6. Results and discussion

These results show that the corrective maintenance program and repair times are effective at preventing equipment failures (see Table 4-9). For the purpose of estimating the effectiveness of inspections, the 0.34 percent of issues that led to failures over issues that were identified and repaired will be used as a forecast of what could fail if issues were not repaired within the 1-year maintenance timelines. This failure rate will be scaled up with severity of inspection findings.

Table 4-9: Risk Events with Pending Infractions Over Repaired Infractions

	5-Year Total	Annual Average
Risk events with pending infractions	8	2
Total equipment risk events	2,342	468
Risk event rate with pending infractions	0.34%	0.34%
Infractions repaired	14,133	2,827
Risk events with pending infractions over repaired infractions	0.000566051	0.000566

7. Follow-up planned

SDG&E will utilize the results of this study to support its inspection effectiveness model and plans to update this model annually when new data becomes available.

4.4.2.7 Impact of Distribution and Transmission Inspection Program on Faults Avoided Due to Fire Risk Infractions Repaired

1. Purpose of Research

The purpose of this study is to measure the effectiveness of each distribution and transmission inspection program by reviewing historical inspection data to determine faults and ignitions avoided.

2. Relevant Terms

Tier 3 HFTD	Per the CPUC Fire-Threat Map, the “Tier 3 fire-threat areas depict areas where there is an extreme risk (including likelihood and potential impacts on people and property) from utility associated wildfires.” For the purposes of this study, Tier 3 represents all of the Tier 3 HFTD area within the service territory
Tier 2 HFTD	Per the CPUC Fire-Threat Map, the “Tier 2 fire-threat areas depict areas where there is an elevated risk (including likelihood and potential impacts on people and property) from utility associated wildfires.” For the purposes of this study, Tier 2 represents all of the Tier 2 HFTD area within the service territory
Locations Outside the HFTD	All other areas within the service territory that are not part of the Tier 2 or Tier 3 HFTD
Risk Event	All overhead system faults, meaning any overhead electrical fault caused by foreign object in line, equipment failure, other or of undetermined cause that impacts the primary electric distribution system (12kV and 4kV systems). An electrical fault includes some kind of electrical system short that results in energy created in the form of heat, this is different from outages that can be a result of opens in absence of electrical faults
Ignition	CPUC reportable ignitions (as defined by D.14-02-015).

Fire Risk Infraction	Inspection finding that if left unaddressed could lead to a risk event, and potentially an ignition
Emergency Finding	Infraction with the greatest risk of failure. Recommended repair timeframe is 0-3 days.
Priority Finding	Infraction with less risk of imminent failure than an emergency finding. Recommended repair timeframe is 4-30 days
Non-Critical/ Non-Priority Finding	Infraction with least risk of failure. Recommended repair timeframe is 6-12 months.
Failure Rate	The assumed rate of failure of an inspection finding over one year if the issue was not found. This rate of failure scales up based on the finding recommend repair timeframe

3. Data Elements

Data Element	Collection Period	Collection Frequency	Spatial Granularity	Temporal Granularity	Comment
Inspection counts	2015-2019	Per inspection	Structure/lat long	Date and time	
Inspection findings	2015-2019	Per inspection	Structure/lat long	Date and time	

4. Methodology

1. Five years of inspection counts and fire risk infraction findings were queried and separated out by priority of findings.
2. From this dataset, the 5-year average finding by priority per 5-year average inspection count was calculated.
3. The research study described in Section 4.4.2.6 Impact of Inspection Programs at Finding and Repairing Equipment Issues found that 0.31 percent of non-critical/non-priority findings would fail if issues were not repaired within one-year maintenance timelines. To estimate the effectiveness of inspections, this rate of failure was scaled up based on the finding severity and recommended repair timeframe. For example, a priority finding is 12 times as likely to fail as a non-critical/non-priority finding. An emergency finding is 10 times as likely to fail as a priority finding.
4. Failure rates were multiplied by the 5-year average findings by priority to determine the five-year average faults avoided per inspection program. Depending on the HFTD Tier where the inspection is performed, the ignition rate from the results of Section 4.4.2.1 Determination of Average Distribution Ignition Percentages by Location and Operating Risk Condition was multiplied by the 5-year average faults avoided to determine the 5-year average ignitions avoided per inspection program.
5. This methodology was repeated to calculate a 5-year average ignition avoided for each inspection program.

5. Timeline

SDG&E will update this study on an annual basis and report out at the annual updates.

6. Results and discussion

The results of this study show that distribution inspection programs historically avoid approximately 110 faults and 3 ignitions annually. Similarly, transmission inspection programs avoid 4.5 faults and 0.4 ignitions annually (see Table 4-10).

Table 4-10: Faults and Ignitions Avoided by Inspection Programs

Program	Historical Annual Faults Avoided	Historical Annual Ignitions Avoided
Annual Patrol Inspections	52	1.60
Wood Pole Intrusive Inspections	17	0.51
HFTD Tier 3 Inspections (QA/QC)	10	0.7
Distribution Infrared Inspections	2	0.055
Distribution Drone Assessments	29	0.804
Circuit Ownership	0.005	0.0001
Transmission Visual Inspections (patrol)	0.4	0.040
Transmission Detailed Inspections (ground)	4	.0374
Transmission Infrared Inspections	0.03	0.002
Additional Transmission Aerial 69kV Tier 3 Visual Inspections	0.1	0.005

7. Follow-up planned

This data is being used for RSE calculations for each inspection program. The RSE values will be updated annually as updated risk event data and cost data becomes available.

4.4.2.8 Impact of Other Special Work Procedures and Infrastructure Protection Teams at Reducing Personnel-Related Faults and Ignitions

1. Purpose of Research

To determine the effectiveness of special work procedures that cancel all work in the HFTD Tier 3 and Tier 2 on days with an FPI rating of Extreme and that require contracted infrastructure protection teams on days that with an FPI rating of Elevated or higher.

2. Relevant Terms

Tier 3 HFTD	Per the CPUC Fire-Threat Map, the "Tier 3 fire-threat areas depict areas where there is an extreme risk (including likelihood and potential impacts on people and property) from utility associated wildfires." For the purposes of this study, Tier 3 represents all of the Tier 3 HFTD area within the service territory.

Tier 2 HFTD	Per the CPUC Fire-Threat Map, the "Tier 2 fire-threat areas depict areas where there is an elevated risk (including likelihood and potential impacts on people and property) from utility associated wildfires." For the purposes of this study, Tier 2 represents all of the Tier 2 HFTD area within the service territory.
Locations outside the HFTD	All other areas within the service territory that are not part of the Tier 2 or Tier 3 HFTD.
Normal FPI	An FPI value of 11 or less represents a normal fire potential based upon combined green-up, fuels, and weather measurements.
Elevated FPI	An FPI value of 12 to 14 represents an elevated risk of fire potential based upon combined green-up, fuels, and weather measurements.
Extreme FPI	An FPI value of 15 or greater represents an extreme risk of fire potential based upon combined green-up, fuels, and weather measurements.
Risk Event	All overhead system faults, meaning any overhead electrical fault caused by foreign object in line, equipment failure, other or of undetermined cause that impacts the primary electric distribution system (12kV and 4kV systems). An electrical fault includes an electrical system short that results in energy created in the form of heat.

3. Data Elements

Data Element	Collection Period	Collection Frequency	Spatial Granularity	Temporal Granularity	Comment
Risk Event	2016-2020	Per Risk Event	Lat/long filtered by HFTD, FPI	Date and time	
FPI Days	2016-2020	Days	Categorized by FPI	Date	

4. Methodology

1. The reliability data set was filtered to convert it to a risk event dataset that included the overhead filtering discussed in Section 4.4.2.1 Determination of Average Distribution Ignition Percentages by Location and Operating Risk Condition.
2. Data was further filtered to include only risk events caused by crews performing work on the system. Crew-caused contacts were filtered by days with FPI ratings of Normal, Elevated, and Extreme FPI, as well as Tier 2 and Tier 3 HFTD.
3. To determine the benefit of special work procedures, risk events per day in the Tier 2 and Tier 3 HFTD that occurred under Normal and Elevated FPI conditions were calculated. It was assumed the same fault per day rate would apply under Extreme FPI conditions if special procedures were not followed (work cancelled in the HFTD). Ignition rates calculated from Section 4.4.2.1 were used to estimate the ignitions reduced.

4. To calculate the benefit of infrastructure protection teams, the 5-year average number of crew-caused risk events under Elevated FPI conditions in the HFTD was multiplied by the calculated ignition rate from Section 4.4.2.1

5. Timeline

SDG&E intends to update this study annually, using a 5-year average.

6. Results and discussion

Based on the historical crew caused risk events, special work procedures mitigate 0.0276 ignitions annually in Tier 2 and 0.0355 ignitions annually in Tier 3 of the HFTD. Infrastructure protection teams perform preconstruction mitigation measures such as watering down the work area. Should a risk event occur that leads to an ignition, the teams work to suppress the ignition before it can grow in an attempt to limit the impacts. This research concluded that the use of infrastructure protection teams mitigates 0.1089 ignitions in Tier 2 per year and 0.1764 ignitions in Tier 3 annually (see Table 4-11).

Table 4-11: Effect of Special Work Procedures on Ignitions

Personnel Work Procedures and Infrasturcutre	Normal FPI					Elevated FPI				Extreme FPI or RFW			
	Normal Days	Non-HFTD	Tier 2	Tier 3	System	Elevated Days	Tier 2	Tier 3	HFTD	Extreme or RFW Days	Tier 2	Tier 3	HFTD
2016	227	8	0	3	11	118	1	3	4	21	0	0	0
2017	196	3	1	1	5	146	2	0	2	23	0	0	0
2018	182	3	4	3	10	169	2	3	5	14	0	0	0
2019	228	7	2	5	14	125	2	4	6	12	0	0	0
2020	201	9	4	6	19	145	4	8	12	20	0	0	0
5 yr avg	**206.8**	**6**	**2.2**	**3.6**	**11.8**	**140.6**	**2.2**	**3.6**	**5.8**	**18**	**0**	**0**	**0**
normalized		365.00	133.83	219.00	717.83		803.00	1314.00	2117.00		0.00	0.00	0.00

	Days	Tier 2	Tier 3		Faults per day Tier 2	Faults per day Tier 3
Normal + Elevated 5 year average	**347.4**	**4.4**	**7.2**		**0.0127**	**0.0207**

Extreme or RFW Procedures (Other Special Work Procedures)		
	Tier 2	Tier 3
Risk events avoided	0.2	0.4
ignition rate	12.12%	9.52%
ign avoided	**0.0276**	**0.0355**

Infrastructure Protection Teams		
	Tier 2	Tier 3
Risk Events	2.2	3.6
ignition rate	4.95%	4.90%
ign mitigated	**0.1089**	**0.1764**

7. Follow-up planned

This data is being used for RSE calculations for these mitigations. The RSE values will be updated annually as updated risk event data and cost data becomes available.

4.4.2.9 Impact of the Enhanced Vegetation Management Program

In addition to the study presented in SDG&E's 2021 WMP Update and the joint IOU enhanced vegetation management study discussed in Attachment I, SDG&E hired a third-party data science team to analyze the effects of enhanced clearances on reducing faults. A summary of this study is provided below, with the full report included in Attachment E.

1. Purpose of Research

This study assesses the effectiveness of enhanced line clearance in mitigating wildfire risk by minimizing vegetation-related outages. The need for enhanced clearance is determined at the time of trim and is based on several tree characteristics, including species, location, tree health, and other issues identified by the tree inspector.

Contact with vegetation through growth, dropped limbs, and fallen trees, can lead to outages and ignitions. SDG&E minimizes this risk through an extensive Vegetation Management Program that catalogs, audits, and trims trees near electrical assets.

Vegetation powerline clearances change because of changes in tree growth, health, and external factors. A data-driven approach will therefore be used to determine the outage risk related to trees that are in the service inventory.

This research examines the impact of several factors on vegetation-related power outages in SDG&E's Vegetation Management Areas. The suggested approach uses a machine-learning predictive model to forecast the predicted tree caused outages based on a range of parameters.

2. Relevant Terms

Risk Event	All overhead system faults, meaning any overhead electrical fault caused by foreign object in line, equipment failure, other or of undetermined cause that impacts the primary electric distribution system (12kV and 4kV systems). An electrical fault includes some kind of electrical system short that results in energy created in the form of heat, this is different from outages that can be a result of openings in absence of electrical faults
Epoch System	The work management system used by vegetation management personnel to input records of vegetation management work
FACILITYID	ID associated to an Inventory Tree. One FACILITYID or Inventory Tree can have multiple units. For accurate average calculations this needs to be considered
Species	A natural group of trees in the same genus made up of similar individuals. Examples of genus are palm, eucalyptus, sycamore, pine, and oak. Examples of oak species are red oak, willow oak, and shumard oak.
Outage Vegetation Code Definitions	318: Tree contact due to growth/encroachment 322: Detached tree branch contact 324: Palm tree contact 326: Detached palm frond contact 420: Tree contact (weather related) 426: Detached tree branch contact (weather related) 428: Palm tree contact (weather related) 430: Detached palm frond contact (weather related)
Completed Trim	An inventory tree that was trimmed in a specific year to a specific post trim clearance level
Inventory Tree	A tree that has the potential to encroach within the minimum clearance required and/or could otherwise impact the overhead electrical facilities within 3 years of the inspection date

3. Data Elements

Activity codes

The activity codes that were included in the analysis were PI (pre-inspection), TT (tree trim), and OI (outage incident). Other events such as adding a tree to inventory, tree inspection audits, and tree trim audits were excluded. Since all trees in the tree inventory get inspected and if needed, trimmed, by returning these events there was information captured about all trees in inventory. The original dataset from 2001-2021 was 14.3 million records, returning these 3 activity codes it brought the dataset to 12.4 million records (87 percent).

Reduce multiple events per tree: Return last event per year per Tree ID

A Tree ID can have multiple activities (inspection and trims) per year. The final dataset included information from the last activity per Tree ID per year. If a Tree ID had an outage event and the activity prior to the outage is not the last activity of the year, the activity prior to outage was also included. Other variables were generated to capture information regarding number of times a tree was inspected or trimmed in one year. Once this methodology was applied the dataset decreased from 12.4 million to 7.5 million records.

Activity date: 2006-2020

The initial dataset included years 2001-2021. Years 2001-2005 were excluded due to lack of confidence in data quality. Year 2021 was excluded from the dataset due to incomplete data. Although there was inspection and trim activities for 2021, there was only outage event information up to Quarter 1. When doing an analysis of data on year aggregates, this significantly decreased the outage rate for 2021. Because of this incompleteness 2021 was excluded. Once the year filter was applied the dataset decreased from 7.5 million to 5.5 million records.

Outages

Outage events were filtered based on outage codes. Codes 318, 322, 324, 326, 420, 426, 428, 430 relate to a vegetation-related outage incident. By studying tree clearance impacts, the outage list needed to be ones where the outage could have possibly been mitigated by a vegetation management activity.

Condition codes: Trimming events filtered to condition codes

Trim activities were paired with condition codes CP (completed pruning), CGRP (completed, green, reliability pruning), or CDRP (completed, dead or dying, reliability pruning). Trim activities listed under other codes were determined to be a data quality issue.

Methodology

Two Proportion Z-Test

To determine the validity of the current mitigation efforts based on enhancement of tree clearance distances, a two-proportion Z-Test was run. The outage rates (number of outages divided by number of inventory trees) between pre- and post-enhanced clearing procedures were compared. SDG&E currently utilizes an enhanced clearing procedure of clearing a higher proportion of trees to a greater than or equal to 12-foot line clearance distance. The enhanced clearing process was implemented in 2017. The two proportion Z-Test showed if there was a statistically significant difference between outage rates from 2006-2016 versus 2017-2020.

Modeling & Variable Coefficients

The dataset was used to train a generalized linear model logistic regression model to predict each tree's probability of outage based on the response variable—if a tree did or did not experience an outage. A model of this type assumes that there is a linear relationship between the input features and the occurrence of outages. Prior to training the model, the data was divided into two data sets: a training dataset and a test dataset. Data from 2006 to 2018 was used as the training set and data from 2019-2020 was used as the test set. The output of the prediction given to each tree was a probability of outage score (0-1). The distribution of risk scores among trees was analyzed and a threshold of 0.15 was determined to classify if a tree was 1- a risk tree (cause outage) or 0- not a risk tree (not cause outage).

Variables used in the model included line clearance distance, tree height, time tree has been in inventory, diameter at breast height, the last activity conducted on the tree (inspection or trim), species, growth rate, number of units, number of trunks, number of stems, tier, vegetation management area, check-back description, last condition code, number of inspections in current year, number of trims in current year, historical number of inspections, historical number of trims.

With a trained model, the test dataset (2019 to 2020) was utilized to test performance. By testing the model on unseen data, this gave confidence in the results of the model. By having a model that identified a set of high-risk trees from the population, these were then reviewed. Reviewing high risk trees gives SDG&E a better understanding of what variables have a high impact on risk. The impact of variables was understood by reviewing the model coefficients as well as specifically looking at returned high-risk trees by variables in the model.

Sensitivity Analysis

For both the sensitivity and counterfactual analysis data from 2017-2020 was used. Once a model was created with the necessary level of performance, the model was utilized to understand the impact of line clearance distance. A sensitivity analysis was conducted to understand the impact of line clearance distance to number of predicted risk trees returned by the model. First, the model was tested on the counterfactual data and performance was analyzed. The true positive and false negative percentages were calculated. Then, line clearance values were adjusted, and the model was run on the changed data to see the shift in number of risk trees identified. The same percentage of true positives and false negatives were assumed and used to calculate potential outage. Potential outage was compared to actual outage rates to understand impact of line clearance distance. For the sensitivity analysis, line clearance levels were adjusted six times to see the impacts of lengthening line clearance to 7, 9, 11, 13.5, 17.5, and 25 feet. A tree's line clearance was only changed if the tree's current line clearance distance was a lower value than what was being tested.

4. Timeline

SDG&E plans to continue to update the study on an annual basis incorporating the data from future years, and report its findings in future WMP annual updates.

SDG&E will continue to participate in the joint enhanced vegetation management study as further detailed in Attachment E.

5. Results and discussion

There were three ways that line clearance distance was analyzed to understand its effect on outage rates historically. First a two-proportion z-test was used to statistically prove the difference between outage rates in different periods of time. Second, the machine-learning model was used to identify and confirm SDG&E's list of targeted trees, and then perform a sensitivity analysis to understand how different line clearance distances could have impacted outages historically.

Two Proportion Z-Test

A two proportion Z-test was conducted to test the outage rate difference between 2006-2016 (Table 4-12) and 2017-2020 (Table 4-13). A one-tailed two proportion Z-test can be used to compare if one proportion is greater or less than the other. The test demonstrated that enhanced clearing years, 2017-2020, had a lower outage rate than pre-enhanced clearing years, 2006-2016, showing a clear advantage in years that followed enhanced line clearance protocols, with a reduction in outage rate of approximately thirty-eight percent. It can be concluded that the outage rate from 2006-2016 is greater than outage rate from 2017-2020 at a statistically significant level (p-value = .0000002472).

Table 4-12: Outage Rate 2006-2016

Pre - Enhanced Clearance Efforts			
Year	TreeCount	Outages	Outage Rate
2006	393,455	60	1.52E-04
2007	380,613	55	1.45E-04
2008	376,928	83	2.20E-04
2009	383,893	62	1.62E-04
2010	402,006	111	2.76E-04
2011	424,450	24	5.65E-05
2012	446,128	22	4.93E-05
2013	453,867	18	3.97E-05
2014	470,931	41	8.71E-05
2015	469,637	22	4.68E-05
2016	465,167	56	1.20E-04
Total	**4,667,075**	**554**	**1.19E-04**

Table 4-13: Outage Rate 2017-2020

Post Enhanced Clearance Efforts			
Year	TreeCount	Outages	Outage Rate
2017	462,479	61	1.32E-04
2018	466,870	23	4.93E-05
2019	465,449	22	4.73E-05
2020	468,860	31	6.61E-05
Total	**1,863,658**	**137**	**7.35E-05**

**See Appendix 9.5 for two proportion Z-Test statistical output*

With this initial conclusion, the second step was to utilize a machine-learning model to conduct a sensitivity analysis specifically adjusting line clearance distances to see impact to outage rates historically.

Effect of Species

The machine-learning model was used to assign weights to variables which drive the outage probability score. The weights for each species were analyzed to understand what the model identified as potentially higher risk related to species. The dataset included 93 species.

Using the test dataset (2019-2020), a probability score threshold of 0.15 was utilized to classify if a tree was a risk-tree or not a risk-tree. Of the 753,847 tree activities in the test set, the model identified 169,698 risk trees which accounted for 32 of the 39 outages during that timeframe. The 169,698 risk trees were summarized by species to get an understanding of higher-risk species. Table 4-14 shows the top 10 risk species based on a risk metric defined as (Count of Risk Trees multiplied by Avg Risk Probability) and included if that group experienced an outage. These top 10 species accounted for 90 percent of risk trees returned by the model and 29 of 32 outages in the test dataset.

Table 4-14: Identified Risk Trees by Species

Species	Count	Pct of Total	Actual Outage	Avg Risk Probability	Risk Metric
Eucalyptus	59,184	34.6%	10	2.82 E-4	16.70
Palm-Fan	26,894	15.7%	11	3.66 E-4	9.84
Pine	28,189	16.5%	4	2.47 E-4	6.96
Oak	13,175	7.7%	1	1.24 E-4	1.63
Sycamore	5,999	3.5%	0	2.51 E-4	1.50
Palm-Feather	8,299	4.8%	1	1.50 E-4	1.25
Pepper (California)	6,045	3.5%	0	1.34 E-4	0.81
Tamarisk/Salt Cedar	2,617	1.5%	0	2.62 E-4	0.69
Cypress	1,617	0.9%	1	1.62 E-4	0.26
Pecan	1,750	1.0%	1	1.92 E-4	0.34

By using a machine-learning model to score individual trees, a quantitative score related to multiple variables is obtained to identify if a tree is high risk. These results quantitatively confirm the species that are believed to be the highest risk and validate the methodology provided in response to Action Statement SDGE-21-06 that list Eucalyptus, Palm, Pine, Oak, and Sycamore as the targeted at-risk tree genus/species.[26]

Sensitivity Analysis

For the sensitivity analysis, line clearance distances were lengthened to understand the potential impact to historical outage rates from 2017-2020. Line clearance distances were lengthened to 7, 9, 11, 13.5,

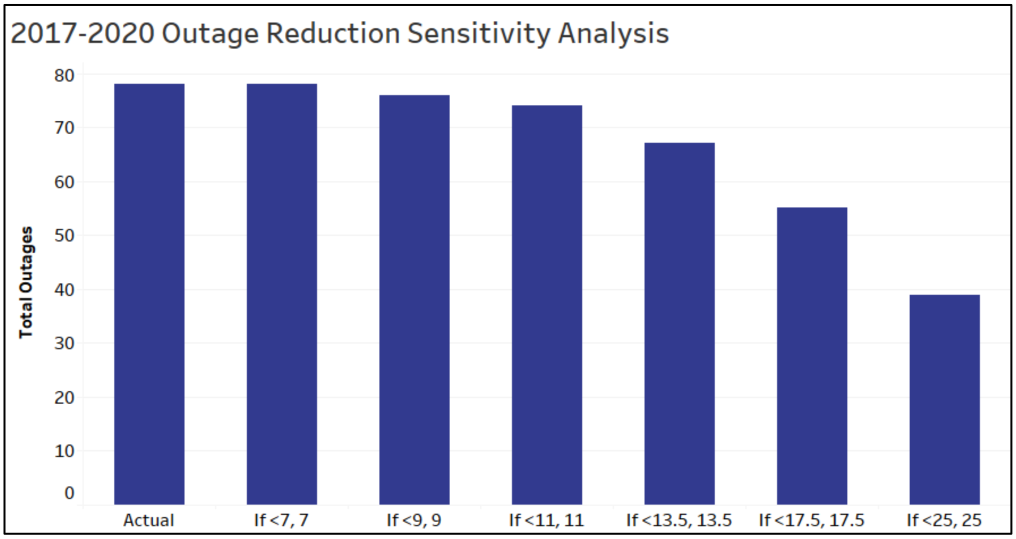
[26] SDG&E 2021 WMP Action Statement Supplemental (November 1, 2021), available at https://efiling.energysafety.ca.gov/eFiling/Getfile.aspx?fileid=51857&shareable=true.

17.5, and 25 feet. Values were only changed if actual line clearance distance was lower than the threshold being tested. After making changes to line clearance distance, the model was run on the data to update the risk probability score per Tree ID and see how many risk trees were identified. The true positive and false negative percentage ratios from the actual data were then used to calculate potential outage effects. Table 4-15 shows the results when changing line clearance distances. Figure 4-18 shows that when tree line clearances are brought up to non-enhanced levels (7-11 feet) there is a smaller impact to outage reduction. When tree line clearances are brought to above 12 feet (13.5+ feet), there is a significant impact to potential outage reduction. If all trees were trimmed to at least 13.5 feet, the total number of vegetation-related outages on the system would be reduced by 11 across the 4-year timeframe. If all trees were trimmed to at least 25 feet, the number of vegetation related outages across the 4-year timeframe would be reduced by half from 78 to 39 outages. The model and analysis show a clear correlation between trim clearance and a reduction in vegetation related outages.

Table 4-15: Sensitivity Analysis Results

Sensitivity Analysis	% of records changed	Risk trees identified by model	Assumed true positive outage rate	Expected outage (T)	Non-risk trees identified by model	Assumed false negative outage rate	Expected outage (F)	Total Outages	Difference
Actual	0	338,373	1.92E-4	65	1,173,298	1.11E-5	13	78	Baseline
If <7, 7	15%	335,660	1.92E-4	64	1,175,998	1.11E-5	13	78	(0)
If <9, 9	35%	330,234	1.92E-4	63	1,181,424	1.11E-5	13	76	(2)
If <11, 11	73%	319,595	1.92E-4	61	1,192,063	1.11E-5	13	74	(4)
If <13.5, 13.5	86%	288,906	1.92E-4	53	1,222,752	1.11E-5	14	67	(11)
If <17.5, 17.5	92%	235,561	1.92E-4	41	1,276,097	1.11E-5	14	55	(23)
If <25, 25	98%	153,119	1.92E-4	24	1,358,539	1.11E-5	15	39	(39)

Figure 4-18: Sensitivity Analysis Results-Outage Count Reduction



6. Follow-up planned

SDG&E's process is to inspect every tree in inventory on a yearly basis. SDG&E tree-trimming contractors determine the need for and scope of a potential trim based on these inspections. The analysis in this study has generally shown that greater line clearance reduces a tree's risk of causing a vegetation-related outage. By targeting the riskiest trees based on several factors (species, location, etc.) the number of vegetation-related outages can continue to be reduced on a yearly basis. To maximize effectiveness on additional inspections and trims, SDG&E will continue to explore how to best utilize the risk probability score generated by the machine-learning model to target at-risk trees.

As more trees are trimmed to the enhanced levels, it will provide more data to analyze and update results in future submissions.

4.4.2.10 REFCL Control and Protection Systems

1. Purpose of Research

The purpose of the Rapid Earth Fault Current Limiter (REFCL) research study is to identify the requirements, costs, and benefits of implementing a REFCL scheme at the 69/12kV Descanso Substation, which feeds three 12kV circuits within the Tier 3 HFTD.

2. Relevant Terms

Falling Conductor Protection (FCP)	A protection system designed to detect broken energized conductors and isolate them before they can reach the ground, thereby reducing ignition risk.
REFCL	A technology designed to significantly reduce the ground fault current resulting from electrical contact between an energized piece of equipment and a grounded object or surface

Sensitive Ground Fault Protection (SGF)	A protection technology utilized to detect high impedance fault events that normal protection systems may otherwise miss. This protection is enabled year-round.
Sensitive Relay Profile (SRP)	A protection setting enabled via supervisory control and data acquisition (SCADA) during high fire threat periods. SRP is designed to trip circuit sections very quickly through reduced setting pickup values and time delays. SRP is designed to reduce fault energy by tripping circuits as fast as possible upon fault detection, thereby reducing ignition risk

3. Data Elements

This evaluation detailed the various electric infrastructure upgrades, new equipment installations, cost estimates, and operational impacts associated with implementing a REFCL scheme on a system that was not initially designed to do so. This report also compared existing system protection practices that are used for fire mitigation and details the pros and cons of each.

Internally, SDG&E's existing electric distribution and substation system architecture, standard equipment specifications, and subject matter expertise were utilized for this research study. Externally, existing REFCL equipment vendor expertise and contracted third party subject matter expertise were both utilized for this research study to ensure designs, costs and deployment methodologies were accurately represented in findings.

4. Methodology

The research study evaluated existing substation and distribution circuit infrastructure and topology to document all system changes required to deploy a REFCL system.

5. Timeline

The research study was performed between 2020 and 2021 and has since been finalized.

6. Results and discussion

The cost to implement REFCL is significant when considering the distribution and substation system rebuilds which must occur to implement the technology. Estimated cost breakdowns provided by the study to implement REFCL at the Descanso substation and the three distribution circuits it feeds are shown in Table 4-16:

Table 4-16: Estimated Implementation Costs for REFCL at Descanso Substation and Three Distribution Circuits

Description	Estimated Cost
Transformer Replacements	$7,347,351
Arrester Replacements	4,173,149
Phase Swaps	0
Cable Replacements	10,582,682
Capacitor Balancing Units	235,009
Miscellaneous	295,685
Descanso Circuits Sub-total	$22,633,876
Descanso Substation	3,505,207
Total	$26,139,083

The primary driver for costs within the Descanso Substation is the new REFCL equipment that needs to be installed to operate the system. These costs will scale higher with more distribution transformers feeding circuits within a substation. The costs referenced for Descanso Substation are for just one distribution transformer and 12kV bus section of circuits, so this cost will be much greater for SDG&E substations which may have up to four distribution transformers.

The primary driver for costs associated with distribution circuits are more related to the rebuild of the overhead system currently serving the areas of the HFTD. Some of the overhead rebuilds needed to implement REFCL include the following:

- Since SDG&E has a significant amount of phase-to-neutral connected customer loads and equipment rated at phase-to-neutral voltages, the equipment will need to be replaced because it will not be rated to operate on a REFCL system.
- To protect a whole circuit with REFCL, all equipment neutral / ground references served on the distribution circuit must be removed and replaced with phase-to-phase / delta connected equipment which would not provide a ground source.
- Increased voltages seen during phase-to-ground faults on a REFCL system also require all equipment to be rated over the 12kV nominal voltage to prevent erroneous equipment failures. This equipment may include insulators, underground cable, switches, arresters, etc. which may not have the right rating to operate under the higher stresses caused by the REFCL system.

With approximately 70 substations and 285 distribution circuits serving the HFTD, the anticipated rebuild of infrastructure alone that would be needed to deploy REFCL would be incredibly costly and would not provide coverage or mitigation for any faults outside of single phase-to-ground types. As explained in SDG&E's study, REFCL will only reduce fault energies for single phase-to-ground faults and provide no mitigation for faults involving multiple phases; of which are common on the electric distribution system. REFCL will have no benefit to reducing multi-phase fault energy, as the technology cannot act for these scenarios. (i.e., wire slaps, phase-to-phase foreign object contact not involving ground, such as vegetation or balloons).

SDG&E instead prefers to rely on the technologies we have developed and deployed with over ten years of experience. Technologies such as SGF Detection, SRP Settings and FCP provide a diverse and layered approach to covering all types of fault scenarios possible on the distribution system. These technologies, combined with strategic undergrounding, covered conductor, advanced meteorology and fire science data to drive their use, are sufficient mitigations to reduce wildfire risks without implementing REFCL in the service territory.

It is also critical to understand that the use of REFCL technology with the objective to reduce fire ignition is a relatively new application or concept. At this time, there is little statistically reliable data available which documents whether this scheme is successful in mitigating fire risk. Fault energies are drastically reduced for phase-to-ground faults, but there is still energy at the fault location with REFCL in service. That energy is still potentially capable of igniting fires and should not be considered a full-proof mitigation.

7. Follow-up planned

SDG&E collaborates monthly with joint California IOUs on various protection technologies for safety and wildfire mitigation. Through this ongoing strategic effort, SDG&E is continuing to learn of our peer's experience with REFCL as well as other technologies. While SDG&E is not currently pursuing a REFCL pilot, we are still working with our peers in industry to remain up to date on the technology should there be any change in our position to implement it in the service territory.

At this time, there is no follow up implementation of REFCL pilot or testing planned within the service territory.

4.4.2.11 Lab Tests of Covered Conductors

1. Purpose of Research

The purpose of this research is to assess the basic electrical performance of two insulation piercing connectors (IPC) manufacturers used on covered conductors. The research was performed by a third party, assessing the product under many possible combinations.

2. Relevant Terms

Covered Conductor	A conductor with a 3-layer covering extruded over the stranded conductors. This conductor is typically installed in an open crossarm configuration and is self-supporting

3. Data Elements

Use of system conditions or historical data was not utilized for this product testing.

4. Methodology

The methodology of this analysis included the following tests:

- Visual inspection of covered conductor and IPC to verify the product is meeting specification and integrity outlined by SDG&E.
- Electrical testing of IPC and other connectors to verify electrical performance that corresponds to operating conditions that a connector could see in the field and compare results with existing connectors.

5. Timeline

The timeline to perform the lab study and testing was 6 months, dependent on findings and results.

6. Results and discussion

The completion of the testing informed SDG&E of the two products and identified areas to be aware of when communicating the construction of the product. The testing helped SDG&E understand and better identify the conductor best suited for installation.

Additionally, IPCs are able to be attached to the covered conductor without having to peel back the insulation that a traditional connector would require. The polymer exterior of the IPC means that they have a higher resistance than traditional connectors, which are exposed metal. SDG&E believes that utilizing IPC's will reduce the potential of faults resulting from connector corrosion, workmanship, and incidental contacts from birds, debris, etc.

The covered conductor itself, from the existing manufacturers utilized, showed some variability in meeting specific standards. This informed SDG&E on priority and assisted with decisions regarding which product to use going forward and any future testing.

Lastly, a design standard, such as Institute of Electrical Engineers (IEEE) or American Society for Testing and Materials (ASTM) relevant for medium voltage IPCs developed by a technical committee in the U.S. does not exist.

7. Follow-up planned

- Discussion with manufacturers on the results and introduction of additional features to assist with addressing some of the issues that occurred.
- Start discussions in the technical community for creating a medium voltage IPC standard pertinent to the U.S.
- As part of the tasks for the joint IOU working group, additional studies will be performed to assess the effectiveness of covered conductor for various modes of failure.

4.4.2.12 Wildfire Suppressing Precipitation in San Diego County

1. Purpose of Research

SDG&E established a 3-year strategic partnership with leading climate experts at Scripps Institute of Oceanography to study the onset of wildfire suppressing precipitation in San Diego County, with attention paid to impacts on wildfire and subsequent later autumn and winter season hydrological measures. Scripps will analyze over 100 years of precipitation data and the impact on fire seasons. They will examine variability from year to year, documenting the types of storms that produce the precipitation, quantifying the current lead time in predicting these events, and identifying potential approaches to display and to predict these important storms. These late season storms and the impact on the wildfire environment could have an impact on PSPS frequency in the future.

2. Relevant Terms

Wildfire Suppressing Precipitation	The amount of rain necessary to terminate fire season

3. Data Elements

Data Element	Collection Period	Collection Frequency	Spatial Granularity	Temporal Granularity	Comment
Autumn Precipitation	1948-2018	Monthly aggregate	NOAA Region 6: S. Coast Climate Division	Monthly aggregate	Average monthly occurrence, 1948-2018, of precipitation events totaling 8.5mm or greater over 3 days, and Santa Ana days.
Total Number of Fires and Acres Burned	1948-2018	Monthly aggregate	NOAA Region 1-6	Monthly aggregate	fires greater than 1 hectare (2.5 acres)

4. Methodology

Variability will be examined from year to year. The types of storms that produce the precipitation will be documented, the current lead time in predicting these events will be quantified, and potential approaches to display and to predict these important storms will be identified.

5. Timeline

Progress and milestone updates are provided quarterly with an expected report completion date of April 2023.

6. Results and discussion

Findings and discussion based on findings are pending.

7. Follow-up planned

Action planned will depend on research findings.

4.4.2.13 LFMC Tools

1. Purpose of Research

SDG&E engaged San Jose State University to develop Live Fuel Moisture Content (LFMC) tools to better assess fire danger in the service territory using state-of-the-science remote sensing data sets. These tools will be developed using the new high-resolution data from various satellite products.

2. Relevant Terms

Live Fuel Moisture	A measure in living plants that is a critical component in the understanding of fire spread modeling

3. Data Elements

Data Element	Collection Period	Collection Frequency	Spatial Granularity	Temporal Granularity	Comment
Landsat 8	2013-present	Daily (about 14.5 orbits/day)	About 15-100 meters, depending on the sensor wavelength	Daily	Repeat coverage is 16 days
Landsat 7	1999-present	Daily (about 14.5 orbits/day)	About 15-100 meters, depending on the sensor wavelength	Daily	Repeat coverage is 16 days
National Fuel Moisture Database	1983-present	Varies by site	Station Sites	Varies by site	

4. Methodology

The result of improved life fuel moisture modeling products derived from the latest satellite remote sensing will eventually leading to a dataset and methodology to incorporate these tools into the Technosylva Wildfire Analyst fire behavior modeling platform.

5. Timeline

Project completion is expected in June 2022.

6. Results and discussion

Findings and discussion based on findings are pending. Additional output from the project will include two peer-reviewed publications and one M.S. thesis.

7. Follow-up planned

Action planned will depend on research findings.

4.4.2.14 Increasing Situational Awareness of Wildfire Ignitions

1. Purpose of Research

SDG&E partnered with the Space Science and Engineering Center (SSEC) at the University of Wisconsin-Madison to increase situational awareness of wildfire ignitions in the service territory. SSEC is a world-class archive of satellite data, receiving, archiving, and redistributing most geostationary weather satellite data produced globally.

2. Relevant Terms

Fire Detection and Characterization (FDC)	The ability to detect and characterize a fire by utilizing 6 confidence-based categories
Wildfire Automated Biomass Burning Algorithm (WFABBA)	A dynamic multispectral thresholding contextual algorithm that uses the shortwave "visible" channel (when available during the

	daytime), middle infrared [(3.9 micrometer (µm)], and longwave infrared (11.2 µm) infrared window bands to locate and characterize hot spot pixels. The fire detection algorithm is based on the sensitivity of the 3.9 µm band to high temperature sub-pixel anomalies compared against the less sensitive longer wavelength infrared window bands, specifically the 11.2 µm band. The shortwave "visible" band, when available, improves the cloud screening and establishes the surface albedo value which aids in reducing the effects of solar contamination in the 3.9 µm band.
Geostationary Operational Environmental Satellites (GOES) Weather Satellite	GOES-16/-17 are the newest Government satellites that constantly monitor the east and west coasts respectively
Advanced Baseline Imager (ABI)	The ABI is the primary instrument on the GOES-R Series for imaging Earth's weather, oceans and environment. ABI views the Earth with 16 different spectral bands (compared to five on the previous generation of GOES), including two visible channels, four near-infrared channels, and ten infrared channels. These different channels (wavelengths) are used by models and tools to indicate various elements on the Earth's surface or in the atmosphere, such as trees, water, clouds, moisture or smoke.
Fire Radiative Power (FRP)	FRP is the rate of emitted radiative energy by the fire at the time of the observation and is expressed in units of power, such as Watts.

3. Data Elements

Utilizing the new GOES-16/-17 with the ABI, fire detection and characterization was enabled at 2 km spatial resolution and temporal resolutions of 5 minutes and in some circumstances 1 minute or faster.

Data Element	Collection Period	Collection Frequency	Spatial Granularity	Temporal Granularity	Comment
Hotspot (fire)	2020-present	Constant	2 km	< 5 min	Detections filtered to SDG&E service territory

4. Methodology

1. FDC is accomplished with the WFABBA adopted for ABI-class sensors on the GOES weather satellite.
2. Hotspots are rated in six fire categories based on confidence in the FRP, size, and temperature estimates. Confirmed hotspots are sent to subscribers as an email with a link that leads to a map of the area with camera images auto triangulated on the fire.

5. Timeline

Project timeline for proof of concept is complete and the system has been operationalized.

6. Results and discussion

The space-based hot spot detection has a near perfect detection rate correlated with ground truth reports of fires with low latency. The technology was operationalized in 2020 and more data will need to be collected before accurate statistical measures can be applied.

7. Follow-up planned

Follow up action planned as a result of the research includes gaining synergy from two disparate systems: space-based hotspot detection and Machine learning camera smoke detection.

4.5 Model and Metric Calculation Methodologies

4.5.1 Additional Models for Ignition Probability, Wildfire, and PSPS Risk

Instructions: *Report details on the models and methodologies used to determine ignition probability, wildfire risk, and PSPS risk. This must include the following for each model – a list of all inputs, details of data elements used in the analysis, modeling assumptions and methodologies, input from Subject Matter Experts (SMEs), model verification and validation (e.g., equation(s), functions, algorithms or other validation studies), model uncertainty and accuracy, output (e.g., windspeed model) and applications of model in WMP (e.g., in selection of mitigations, decision-making).*

The narrative for each model must be organized using the headings described below. A concise summary of the model(s) must be provided in the main body of the WMP in this section, with additional detail provided for each model in an appendix.

1. *Purpose of model – Brief summary of context and goals of model*
2. *Relevant terms – Definitions of relevant terms (e.g., defining "enhanced vegetation management" for a model on vegetation-related ignitions)*
3. *Data elements – Details of data elements used for analysis. Including at minimum the following:*
    a. *Scope and granularity (or, resolution) of data in time and location (i.e., date range, spatial granularity for each data element, see example table above).*
    b. *Explain the frequency of data updates.*
    c. *Sources of data. Explain in detail measurement approaches.*
    d. *Explain in detail approaches used to verify data quality.*
    e. *Characteristics of the data (field definitions / schema, uncertainties, acquisition frequency).*
    f. *Describe any processes used to modify the data (such as adjusting vegetative fuel models for wildfire spread based on prior history and vegetation growth).*
4. *Modeling assumptions and limitations – Details of each modeling assumption, its technical basis, and the resulting limitations of the model.*
5. *Modeling methodology – Details of the modeling methodology. Including at minimum the following:*
    a. *Model equations and functions*
    b. *Any additional input from Subject Matter Experts (SME) input*
    c. *Any statistical analysis or additional algorithms used to obtain output*
    d. *Details on the automation process for automated models.*
6. *Model uncertainty – Details of the uncertainty associated with the model. This must include uncertainty related to the fundamental formulation of the model as well as due to uncertainty in model input parameters.*
7. *Model verification and validation – Details of the efforts undertaken to verify and validate the model performance. Including at minimum the following:*

a. Documentation describing the verification basis of the model, demonstrating that the software is correctly solving the equations described in the technical approach.

b. Documentation describing the validation basis of the model, demonstrating the extent to which model predictions agree with real-world observations.

8. Modeling frequency – Details on how often the model is run (for example, quarterly to support risk planning versus daily to support on-going risk assessments).

9. Timeline for model development – Model initiation and development progress over time. If updated in last WMP, provide update to changes since prior report.

10. Application and results – Explain where the model has been applied, how it has informed decisions, and any metrics or information on model accuracy and effectiveness collected in the prior year.

11. Key improvements from working group – For each model, describe changes which have been implemented as a result of wildfire risk modeling working group discussions. Provide a high-level summary of recommendations from the wildfire risk modeling working group.

SDG&E uses a variety of tools to assess aspects of ignition probability, the risk of wildfires, and the impacts of PSPS. These tools vary in their maturity and granularity depending on need and the timing of when they were developed as well as their future trajectory (see e.g., the enterprise risk model in Section 4.2 Understanding Major Trends Impacting Ignition Probability and Wildfire Consequence). This section covers additional tools that are used to inform existing programs or programs in development. Models/indices in this section include:

- LoRE Models/Indices
  - PoI Model
  - Vegetation Risk Index (VRI)
- CoRE Models/Indices
  - WRRM
  - WRRM-Ops
  - FPI
  - Santa Ana Wind Threat Index (SAWTI)
- Total Expected Outcome Risk Models/Indices
  - WiNGS-Planning
  - WiNGS-Operations

4.5.1.1 PoI Model

1. Purpose of Model

The PoI model was initiated in 2020 to develop wildfire risk assessments for circuits to support PSPS operations. The initial phase of work and a preliminary version of the model, which considered only asset failure and not ignition likelihood, was created in 2020 but had not been incorporated into decision making. The preliminary version of the model was called the CRI and is detailed in the 2021 WMP Update. However, there was a continued need to consider ignition likelihood and its relation to observable wind gusts. As a result, further refinements to the original probability of failure (PoF) model were explored and a second phase of the project expanding to PoI models based on different risk drivers (i.e., different assets and different causes) was identified. The model was renamed the PoI to reflect the expansion of scope and modeling features.

To extend the PoF model, a conditional probability model (PoI_F) was developed, reflecting the likelihood of an ignition to occur given that a failure had occurred. When the PoF model is multiplied by the PoI_F model, the probability of ignition is approximated, thereby formulating the PoI, according to Bayes Theorem:

$$PoI = \frac{PoF \times PoI_F}{PoF_I}$$

PoI = probability of ignition
PoF = probability of failure
PoI_F = conditional probability of ignition given a failure
PoF_I = conditional probability of failure given ignition (≈ 1)

The PoF model is comprised of several statistical models, one for each of the primary risk drivers (e.g., conductor failure, balloon contact, vehicle contact), which can be summed to reflect the total likelihood of asset failure. Each of these statistical models can also be utilized individually to assess the risk of specific drivers. For example, the regression model developed for conductor failure is used to quantify the conductor risk based on physical attributes (e.g., type, material, size) to inform long-term decision making and is also used in the PoI model for operational PSPS decision making (WiNGS-Ops). The different risk driver models are under varying levels of development. However, all historical outages must be associated to one and only one of these models during development for the model outputs to collectively reflect the true system-wide failure likelihood. The different risk drivers are reported in #5: Modeling Methodology.

2. Relevant terms

Asset	A specific feature on the electric utility infrastructure network, such as a pole, conductor, capacitor, transformer, fuse, etc.
PoF	The probability of outage/fault based on equipment failure or external conditions
PoI_F	The probability that an outage/fault leads to an ignition
POI	The probability of an ignition based on equipment failure or external conditions
CRI	A metric characterizing the risk of conductor failure (Low-Medium-High) based upon underlying probability of failure and probability of ignition models
Risk Driver	A logical grouping of risk event observations based on failure mechanism and/or outcome
Segment	Part of a circuit in-between two connecting, adjacent sectionalizing devices.
Span	Part of a circuit in-between two connecting, adjacent poles
Training set	The set of observations and associated attributes used to develop or “train” statistical models

3. Data elements

Data Element	Data Sources	Collection Period	Collection Frequency	Spatial Granularity	Temporal Granularity	Comment
Probability of Failure						
Outage Data (SAIDIDAT)	Reliability, Electric Risk Analysis database, vegetation	From 2010-Present	On demand	Linked to asset	Estimated time of outage	Modifications: mapping outages to assets
Asset attributes (geospatial location, characteristics)	GIS, EAMP	From 2010-Present	Live connection	GIS coordinate resolution (+/- 10 m)	Static	Modifications: aggregating/normalizing asset data object into single source
Weather Data (present, historical)	SDG&E weather	From 2010-Present	Live connection	Average distance between weather stations	10 min	Modifications: where raw weather station data gaps present, imputation is performed utilizing data from nearby weather stations, and/or regression analysis of conditions around the time of the gap
Probability of Ignition*						
Ignition observations	SDG&E Significant Ignitions Reporting	From 2015-Present	On demand	Linked to asset	Estimated time of ignition	Modifications: Manually linking ignitions to outages
Fuel Sources Map	Technosylva Inc	From 2014-Present	On demand	9 miles	Static, updated annually	Modifications: Technosylva utilizes object-oriented image processing methods to create the fuels dataset from raw imagery and LiDAR data
Weather Forecast Data	NOAA, ADS, SDSC	From 2014-Present	Twice a day	2 km	Hourly	Modifications: None

*In addition to sources used above

4. Modeling assumptions and limitations

The assumptions used for the PoI models can be grouped into three distinct categories:

1. Data collection filtering and annotations
2. Linkages of observations to additional data sources
3. Data gaps and imputations for the model training set

<u>Data collection filtering and annotations</u>

The PoI models are trained on datasets that are derived from records not collected for the purpose of model development. Therefore, each individual outage and subsequent ignitions are reviewed to identify which observations should be included for model training based on official record, field notes, and comments. This process is typically straightforward, but sometimes requires discretion when observations are ambiguous. The outage records used for model training do not include any events that are caused by crew-related incidents, lightning, ice, snow, or intentional shutoffs. Ultimately, these observations, along with others filtered out for miscellaneous reasons, make up a fixed PoI value representing pseudo-random events, which must be added to the model outputs to account for the total ignition likelihood.

For the latest conductor failure model, an additional process is used to exclude observations that are not related to windy conditions based on the wind gusts observed around the time of the outage. This step is intended to bias the PoF model towards conductor failure modes that are directly related to wind, thereby enhancing the wind-related relationships with the response variable. This maximizes the usefulness of the model for operational decision-making, which is primarily dependent on real-time wind speed observations. As noted, observations that are excluded during this step are considered to be caused by pseudo-random events.

<u>Linkages of observations to additional data sources</u>

All models are spatial at the span level and some have hourly temporal resolution. To acquire training sets suitable for developing models at this level of granularity, outage and ignition records must also contain information with at least this level of detail. However, some records estimate the general vicinity of the outage or ignition, and therefore some assumptions would may be made to associate the event to a specific asset. For example, a conductor outage my indicate only the nearest pole structure to which the severed line was attached without indication of whether the damage occurred on the upstream or downstream span relative to the structure. Some modeling methodologies allow for the failure to be attributed equally among the two spans, while others (e.g., binary classification) require a definitive labeling of the asset. In the latter case, “engineering judgement” is required and discretionary.

Once observations are associated to an asset, the GIS database is used to identify the geographic location of the observation. This step allows for the linkage of countless geospatial datasets (i.e., maps) for which features can be derived for model training. However, when features are derived in this way, the geospatial resolution of the linked dataset must also be considered, and some assumptions are required around interpolation (when the linked dataset has smaller resolution that the GIS assets) and aggregation (when the linked dataset has finer resolution than the GIS assets).

The prime example is in associating weather station data with assets. There are 221 weather stations distributed across the territory at spatially irregular locations, but in areas of meteorological interest. To estimate weather conditions at the asset location, such as wind speed, methods such as closest proximity, linear interpolation, and manual mappings by Meteorology were explored.

<u>Data gaps and imputations for the model training set</u>

To address gaps in “ground truth” data sources, such as GIS asset information, the Enterprise Asset Management Platform (EAMP) provides users with the technology to make better informed decisions on maintenance, inspection, risk identification, and prioritizing electric asset investments. For example, when multiple data sources hold conflicting information on a single asset, data engineers must resolve this conflict, typically by prioritizing data sources deemed to be of higher quality. Similarly, the determination of asset installation date for older assets, which is critical for failure rate calculations, requires heavy investigation into documents that are often difficult to manage or access. The PoI models rely on this foundational data infrastructure and are limited by the quality of this data.

Minor data gaps can also be addressed by a variety of imputation techniques common in data science. These techniques are leveraged when specific features are determined to be significant for prediction. For example, in the case of missing numerical features, the mean of all values in the training set can be used. Imputations may be prominent in features derived from geographic maps if the maps do not perfectly cover the service territory.

Linked data sources may also have gaps in data. The most significant example of this weather station data, in which the hardware may intermittently fail to record or transmit. Since this linked dataset is key for modeling relationships with wind, a simple linear model is employed to interpolate missing historical sensor readings for use in model training.

5. Modeling methodology

PoF models were developed for each of the risk drivers shown in Table 4-18. This logical grouping was determined based on a combination of past industry experience, data availability, and engineering judgement.

The conditional PoI_F models, however, are aggregated into only two groups due to limited data availability on ignitions: ignitions that would occur along a span (line), and those that would occur by a pole (point). For the set of PoF models shown in Table 4-18, only the vehicle contact PoF model is considered to be capable of causing a pole-based ignition. Therefore, the remaining PoF models are multiplied by the span-based conditional PoI_F model to calculate PoI from span-based events. The likelihood of ignition for an entire segment is the total of the PoI from both span-based and pole-based events.

After the training sets have been established, a variety of statistical learning methods (sometimes referred to as “models”, particularly in the context of “model selection”) are used to create the PoI models. In practice, results from the varying methods are similar, but each method differs in level of interpretability, tunability, and computational requirements. The model development process is ongoing, however, the models in use as of the time of this WMP are detailed in Table 4-18.

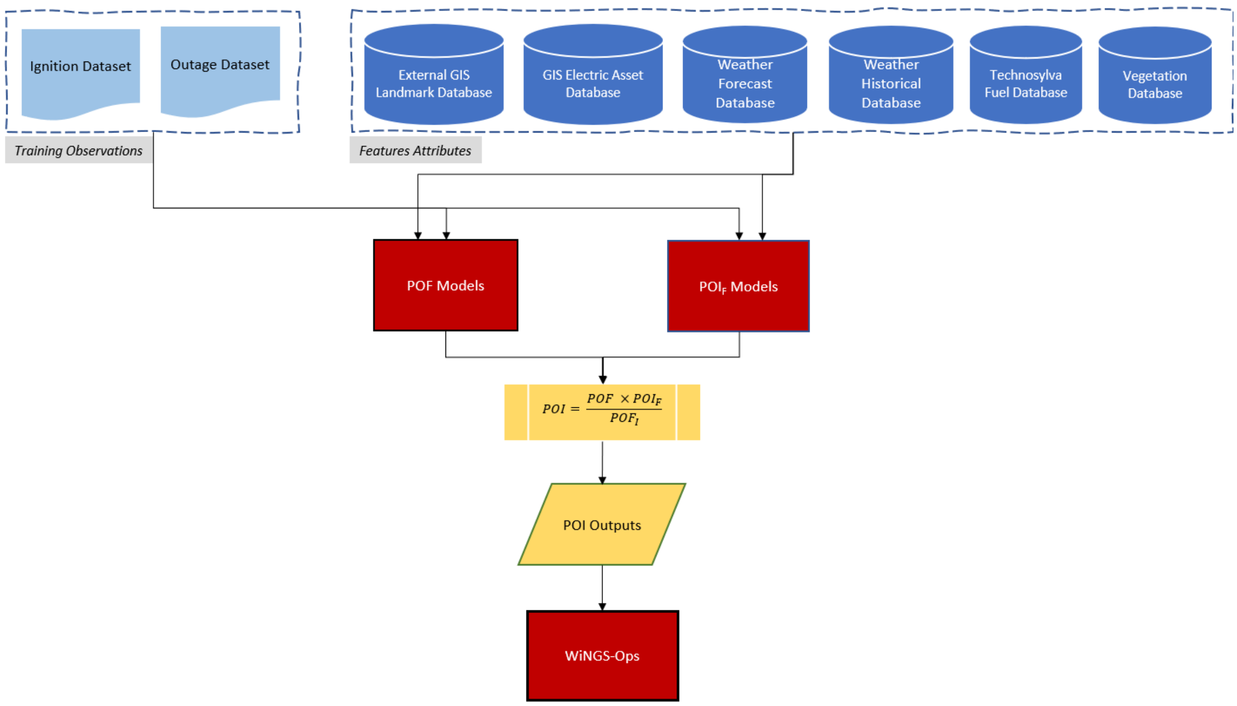
Table 4-17: Risk Drivers for PoI Models

Model	Algorithm	Function	SME	Feature Selection Methodology	Python Library (automation)
			Probability of Failure (PoF)		
Conductor Failure	Linear regression (log-log)	Wind gust, wind direction, conductor type, elevation	Electric District Operations feedback on feature selection	Bottom-up p-value	Statsmodels
Balloon Contact	Logistic regression	Time of day, day of week, month, land use (population) density	n/a	Bottom-up p-value	Statsmodels
Animal contact	Extreme gradient boosted trees	Outages, conductor attributes, species habitat models, vegetation, spatial	n/a	Review of the Feature Importance list	xgboost
Vegetation	Empirical	Number of trees, tree species	Vegetation management	n/a	n/a
Vehicle	Extreme gradient boosted trees	Pole location, attributes, road attributes, landmarks	Electric District Operations feedback on feature selection	Review of the Feature Importance list	xgboost
			Conditional Probability of Ignition (POI_F)*		
Span	Ensemble decision trees (random forest)	Forecasted wind gust, forecasted temperature, fuel source prevalence, wire type, wire length	Fire science review, Technosylva feedback and fuel layer	Gini importance, discretionary	Pycaret
Pole	Ensemble decision trees (random forest)	Pole age, pole material, pole class, number of wires, upstream sectionalizer type, WRRM value (see Section 4.5.1.3)	n/a	Review of the Feature Importance list	RandomForestClassifier

*Elements within these fields are constantly changing and improving

The high-level process flow for the current modeling methodology to create and utilize these models is detailed in Figure 4-19, outlining the various data sources leveraged, major process steps in the methodology, and where the output of the model is utilized.

Figure 4-19: High-Level Process Flow for Current Modeling Methodology



6. Model uncertainty

Table 4-19 details the model performance metrics and methods associated with each failure/asset model for both PoF and PoI_F, as well as the model input uncertainties.

Table 4-18: Model Performance Metrics and Input Uncertainties

Model	RSQ*	ROC AUC**	Quantification Method	Input Uncertainties
		Probability of Failure (POF)		
Conductor Failure	0.89	n/a	OLS	GIS coordinates, weather readings
Balloon Contact	n/a	n/a	inferential	GIS coordinates, weather forecasts
Animal Contact	n/a	0.81	n/a	GIS coordinates
Vegetation	n/a	n/a	n/a	GIS coordinates
Vehicle	n/a	n/a	n/a	GIS coordinates
		Conditional Probability of Ignition (POI_F)		
Span	n/a	0.7	k-fold cross-validation	GIS coordinates
Pole	n/a	n/a	Precision/Recall/Accuracy metrics	GIS coordinates

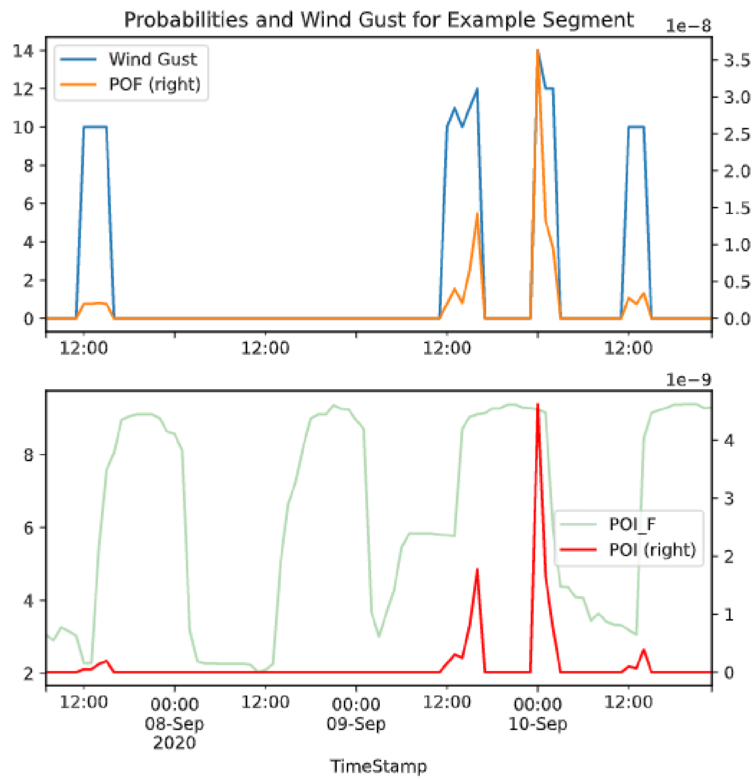
* R-Squared = statistical measure for linear regression models depicting the model goodness-of-fit
**Area under the curve (AUC) of a Receiver Operating Characteristic (ROC) plot = metric to calculate the performance of a classification model

7. Model verification and validation

As an initial form of validation, PoF and PoI models are backcasted for every span, pole, and hour of the previous year. When summed, the values should reflect the expected annual totals within a reasonable range of deviation. This validation is performed on every statistical model to ensure that they are performing as intended.

Additionally, spot checks on shorter time durations are performed regularly using data that was not included in model training. This ensures that the model performs as intended at an hourly resolution. For example, in Figure 4-20, actual wind gust data (blue) is shown over a four-day period which was known to have moderate gusts. The dynamic probability of conductor failure from the latest PoF model (orange) is overlayed. From this chart, it is evident that this PoF is highly responsive to wind gusts. However, the outputs also depend on other factors, such as wind direction, and so the two plots have different, albeit similar shapes when plotted over time. A conditional PoI_F model output (green) is shown in the bottom chart. As expected from this version of the model, the PoI_F is highly dependent on temperature, which fluctuates in daily cycles. The calculated PoI (product of PoF and PoI_F) is shown in red.

Figure 4-20: Wind Gust over PoI/PoF/PoI$_F$ metrics



8. Modeling frequency

These models are run prior to each potential PSPS event.

9. Timeline for model development

Further improvements have been identified that will continue to be developed in 2022, including migrations of models into the cloud platform to enable more dynamic updates to those models.

10. Application and results

The PoI models will be used to inform decision makers of PSPS by:

- Providing situational awareness during severe weather events
- Setting alert wind speed for PSPS operations
- Identifying segments with high conductor risk during the pre-event phase
- Using in WiNGS-Ops (See Section 4.5.1.4 Wildfire Risk Reduction Model – Operations)

For PSPS operations, only the conductor failure model was considered because it would best complement the existing models currently in use, such as the VRI. Since the amount of detail contained in the model may overwhelm decision-makers during activation, key information was distilled into a "high-medium-low" CRI to match the format, simplicity, and familiarity of the VRI. The CRI of each segment reflects the relative ranking of the ignition likelihood for that segment at elevated wind speeds.

To calculate CRI for each segment, the PoI for every span within the segment was calculated for each hour of the previous fire season. These values represent a distribution of ignition probabilities within the segment due primarily to varying wind gusts, but also to other variations within the date range. A cubic polynomial fit was performed on these outputs to represent them as a function of only wind gust. From here, several approaches could be taken to rank the "relative riskiness" of segments based on these curves. After consulting with emergency operators, SDG&E found it favorable and intuitive to define the CRI based on the wind gust at which a certain probability threshold is surpassed. The wind gust thresholds for indexing are fixed at 45 miles per hour (mph) and 58 mph, while the probability threshold continues to undergo review and analysis. In initial operations, for example, an ignition probability of one in ten thousand was used.

11. Key improvements from working group

The OEIS has initiated a joint IOU Wildfire Risk Modeling working group for which discussions are underway. Possible direct improvements for the model from the discussions are still under consideration.

4.5.1.2 Vegetation Risk Index

1. Purpose of Model

The VRI is used to determine which distribution circuit segments are most at risk of vegetation-related outages during adverse weather conditions based on the number of trees, species of trees, height of the trees, and outage history along that given circuit segment.

2. Relevant terms

Inventory Tree	A tree that could encroach the minimum clearance or otherwise impact the electrical facilities within three years of the inspection date.
Tree Inventory Database	A database of inventory trees which includes information on height, species, diameter, growth rate, clearance, and other characteristics
Distribution Segment	The portion of a circuit that lies between two automatic recloser devices within the distribution circuit network.

3. Data elements

Data Element	Data Sources	Collection Period	Collection Frequency	Spatial Granularity	Temporal Granularity	Comment
Transmission Lines in HFTD)	GIS Business Solutions	n/a	Annually	n/a	n/a	
Distribution Segments in HFTD	GIS Business Solutions	n/a	Annually	n/a	n/a	
Location of Trees	Vegetation Management's	n/a	Annually	n/a	n/a	

Data Element	Data Sources	Collection Period	Collection Frequency	Spatial Granularity	Temporal Granularity	Comment
	Tree Inventory Database					
Tree Height	Vegetation Management's Tree Inventory Database	n/a	Annually	n/a	n/a	
Tree Species	Vegetation Management's Tree Inventory Database	n/a	Annually	n/a	n/a	
Tree related Outages	Outage Management System	Year 2000 to present	Annually	n/a	n/a	

4. Modeling assumptions and limitations

The model assumes that every tree poses a potential outage risk, which may result in overprediction of risk.

Tree-related outage during all adverse weather conditions were considered during model development, but the final VRI rating for a particular polygon was not filtered based on weather type. This may result in an overprediction of outage risk during a weather event.

5. Modeling methodology

To determine which transmission lines and distribution circuit segments are most at risk of vegetation-related outages:

1. The electric distribution system within the HFTD was divided into circuit segments based primarily on existing weather station/sectionalizing device associations and known local wind climatology.
2. Polygons were drawn around the circuit segments, as well as around transmission lines within the HFTD.
3. The Tree Inventory Database was used to catalog the number of inventory trees along each circuit segment or transmission line within the polygon, including the height and species of each tree.
4. Historical tree-related outage data was also collected and included in the VRI calculation.
5. Results of the VRI calculations were analyzed to create breakpoints from the data.
6. Each circuit segment was assigned a VRI rating of low, medium, or high, based on those breakpoints.

Data quality verification of the inventory tree data information is performed by certified arborists. Tree-related outages are vetted by Vegetation Management before the Tree Inventory Database is finalized. Additionally, VRI polygons surrounding distribution circuits and transmission lines are created and maintained by meteorologists.

There are no significant data modifications conducted, though the data is cleaned and scrubbed, for example, removing vegetation-related outages that were caused by tree-trimming activities and improperly recorded vegetation-related outages, to increase the quality of the overall dataset for improved analysis outcome.

6. Model uncertainty

The VRI algorithm was created based on subject matter expertise with the intent to lay a foundation for future improvements on risk modeling as it pertains to vegetation around electrical assets. In that regard, model parameters need further assessment and refinement to ensure all risk factors are accounted for and integrated into the algorithm.

7. Model verification and validation

This is not a predictive model but rather a qualitative index, therefore no standard verification or validation are conducted. Rather, this is a measure of the overall quantity of trees in close proximity to the lines, including height, species and historical outages. Data is on an annual update cycle to incorporate the latest vegetation management activities and is reviewed by Arborists.

8. Modeling frequency

This index is updated annually.

9. Timeline for model development

The VRI was first created in 2019 and is updated annually as conditions on the system change. In 2021, transmission lines were added to the analysis that was originally only done with distribution circuit segments. Currently, ways to enhance the VRI by incorporating real-time and forecasted weather conditions are being explored.

10. Application and results

The VRI has been instrumental for real-time PSPS decision making. Circuit segments that have a “High” VRI rating may experience a PSPS event at lesser wind speeds compared to a climatologically similar circuit segment with a “lower” VRI due to the increased risk of tree-related outages. The VRI has been used to make timely PSPS decisions on certain “High” VRI circuit segments prior to instances of tree-related damages, preventing potential ignitions during critical fire weather conditions.

11. Key improvements from working group

Wildfire Risk Modeling working group discussions are underway. Direct improvements to the model from the discussions have not yet been determined. SDG&E is currently exploring ways to further enhance the VRI by incorporating real-time and forecasted weather conditions.

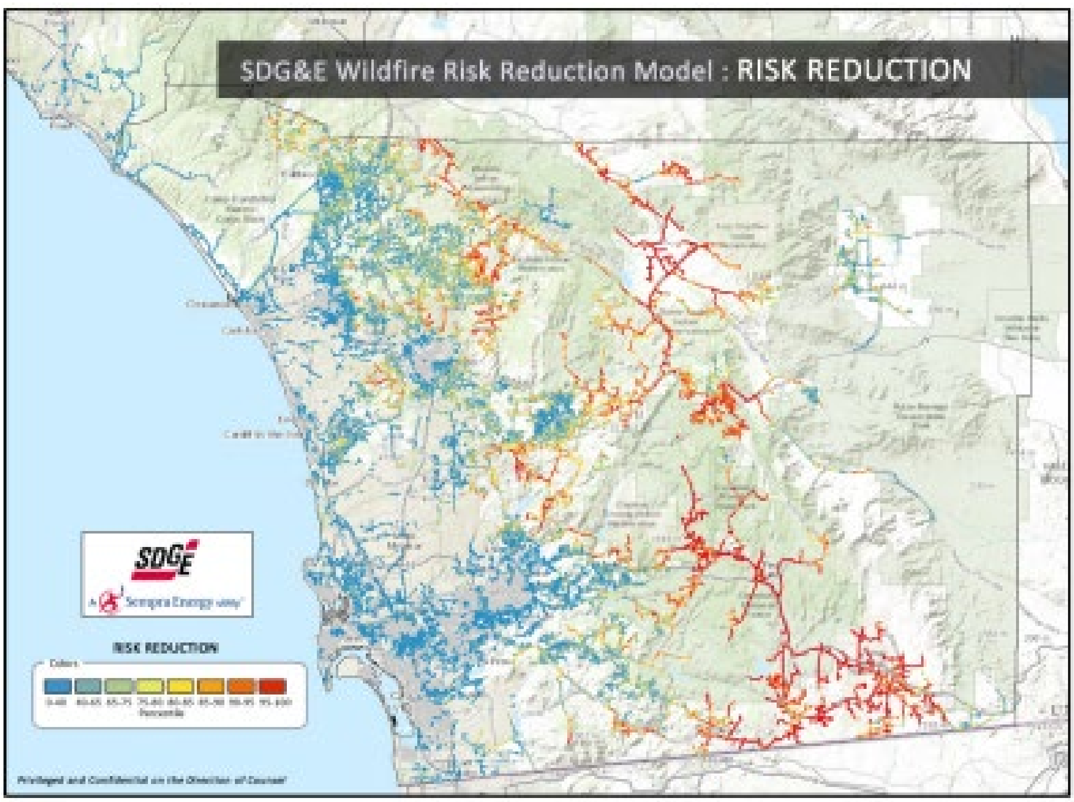
4.5.1.3 Wildfire Risk Reduction Model

1. Purpose of Model

WRRM, developed by Technosylva and SDG&E SMEs, was the first project-scoping tool used to prioritize electric distribution fire hardening for the FiRM Program. WRRM combines electric distribution asset data and wildfire simulations to predict the risk of potential equipment-related ignitions. To accomplish this, Technosylva aggregated millions of wildfire computer simulations to build a geospatial layer of wildfire vulnerability over the electric distribution overhead assets. This layer, combined with the assets' expected failure and ignition rates, was used to assign a wildfire risk score. The wildfire risk score, called the expected impact, was also generated for assets considered hardened by SDG&E construction standards. These hardened assets have reduced failure and ignition rates. The difference in risk scores between assets provided a risk reduction score used to prioritize circuits and sections for projects inside the FiRM program.

Further refinement of fire modeling technologies, geospatial data, and computer capabilities allowed WRRM to evolve into WRRM-Ops, a tool with more granular fire weather forecasting instead of a single aggregated simulation model (see Section 4.5.1.4 Wildfire Risk Reduction Model – Operations). The previous iteration of WRRM is also utilized in the WiNGS-Planning to help characterize sub-circuit fire consequence and the latest WRRM and WRRM-Ops models are currently utilized as tools to understand the consequence of ignitions at different locations as the latest PoI models are incorporated to evaluate likelihood of risk. Figure 4-21 demonstrates one illustrative example of heatmap output of the model that serves to help characterize the service territory by its wildfire risk across the system.

Figure 4-21: Illustrative WRRM Risk Heat Map



2. Relevant terms

Asset	A specific feature on the electric utility infrastructure network such as a pole, conductor, capacitor, transformer, or fuse.
Asset Class	A grouping of assets based on their characteristics, such as material type, size, or age, that reflects a specific likelihood for equipment failure and wildfire ignition.
Asset Index	A 6-digit number used to delineate asset classes.
Burn probability	The probability of a wildfire burning into an area, sometimes referred to as a wildfire threat. Burn Probability is the combination of numerous individual fire growth potential simulations to create an overall fire growth potential map using only SDG&E Assets as possible ignition sources.
Conditional Impacts	The mean wildfire impact given that an equipment-related wildfire occurs at a specific location (also referred to as conditional risk). Conditional impacts are combined with ignition rate and wind factor characteristics to calculate the Expected Impacts. They are calculated for each asset and can be summed to quantify the conditional impacts for a specific hardening project.
Downfire	The location of a HVRA within the fireplain (fire growth from a specific ignition location)
Expected Impacts	The mean annual equipment-related wildfire impact after incorporating the likelihood of equipment failure and subsequent wildfire (also referred to as expected risk). This is a primary output of the WRRM model. It is calculated for each asset and can be summed to quantify the expected impacts for a specific hardening project.
Exposure	The placement of a Highly Valued Resources and Asset (HVRA) in a hazardous environment. For example, building a home within a flammable landscape.
Fireplain	The area where fire can spread to if ignited at a particular location. The fireplain is identified by either a deterministic simulation of fire growth or through a stochastic simulation of fire growth. A fireplain represents the spread area commonly referred to as Time of Arrival, a raster representation of the fire spread, while Fire Perimeters is the vector format representation of the fire spread.
GIS Assets	The GIS database of assets used as the source of potential ignitions for the WRRM.
Hardening Project	A series of projects that may occur to change, repair, replace, or affect asset equipment. The intent of these projects is to “harden” the equipment so that it is more durable and less likely to fail. A project is a series of activities that may be combined under a single work order or field visit for planning, budgeting, and/or administrative management.

Ignition Likelihood	The probability of an asset to start a fire ignition based on equipment failure or external weather conditions.
HVRA	Resources and assets such as structures/homes or environmentally sensitive areas.
Replacement Asset	The new asset class used to replace an existing asset class. Replacement assets have lower equipment failure rates and ignition rates than existing assets.
Risk Reduction	The expected risk over a 20-year planning horizon for an asset. This is the primary WRRM model output used to quantify risk reduction for an asset replacement. Risk reduction values are summed for assets in specific hardening projects to provide an overall risk reduction for that project.
Susceptibility	A measure of how easily a HVRA is damaged by wildfires of different types and intensities.
Values-at-risk	A general term that is commonly used to describe the HVRA and the risk assigned to them.
Vulnerability	A combination of Exposure and Susceptibility, Vulnerability is the measure of potential (sometimes called conditional) impacts to HVRA from wildfires of different intensities.
Wildfire hazard	A physical situation with potential for causing damage to resource or assets. Wildfire hazard is measured by two main factors: burn probability and intensity.
Wildfire risk	Overall measure of the possibility for loss or harm caused by wildfire. Wildfire risk is a product of Wildfire hazard and Vulnerability.

3. Data elements

Data Element	Data Sources	Collection Period	Collection Frequency	Spatial Granularity	Temporal Granularity	Comment
Vegetation/ Fuels Data	Technosylva custom fuels derived using object-oriented segmentation methods from numerous imagery sources, including LiDAR. Advanced methods are applied to derive canopy fuels	Fuels derived pre-fire season, monthly during fire season, and post-fire season. 2021 imagery collected weekly to support on-going updating of fuels during fire season. Field surveys conducted during pre-fire season and post-fire season	6 times annually Monthly during fire season For some analysis fuels are projected for future conditions	Vector polygons of fuels areas Resampled to 10m and 20m for fire modeling	Continually up-to-date using Technosylva updating process For 2021 WRRM analysis up-to-date fuels for August 4, 2021 were used	7.

Data Element	Data Sources	Collection Period	Collection Frequency	Spatial Granularity	Temporal Granularity	Comment
		to confirm burn area fuels. Cameras used to verify fuels regrowth				
Weather (real-time & predictive)	SDG&E Re-analysis WRF data is used for WRRM analysis Real-time weather observation data is not used for WRRM analysis	141 weather days selected by SDG&E Met team from WRF Re-analysis data. Re-analysis data is from 1986 to 2015	Hourly WRF re-analysis data derived by SDG&E Met team	2km	Hourly	WRRM analysis only uses SDG&E WRF re-analysis data as input for defining weather days (scenarios)
Historical Fires	CAL FIRE Technosylva Wildfire Analyst-Enterprise (WFA-E) live data feeds from CAL FIRE and NIFS	1940-2022	Daily as fires occu	Polygons captured from aerial survey	Daily	The Technosylva WFA-E environment seamlessly obtains fire perimeter data directly from agency postings as they are captured.
Fire Behavior (FB) Analysis	Technosylva's WFA-E software (HPC version)	Uses static landscape characteristics data combined with 141 weather days from SDG&E WRF re-analysis data	Typically WRRM is run twice annually, although the latest SDG&E WRRM is from August 2021	20-meter raster input data and output metrics	WRRM uses 141 weather days as input Fuels from August 4, 2021 Other inputs updated to current 2021	FB outputs are derived as part of the asset risk fire spread prediction (simulation) modeling. This includes 20+ advanced models including custom urban/WUI encroachment and building loss analysis to enhance output consequence values.
Fire Simulation Modeling	Technosylva's WFA-E software (HPC version)	Uses static landscape characteristics data combined with 141 weather days	Typically WRRM is run twice annually, although the latest SDG&E	20-meter raster input data and output metrics	Outputs reflect the 141 historical weather days used.	Includes 20+ advanced models including custom urban/WUI

Data Element	Data Sources	Collection Period	Collection Frequency	Spatial Granularity	Temporal Granularity	Comment
		from SDG&E WRF re-analysis data.	WRRM is from August 2021.	Time of Arrival output is vector polygons depicting fire spread extent Impact analysis is conducted for overlapping vector features, i.e., building footprints, critical facilities. Population impacts are calculated from 90-meter LandScan population count input data.	Percentiles are created from the 141 risk outputs for each asset	encroachment and building loss analysis to enhance output consequence values
SDG&E Distribution Assets	SDG&E from July 2021	Last updated in SDG&E GIS system in July 2021	Daily	Vector data points (poles) and linear segments (lines)	July 2021	Distribution assets, lines plus poles, are provided by SDG&E using the latest update. 2021 WRRM used July 2021 data vintage
Subjective VAR Parameters	Technosylva enhanced building footprints (uses Microsoft 2020 update as source). Technosylva updates the building data annually based on change detection methods. 2020 LandScan Data (ORNL) July 2021 SDG&E Assets Data	2020 source data with 2021 manual update for buildings 2020 LandScan Data from Oak Ridge National Laboratory (ORNL) July 2021 SDG&E Assets	Annual (buildings & population) Monthly (SDG&E assets)	Population = 90-meter raster of pop count SDG&E assets = vector data	Annual (buildings & population) Monthly (SDG&E assets)	Primary data used for defining Values at Risk are building footprints, population counts and SDG&E assets. Other consequence outputs may be calculated by SDG&E applying factors to the baseline risk metrics identified.

Data Element	Data Sources	Collection Period	Collection Frequency	Spatial Granularity	Temporal Granularity	Comment
Electric System Conditions & Characteristics	SDG&E GIS Production database	2011-2015	As needed	Pole, span level	Daily	
Outages	SDG&E System Average Duration Index Data (SAIDIDAT) database	2011-2015	As needed	Pole, span level	Daily	
ERA (Wire down) Data	ERA Database	2011-2017	As needed	Pole, span level	Weekly	Wire downs were added to the model in 2017

4. Modeling assumptions and limitations

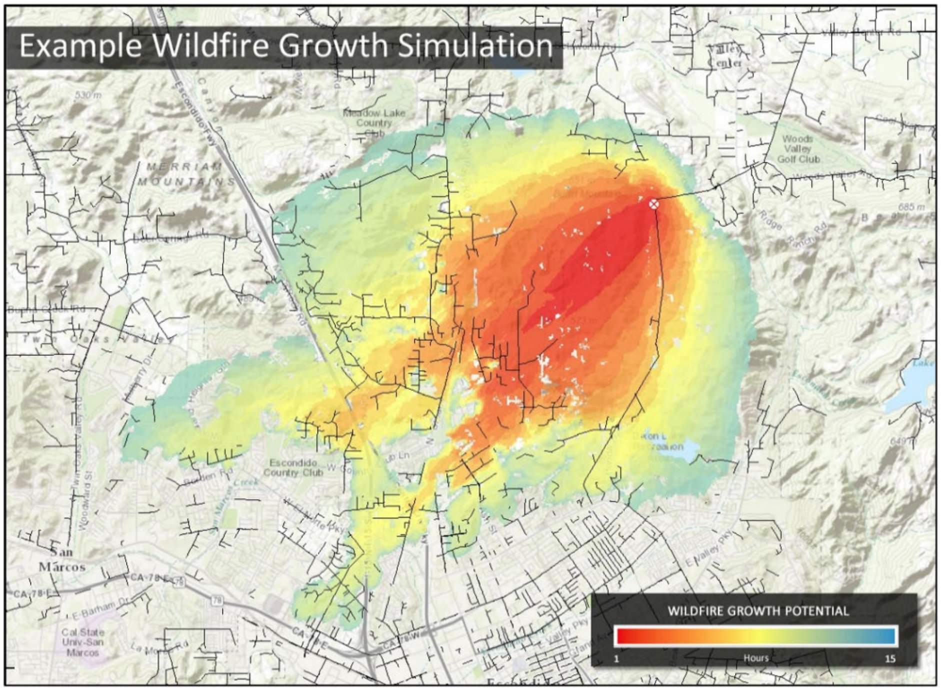
- There is a convention of using 141 historic weather days for fire modeling, which is assumed to capture the most significant risk.
- The WRRM update for 2021 does not include system information such as outages, equipment failures, electric system conditions, or risk reduction projects. Since electric system information changes daily, it is more accurate to track this information separately in mitigation scoping models, such as WiNGS-Planning.
- Viewing system information in operations models, such as WiNGS-Ops, is best done outside of the WRRM model due to the rapidly changing nature of electric data. Electric data can become obsolete in the time spanning the biannual WRRM update schedule, especially when considering ongoing hardening projects in the backcountry.
- Pole and span data are used in the WRRM 2021 Update to provide locational information for fire ignition point modelling. Pole and span attributes are not used to provide a likelihood of ignition score in the 2021 update.

5. Modeling methodology

WRRM was built on a quantitative risk model that associated wildfire hazards with the location of electric distribution overhead assets. Development started with fire growth simulations that would identify both fire growth potential and vulnerability of impacted structures at each simulated fire location inside the service territory.

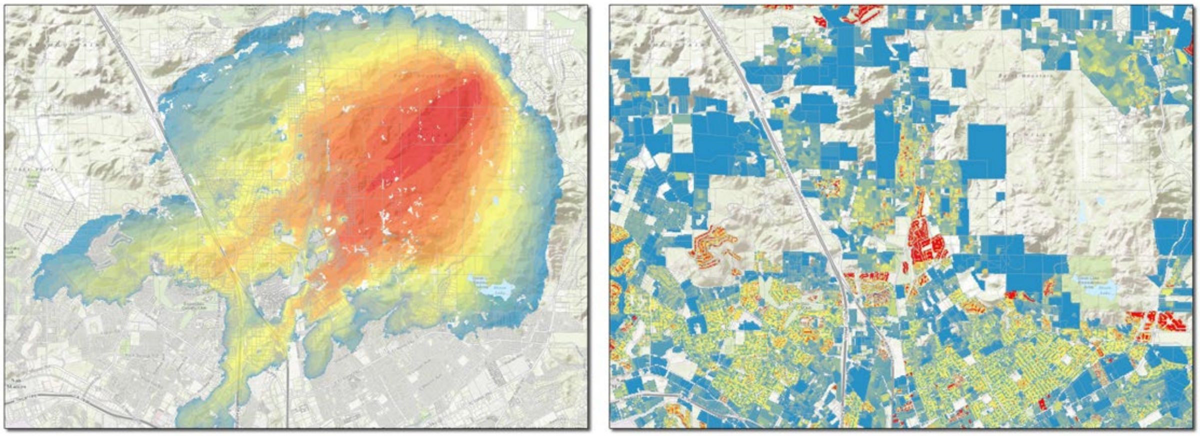
A landsat digital model of surface and canopy fuels, topography, and climate data are used as inputs into numerous fire growth potential simulations. Thousands of simulations are run for each potential ignition location in a Monte Carlo approach, a random sampling simulation methodology that helps solve deterministic problems, to identify the total fire growth potential for that location (see Figure 4-22).

Figure 4-22: Wildfire Growth Simulation Example



Once the fire growth potential for a location is determined, the geospatial simulation is overlaid with property and parcel information relating to the surrounding community to identify potentially impacted structures. Identifying the susceptibility of each structure type to a wildfire (i.e., residences, commercial spaces, parking lots) can be used to estimate a value of impacted square footage or structure damage if an ignition were to occur. This mean value of impacted structure damage generates the conditional impact value for that given location. Figure 4-23 displays the resulting fireplain from a simulation with a 15-hour duration (left diagram). The right diagram shows structure values adjusted by percent loss associated with the fireplain from a wildfire simulation.

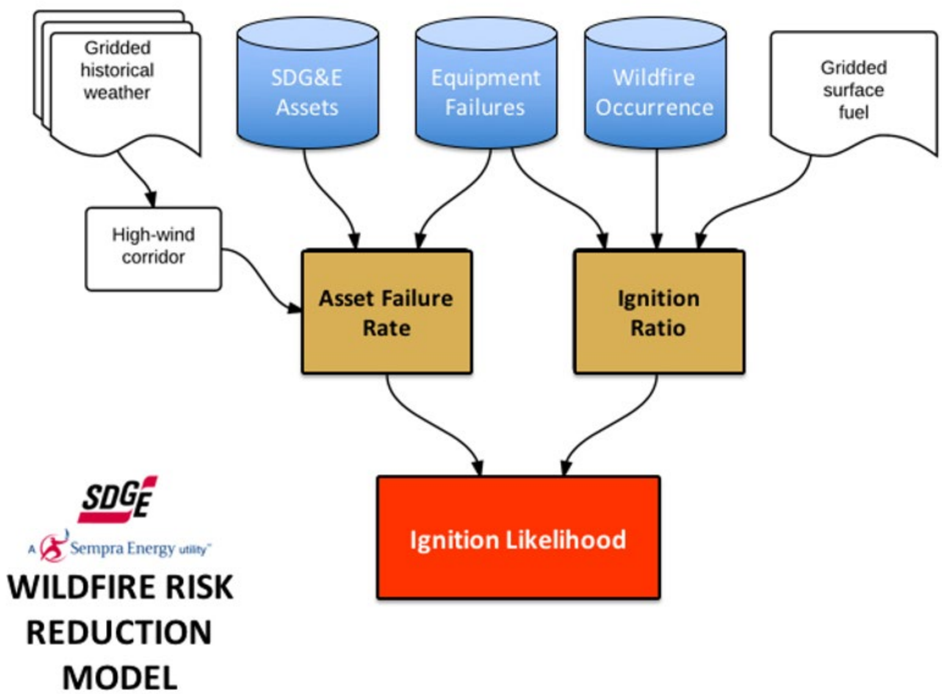
Figure 4-23: Wildfire Growth Simulation and Structure Values



Once the conditional impact of the asset location is determined, the assets at that location are assigned an ignition likelihood[27]. This ignition likelihood is the combination of each asset failure rate and the ratio for when those failures might result in an ignition (see Figure 4-24).

[27] Prior to the 2021 WRRM updates, ignition likelihood estimates were developed and incorporated in the WRRM model to guide grid hardening prioritization. In 2021, with the development of new probability of ignition models, the WRRM tool was updated to focus primarily on consequence assessment with the intention of combining the latest PoI analysis and WRRM consequence outputs in other models used for decision-making such as WiNGS-Planning.

Figure 4-24: Ignition Likelihood



During model development, there were challenges in providing detailed records granular enough to characterize every class of assets and/or the individual assets themselves. There were similar challenges when identifying equipment-related ignitions, their causes, or conditions of failure. In lieu of this data, SMEs categorized and characterized assets into classes to assign equipment failure rates and ignition ratios in a proportional manner to model the number of historic failures and equipment ignitions to match the records available.

For example, overhead conductor failure records (often called wire downs) were used to assign an equipment failure rate for a generic conductor wire size. Overhead wire length was also found to be a factor in potential failure. Spans greater than 1,000 feet are assigned a higher failure rate than spans less than 500 feet or 250 feet. Areas with higher wind speeds influence this failure rate and would be further modified by the location of the asset in the models identified wind corridors.

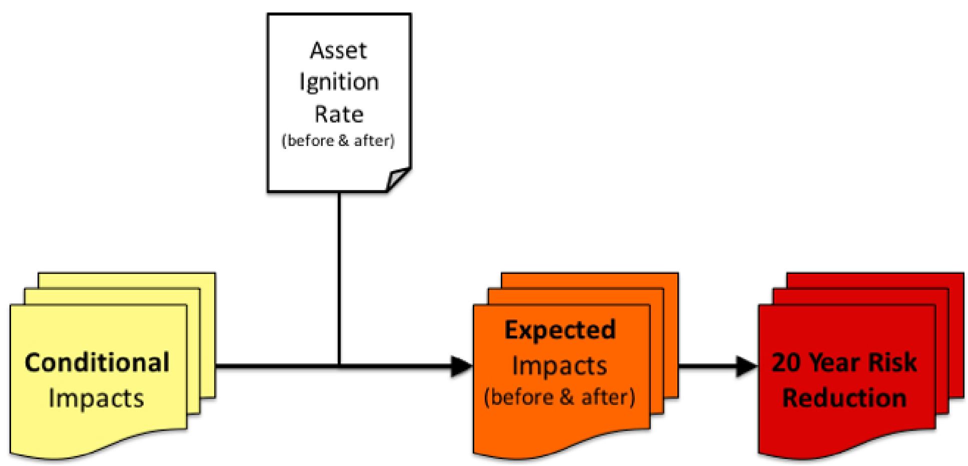
Equipment attributes in the GIS asset information were then categorized into the necessary bins to build the asset classes with each developed equipment failure rate and ignition ratio. When an asset is identified as belonging to a specific asset class, the associated equipment failure rate and ignition ratio is assigned and combined to generate the ignition likelihood.

Once ignition likelihoods were assigned to all assets across the overhead distribution network, a combined number of predicted equipment failures and ignitions were summarized for comparison with historic records, including the locations of prior fire history. This was used to calibrate the failure rates and ignitions across the model to achieve a realistic result and relative ranking of where assets of concern exist in the electric distribution network.

When conditional impact and ignition likelihood are determined for each asset at each location, it is then possible to calculate the overall expected impact of an equipment-related ignition. The expected impact accounts for the mean annual equipment-related wildfire impact after incorporating the data and methods discussed.

Understanding that different assets have different failure rates and therefore different ignition likelihoods, a reduction of the expected impact can be estimated by replacing the assets with fire-hardened assets. In terms of the FiRM program, this would be accomplished with the replacement of wood poles with steel poles and reconductoring to a stronger overhead conductor type. The difference between the current asset-expected impact and the fire-hardened asset-expected impact provides a risk reduction score. Given the longevity of these assets, the risk reduction score was expanded over a 20-year benefit period for project comparison. Figure 4-25 outlines the major process steps described above to produce the expected impact scores connected to an asset and computing the subsequent risk reduction associated to a fire-hardening effort on that asset.

Figure 4-25: Expected Outcome Process Steps



6. Model uncertainty

The GIS data used in this model is captured via As-built drawings and reviewed according to set protocols according to the Electric GIS production team standards. This data does not reflect ongoing switching or temporary configurations.

7. Model verification and validation

WRRM data delivery consisting of GIS Feature classes is visually inspected in a map environment upon receipt to make sure the data results coincide with known conditions around the service territory.

8. Modeling frequency

See the Data Elements Table in #3 for model frequency and data refresh rates.

9. Timeline for model development

Version 1.0 of the WRRM model was released December 2015 and version 2.0 was released August 2017. Refinements for version 2.0 included updated GIS information, more granular asset data, and enhanced GIS asset query functions to assist in project creation.

The August 2021 model deployment included the following changes:

- Ignition likelihood methodology and application was replaced by WiNGS-Ops modeling output (see Section 4.5.1.8 Wildfire Next Generation System-Operations)
- Fire consequence analysis was reran using latest weather history
- Additional conditional impact factors were incorporated in the model, including buildings impacted, populations impacted, acres burned flame length, rate of spread, and FPI. Previous version of the model had one conditional impact score without this breakdown.
- Fire spread is calculated along primary overhead conductor and overhead transmission lines
- Likelihood score is no longer included in WRRM calculations

10. Application and results

- The WRRM and subsequent data tables are useful in identifying and prioritizing projects for overhead electric distribution fire hardening programs including FiRM, Pole Risk Mitigation Engineering (PRiME), and WiSE. This same data also was aggregated to support the Electric System Hardening (ESH) team in comparing and prioritizing fire hardening mitigation strategies and was incorporated into the CRI project to further identify wildfire risks with refreshed equipment failure models and updated GIS information.
- The WiNGS-Planning model incorporates the WRRM conditional impact score using the original WRRM methodology, which includes the PoI score. Subsequent versions of the WiNGS-Planning model will transition to the 2021 version of the WRRM model.
- The WiNGS-Ops model utilizes the 2021 version of the WRRM model.

11. Key improvements from working group

Wildfire Risk Modeling working group discussions are underway. Direct improvements from the discussions have not yet been determined.

4.5.1.4 Wildfire Risk Reduction Model – Operations

1. Purpose of Model

The purpose of the WRRM-Ops model is to leverage the latest fire science available to help anticipate, prepare for, react to, and recover from wildfire activity during emergency operations, including PSPS. The model uses the latest available fuels and weather information to model wildfire consequence, anticipate where risk is highest across the service territory, and predict how a wildfire may grow and impact the community once ignited. Increasingly, the WRRM-Ops model is being used to inform internal wildfire risk modeling efforts.

2. Relevant terms

Asset	A specific feature on the electric utility infrastructure network such as a pole, conductor, capacitor, transformer, or fuse.
Asset Class	A grouping of assets based on their characteristics, such as material type, size, or age, that reflects a specific likelihood for equipment failure and wildfire ignition.
Asset Index	A 6-digit number used to delineate asset classes.
Burn probability	The probability of a wildfire burning into an area, sometimes referred to as a wildfire threat. Burn Probability is the combination of numerous individual fire growth potential simulations to create an overall fire growth potential map using only SDG&E Assets as possible ignition sources.
Downfire	The location of a HVRA within the fireplain (fire growth from a specific ignition location)
Exposure	The placement of an HVRA in a hazardous environment. For example, building a home within a flammable landscape.
Fireplain	The area where fire can spread to if ignited at a particular location. The fireplain is identified by either a deterministic simulation of fire growth or through a stochastic simulation of fire growth. A fireplain represents the spread area commonly referred to as Time of Arrival, a raster representation of the fire spread, while Fire Perimeters is the vector format representation of the fire spread.
GIS Assets	The SDG&E GIS database of assets used as the source of potential ignitions for the WRRM.
Wildfire hazard	A physical situation with potential for causing damage to resource or assets. Wildfire hazard is measured by two main factors: burn probability and intensity.
Wildfire risk	Overall measure of the possibility for loss or harm caused by wildfire. Wildfire risk is a product of Wildfire hazard and Vulnerability.

3. Data elements

Data Element	Data Sources	Collection Period	Collection Frequency	Spatial Granularity	Temporal Granularity	Comment
Vegetation and Fuel Moisture Data	Dead Fuel Moisture provided by vendor	Daily	Daily	2 km	Hourly	
Weather (Real-time & Predictive)	WRF model	Daily	Daily	2 km	Hourly	
Historical Fires	Fire agencies	All recorded	annual	n/a	annual	

Data Element	Data Sources	Collection Period	Collection Frequency	Spatial Granularity	Temporal Granularity	Comment
Outages	n/a	n/a	n/a	n/a	n/a	
Fire behavior analysis	Provided by vendor	n/a	n/a	n/a	n/a	
Fire Simulation modeling	Provided by vendor	n/a	n/a	n/a	n/a	
SDG&E Distribution/Transmission assets	SDG&E GIS	n/a	n/a	n/a	n/a	
Subjective 'values at risk' parameters	Provided by vendor	n/a	n/a	n/a	n/a	

To perform data quality verification on data elements associated to the wildfire prediction, Technosylva works directly with CAL FIRE to validate the model performance. No formal data modification process is in place with the model process, although data is interpreted by SMEs.

Fire Behavior Outputs: FireSim has the ability to generate conventional fire behavior outputs based on specific ignition location points. These outputs include Time of Arrival (fire perimeter) for a specific forecasted time period (duration), and fire behavior characteristics including the rate of spread, flame length and fireline intensity. These FB outputs are only shown for the final time slice of the prediction duration, i.e., hour 8 of an 8-hour duration.

4. Modeling assumptions and limitations

Modeling assumptions and limitations are available from the vendor.[28]

5. Modeling methodology

To calculate risk for each asset, a fire spread prediction is simulated using the asset location as the ignition point(s). Millions of ignition points are defined along the assets to run the simulations for different start times during a daily weather forecast. These simulations are undertaken nightly using the weather forecast that is updated daily as inputs. This produces a new asset risk forecast each day with a 72-hour horizon.

The processing steps involved to calculate the output risk values for each CUSTOMER asset are:

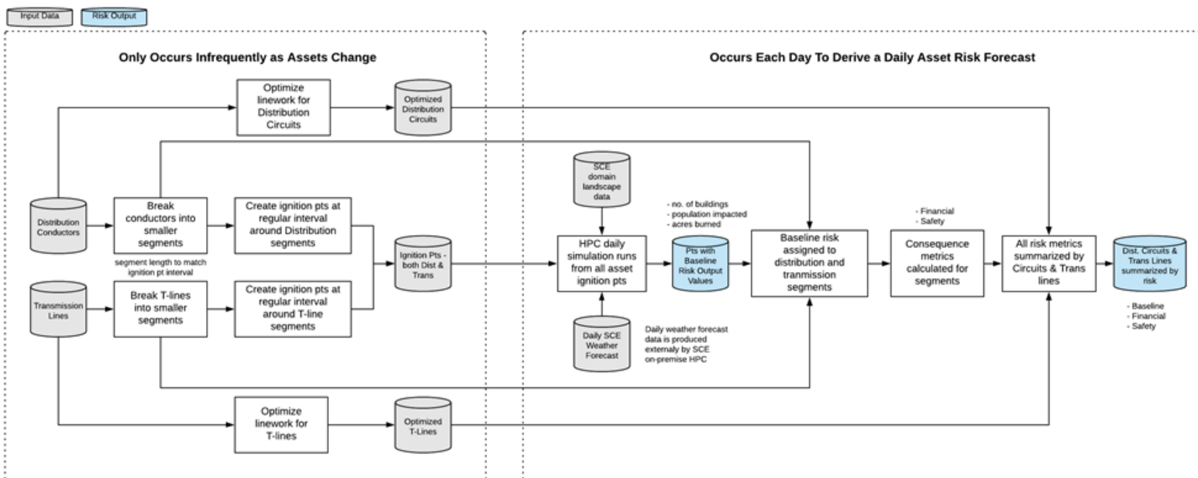
1. Pre-processing of electric utility asset GIS data (once)
2. Creation of asset ignition points (once)
3. Running spread predictions from ignition points (daily)
4. Calculating impacts for baseline risk outputs for each ignition point (daily)
5. Assigning baseline risk values to asset segments from ignition points (daily)
6. Calculating consequence model outputs for each segment (daily)
7. Aggregating maximum values for risk metrics for each circuit and T-line (daily)

[28] See Wildfire Analyst, available at https://www.wildfireanalyst.com/features/

8. Publishing the daily risk forecast (daily)

Figure 4-26 presents the detailed data flow for calculating risk metrics for the CUSTOMER overhead assets.

Figure 4-26: Data Flow for Calculating Risk Metrics for Customer OH Assets



6. Model uncertainty

Model uncertainty is based on the inputs which are all modeled parameters, justifying the requirement to maintain SMEs to analyze and validated the information.

7. Model verification and validation

Model verification and validation is a continuous effort in partnership with CAL FIRE.

8. Modeling frequency

The Model is run daily to generate fire risk and consequence and can be run in real time with current data if an ignition and subsequent wildfire were to occur.

9. Timeline for model development

Development started in 2014 and development continues through has continued through 2021 and beyond. As the understanding of fire science improves, enhancements can be made to the model's performance.

Enhancements in 2020 include:

1 Integration of a tree inventory database, with approximately 460,000 trees that are monitored near SDG&E equipment.

2 The ability to adjust weather- and fuel-related data within the model to improve simulation of real time conditions and assessment of risk.

3 Addition of new layers including historical fire perimeters, Alert SDG&E Cameras, granular weather data, weather station locations, and new view options.

4 The ability to efficiently export information from the program to enhance collaboration pre-incident, during a fire, and post incident.

Enhancements in 2021 include:

- Surface and Canopy Fuels Data
  - Update of fuels to June 2021 to reflect burn severity updates for fire disturbances and urban growth for 2021 fire season.
  - Implementation of a regular on-going fuels updating program that ensures fuels data is updated several times throughout 2021, including fire season, so that fuels data always reflects up-to-date conditions on the ground. This is essential for conducting fire spread prediction simulations, and daily asset risk forecasts.
  - Enhancement of canopy fuels with Light detection and ranging (LiDAR) data integration for deriving more accurate canopy height and related data to support enhanced crown fire modeling.
  - Addition of 21 new custom fuel models to better delineate non-burnable fuels to support WUI categorization based on density of buildings and adjacent fuel load; agricultural areas to reflect seasonal ability to burn; road and water classification to better represent barriers to fire spread.
  - Calibration of fuels to match observed and expected fire behavior from 2017-2021 fires. This calibration is on-going throughout the fire season and reflected in the fuels updating that is on-going.
  - Enhancement of fuels to 20-meter spatial resolution to better capture pencil canyons and spread landscape corridors.
- Fuel Moisture Data
  - Development and implementation of a new Live Fuel Moisture machine learning models for both herbaceous and woody fuels. This was tested in 2020 fire season with CAL FIRE and implemented into production for SDG&E in 2021 (along with other IOUs and CAL FIRE)
  - This Live Fuel Moisture data updated was battle tested in 2020 fire season to confirm it provides the best possible update for accurately reflecting up-to-date changes (no lag) in conditions.
  - The model was developed with support of the U.S. Forest Service Missoula Fire Lab.
- Weather Modeling
  - The ability to accommodate twice daily weather and risk forecasts production.
  - Added numerous weather and predictive services datasets to the WFA-E environment, the software system utilized by Technosylva for the WRRM-Ops model, including Normalized Difference Vegetation Index (NDVI), NDVI 5-year change, drought monitor, lightning strikes, snow depth, and Terrain Difficulty Index.
- Fire Behavior Modeling
  - Enhanced the “urban encroachment” algorithms to fully leverage the custom WUI fuel models reflecting building density and surrounding fuel load. This has been calibrated with

CAL FIRE Damage Inspection Specialists (DINS) data for 2013-2021. These enhancements result in more accurate impact analysis and consequence metrics. Calibration is on-going with CAL FIRE and updated in the SDG&E implementation.

- Significant enhancements to the FireSim on-demand fire spread prediction capabilities, including:
    - Integration of National Guard FireGuard data in a real-time, temporal environment.
    - Ability to utilize FireGuard data for calibration of Rate of Spread (ROS) factors in near real-time. This includes the analysis of ROS vectors for the FireGuard data and development of a machine learning model to integrate these seamlessly into the FireSim spread prediction models.
    - Simulations can use perimeters, hotspots and FireGuard data to conduct spread simulations.
    - Development of both one-page and full reports on each simulation conducted.
    - Addition of an Adjustment mode for spread prediction that allows the user to define observed fire points for adjusting the ROS factors to field observations.
    - Ability to digitize fuel model changes for a specific simulation.
    - Ability to integrate constant weather and fuel moisture values to override the forecast data to be used together.
    - Ability to interpolate a weather grid dataset from weather station observations and use this as input for simulations.
    - Ability to use post-PSPS damage asset survey data to conduct simulations reflecting “what could happened” scenarios.
- FireSim supports multiple temporal fuel scenarios that are seamlessly linked with forecasts, allowing users to ensure the best temporal fuels data is used as input.
- Ability to test Fire Behavior Officer (FBO) and U.S. Forest Service fuels data for simulations to evaluate accuracy and utility of external fuels data scenarios. Neither of these fuel model datasets matched observed or expected fire behavior when compared to actual incidents. The fuels classification for FBO in particular is poor and does not result in actual fire behavior for fires.
- Development and testing of a new Building Loss Factor (BLF) metric that will allow for identification of Buildings Destroyed as a new consequence metric. This BLF has been developed based on analysis of 10 years of DINS data in concert with spatial analysis of landscape characteristics for destroyed versus survived buildings. BLF is a spatially variable factor based on a per-building basis allowing for more accurate definition of potential buildings loss in addition to the current buildings threatened metric. This has been calibrated against major fires from 2017-2021 (current season).

- Risk Metrics & Forecasting
    - Updated building footprints by integrating new Microsoft 2020 dataset, in addition to manually adding buildings for missing data areas from high resolution imagery.
    - Regularly update asset data including poles and equipment data in addition to conventional distribution lines and transmission lines.
    - Add the Fire Behavior Index (FBI) metric that combines Rate of Spread with Flame Length with the hauling chart to provide a more comprehensive measure of fire behavior.
    - Addition of new BLF metric to augment the current Buildings Impacted metric. This helps quantify potential loss and damage to buildings from asset risk.
    - Enhanced approach for implementing asset simulations for daily asset risk modeling. This includes incorporating wind direction and speed to define an ignition spark curve for identifying how far a spark may fly to cause an ignition from an asset in windy conditions.
- Operational Data Integration
    - Added the ability to track resource locations via Automatic Vehicle Location (AVL) and other locations services in real-time.
    - Added the ability to integrate drone and aerial full motion video into the WFA-E viewing environment, synchronized with the risk viewing map canvas. This can include infrared data if available.
- PSPS Monitoring
    - Integration of consequence risk metrics into the PSPS Monitor application so that this data is retrieved in concert with wind alert speeds and FPI data values every 10 minutes.
    - Integration of a real-time service to provide display of de-energized circuits and changes in alert speeds.

10. Application and results

The WRRM-Ops model has been applied across SDG&E to support how wildfires are anticipated, prepared for, and responded to. Output is used by FS&CA to support operations to anticipate and prepare for wildfire risk.

11. Key improvements from working group

Wildfire Risk Modeling working group discussions are underway. Direct model improvements from the discussions have not yet been determined.

4.5.1.5 Fire Potential Index

1. Purpose of Model

The FPI was developed by SMEs to communicate the wildfire potential on any given day to promote safe and reliable operations. This 7-day forecast product, which is produced daily, classifies the fire potential based on weather and fuels conditions and historical fire occurrences within each of SDG&E’s eight operating districts.

2. Relevant terms

FPI Green-Up	The state of native grasses determined using satellite data for various locations. This component is rated on a 0-to-5 scale ranging from very wet (or "lush") to very dry (or "cured"). The scale is tied to the NDVI, which ranges from 0 to 1
FPI Fuels	The measurement of the overall state of potential fuels which could support a wildfire. Values are assigned based on the overall state of available fuels (dead or live) for a fire using the equation: FC = FD ÷ LFM. Where FC represents Fuels Component, FD represents 10-hour Dead Fuel Moisture (using a 1-to-3 scale), and LFM represents Live Fuel Moisture (percentage). The product of this equation represents the fuels component that is reflected in the FPI
FPI Weather	A combination of sustained wind speeds and dew point depression
Normal FPI	An FPI value of 11 or less represents a normal fire potential based on combined green-up, fuels, and weather measurements
Elevated FPI	An FPI value of 12 to 14 represents an elevated risk of fire potential based on combined green-up, fuels, and weather measurements
Extreme FPI	An FPI value of 15 or greater represents an extreme risk of fire potential based on combined green-up, fuels, and weather measurements

3. Data elements

Data Element	Data Sources	Collection Period	Collection Frequency	Spatial Granularity	Temporal Granularity	Comment
FPI Green-Up	1. NASA MODIS NDVI 2. Planet Labs NDVI	1. Past 16 days rolling avg 2. Past week avg	1. Weekly 2. Weekly	1. 250m 2. 3.7m	1.Once daily 2.Once daily	
FPI Fuels	1. National Fuel Moisture Database [Live Fuel Moisture (LFM)] 2. RAWS Network (DFM) 3. WRF Model	1. Bimonthly 2. Hourly 3. Lowest avg hourly value	1. Bimonthly 2. Hourly 3. Twice daily	1. Representative locations 2. Representative locations 3. 2 km grid	1.Bimonthly 2.Hourly 3.Hourly	
FPI Weather	1. RAWS Network 2. Weather Station Network 3. WRF Model	1. Hourly 2. 10 min increments 3. Twice daily	1. Hourly 2. 10-minute 3. Twice Daily	1. Representative locations 2. Representative locations 3. 2 km grid	1. Hourly 2. 10 min 3. Hourly	

4. Modeling assumptions and limitations

The FPI first assumes that an ignition takes place and attempts to predict fire size from that presumed ignition. There is a necessary assumption that the weather and fuels forecast will be accurate and also that the fuel types and terrain characteristics are homogeneous. The result is a blanket FPI applied over a spatially diverse district.

5. Modeling methodology

The formula for FPI is as follows:

$$FPI = \frac{DFM}{LFM} + G + Wx$$

Where DFM is the 10-hour dead fuel moisture, LFM is the live fuel moisture of local chamise expressed as a decimal, G is the greenness of the grass on a scale of 0-5, and Wx is the weather component derived from a matrix between sustained wind speed and dewpoint depression.

SMEs review the FPI output before every issuance to allow for forecast model variability. The numerical output of the FPI corresponds to a rating of Normal, Elevated, or Extreme, as shown in Figure 4-27.

Figure 4-27: Rating Scale for the FPI

Normal	Elevated	Extreme
≤ 11	12 to 14	≥ 15

6. Model uncertainty

While the FPI has undergone verification and validation studies (see below), there is some uncertainty regarding the specific weight of the FPI components within the formula. The projected FPI is based on a forecast model, which inherently produces uncertainty.

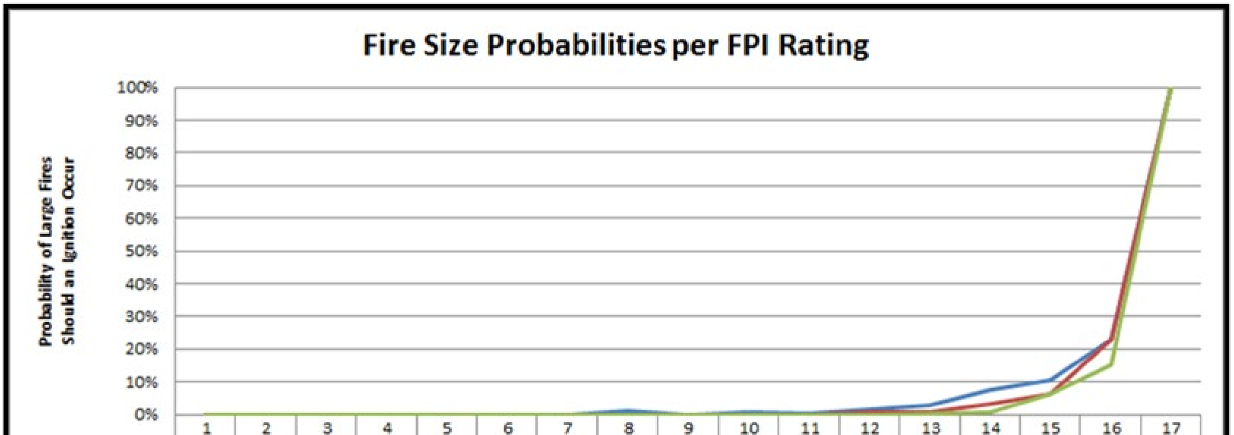
7. Model verification and validation

SDG&E meteorologists maintain documentation verifying the daily FPI for each operational district using the RAWS network.

Validation

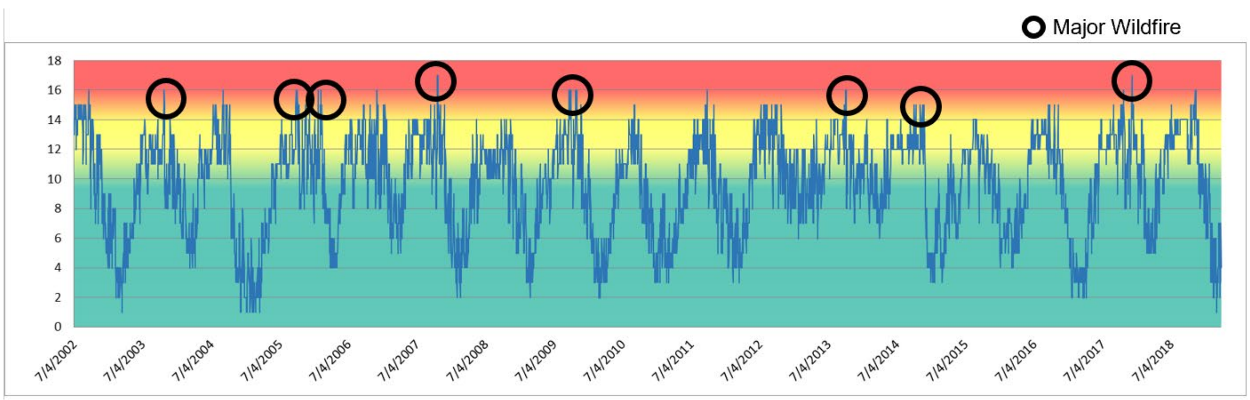
To validate the FPI, it was calculated using historical weather and fuels data and then compared to historical fires in the service territory. As the FPI value increased, so did the occurrence and severity of large fires. Figure 4-28 demonstrates the probability of a large fire occurring given a specific FPI value. At an FPI of 13, the occurrence of 250-acre fires showed a significant increase. An FPI of 14 or higher corresponded with an increase in fires of 1,000 and 5,000 acres respectively. These breakpoints were then selected to categorize the FPI values into Normal (11 and below), Elevated (12-14), and Extreme (15-17). As this historical FPI was compared to past large fires (Figure 4-29), it can be shown that large, destructive fires were occurring at FPI values of 14 and above.

Figure 4-28: Fire Size Probabilities per FPI Rating



	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17
250 acres	0%	0%	0%	0%	0%	0%	0%	1%	0%	1%	0%	1%	3%	8%	11%	23%	100%
1000 acres	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	1%	3%	6%	23%	100%
5000 acres	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	1%	6%	15%	100%

Figure 4-29: FPI Across Time and Incidences of Major Wildfires



8. Modeling frequency

Models that provide input to the FPI are run twice daily

9. Timeline for model development

The FPI was originally released in 2012 to support its operations. In 2020, enhanced analytical capabilities were operationalized by leveraging high performing computing clusters to update the weather component and AI was incorporated into the Live Fuel Moisture component. In 2021, dead fuel moisture sensors were installed on existing weather stations where fuel moisture data was sparse and grass Green-Up data was ingested from higher resolution satellites. A partnership with San Jose State University is currently in place to improve live and dead fuel moisture models that provide input into the FPI calculation described in #5 Modeling Methodology above (see Section 4.4.2.13 LFMC Tools).

10. Application and results

Proactive and reactive operational practices and measures are tied to FPI values through standard operating procedures, with the expectation that the likelihood facilities and operations will be the source of ignition for a fire during times when the risk of fire, as measured by the FPI, is elevated or extreme will be reduced. Moving forward, predictors that contribute to the FPI will continue to be enhanced, including live fuel moisture and green-up, to modernize the data inputs and better leverage the high-performance computing environment to generate the product.

Additionally, this is also shared with local fire agencies, emergency responders, and the National Weather Service.

11. Key improvements from working group

Wildfire Risk Modeling working group discussions are underway. Direct improvements from the discussions have not yet been determined.

4.5.1.6 Santa Ana Wildfire Threat Index

1. Purpose of Model

The SAWTI calculates the potential for large wildfire activity based on the strength, extent, and duration of the wind, dryness of the air, dryness of the vegetation, and greenness of the grasses. Similar to the hurricane-rating system (category 1-5), the SAWTI compares current environmental data to climatological data and correlates it with historical wildfires to rate a Santa Ana wind event on a scale from “marginal” to “extreme.” To help the region prepare for hazardous conditions, information from the SAWTI is issued daily to fire agencies and other first-responders, which has led to specific preparedness and operational decisions based on the likelihood of a catastrophic wildfire fueled by Santa Ana winds. The public also has access to SAWTI to make personal safety decisions.

2. Relevant terms

Dryness Level (DL)	A function of ERC and/or DFM10hr calibrated to historical fire occurrence across Southern California with unitless values ranging from 1 to 3.
Energy Release Component (ERC)	A relative index of the amount of heat released per unit area in the flaming zone of an initiating fire and composed of live and dead fuel moisture as well as temperature, humidity, and precipitation
Live Fuel Moisture (LFM)	The moisture content of live fuels (e.g., grasses, shrubs, and trees) expressed as a ratio of the weight of water in the fuel sample to the oven dry weight of the fuel sample.
Annual Grasses (Gag)	The new grasses that emerge following the onset of significant wetting rains in a process called green-up
Fuel Moisture Component (FMC)	The combination of DL, LFM, and Gag

Large Fire Potential (LFP)	The likelihood of an ignition reaching or exceeding 250 acres or approximately 100 hectares.
Dead Fuel Moisture (DFM)	Nonliving plant material whose moisture content responds only to ambient moisture. Dead fuel is typically grouped into ''time lag'' classes according to diameter: 0.20cm, DFM1hr; 0.64cm, DFM10hr; 2.00cm, DFM100hr; and 6.40cm, DFM1000hr

3. Data elements

Data Element	Data Sources	Collection Period	Collection Frequency	Spatial Granularity	Temporal Granularity	Comment
Dryness Level	WRF model output	Daily	Twice daily	2 km	Hourly	
Live Fuel Moisture	WRF Model output	Daily	Twice daily	2 km	Hourly	
Green-Up of Annual Grasses	WRF Model output	Daily	Twice daily	2 km	Hourly	

The San Diego Supercomputer Center (SDSC) ingests and stores SAWTI datasets to enable findability and accessibility of these datasets for various stakeholders through web services and visual maps. Application Programming Interfaces (APIs) will enable time range or geolocation and tagged metadata-based querying, as well as grouping and sub-setting of datasets for context-driven use by authorized users to include the U.S. Forest Service. The map services will enable layering of these datasets for use in fire modeling. The project will maintain a server at SDSC for data access along with data storage capabilities stored at SDSC and back up storage on Amazon Cloud.

To verify the quality of the data, SDG&E sends the data to the U.S. Forrest Service, which ultimately reviews and verifies the information. No further modification of data elements in performed, though SMEs to review the data prior to utilization within the model.

4. Modeling assumptions and limitations

All components are modeled and thus there are inherent limitations to each.

5. Modeling methodology

While variables within the FMC often act in concert, there are times when they are out of phase as a result of the variability in precipitation (frequency and amount) that occurs across Southern California during the winter. Through a comprehensive empirical investigation, the governing equation for FMC can be expressed as:

$$FMC = \left\{0.1\left[\left(\frac{DL}{LFM} - 1\right) + G_{ag}\right]\right\}^{1.7}$$

where DL is the dryness level consisting of the ERC and/or the DFM10hr, LFM is the live fuel moisture, and G_{ag} is the degree of green-up of the annual grasses. Currently, All the terms in the FMC equation have equal weight, but further study may lead to future modifications.

The full methodology is described in the peer-reviewed publication: *The Santa Ana Wildfire Threat Index: Methodology and Operational Implementation.*[29]

6. Model uncertainty

All components are modeled and thus there are inherent limitations to each. Refer to *The Santa Ana Wildfire Threat Index: Methodology and Operational Implementation* for technical details.

7. Model verification and validation

Refer to *The Santa Ana Wildfire Threat Index: Methodology and Operational Implementation* for detailed efforts undertaken to verify and validate model performance.

8. Modeling frequency

Model is run twice daily to support risk planning and on-going risk assessments.

9. Timeline for model development

SDG&E, the U. S. Department of Agriculture, the U.S. Forest Service, and the University of California Los Angeles (UCLA), in collaboration with CAL FIRE, the Desert Research Institute, and the National Weather Service began a three-and-a-half-year collaboration in 2009 on an index to categorize Santa Ana wind events according to the potential for a large fire to occur, much the same way that tropical cyclones have been categorized. In September 2014, the collaborative group unveiled a web-based tool to classify the fire threat potential associated with the Santa Ana winds that are directly linked to the largest and most destructive wildfires in Southern California. Online SAWTI is hosted by the U.S. Forest Service.[30]

10. Application and results

To help the region prepare for hazardous conditions, information from the SAWTI is issued daily to fire agencies and other first-responders, which has led to specific preparedness and operational decisions based on the likelihood of a catastrophic wildfire fueled by Santa Ana winds. The public also has access to SAWTI to make personal safety decisions.

11. Key improvements from working group

Wildfire Risk Modeling working group discussions are underway. Direct improvements from the discussions have not yet been determined.

4.5.1.7 Wildfire Next Generation System-Planning

1. Purpose of Model

The innovative WiNGS-Planning model, building upon the RSE methodology in RAMP, evaluates both wildfire and PSPS impacts at the sub-circuit/segment level to inform investment decisions by determining which initiatives provide the greatest benefit per dollar spent in reducing both wildfire risk and PSPS impact.

[29] American Meteorological Society, *The Santa Ana Wildfire Threat Index: Methodology and Operational Implementation* (December 1, 2016), available at https://journals.ametsoc.org/view/journals/wefo/31/6/waf-d-15-0141_1.xml.
American Meteorological Society, *The Santa Ana Wildfire Threat Index: Methodology and Operational Implementation* (December 1, 2016), available at https://journals.ametsoc.org/view/journals/wefo/31/6/waf-d-15-0141_1.xml.

WiNGS-Planning analysis is conducted at the segment level. A segment is composed of one or many spans located between two SCADA sectionalizers in the electric network. The segment level of data granularity is required to establish the segment parameters.

Although WiNGS-Planning was developed in 2020, the model did not inform the entire scope of grid hardening work in the 2020 WMP. Additional details on this model are being shared because it represents the future framework that will be used to identify future strategies for mitigating wildfire. The use of WiNGS-Planning to inform priorities in the WMP is limited to some of the covered conductor and undergrounding scope identified for 2022 as well as the Standby Power Program.

2. Relevant terms

Critical Health Index (CHI)	A unitless index figure representing an asset health estimate
MAVF	Framework to quantify risk designed in accordance with the Safety Model and Assessment Proceeding (S-MAP) settlement agreement
RAMP	CPUC adopted procedure that incorporates a risk-based decision framework to evaluate the safety and reliability improvements of the utility in the GRC application
WRRM	A collaboration project between SDG&E and Technosylva Inc., that leverages historical high-resolution weather data to establish the impact of a potential high consequence fire event

3. Data elements

Data Element	Description	Data Sources	Collection Period	Collection Frequency	Spatial Granularity	Temporal Granularity	Comment
Segment Length	Spans coalesced into segments and broken into different lengths based on HFTD Tier	GIS Production: PRO_VAQ_ELEC/ PriOHConductor	2011-2020	Quarterly	Span level dissolved to segment level – Accuracy within 50 feet	Source data updated daily via GIS As-built drawings	
Hardening Status	Steel pole count on a segment	GIS Production: PRO_VAQ_ELEC/ OverheadStructure	2011-2020	Quarterly	Pole level – Accuracy within 50 feet	Source data updated daily via GIS As-built drawings	Upcoming project scoping for future hardening status is also considered
Conductor Age	Average age of spans on a segment	GIS Production: PRO_VAQ_ELEC/ PriOHConductor and WorkHistory	2011-2020	Quarterly	Span level – Accuracy within 50 feet	Source data updated daily via GIS As-built drawings	Age of current work order is used
Tree Strike Data	Count of trees which	GIS Production:	2011-2020	Quarterly	Spans: Accuracy	Source data updated daily	The tree points are

Data Element	Description	Data Sources	Collection Period	Collection Frequency	Spatial Granularity	Temporal Granularity	Comment
	have the potential to strike lines	PRO_VAQ_ELEC/ PriOHConductor and Veg Mgmt Tree Inventory			within 50 feet, Trees GPS'd Accuracy within 50 feet	via GIS As-built drawings and Vegetation Management inspections	buffered by their respective height and spatially intersected with the segments
Circuit Connectivity	Tabular Data Network relationships used for upstream downstream relationships	GIS Production: PRO_VAQ_ELEC/ AtRiskCustomerSCADA and AtRiskDownstreamSCADA	2011-2020	Quarterly	Point and line features: Accuracy within 50 feet	Source data updated daily via GIS As-built drawings and GIS automated nightly processes	
Wind Speed	Maximum historic wind speed for segment	OSI Pi wind anemometer data feeds	2011-2020	Quarterly	Anemometer location based on related pole. Accuracy within 50 feet	Source data updated every 15 minutes	
PSPS Probabilities	The likelihood of wind speeds at weather station closest to a segment will exceed a set wind speed threshold in a year	Meteorology	2020	As needed	Closest weather Station to a segment is used: GIS accuracy is within 50 feet	Source wind speed data updated every 15 minutes	
Historical Ignitions	Ignitions recorded by fire coordination team	Fire Coordination: Ignition spreadsheet	2014-2020	As needed	Varies: Finest accuracy at pole or span level. Crudest accuracy at circuit level	Sporadic, based on fire events	
CHI	A unitless index figure representing an asset health estimate	GIS, PRiME Pole loading model	2019	One time run	Span level accuracy	n/a	

Data Element	Description	Data Sources	Collection Period	Collection Frequency	Spatial Granularity	Temporal Granularity	Comment
WRRM Conditional Impact	Leverages historical high-resolution weather data to establish the impact of a potential high consequence fire event	Fire data, GIS, Wind, vegetation	Q4 2020	As needed	Pole level accuracy	Based on worst fire conditions	Developed by Technosylva
Annual RFW Data	Dates of RFWs as declared by the National Weather Service	National Weather Service forecast product archives	Q4 2020	As needed	Fire weather zones	Sporadic, based on level of	
Number of Customers	Count of customer on a segment	GIS Production: PRO_VAQ_ELEC/ AtRiskCustomerSCADA	2011-2020	Quarterly	Point and line features: Accuracy within 50 feet	Source data updated daily via GIS As-built drawings and GIS automated	
Customer Type	High risk customers	GIS Production: PRO_VAQ_ELEC/ AtRiskCustomerSCADA	2011-2020	Quarterly	Accurate to the transformer. Customer points are not mapped	Source data updated daily via GIS As-built drawings and GIS automated	
Outage Duration	SAIDIDAT	OUA	2011-2020	Quarterly	Mapped to the up and downstream structures for the affected circuit of an outage	Source data updated daily	

Data Quality Verification

GIS Electric System data

Data obtained from GIS is digitized internally from As-built drawings and undergoes a rigorous series of quality assurance tests prior to being released as official As-built GIS features. Field quality validation is accepted on an as-needed basis

Outage data

Outage data undergoes an internal audit process by qualified reliability staff to verify the details surrounding the outage. The reliability staff obtains outage information from the OUA application and verifies the relevant details of the outage (such as root causes, time stamps, and customer counts) and its effects using NMS.

Ignition data

Ignition data is collected and investigated by qualified fire coordinators. This data includes information on fires started by SDG&E electric assets.

Weather data

Weather data is collected by real time location system (RTLS) units (anemometers and RAWS stations) and coalesced into the OSI Pi database. Meteorology maintains relationships between the weather stations and electric assets.

Vegetation data

Vegetation data is collected and maintained by Vegetation Management, who has ongoing maintenance on this table to ensure inspection information is current and correct.

<u>Data Modification Process</u>

The WiNGS-Planning model undergoes various data conversion and data aggregation to obtain a segment-granular level of analysis. These include:

- Aggregation of pole age and conductor age metrics to form average pole age and average conductor age associated to each segment
- Utilization of subject matter expertise to match weather station data to associated segments with appropriate wind/weather conditions
- Tree strike data calculation utilizing height of tree as a buffer distance against the conductor feature to calculate tree strike count and tree strike length
- Imputation of Circuit Health Index (CHI) values where missing for a segment utilizing average values of available data, grouped by HFTD and non-HFTD designations

4. Modeling assumptions and limitations

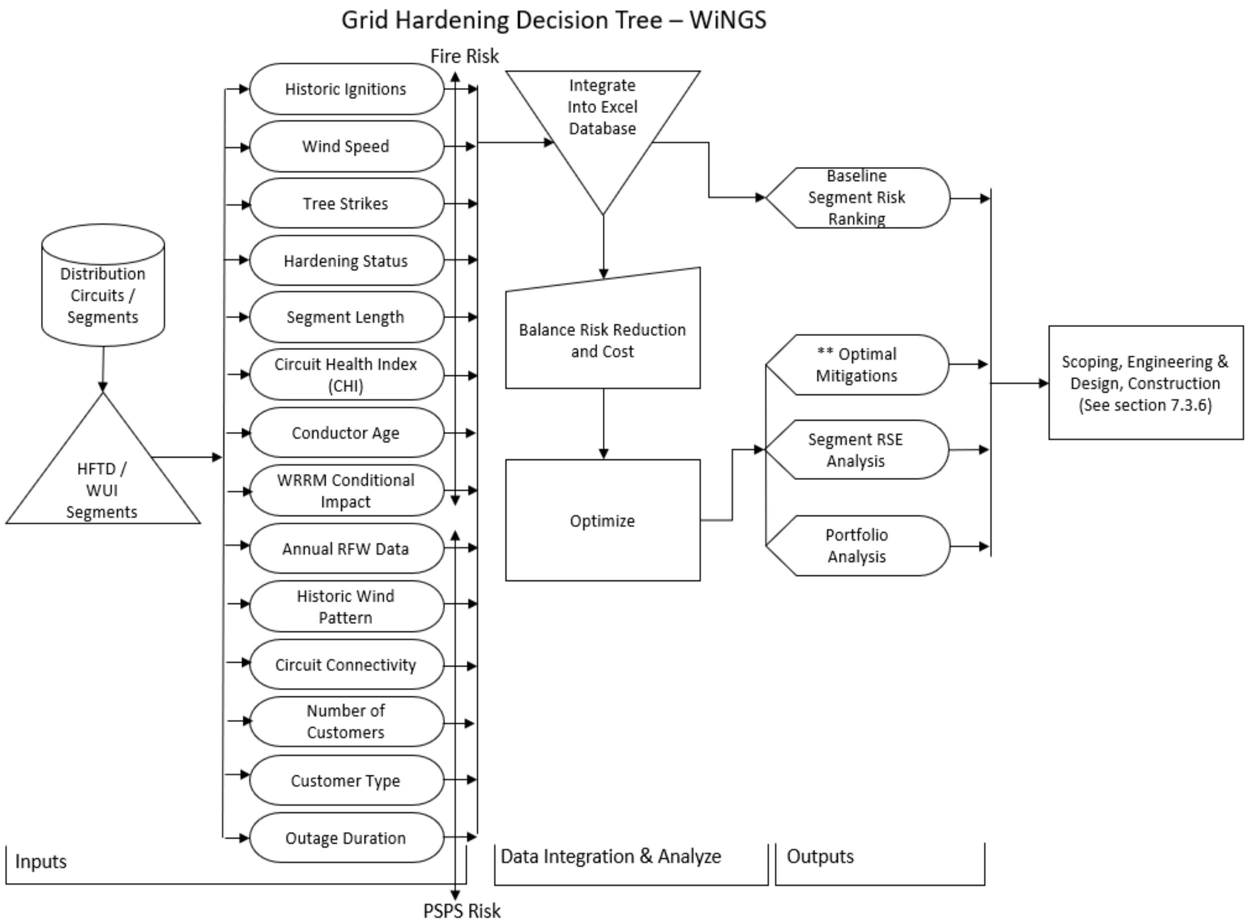
Key assumptions of the WiNGS-Planning model include:

- The composition of its MAVF. See Multi Attribute Value Function in Section 4.2 Understanding Major Trends Impacting Ignition Probability and Wildfire Consequence
- Effectiveness of mitigations evaluated in WiNGS-Planning
- Effect of hardening, vegetation and wind on ignition rate

5. Modeling methodology

Figure 4-30 displays the steps and criteria that the WiNGS-Planning model uses to aid in grid hardening decisions

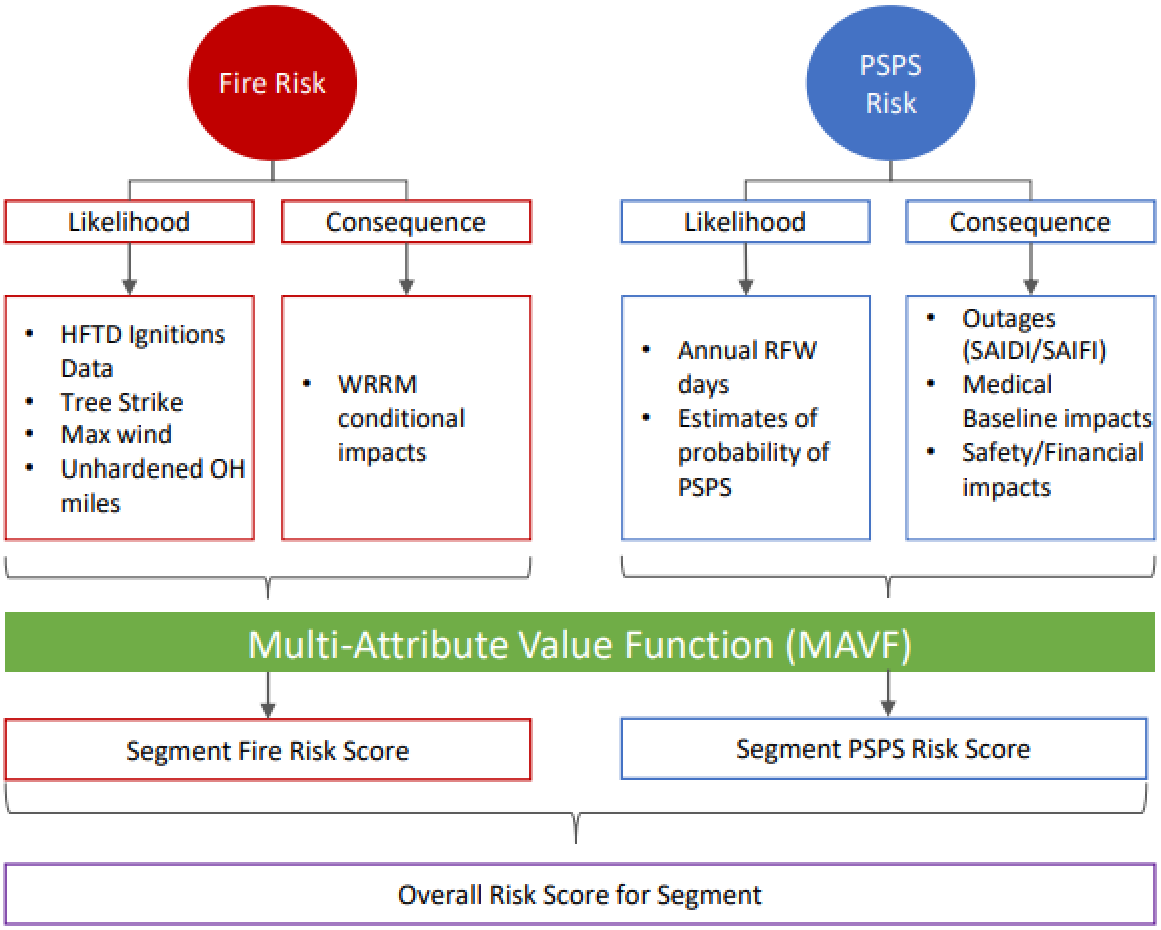
Figure 4-30: Grid Hardening Decision Tree-WiNGS-Planning



<u>Baseline Risk</u>

Figure 4-31 shows the calculation of the Overall Risk Score for a segment. In order to calculate the baseline wildfire and PSPS impact, the respective likelihood and consequence figures must be determined. The likelihood of a fire event is determined by prorating historical annual ignition rates by the mileage of the segment and adjusting to account for wind speed, historical tree strikes, vegetation density, asset hardening, and asset health. Asset health is determined by evaluating conductor age and the CHI portion of the CRI analysis. The final adjusted figure represents the likelihood of a significant wildfire event on the segment. The consequence of wildfire events is determined by the maximum WRRM output for each segment. In order to translate the event consequences into risk values, WRRM values are converted to natural units. The natural units and event likelihood are then inserted into the MAVF developed for RAMP to arrive at a final baseline wildfire risk per segment. MAVF attributes, scales, and weights are outlined in Section 4.2 Understanding Major Trends Impacting Ignition Probability and Wildfire Consequence.

Figure 4-31: Calculation of Overall Risk Score by Segment



<u>Mitigation Analysis</u>

Once the baseline risk per segment has been established, the next step is evaluating the effect and costs of different mitigations. For each mitigation there are associated percentage decrease in wildfire risk and PSPS impact. For wildfire risk mitigation effectiveness, SME input is used to estimate the impact of a mitigation on various wildfire triggers (e.g., animal contact, vegetation contact). Where possible, additional analyses are conducted using internal data (e.g., historical fault data). For PSPS mitigation effectiveness, internal SME input and historical event data is used to estimate the reduction in PSPS likelihood for the individual segment probability. The total cost of the mitigation is determined by the per unit cost.

Since the PSPS risk on a segment is influenced by the maximum upstream segment probability, mitigations that occur upstream of segments will influence the PSPS of probability for analysis. Thus, the PSPS impact of a segment cannot be looked at in isolation and must be considered with the other segments on that circuit and their respective mitigations via the use of a dynamic model. The dynamic nature updates the maximum upstream probability of a segment as mitigations upstream are determined.

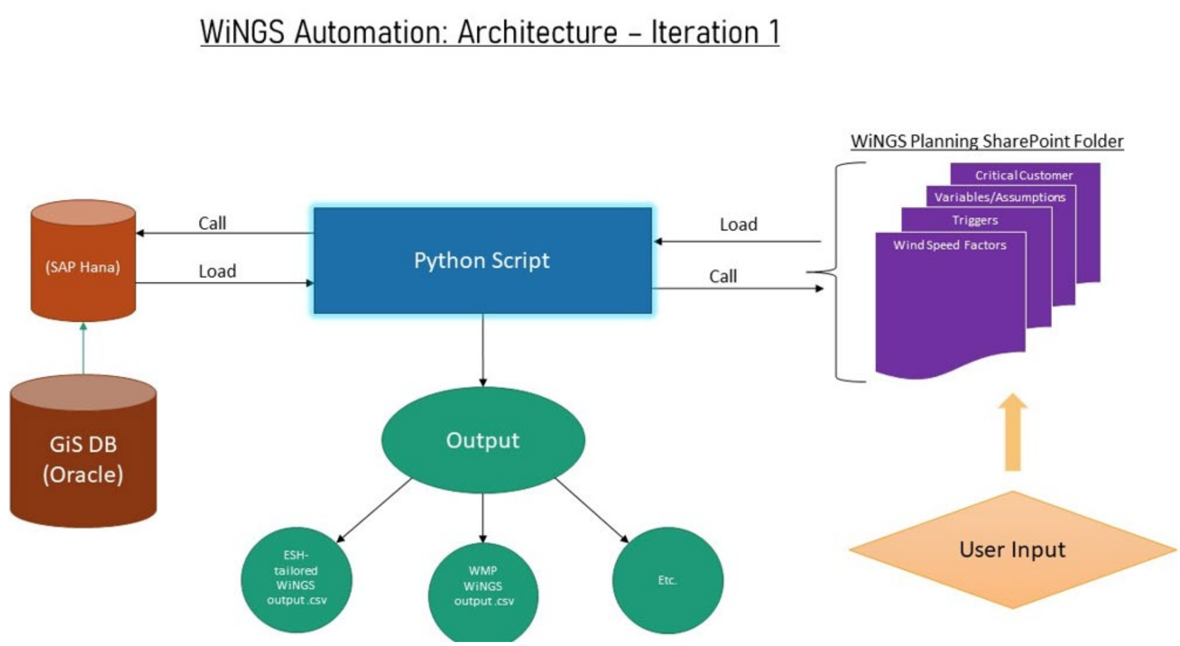
Portfolio Analysis

The primary goal of the WiNGS-Planning model is to analyze and compare different investment planning portfolios and scenarios. The dynamic requirements of the model require that every possible combination of mitigations be evaluated for many scenarios. In these situations, an optimization solver is required to compare the risk reduction and costs associated with each mitigation combination and identify the ideal set of mitigations that satisfy the requirements and constraints set by the scenario.

Automation elements of WiNGS-Planning model

A reproducible Python script is used to generate inputs and calculations for the segment-level analysis (see Figure 4-32).

Figure 4-32: Automation Elements of WiNGS-Planning Model



6. Model uncertainty

Uncertainty is inherent in the risk assessments conducted in WiNGS-Planning. For example, the current version of WiNGS-Planning uses a simplified methodology to estimate the effect of wind on ignition rates. This is a particular area of uncertainty that will likely be improved with the integration of the latest machine learning PoI models described in Section 4.5.1.1 POI Model.

7. Model verification and validation

During initial data gathering and processing, queries are validated with GIS data model experts to ensure the data returned by each query is consistent with the intention of the analyst. The GIS data model is highly normalized and contains a myriad of relationships which are not obvious to navigate. Cooperative development with internal GIS Business Solutions staff is a necessary part of the complicated data processing involved with the WiNGS-Planning model.

After initial data compilation, a series of validation processes are employed to guard against random machine and user error.

- Current variables for each segment are compared with prior versions of the model.
- Segments showing discrepancies between model versions are further scrutinized for either errors in the current model or valid changes in the composition of the assets associated with the segments.
- Changes to segments including the addition of new sectionalizers, or removal of old ones are examined. Removed sectionalizers are mapped to their corresponding new sectionalizers using the Primary Overhead Conductor relationship and are subsequently documented and accounted for.

Quality control data, model versions, scripts, and documentation are stored in a SharePoint repository to ensure persistence of model components across machines.

Segment-level asset counts, lengths, and other attributes derived from the Python script are compared to GIS production data manually in a GIS application to make sure the data is coincident across platforms. Discrepancies are noted and investigated and corrections are applied to the Python script.

A sensitivity analysis is employed to validate the RSE and mitigation sections of the WiNGS-Planning model. In this analysis, constants, including cost per mile estimates and RSE thresholds, are adjusted to see how sensitive the mitigation recommendations are to different size variable adjustments.

Subject matter expertise provides a realistic assessment of the proposed mitigations and variables that should feed into the model. The ESH team is critical in this regard and is in frequent communication with the WiNGS-Planning team during development. Their feedback is utilized to help better inform model optimization and interpretability.

8. Modeling frequency

The current version of WiNGS-Planning was run in the fourth quarter of 2020. A new version is set to release in early 2022. Subsequent releases will be conducted quarterly or more frequently depending on need in coordination with the ESH team’s project scoping efforts. Full automation of the model is anticipated to occur first quarter of 2022, which will allow for more frequent updates compared to the current framework. Automation will include data extraction, modification, and validation and will be built on Python hosted in the Amazon Web Services cloud environment.

9. Timeline for model development

The WiNGS-Planning modeling concept was introduced in the 2020 WMP update and a three-year timeline was proposed covering the development and implementation of the model and its findings. The key changes since the prior report have included updated segment data, incorporation of additional analyses, and the shift from a static to a dynamic model. The inclusion of attributes is considered on an as-needed basis to assist with client construction scoping efforts.

10. Application and results

The key decisions being driven from the WiNGS-Planning model are how to most efficiently and effectively apply wildfire and PSPS mitigations in the back country. Currently, the main mitigations being proposed in the model results are undergrounding and covered conductor, starting in 2023. The model has been reviewed by multiple internal SMEs to validate any assumptions and model outputs.

11. Key improvements from working group

Wildfire Risk Modeling working group discussions are underway. Direct improvements from the discussions have not yet been determined.

4.5.1.8 Wildfire Next Generation System-Operations

1. Purpose of Model

WiNGS-Ops is a new iteratively-improving, real-time risk assessment model built to evaluate and compare Wildfire and PSPS risks at the asset level (pole/span) and the sub-circuit/segment level at hourly intervals. The primary purpose of the model is to help inform decision makers in real-time about the Wildfire and PSPS risks, which will guide risk-based de-energization decisions during risk events. The model outputs used to help guide decision makers are understood to represent a range of potential risk of Wildfire versus PSPS comparisons and not absolute predictions of outcomes.

2. Relevant terms

Asset	A specific feature on the electric utility infrastructure network such as a pole, conductor, capacitor, transformer, or fuse.
Conditional Consequence	The impact of an event happening taking into account various factors, including fatality, damages, safety, financial, reliability, etc.
GIS Assets	The GIS database of assets used as the source of potential ignitions for the WRRM.
MAVF	Framework to quantify risk designed in accordance with the SMAP settlement agreement
PoF	The probability of an asset to lead to an outage/fault based on equipment failure or external conditions.
PoI	The probability of an asset to start a fire ignition based on equipment failure or external conditions.
PSPS risk	Overall measure of the loss or harm caused by PSPS de-energization.
Segment	Part of a circuit in-between two connecting, adjacent sectionalizing devices.
Span	Part of a circuit in-between two connecting, adjacent poles
Wildfire risk	Overall measure of the loss or harm caused by wildfire
WRRM	A collaboration project between SDG&E and Technosylva Inc. that leverages historical high-resolution weather data to establish the impact of a potential high consequence fire event.

3. Data elements

The WiNGS-Ops analysis is computed at the individual asset level and then aggregated to the segment level to match the granularity at which de-energization is performed. The computations are made on models reported in Sections 4.5.1.1 POI Model and Section 4.5.1.3 Wildfire Risk Reduction Model.

Data Element	Source	Collection Period	Collection Frequency	Spatial Granularity	Temporal Granularity	Comment
PoI Models	See Section 4.5.1.1	See Section 4.5.1.1	On demand	Span	Hourly	Modifications Performed: None
Wildfire Consequence (Conditional WRRM)	See Section 4.5.1.3	See Section 4.5.1.3	Twice a day	Sub-span	Varied for each comprised data element. See Section 4.5.1.3	Modifications Performed: Convert to MAVF*
PSPS Consequence	n/a	n/a	On demand	Segment	n/a	

* See # 4 Modeling assumptions and limitations

PSPS Consequence is calculated at the segment level, utilizing data inputs such as downstream customer counts, customer types, and average PSPS duration. Weather-related data and assumptions are gathered from the weather station closest to the segment.

Due to the iterative nature of the model updates for the purposes of maintaining the most predictive capability possible for decision makers at the time of need, both data inputs and model methodology are considered to be continually improving in their selection and application.

4. Modeling assumptions and limitations

To quantify the consequence of PSPS and wildfire, models were used to estimate the core attributes that comprise the MAVF. The model assumptions for PSPS consequence are described in Table 4-20. For wildfire consequence, fire spread models developed by Technosylva, Inc are used. The Technosylva models output fire consequence in units not directly relatable to the MAVF core attributes: structures impacted, population impacted, acres burned, etc. Therefore, an additional layer of assumptions is required to "convert" the Technosylva model outputs to MAVF values (see Table 4-20). These values are assessed prior to PSPS events and are typically reported in post-PSPS reports.

Table 4-19: Model Assumptions for PSPS and Wildfire Consequence

	PSPS Methodology	Wildfire Methodology
Safety	number of affected customers × PSPS duration × Serious Injuries and Fatalities (SIF) per customer-minutes	structures impacted × SIF per structure impacted + population impacted × smoke fatality fraction + affected customers[1] × pole restoration duration × SIF per customer-minutes
Reliability	SAIDI + SAIFI (based on PSPS duration)	SAID + SAIFI (based on pole restoration duration)

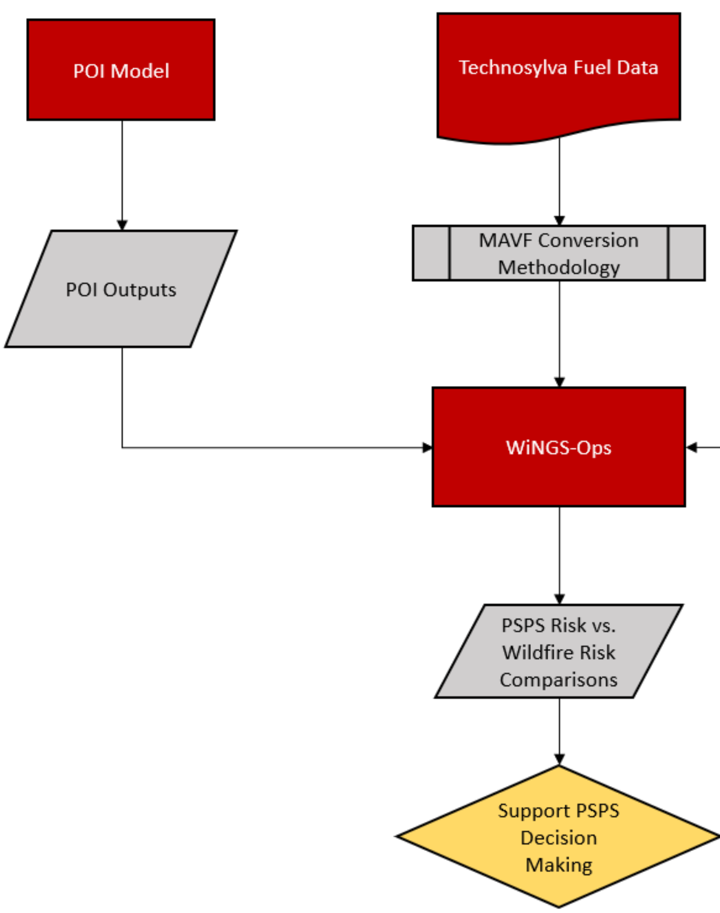
	PSPS Methodology	Wildfire Methodology
Financial	number of affected customers × dollars per affected customer	structures impacted × dollars per structure + acres impacted × dollars per acre + acres impacted × suppression dollars per acre + affected customers[1] × dollars per affected customer

[1] affected customers for wildfire must be estimated from the number of customers downstream of impacted assets

5. Modeling methodology

Figure 4-33 details the high-level process flow of the major elements of the current modeling methodology for WiNGS-Ops. It also outlines relations between WiNGS-Ops and other models and how the outcome of the model is currently utilized.

Figure 4-33: High-Level WiNGS-Ops Methodology Process Flow



The calculation of both Wildfire Risk and PSPS Risk is performed utilizing the general Expected Outcome formulation:

$$Expected\ Outcome = Likelihood \times Consequence$$

Likelihood and Consequence are calculated at the span/pole level, before being aggregated to the sub-circuit/segment level, for de-energization granularity alignment.

For Wildfire Risk, Likelihood is calculated utilizing failure mode risk probability outputs estimating the probability of a wildfire event for a given time interval (e.g., hourly). Consequence is calculated utilizing the conditional impact component of Technosylva's WRRM model at the associated ignition points related to an individual span/pole. The Expected Outcome is then calculated at the span/pole level for each time interval and subsequently all span/pole Expected Outcome values are aggregated to the sub-circuit/segment level. The following equation outlines the formulation described above:

$$Expected\ Outcome_t = \sum_{i=0}^{m}(\sum_{j=0}^{n}(PoF_i \times PoI_i) \times Consequence_i\ )$$

Where:

- PoF_i = Probability of Failure at pole/span location
- PoI_i = Conditional Probability of Ignition (given a Failure has occurred) at each pole/span location
- $Consequence_i$ = Consequence of risk event at each pole/span location
- i = variable iterating through each pole/span location
- j = variable iterating through each failure modes
- m = number of poles/span per segment
- n = number of failure modes
- t = time interval

After the Expected Outcome values are calculated for each span and pole downstream of a sectionalizing device, a simple regression is performed to acquire an average value for the segments as a function of wind speed.

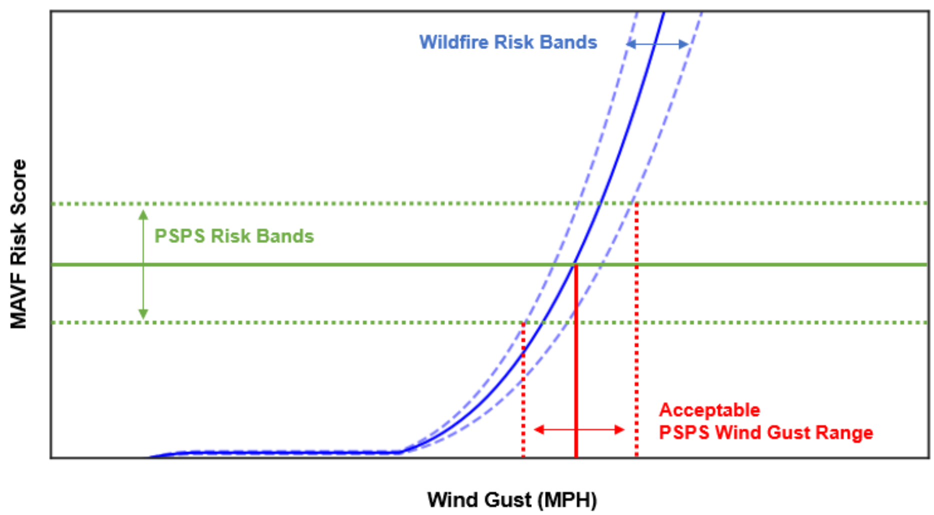
For PSPS events, risk is primarily a function of shut-off duration, which may be tied to weather conditions. However, for purposes of comparison, a constant duration that is independent of wind conditions is assumed and, unlike Wildfire Risk, the risk score is assumed to remain constant over wind gust variations. Likelihood is not considered since this operational model weighs the expected wildfire risk against the full consequence of a PSPS event. The Consequence is calculated utilizing the MAVF, applying the same assumptions used in the WiNGS-Planning model.

With the calculation of PSPS Risk and Wildfire Risk curves as a function of wind gust, the intersection of risk scores is computed and evaluated as the wind gust at which the wildfire risk surpasses the PSPS Risk.

Wildfire and PSPS event risk curves are evaluated as a range of possible values using bands that account for variation of risks within individual spans/poles of a given segment (specifically for Wildfire Risk), uncertainties, and variations in other assumptions, such as those made around PSPS event consequence. The range of values for each metric allows decision makers to balance flexible decision-making with risk-informed situational awareness, thereby adding to a more holistic approach to PSPS de-energization decision making capabilities.

Figure 4-34 shows wind gust ranges where the expected Wildfire Risk impact will start to more likely be greater than the risk impact of performing a PSPS de-energization on that segment. This helps decide at which ranges of wind gusts to consider de-energization of a particular segment. It is important to note that WiNGS-Ops outputs are not the sole decision-making points. Other variables and dynamic input from the field are also considered. Additionally, since WiNGS-Ops implementation is preliminary in 2021, its use is largely to gather lessons learned for the purpose of enhancing the model.

Figure 4-34: MAVF Risk Score by Wind Gust (MPH)



6. Model uncertainty

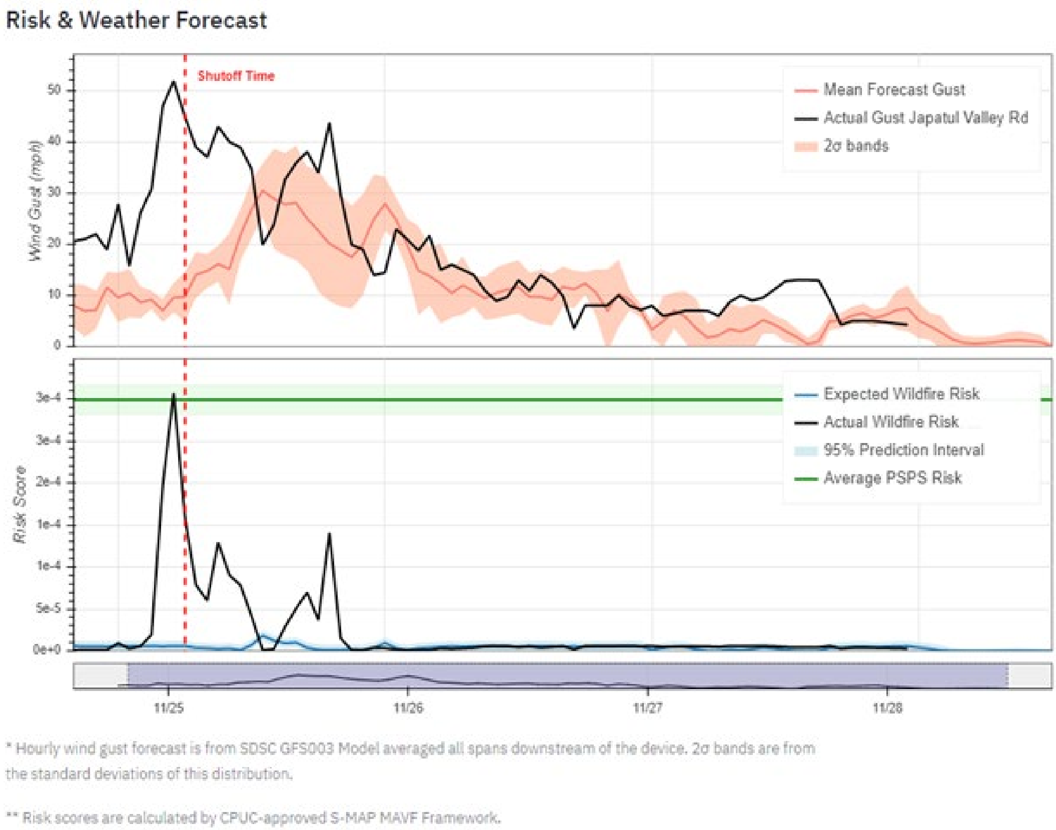
Sensitivity analyses are currently being conducted and results will be benchmarked with past decisions to determine areas of improvement and whether the quantifications are adequate.

7. Model verification and validation

WiNGS-Ops is at an early stage, and model outputs undergo heavy review, observation, and scrutiny. Due to its novelty, there are no clear methods for verification and validation. However, sensitivity analyses are being conducted and results are benchmarked with past decisions to determine areas of improvement and whether the quantifications are adequate.

Figure 4-35 demonstrates the ongoing analysis of the WiNGS-Ops results. The charts show data from an actual PSPS event where PSPS protocols were activated. The top chart shows weather forecast and actual weather data over time, and the bottom chart shows the corresponding Wildfire and PSPS event risk calculations during the same time frame. Figure 4-35 suggests that the model outputs are responding to weather patterns as intended, with a correlation observed between high wind gust and high calculated Wildfire risk.

Figure 4-35: Risk Weather Forecast



8. Modeling frequency

This model is run prior to each PSPS event.

9. Timeline for model development

The first iteration of the WiNGS-Ops model was implemented for the 2021 fire season. Development of the model will continue in 2022 and beyond to enhance modeling outputs and develop cloud support to enable dynamic analysis capabilities to support real-time operations.

10. Application and results

The purpose of the WiNGS-Ops model is to inform decision makers of PSPS events and wildfire risk assessments and comparisons for de-energization decision making purposes. The model has been reviewed by multiple internal SMEs to validate assumptions and model outputs.

In Quarter 4 of 2021, the model was first implemented and utilized to help inform decision makers during PSPS events that occurred during November of that year. The WiNGS-Ops output for various segments was considered as a factor of interest to help assess when and where a PSPS was needed to be performed during this time. The implementation of WiNGS-Ops to serve as factor to help inform PSPS decision making is planned to continue for future PSPS events.

11. Key improvements from working group

Wildfire Risk Modeling working group discussions are underway to determine how improvements can be made.

4.5.2 Calculation of Key Metrics

***Instructions**: Report details on the calculation of the metrics below. For each metric, a standard definition is provided with statute cited where relevant. The utility must follow the definition provided and detail the procedure they used to calculate the metric values aligned with these definitions. The utility must cite all data sources used in calculating the metrics below. In addition, the utility must include GIS layers showing Red Flag Warning (RFW) frequency and High Wind Warning (HWW) frequency, (use data from the previous 5 years, 2016-2021), as well as GIS layers for distribution of Access Functional Need (AFN) customers and urban/rural/highly rural customers, and disadvantaged communities[31] in its service territory.*

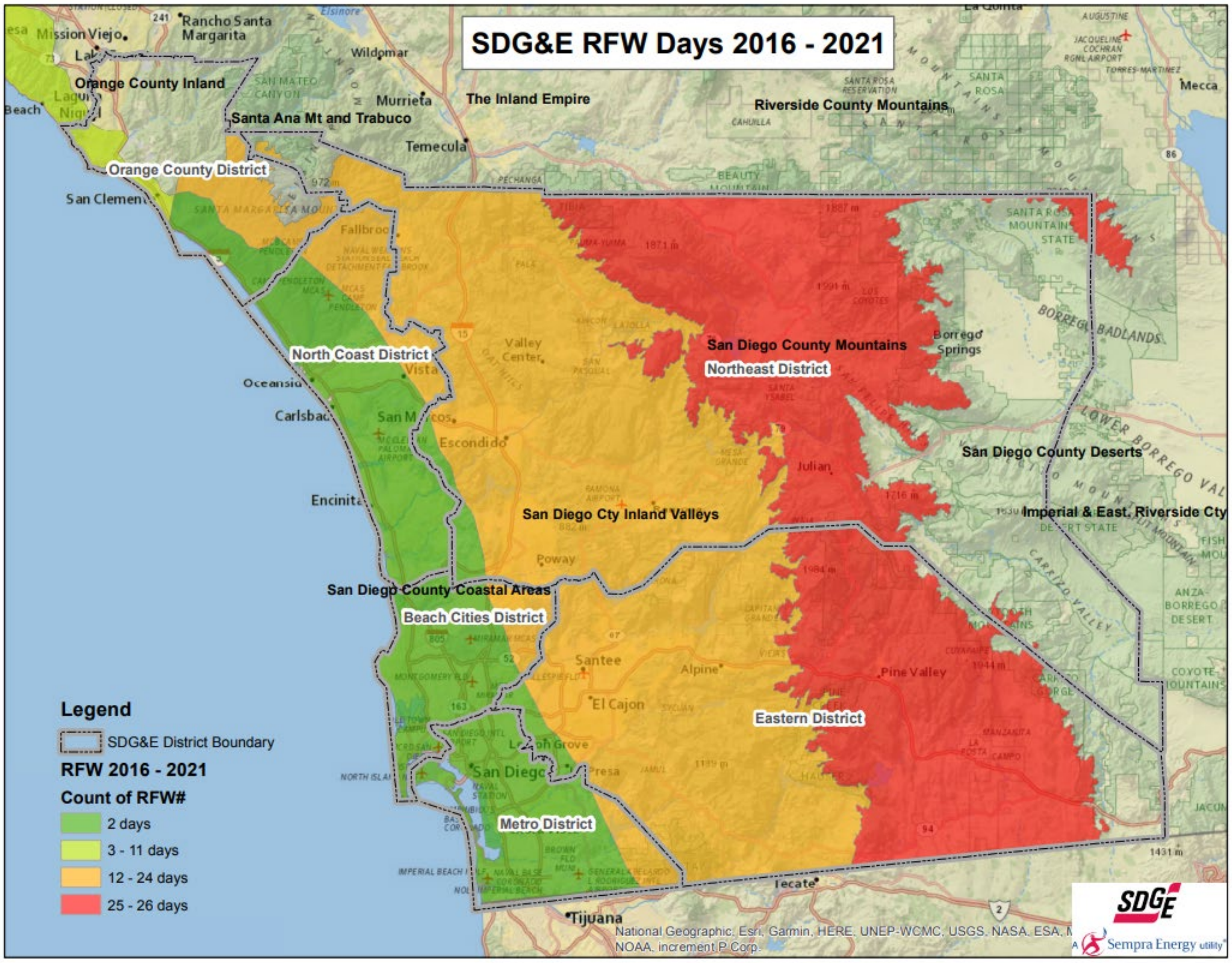
1. ***Red Flag Warning overhead circuit mile days** – Detail the steps to calculate the annual number of red flag warning (RFW) overhead (OH) circuit mile days. Calculated as the number of circuit miles that are under an RFW multiplied by the number of days those miles are under said RFW. Refer to the National Weather Service (NWS) Red Flag Warnings. For historical NWS data, refer to the Iowa State University Iowa archive of NWS watch / warnings.[32] Detail the steps used to determine if an overhead circuit mile is under a RFW, providing an example of how the RFW OH circuit mile days are calculated for a RFW that occurred within utility territory over the last five years.*

The National Weather Service issues a RFW by zones. These zones are identified as part of SDG&E's GIS system and a spatial query can be run to identify the total circuit mileage impacted by a RFW (See Figure 4-36). To determine RFW circuit mile days (down to the decimal value), the RFW end date/time is subtracted from the RFW start date/time.

[31] Energy Safety recommends using CalEnviroScreen and Senate Bill 535 to identify disadvantaged communities.

[32] Iowa State University, Iowa Environmental Mesonet, available at https://mesonet.agron.iastate.edu/request/gis/watchwarn.phtml.

Figure 4-36: SDG&E RFW Days 2016-2021

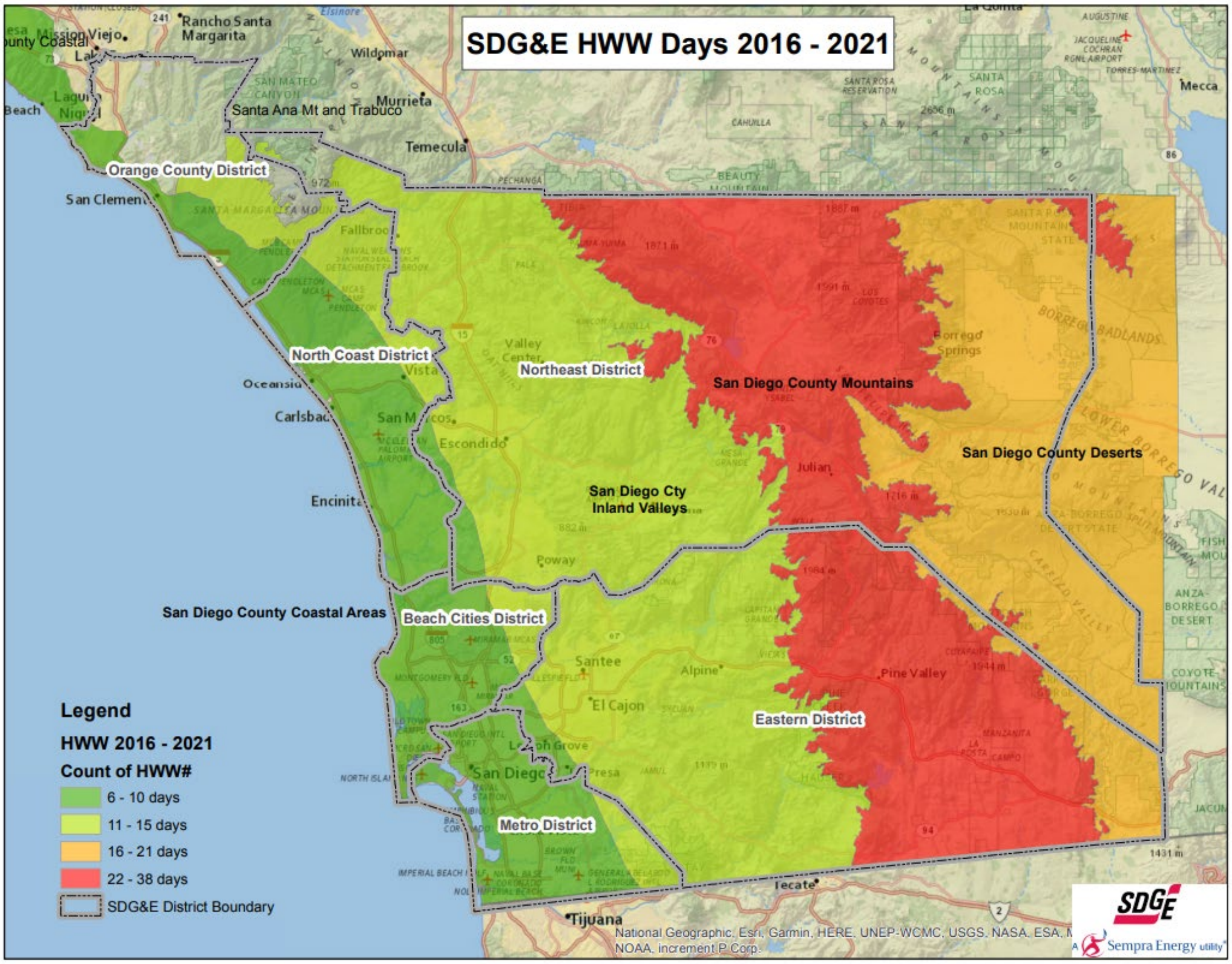


2. ***High Wind Warning overhead circuit mile days*** *– Detail the steps used to calculate the annual number of High Wind Warning (HWW) overhead circuit mile days. Calculate as the number of OH circuit miles that are under an HWW multiplied by the number of days those miles are under said HWW. Refer to High Wind Warnings as issued by the National Weather Service (NWS). For historical NWS data, refer to the Iowa State University Iowa archive of NWS watch / warnings.[33] Detail the steps used to determine if an OH circuit mile is under a HWW, providing an example of how the OH HWW circuit mile days are calculated for a HWW that occurred within utility territory over the last five years.*

The National Weather Service issues high wind warnings in zones. These zones are identified as part of SDG&E's GIS system and a spatial query can be run to determine the total circuit mileage impacted by a high wind warning. To determine high wind warning overhead circuit mile days (down to the decimal value), the high wind warning end date/time is subtracted from the high wind warning start date/time (see Figure 4-37).

33 Iowa State University, Iowa Environmental Mesonet, available at https://mesonet.agron.iastate.edu/request/gis/watchwarn.phtml.

Figure 4-37: SDG&E HWW Days 2016-2021



The geospatial map file is provided in Attachments:

2022_02_05_SDGE_2022_WMP Update_GIS Layer_452_2.zip

3. ***Access and Functional Needs population** – Detail the steps to calculate the annual number of customers that are considered part of the Access and Functional Needs (AFN) population. Defined in Government Code § 8593.3 and D.19-05-042 as individuals who have developmental or intellectual disabilities, physical disabilities, chronic conditions, injuries, limited English proficiency or who are non-English speaking,[34] older adults, children, people living in institutionalized settings, or those who are low income, homeless, or transportation disadvantaged, including, but not limited to, those who are dependent on public transit or those who are pregnant.*

Customers in the following categories within SDG&E's databases are considered to be AFN:

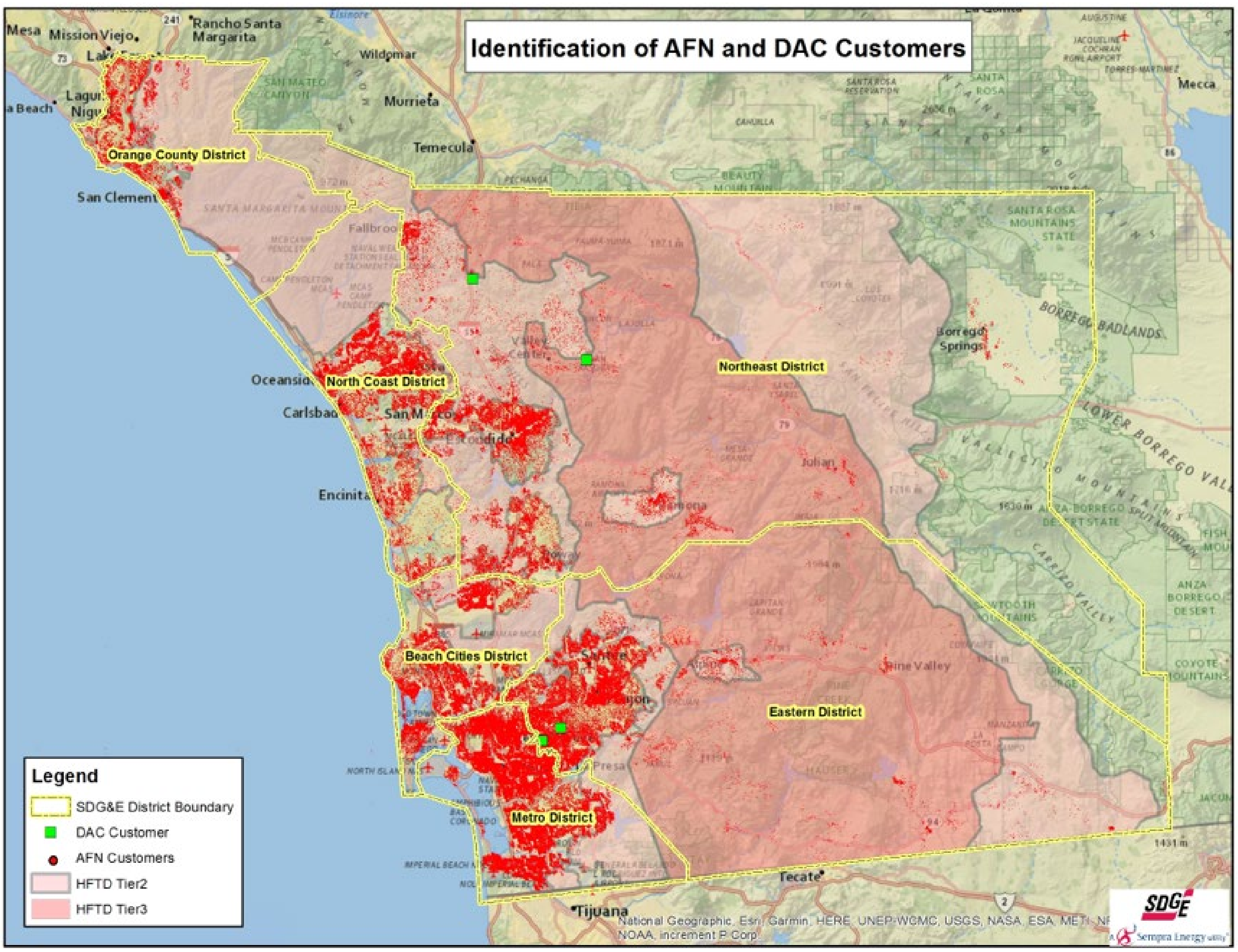
- Customers enrolled in the following programs: CARE, FERA, MBL, Temperature Sensitive
- Customers who receive their utility bill in an alternate format: Braille, Large Font Bill
- Customers whose preferred language is a language other than English

[34] Guidance on calculating number of households with limited or no English proficiency can be found in D.20-03-004.

- Seniors (over age 62)
- Customers who self-identify to receive an in-person visit prior to disconnection for nonpayment or self-identify as having a person with a disability in the household: disabled deaf/hearing impaired; disabled blind/vision impaired; disability – not defined
- Customers who have self-identified as having an AFN

There are approximately 420,000 customer accounts associated with AFN, of which approximately 185,000 are located within the HFTD (See Figure 4-38). While the primary methodology for identifying AFN populations is through SDG&E's databases, customers can also self-identify through the Customer Contact Center[35] and various marketing campaigns. Additionally, AFN customers may be reached through local community partners who represent or provide services to these constituencies (e.g., 2-11 San Diego). SDG&E does not receive a number of customers from these partners, and as such, they are not included in the count. Disadvantaged Communities (DAC) are identified using the CalEnviro 4.0 layer with within the HFTD.

Figure 4-38: AFN and DAC Customers in the HFTD Tier 2 and Tier 3



The geospatial map file is provided in Attachments:

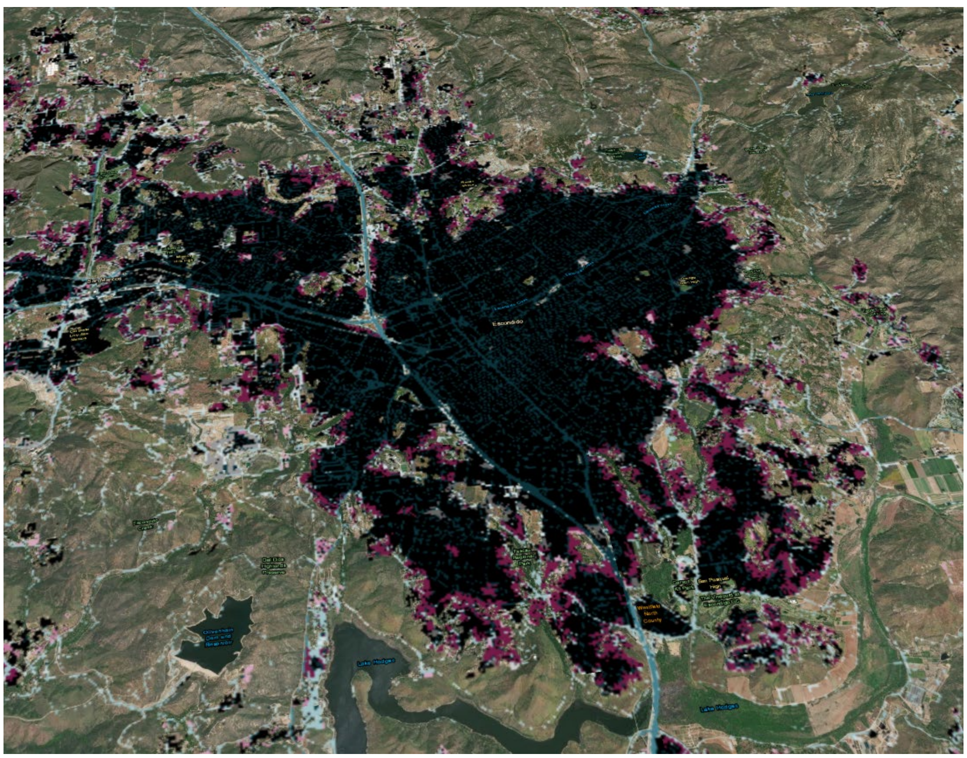
35 SDGE.com, Commitment to Supporting Accessibility, available at https://www.sdge.com/access-and-functional-needs-afn.

2022_02_05_SDGE_2022_WMP Update_GIS Layer_452_AFN_DAC_Confidential.zip

> 4. ***Wildlife Urban Interface** – Detail the steps to calculate the annual number of circuit miles and customers in Wildlife Urban Interface (WUI) territory. WUI is defined as the area where houses exist at more than 1 housing unit per 40 acres and (1) wildland vegetation covers more than 50% of the land area (intermix WUI) or (2) wildland vegetation covers less than 50% of the land area, but a large area (over 1,235 acres) covered with more than 75% wildland vegetation is within 1.5 mi (interface WUI) (Radeloff et al, 2005).[36]*

Efforts to calculate and analyze the circuitry and WUI is conducted by internal SMEs leveraging in-house GIS capabilities. For example, Figure 4-39 shows the community of Escondido. Black areas indicate urban setting, while WUI areas are mapped in purple. The figure shows that the greatest threat posed to the WUI in this community would be from a wildfire that started in the mountains to the east and was pushed into the WUI by a strong Santa Ana wind.

Figure 4-39: Example of WUI (Escondido, CA Area)



In addition to the traditional WUI areas, areas in the service territory such as coastal canyons, river valleys, and highly vegetated areas outside of the HFTD are also closely analyzed. These areas are generally closer to the coastline and do not have the same magnitude of wildfire risk that is seen across the HFTD; however, they do represent areas of WUI in the service territory and therefore operational steps are taken to decrease risk in these areas.

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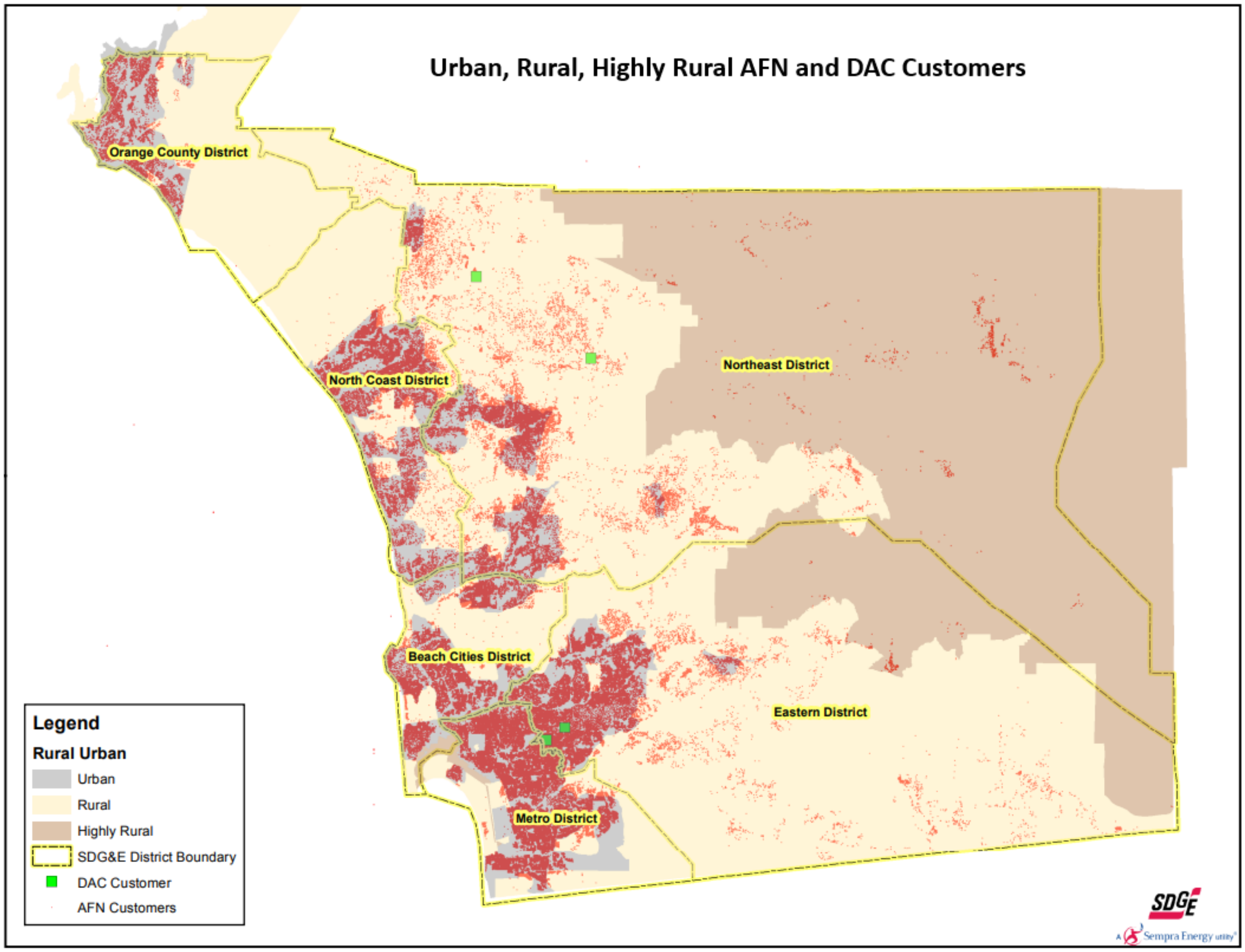
[36] Spatial Analysis For Conservation and Sustainability, Wildland-Urban Interface (WUI) Change 1990-2010, available at https://www.fs.fed.us/pnw/pubs/journals/pnw_2005_radeloff001.pdf.

5. ***Urban, rural and highly rural*** *– Detail the steps for calculating the number of customers and circuit miles in utility territory that are in highly rural, rural, and urban regions for each year. Use the following definitions for classifying an area highly rural/rural/urban (also referenced in glossary):*
    a. *Highly rural – In accordance with 38 CFR 17.701, "highly rural" must be defined as those areas with a population of less than 7 persons per square mile as determined by the United States Bureau of the Census. For the purposes of the WMP, "area" shall be defined as census tracts.*
    b. *Rural – In accordance with GO 165, "rural" must be defined as those areas with a population of less than 1,000 persons per square mile as determined by the United States Bureau of the Census. For the purposes of the WMP, "area" shall be defined as census tracts.*
    c. *Urban – In accordance with GO 165, "urban" shall be defined as those areas with a population of more than 1,000 persons per square mile as determined by the United States Bureau of the Census. For the purposes of the WMP, "area" shall be defined as census tracts.*

Population density numbers are calculated using the American Community Survey (ACS) 1-year estimates on population density by census tract for each corresponding year (2016 ACS 1-year estimate for 2016 metrics, 2017 ACS 1-year estimate for 2017 metrics, etc.). For years with no ACS 1-year estimate available, use the 1-year estimate immediately before the missing year (use 2019 estimate if 2020 estimate is not yet published, etc.)

Census tracts for San Diego and Orange counties were utilized to develop urban, rural, and highly rural layers by census tract. The number of customers was provided by the 2010 census data. To determine population density for each census tract, the total number of customers was divided by the total square miles of the tract. Each tract was then categorized as Urban, Rural, or Very Rural according to the GO 165 and Code of Federal Regulations Section 17.701 definitions. The Rural definition was modified to be 7-999 people per square mile in order to distinguish between Rural (7-999 people per square mile) and Highly Rural (0-6 people per square mile). An image of these census tract layers with an overlay of AFN and DAC customers is provided in Figure 4-40.

Figure 4-40: Urban, Rural, Highly Rural AFN and DAC Customers



To fill out Tables 8, 9, and 10 in Attachment B of this WMP Update using this layer as required, spatial queries were run on the actual and planned improvements in 2020, 2021, and 2022.

The geospatial map file is provided in Attachments:

2022_02_05_SDGE_2022_WMP Update_GIS Layer_WUI_RUHR.zip

4.6 Progress Reporting on Key Areas of Improvement

Instructions: *Report progress on all key areas of improvement identified in Section 1.3 of the utility's 2021 Action Statement[37]. Provide a summary table of the actions taken to address these key areas and report on progress made over the year. Summarize the progress in a table using a high-level bullet point list of key actions, strategies, schedule, timeline for completion, quantifiable performance-metrics, measurable targets, etc. The table must also include a cross-referenced link to a more detailed narrative and substantiation of progress in an Appendix. The summary table must follow the format illustrated in Table 4.6-1.*

[37] Draft Action Statement on SDG&E's 2021 Wildfire Mitigation Plan Update (June 2021) (Action Statement) at 5, available at https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M387/K708/387708478.pdf

The OEIS evaluation of the 2021 WMP update and the Action Statement approving the 2021 WMP update was completed July 14 ,2021. The Action Statement acknowledged SDG&E has made significant progress over the past year and/or has matured in its mitigation strategies for future years in several areas. The Action Statement also identified the following key areas for improvement and remedies for SDG&E to focus on over the next year to continue to drive down utility-related wildfire risk.

Table 4-20: List of utility deficiencies and summary of response, 2020[38]

Action Statement Number	Issue Title	Summary of Progress
SDGE-21-01	Inadequate transparency in accounting for ignition sources in risk modeling and mitigation selection	SDG&E has been working to develop Probability of Failure (PoF) and Probability of Ignition (PoI) models with more granularity at the asset and ignition source level, including clarity on how: • Various ignition sources (including third-party sources) feed into SDG&E's risk models • Ignition sources will impact decision-making Reference Attachment D for details
SDGE-21-02	Lack of consistency in approach to wildfire risk modeling across utilities	The utilities have prepared a joint response to this Issue/Remedy including: • Modeling baselines, alignment and past collaboration • Modeling components, linkages, and interdependencies • Modeling algorithms • Fault, outage, and ignition data • Asset and vegetation data • Initiative implementation impact, and PSPS event risk impact • Climate change impacts, suppression and ingress/egress Reference Attachment D and F for details
SDGE-21-03	Limited evidence to support the effectiveness of covered conductor	The utilities have prepared a joint response to this Issue/Remedy including subworkstreams to compile and analyze existing data sets and capture additional information including: • Benchmarking • Testing/Studies • Estimated Effectiveness • Additional Recorded Effectiveness • Subworkstreams to meet the remedy requirements: • Alternative comparison • Potential to reduce PSPS risk • Costs Reference Attachment D and Attachment H for details
SDGE-21-04	Inadequate joint plan to study the effectiveness of enhanced clearances	The utilities have prepared a joint response to this Issue/Remedy including: • Establishing uniform data collection standards • Creating a cross-utility database of tree-caused risk events (I.e., outages and ignitions caused by vegetation contact) Reference Attachment D and I for details

38 This table is numbered 4.6-1 in the 2022 WMP Guidelines.

Action Statement Number	Issue Title	Summary of Progress
SDGE-21-05	Incomplete identification of vegetation species and record keeping	SDG&E has begun implementing remedies to address incomplete identification of vegetation species and record keeping including: • Identifying specific data fields to record genus and species • Developing interim solution until data field above is implemented • Determining applicability of species identification in conjunction with other vegetation activities Reference Attachment D for details
SDGE-21-06	Limited evidence of quantitative analysis to identify "at-risk" species	Methodologies were completed for determining what species SDG&E considers "at-risk" including: • Explaining in complete detail why discrepancies exist between the genera with the highest number of outages per 1000 trees per year and SDG&E's "targeted species identified as a higher risk due to growth potential, failure characteristics and relative outage frequency" • Defining quantitative threshold values for the criteria used to define a tree as "at-risk" Reference Attachment D for details
SDGE-21-07	Need for quantified vegetation management (VM) compliance targets	Ten of the 20 Vegetation Management initiatives in Table 12 are related to and covered under one or more of the other 10 initiatives. Therefore, they are not individually and separately quantified or qualified. Of the remaining 10 Vegetation Management initiatives, 4 can be quantified and 6 can be qualified. Reference Attachment D for details
SDGE-21-08	Non-communicative remote-controlled switches	**This issue was closed with SDG&E's response during the November 1 progress report.** Reference Attachment D for details
SDGE-21-09	Inadequate transparency associated with SDG&E's decision-making process	Comprehensive flowchart process diagrams were outlined to describe in step-by-step detail the decision-making process related to the three largest categories of work, namely: • Grid Hardening • Asset Management and Inspections • Vegetation Management and Inspections Reference Attachment D for details
SDGE-21-10	Insufficient detail regarding prioritization of HFTD in undergrounding and covered conductor mitigation efforts	Further details were provided to illuminate the prioritization methodology applied to circuit segments and mitigation selections as evolved over time, detailing both covered conductor and undergrounding efforts. In addition to outlining a timeline of evolving methodologies that were applied from 2020 onwards, grid hardening process flow diagrams related to the latest WiNGS-Planning model and the related Grid Hardening processes were referenced (Sections 4.5.1.7 and 7.3.3, respectively) Reference Attachment D for details
SDGE-21-11	RSE values vary across utilities	The utilities have prepared a joint response to this Issue/Remedy. Energy Safety facilitated a public workshop on utility RSE estimates. Each of the utilities presented the current status of their RSE calculation methodologies, and stakeholders had an opportunity to ask questions of utility representatives as well as RSE experts.

Action Statement Number	Issue Title	Summary of Progress
		At the conclusion of the workshop, Energy Safety requested that the utilities submit reports providing a detailed description on their RSE calculation methodology. These reports were submitted on December 17, 2021. Reference Attachment D and G for details

5 Inputs to the Plan and Directional Vision for WMP

5.1 Goal of Wildfire Mitigation Plan

Instructions: *The goal of the WMPs are shared across Energy Safety and all utilities: Documented reductions in the number of ignitions caused by utility actions or equipment and minimization of the societal consequences (with specific consideration to the impact on AFN populations and marginalized communities) of both wildfires and the mitigations employed to reduce them, including PSPS.*

The following sub-sections report utility-specific objectives and program targets towards the WMP goal. No utility response is required for Section 5.1.

5.2 The Objectives of the Plan

Instructions: *Objectives are unique to each utility and reflect the 1, 3, and 10-Year projections of progress towards the WMP goals. Objectives are determined by the portfolio of mitigation strategies proposed in the WMP. The objectives of the plan must, at a minimum, be consistent with the requirements of California Public Utilities Code §8386(a) – Each electrical corporation shall construct, maintain, and operate its electrical lines and equipment in a manner that will minimize the risk of catastrophic wildfire posed by those electrical lines and equipment.*

Describe utility WMP objectives, categorized by each of the following timeframes, highlighting changes since the prior WMP:

In accordance with California Public Utilities Code (P.U. Code) § 8386(a), SDG&E constructs, maintains, and operates its electric system in a manner that minimizes the risk of catastrophic wildfire posed by its electric power lines and equipment. Building on over 10 years of wildfire prevention and mitigation work, the 2022 WMP Update continues to focus on reducing wildfire risk. Each year, SDG&E identifies ways to enhance its wildfire prevention and mitigation efforts through enhancing or expanding existing programs and developing and implementing new programs. A description of the WMP objectives for each of the specified timeframes is provided below. For a detailed, year-by-year timeline refer to Attachment A. This information was also provided in SDG&E's 2021 WMP QDR.

1. *Before the next Annual WMP Update*

The annual WMP updates allow for new activities to be identified and implemented and/or for existing activities to be modified. In 2022, SDG&E will continue to make progress on the initiatives outlined in the 2021 WMP. Near-term mitigation strategy objectives before the 2023 WMP Update are provided in Table 7-1 and discussed further in Section 7.3 Detailed Wildfire Mitigation Programs

2. Within the next 3 years

The WSD developed a Utility Wildfire Mitigation Maturity Model (Maturity Model) as a method to assess utility wildfire risk reduction capabilities and examine the relative maturity of wildfire mitigation programs. While SDG&E will refer to the Maturity Model as a guide towards improving each area of mitigation, it is important to note that the Maturity Model does not represent an absolute assessment of a utility's ability to mitigate and prevent wildfire. The Maturity Model should be part of an iterative process to improve utility wildfire mitigation and prevention efforts over time. Areas highlighted in the Maturity Model as having lower relative maturity levels are further automation, review from external stakeholders, and granularity of the initiatives. Within the next three years, SDG&E will focus on these areas and others to further mature its wildfire initiatives. Additional details are provided in Table 5-1 and in Attachment A.

3. Within the next 10 years – long-term planning beyond the 3-year cycle

The WMP demonstrates how SDG&E has advanced wildfire mitigation in each of the ten categories identified in the Maturity Model. Capability advancements should be a major focus in each category, however, the specific direction the Maturity Model indicates some capabilities should be examined further. For example, fully automated systems to inform utilities regarding the risk associated with each asset from flying debris, vegetation, and weather patterns may seem desirable but may take away from sound judgment based on human experience and on-the-ground intelligence. In addition, as risk modeling continues to mature, it will inform the optimal mix of wildfire mitigation initiatives. Based on data, experience, and modeling, some of these fully automated systems may not apply as much as they would for an overhead system and there may need to be a shift to other mitigations such as increasing strategic undergrounding. SDG&E sets forth its general plan for each of the ten categories in Table 5-1 and Attachment A.

Table 5-1: SDG&E's 3- and 10-Year Vision for Wildfire Risk Mitigation

Category	Three Years (2021 – 2023)	Ten Years (2021 – 2030)
Risk Assessment and Mapping	• Operationalize the WRRM-Ops platform into a single visual and configurable live map that can be utilized to support operational decisions, including with respect to PSPS. • Enhance WRRM Model[39] • Expand and integrate academic partnerships. • Enhance PoI Models within Ignition Management Program • Integrate and align models with SDG&E's Climate Vulnerability Assessment • Develop of WiNGS-Ops	• Increase granularity and accuracy in risk assessments • Incorporate broader range of inputs in risk assessment • Increase automation of risk modeling • Provide more real-time updates of risk models • Enhance capabilities through expanded academic partnerships

[39] Refresh data with new observations, explore new methodologies, explore new datasets.

Category	Three Years (2021 – 2023)	Ten Years (2021 – 2030)
	• Migrate existing models and execute risk models to Amazon Web Services Cloud. • Integrate of PoI into WiNGS-Planning and WiNGS-Ops • Evaluate updates on WiNGS-Planning and existing PoI models and finalize methodology • Develop visualization tools (proof of concept) for WiNGS-Ops and WiNGS-Planning	
Situational Awareness and Forecasting	• Integrate weather data into NMS for more automated, real-time operational decision-making • Integrate and increase automation of broader datasets such as the VRI, PoI/PoF and historical wind conditions into the PSPS Situational Awareness Dashboard • Enhance fault detection via Wireless fault indicators (WFIs) • Modernize and expand the Weather Station Network • Establish a tuition reimbursement program for SDG&E employees to prepare a workforce trained to deal with the evolving needs associated with wildland fire management and climate change as it relates to power utilities	• Increase the scope of reliable weather data and improve processes for validating readings • Create sub-1 km resolution of weather data across the grid • Develop new AI models for weather forecasts • Increase use of external weather data for validation • Develop full automation in fire detection capabilities • Improve model output bias with machine learning and analytic results
Grid Design and System Hardening	• Continue overhead fire-hardening infrastructure programs • Increase scope of strategic undergrounding • Install enhanced advanced protection capabilities • Install private LTE Communication Network • Install PSPS Sectionalizing Enhancements • Expand the Generator Grant Program (GGP) to mitigate PSPS impacts • Expand microgrid solutions in the new Backup Power for Resilience Program	• Increase granularity in prioritizing initiatives across the grid • Incorporate strategic grid design and localization that includes microgrid solutions and location of lines away from highest risk areas • Increase redundancy for grid topology and increase sectionalizing capabilities • Increase investment in ignition-preventing equipment and advanced technologies • Significantly increase strategic undergrounding and implementation of covered conductor • Complete specific equipment programs conversion to 100 percent CAL FIRE-approved equipment and other fire safe standards in HFTD (e.g., capacitors, fuses, hot line clamps, lightning arrestors)
Asset Management and Inspections	• Continue infrastructure inspections per regulatory requirements while exceeding requirements in certain high-risk areas (Tier 3 of HFTD) • Expand deployment of enhanced inspection technologies such as Infrared inspections of	• Enhance data collection of wildfire-related attributes to more granular asset levels with greater frequency • Optimize inspection cycles based on risk mitigation efficacy

Category	Three Years (2021 – 2023)	Ten Years (2021 – 2030)
	overhead distribution and drone assessments • Continue intelligent image processing, utilizing artificial intelligence and innovation, to detect damage to high fire risk distribution assets and vegetation • Assess wildfire reduction benefit cost effectiveness after drone pilot assessments completion.	• Enhance inspection capabilities to identify high risk assets • Explore LIDAR use cases in advancing QA/QC processes and informing other asset management strategies • Develop more robust processes, training, and technologies to monitor and validate work performed
Vegetation Management Plan	• Continue development of the inventory tree database • Complete design and development of new electronic work management system (Epoch) to enhance data management performance • Continue to implement the vegetation management work plan with enhanced clearances in high-risk areas (going above regulatory requirements) • Continue to test and deploy LIDAR technology to enhance vegetation management • Continue development of the VRI to further support risk-informed optimization of vegetation management efforts • Continue Fuels Management program	• Increase granularity in vegetation database • Enhance modeling capabilities to better predict vegetation growth patterns and probability of failure • Optimize vegetation inspection cycles based on risk mitigation efficacy • Enhance vegetation inspection capabilities to identify high risk areas • Enhance understanding of individual vegetation strike potential • Develop more robust processes, training, and technologies to monitor and validate work performed • Engage IOUs on best practices in vegetation management operations • Expand VRI and supercomputing technologies for improved predictive modeling
Grid Operations and Protocols	• Complete integration of operational decision-making such as the FPI and the SAWTI into DMS platform • Continue to use enhanced recloser protocols with more sensitive relay settings to minimize safety risks and potential fire ignitions • Continue to use special work procedures during high-risk conditions • Replace and automate tools including dispatch and damage inspection protocols as part of Field Service Delivery (FSD) • Refresh, replace and update software for all mobile devices	• Automate distribution relay profile changes in field devices based on risk pre-defined levels • Enhance protocols for grid operations and better understanding of associated wildfire risk • Eliminate use of PSPS as a primary wildfire mitigation measure for localized wind events • Enhance prediction, communication, and mitigation of PSPS consequences • Utilize advanced technologies to increase efficiency in post-PSPS inspections • Enhance training, tools, and policies to prevent and suppress ignitions related to grid activities • Leverage academic partnerships to analyze risk factors and incorporate into PSPS protocols
Data Governance	• Document central repository of data sources, assumptions, and algorithms into a single document	• Enhance data analytics capabilities to process large amounts of data and conduct real-time reporting

Category	Three Years (2021 – 2023)	Ten Years (2021 – 2030)
	• Leverage enterprise-wide Data Governance methodologies, tools and training • Enhance risk event models and analytics to drive utility wildfire mitigation decisions • Implement OEIS GeoDatabase schema • Increase collaboration with agency stakeholders to provide data in a timely manner by developing a Cloud Managed Service infrastructure for controlled sharing of information	• Establish more comprehensive databases, analyses, and algorithms with advanced sharing capabilities • Enhance tracking of near-misses and increase accuracy in estimating potential ignitions • Increase participation in utility-ignited-wildfire research, such as investing in platforms such as SDSC, and WUI FIRE Institute research
Resource Allocation Methodology	• Establish a new organization dedicated to overseeing portfolio of wildfire mitigations • Optimize proof of concept for portfolio approach to resource allocation • Establish more granular assessment of risk across the system to determine most appropriate risk reduction efforts	• Increase granularity in estimating risk reduction potential of wildfire mitigation efforts (risk spend efficiencies) • Establish more real-time updates of RSEs • Enhance methodology and process for portfolio-wide assessment of wildfire mitigations • Establish process for evaluating and developing new technologies • Improve existing models for resource allocation within programs and develop new tools to support resource allocation within programs • Expand and implement the investment prioritization prototype development to other lines of business (i.e. Gas, IT, Fleet, Facilities, etc.) to adopt a consistent, common value framework
Emergency Planning and Preparedness	• Modernization and enhancements of workforce training in the areas of storm response, process and documentation • Collaborate with 211 in San Diego and Orange County to continue to support AFN customers • Enhance community outreach by incorporating effectiveness outreach survey feedback, expanding Tribal and AFN campaigns, enhancing partnerships with Indian Councils, Community Based Organizations (CBOs) and local school districts • Continue maintenance of emergency response plans using an ICS structure and process • Participate and support Mutual Assistance Programs • Expand Emergency Management Operations to include additional personnel dedicated to enhanced after-action review program, coordination of PSPS events, and	• Increase stakeholder engagement and use of simulations to stress-test response plans • Increase granularity and customization of response plans • Enhance customer communication and ability to reach vulnerable populations during emergencies • Enhance documentation and use of lessons learned to update plans • Establish more formalized review of procedures, benchmarking, and stakeholder engagement

Category	Three Years (2021 – 2023)	Ten Years (2021 – 2030)
	enhancement of technology solutions to support emergency operations • Implement 24/7 Watch Command Desk • Implement Human Factors Engineering (HFE) into design of PSPS decision making tools • Put two new state of the art Tactical Command Vehicles in service	
Stakeholder Cooperation and Community Engagement	• Continue community outreach and public awareness efforts with year-round wildfire safety education and communication campaign • Continue deployment of Community Resource Centers (CRCs) • Promotion and amplification of PSPS, wildfire, and readiness messaging through CBO partnership activities • Assess and resolve any customer support and communications gaps identified through AFN stakeholders • Develop Public Safety Partner Mobile Application • Enhance communication channels and utilize technology to create more accessibility	• Establish more formalized processes of learning from peers in and outside the State • Establish more successful engagement with communities • Utilize enhanced partnerships with AFN and Limited English Proficiency (LEP) populations to reduce impacts of PSPS and wildfire mitigation measures to those populations • Establish broader engagement and deeper planning with emergency and non-emergency planning agencies • Enhance Public Safety Partner Mobile Application

5.3 Plan Program Targets

Instructions: *Program targets are quantifiable measurements of activity identified in WMPs and subsequent updates used to show progress towards reaching the objectives.*

List and describe all program targets the electrical corporation uses to track utility WMP implementation and utility performance over the last five years. For all program targets, list the 2019 to 2021 performance, a numeric target value that is the projected target for end of year 2022 and 2023, units on the metrics reported, the assumptions that underlie the use of those metrics, update frequency, and how the performance reported could be validated by third parties outside each utility, such as analysts or academic researchers. Identified metrics must be of enough detail and scope to effectively inform the performance (i.e., reduction in ignition probability or wildfire consequence) of each targeted preventive strategy and program.

Pub. Util. Code Section 8386.3(c)(5) requires a utility to notify Energy Safety "after it completes a substantial portion of the vegetation management (VM) requirements in its wildfire mitigation plan." To ensure compliance with this statue, the utility is required to populate Table 5.3-1 with VM program targets that the utility can determine when it has completed a "substantial portion"[40] and that Energy Safety can subsequently audit. Energy Safety has provided some required, standardized VM targets below. It is expected that the utilities provide additional VM targets beyond those required. The identification of other VM targets and units for those targets (e.g., for inspections, customer outreach, enhanced vegetation management, etc.) are at the discretion of the utility.

Additionally, in Table 5.3-1, utilities must populate the column "Target%/ Top-Risk%" for each 2022 performance target related to initiatives in the following categories: Grid design and system hardening; Asset management and inspections; and Vegetation management and inspections. This column allows utilities to identify the percentage of the target that will occur in the highest risk areas. For example, if a utility targets conducting 85% of its vegetation management program in the top 20% of its risk-areas, it should input "85/20" in this column. In the "Notes" column, utilities must provide definitions and sources for each of the "Top-Risk%" values provided. In the given example above, an acceptable response would be: "The top 20% of risk areas used for this target relate to the circuit segment risk rankings from [Utility Company's] Wildfire Risk Model outputs, as described in [hyperlink to Section XX] of the 2022 WMP Update."

Table 5-2: List and Description of Program Targets, Last 5 Years[41]

Program Target	2019		2020		2021		2022		Units	Audited 3rd Party
	Target	Performance	Target	Perf	Target	Perf	Target	Target% / Top-Risk% *		
Install weather stations	13	13	30	30	25	46	20	N/A	Weather stations	No
Install cameras	NA	NA	4	4	17	17	8	N/A	Cameras	No

40 Energy Safety intends to define "substantial portion" in its forthcoming Compliance Guidelines. This definition may be included in the Final version of the 2022 WMP Update Guidelines

41 This table is numbered 5.3-1 in the 2022 WMP Guidelines.

Program Target	2019		2020		2021		2022		Units	Audited 3rd Party
	Target	Performance	Target	Perf	Target	Perf	Target	Target% / Top-Risk% *		
Install wireless fault indicators	500	594	500	502	500	544	500	T3: 85 17.0%/61.4% T2: 40 8.0%/36.2% Non HFTD: 375 75.0%/2.4%	Wireless fault indicators	No
Replace SCADA capacitors	NA	NA	30	30	35	32	36	T3: 2 5.6%/61.4% T2:22 61.1%/36.2% Non HFTD: 12 33.3%/2.4%	SCADA capacitors	No
Covered Conductor Installation	0	0	1	1.9	20	20.6	60	77.3%/71.9%	Miles	No
Expulsion fuse replacement	2,250	2,490	3,000	3,179	3,970	3,976	277	T3: 50 18.1%/61.4% T2:227 81.9%/36.2%	Expulsion Fuses	No
Install sectionalizing devices	7	7	7	23	10	13	10	T3: 10 100.0%/61.4%	Sectionalizing devices	No
Install micro grids	0	0	4	4	0	6	4	T3: 3 75.0%/61.4% T2: 1 25.0%/36.2%	Microgrids	No
Enable circuits with Advanced Protection	NA	NA	8	6	8	4	8	T3: 8 100.0%/61.4%	Circuits	No

Program Target	2019		2020		2021		2022		Units	Audited 3rd Party
	Target	Performance	Target	Perf	Target	Perf	Target	Target% / Top-Risk% *		
Replace hotline clamps	500	660	1,650	2,061	2,250	2,743	1,700	T3: 224 13.2%/61.4% T2: 1476 86.8%/36.2%	Hotline clamps	No
Provide generators to MBL and AFN customers impacted by PSPS	65	65	1,250	1,420	2,000	2,310	2,000	T3: 1000 50.0%/61.4% T2: 1000 50.0%/36.2%	Generators	No
Provide whole facility generators to customers impacted by PSPS	NA	NA	300	75	413	355	415	T3: 207 49.9%/61.4% T2: 208 50.1%/36.2%	Generators	No
Provide generator rebates to customers impacted by PSPS within HFTD	NA	NA	130	1,274	1,250	735	1,250	T3: 625 50.0%/61.4% T2: 625 50.0%/36.2%	Generators	No
Underground electric lines/equipment	1.6	2.6	11	15.5	25	25.92	65	70%/91.5%	Miles	No
Harden the overhead distribution system - traditional	129.75	122.9	102	99.5	100	100.4	5	T3: 2.9mi 58.0%/61.4% T2: 2.1mi 42.0%/36.2%	Miles	No
Harden transmission system - overhead	7	7	25	21.6	6.7	6.7	23.83	T2: 23.83mi 100.0%/36.2%	Miles	No
Harden transmission system - underground	3	3	0	0	0	0	5.5	T2: 5.5 100.0%/36.2%	Miles	No

Program Target	2019		2020		2021		2022		Units	Audited 3rd Party
	Target	Performance	Target	Perf	Target	Perf	Target	Target% / Top-Risk% *		
Harden transmission system - distribution underbuilt	10	10	9.4	9.4	2.7	3.4	2.7	T2: 2.7 100.0%/36.2%	Miles	No
Fire harden CNF - transmission overhead	28	25	26	29.1	0	0	0	0	Miles	No
Fire harden CNF - distribution overhead	22	26.4	28	21.8	6.86	6.86	0	0	Miles	No
Fire harden CNF - distribution underground	17	8.7	14	14.4	0	0	0	0	Miles	No
Replace lightning arrestors	NA	NA	0	0	924	1,789	1,848	T3: 1848 100.0% /61.4%	Lightning arrestors	No
Install LTE communication network stations	NA	NA	25	15	10	10	25	T3 48.0%/61.4% T2 52.0%/36.2%	Base stations	No
Perform compliance maintenance program HFTD - 5-year detailed	16,500	16,329	17,500	17,977	22,269	22,354	18,000	T3:6530 16.1%/61.4% T2:11647 28.8%/36.2% Non HFTD:22292 55.1%/2.4%	Inspections	No
Perform transmission system inspections - detailed	37	37	41	41	1,680	1,957	2,087	T3: 644 29.5%/61.4% T2: 1443 66.0%/36.2% Non HFTD: 98	Inspections	No

Program Target	2019		2020		2021		2022		Units	Audited 3rd Party
	Target	Performance	Target	Perf	Target	Perf	Target	Target% / Top-Risk% *		
								4.5%/2.4%		
Perform distribution infrared inspections	NA	NA	8,500	13,077	18,000	17,068	12,000	T2: 12000 100.0%/36.2%	Inspections	No
Perform transmission infrared inspections	113	112	113	110	6,565	6,239	6,154	T3: 1993 32.4%/61.4% T2: 4161 67.6%/36.2%	Inspections	No
Perform compliance maintenance program HFTD - wood pole intrusive	19,000	19,729	18,000	14,450	9,796	8,721	350	T2: 350 100.0%/36.2%	Inspections	No
Perform HFTD Tier 3 inspections	11,500	15,176	11,500	11,864	10,815	11,535	12,286	T3:12268 99.9%/61.4% T2:18 0.1%/36.2%	Inspections	No
Perform drone assessments of distribution infrastructure	10,000	10,400	33,000	37,310	22,000	21,420	22,000	T2: 22000 100.0%/36.2%	Inspections	No
Perform drone assessments of transmission infrastructure	NA	NA	1,681	2679	2,715	1,440	500	T3: 50 10.0%/61.4% T2: 450 90.0%/36.2%	Inspections	No
Perform transmission system inspections - aerial 69kV Tier 3 visual	27	27	21	21	1,654	1,652	1,654	T3: 1654 100.0% /61.4%	Inspections	No

Program Target	2019		2020		2021		2022		Units	Audited 3rd Party
	Target	Performance	Target	Perf	Target	Perf	Target	Target% / Top-Risk% *		
Perform compliance maintenance program HFTD - annual patrols	86,000	86,401	86,000	86,075	86,000	86,490	86,490	T3: 39550 45.7%/61.4% T2: 46940 54.3%/36.2%	Inspections	No
Perform transmission system inspections - visual	117	116	117	114	7,024	6,423	6,312	T3: 1993 31.6%/61.4% T2: 4319 68.4%/36.2%	Inspections	No
Perform substation system inspections	330	301	330	405	330	405	330	T3: 215 65.2%/61.4% T2: 115 34.8%/36.2%	Inspections	No
Perform detailed inspections (tree trimming)	455,000	453,330	455,000	451,207	455,000	502,132	491,822	T3:115,038 23.4%/61.4% T2: 142,139 28.9%/36.2% Non HFTD: 234,645 47.7%/2.4%	Trees inspected	Yes
Perform fuels management	550	511	300	324	500	463	500	T3: 400 80.0%/61.4% T2: 100 20.0%/36.2%	Poles cleared	No
Remote sensing inspections of vegetation around distribution lines and equipment	NA	NA	NA	NA	NA	NA	730	T3: 309 42%/61.4% T2: 396 54%/36.2% Non HFTD: 33	Miles	No

Program Target	2019		2020		2021		2022		Units	Audited 3rd Party
	Target	Performance	Target	Perf	Target	Perf	Target	Target% / Top-Risk% *		
								4%/2.4%		
Perform enhanced inspections, patrols and trimming	7,500	8,310	17,000	17,075	17,000	12,578	12,824	T3: 5,526 43.1%/61.4% T2:7,298 56.9%/36.2%	Trees trimmed/ removed	No
Perform pole brushing	35,500	34,000	35,500	36,563	35,500	35,102	35,000	T3: 14751 43.4%/61.4% T2: 15787 46.4%/36.2% Non HFTD: 3461 10.2%/2.4%	Poles brushed	No
Remove trees with strike potential	NA	NA	NA	NA	NA	NA	106	T3: 40 37.7%/61.4% T2: 46 43.4%/36.2% Non HFTD: 20 18.9%/2.4%	VMAs inspected	No
Install Avian Protection	NA	NA	NA	NA	NA	NA	847	T3: 91 10.7%/61.4% T2: 711 83.9%/36.2% Non HFTD: 45 5.3%/2.4%Yes	Poles	No

* The Top-Risk% values are as follows:

- For covered conductor and undergrounding the Top Risk % was calculated using the wildfire risk scores of each distribution circuit from SDG&E's WiNGS-Planning tool which is described in Section 4.5.1.7. Please note that work is currently being scoped using the WiNGS-Planning tool, but the work planned for 2022 was scoped prior to the development of WiNGS-Planning.

- For all other programs, which are not prioritized using WiNGS-Planning, the Top Risk % was calculated using the Pre-Mitigation Wildfire Risk Score for Tier 3, Tier 2 and Non-HFTD (See Table 4-3) divided by the Total Pre-Mitigated Wildfire Risk Score (See Table 4-2). The Top Risk % is in Tier 3, followed by Tier 2 and Non-HFTD. For each target, SDG&E provides the percentage of planned work in each Tier, and the accompanying percentage of overall wildfire risk.
    - Top Risk % are:
        - Wildfire Risk – Tier 3 61.4%
        - Wildfire Risk – Tier 2 36.2%
        - Wildfire Risk – Non-HFTD 2.4%

5.4 Planning for Workforce and Other Limited Resources

Instructions: *Report on worker qualifications and training practices regarding wildfire and PSPS mitigation for workers in the following target roles:*

1. *Vegetation inspections*
2. *Vegetation management projects*
3. *Asset inspections*
4. *Grid hardening*
5. *Risk event inspection*

For each of the target roles listed above:

1. *List all worker titles relevant to target role (target roles listed above)*
2. *For each worker title, list and explain minimum qualifications with an emphasis on qualifications relevant to wildfire and PSPS mitigation. Note if the job requirements include the following:*
    a. *Going beyond a basic knowledge of General Order 95 requirements to perform relevant types of inspections or activities in the target role*
    b. *Being a "Qualified Electrical Worker" (QEW) and define what certifications, qualifications, experience, etc. is required to be a QEW for the target role for the utility.*
    c. *Include special certification requirements such as being an International Society of Arboriculture (ISA) Certified Arborist with specialty certification as a Utility Specialist*
3. *Report percentage of Full Time Employees (FTEs) in target role with specific job title*
4. *Provide a summarized report detailing the overall percentage of FTEs with qualifications listed in (2) for each of the target roles.*
5. *Report plans to improve qualifications of workers relevant to wildfire and PSPS mitigation. The utility must explain how they are developing more robust outreach and onboarding training programs for new electric workers to identify hazards that could ignite wildfires.*

1. Vegetation Inspections

1) worker titles, 2) minimum qualifications, 2a-c) special certification requirements, 3) percent of full-time employees (FTEs) in target roles and 4) percent of FTEs with special certification are listed for SDG&E in Table 5-3 and Contractors in Table 5-4. Plans to improve worker qualifications (5) are discussed separately.

Vegetation management and inspections are discussed in Section 7.3.5 Vegetation Management and Inspections.

Table 5-3: Workforce Planning and Limited Resources-Vegetation Inspections (SDG&E)

1 Worker Titles	2 Minimum Qualifications	2a, b, c Special Certification Requirements	3 Percent FTE in Target Role	4 Percent FTEs with Special Certification
Vegetation & Pole Integrity Manager	• Bachelor's Degree in Forestry, Biology, or Horticulture and/or equivalent training/experience	• International Society of Arboriculture (ISA) Certified Arborist • ISA Utility Specialist	5%	100%

1 Worker Titles	2 Minimum Qualifications	2a, b, c Special Certification Requirements	3 Percent FTE in Target Role	4 Percent FTEs with Special Certification
	• 7 years' experience in Utility Vegetation Management, including 3 years in contractor management 7 years' experience Utility Vegetation Management, including 3 years contractor management required			
Vegetation Management WMP Manager	• Bachelor's Degree in Forestry, Biology, or Horticulture and/or equivalent training/ experience • 7 years' experience in Utility Vegetation Management, including 3 years contractor management • 3-5 years' experience in resource conservation management (preferred)	• ISA Certified Arborist • ISA Utility Specialist	5%	100%
Area Forester/ Contract Administrator/ Supervisor	• 3 years' utility vegetation management experience • Bachelor's degree in Forestry, Biology, Horticulture, or related field (preferred)	• ISA Certification	48%	100%
Fuels Management Lead Forester	• Bachelor's degree in Forestry, Biology, Horticulture, or related field (preferred) • 3-5 years' experience administering vegetation management programs • Supervisory experience working with external contractors	• ISA Certification	5%	100%
Forester Patrol Person	• 3 years' utility vegetation management experience • Bachelor's degree in Forestry, Biology, Environmental Science, Horticulture, or related field (preferred)	• ISA Certification	21%	100%
Resource Coordinator (Customer Help Desk)	• High school diploma • College courses (preferred) • 3 years' customer service experience • Utility background or experience (preferred) • Microsoft Office proficiency • Strong technical writing skills (preferred) • Working knowledge of Mainframe, GIS, SAP and Distribution Planning Scheduling applications (preferred)	• No special certification required	16%	n/a
Total			**100%**	

Table 5-4: Workforce Planning and Limited Resources-Vegetation Inspections (Contractor)

1 Worker Titles	2 Minimum Qualifications	2a, b, c Special Certification Requirements	3 Percent FTE in Target Role	4 Percent FTEs with Special Certification
Auditor	• 3 years' utility vegetation management experience (preferred) • Bachelor's degree in Forestry, Biology, Environmental Science, Horticulture, or related field (preferred) • Current Class C Driver's License with clean driver safety record	• ISA Certification	28%	55%
Pre-Inspector	• Bachelor's degree in Forestry, Biology, Environmental Science, Horticulture, or related field (preferred) • 3-5 years' experience in Utility Vegetation Management • Current Class C Driver's License with clean driver safety record • Tree Risk Assessment Qualification (TRAQ) (preferred) • Lift a minimum of 50 pounds	• ISA Certification	72%	66%
Total			**100%**	

Vegetation Inspections-Qualification Improvement Plans

The vegetation work management system (Epoch) was updated to a new version in 2021. All contractor and internal users were trained on the application to improve workflow process, data capture, and reporting. All contractor and internal users also received new mobile data terminals (MDTs) in association with the new Epoch software. Training documents such as user guides and the company fire plan [Electric Standard Practice (ESP) 113.1] will be loaded on all units for worker reference and application.

In July 2021 SDG&E sponsored and participated in the initiative to develop a Utility Line-Clearance Arborist training program in collaboration with academia, utilities, contractors, and industry specialists. The goal of this program was to develop an accredited curriculum to improve the professionalism and training for line-clearances arborists. The class consisted of students from the California Conservation Corps (CCC). Eleven individuals graduated in this first class. Building on this program, a Pre-Inspector Training Program will be developed and offered at the college level to promote industry professionalism and standards. This curriculum is scheduled to be implemented in early 2022.

All vegetation management internal staff recently completed required Occupational Safety and Health Administration (OSHA) training for monitoring and protective measures against wildfire smoke conditions.

2. Vegetation Management Projects

1) worker titles, 2) minimum qualifications, 2a-c) special certification requirements, 3) percent of FTEs in target roles and 4) percent of FTEs with special certification are listed in Table 5-5. Plans to improve worker qualifications (5) are discussed separately.

Vegetation management and inspections are discussed in Section 7.3.5 Vegetation Management and Inspections.

Table 5-5: Workforce Planning and Limited Resources-Vegetation Management Projects (Contractor)

1 Worker Titles	2 Minimum Qualifications	2a, b, c Special Certification Requirements	3 Percent FTE in Target Role	4 Percent FTEs with Special Certification
Tree Trim General Foreman/ Supervisor	• 5 years' line clearance tree pruning experience in a Foreman role • Current California Driver License Class B endorsement • General computer knowledge • Good leadership qualities	• ISA Certification • Line-clearance qualified tree-trimmer certification	6%	71%
Tree Trimmer	• Current California Driver License (Class B endorsement) • General computer skills • Strong work ethic	• Line-clearance qualified tree-trimmer certification (or trainee)	79%	75%
Pole Brush General Foreman	• 5 years' brush field experience • Current California Driver License • General computer knowledge • Good leadership qualities	• Qualified Applicator Certification	13%	80%
Pole Brusher (Contractor)	• Current California Driver License • General computer knowledge • Strong work ethic	• No special certification required	2%	n/a
Total			**100%**	

Vegetation Management Projects-Qualification Improvement Plans

See Vegetation Inspections-Qualification Improvement Plans

3. Asset inspections

1) worker titles, 2) minimum qualifications, 2a-c) special certification requirements, 3) percent of FTEs in target roles and 4) percent of FTEs with special certification are listed for Distribution in Table 5-6 and Transmission in Table 5-7. Plans to improve worker qualifications (5) are discussed separately.

Distribution and transmission asset inspections are discussed in Section 7.3.4 Asset Management and Inspections.

Table 5-6: Workforce Planning and Limited Resources Distribution Asset Inspections (SDG&E)

1 Worker Titles	2 Minimum Qualifications	2a, b, c Special Certification Requirements	3 Percent FTE in Target Role	4 Percent FTEs with Special Certification
Distribution Lineman	• Journeyman Lineman having completed an accredited apprenticeship program • International Brotherhood of Electrical Workers (IBEW) Journeyman Lineman status in good standing • Class A California Driver's License	• Qualified electrical worker (QEW), Overhead and/or Underground Inspection Training	63%	99%
Fault Finding Specialist	• Journeyman Lineman having completed an accredited apprenticeship program • IBEW Journeyman Lineman status in good standing • 4-week Relief Fault Finder (RFF) class completed and associated written and practical exams passed	• QEW, Overhead and/or Underground Inspection Training	3%	100%
Electric Troubleshooter	• Journeyman Lineman having completed an accredited apprenticeship program • IBEW Journeyman Lineman status in good standing • Complete 7-week Relief Trouble Shooter (RETS) class and pass written and practical exams	• QEW, Overhead and/or Underground Inspection Training	18%	100%
Working Foreman	• Journeyman Lineman having completed an accredited apprenticeship program • IBEW Journeyman Lineman status in good standing • 6 months' experience in both overhead and underground electric during the past three years • Construction Standards and Practices tests passed	• QEW, Overhead and/or Underground Inspection Training	16%	95%
Total			**100%**	

Table 5-7: Workforce Planning and Limited Resources Transmission Asset Inspections (SDG&E)

1 Worker Titles	2 Minimum Qualifications	2a, b, c Special Certification Requirements	3 Percent FTE in Target Role	4 Percent FTEs with Special Certification
Transmission Lineman	• Journeyman Lineman having completed an accredited apprenticeship program • IBEW Journeyman Lineman status in good standing • Class A California Driver's License	• QEW, Overhead and/or Underground Inspection Training	63%	99%
Transmission Patroller	• Journeyman Lineman having completed an accredited apprenticeship program • IBEW Journeyman Lineman status in good standing • Class A California Driver's License • 18 months experience in overhead and underground transmission construction and maintenance within the past 3 years	• QEW, Overhead and/or Underground Inspection Training	11%	100%
Working Foreman-Electric Transmission	• Journeyman Lineman having completed an accredited apprenticeship program • IBEW Journeyman Lineman status in good standing • Valid California Class A driver's license • Class A Medical Certificate • 18 months' experience in transmission construction and Energized High Voltage hotline maintenance within the past 5 years	• QEW, Overhead and/or Underground Inspection Training	21%	100%
Thermographer	• Part 107 drone license or must obtain within first year • Level I Infrared Certification or must obtain within first year	• QEW or Electrician	11%	100%
Senior Thermographer	• Part 107 drone license or must obtain within first year • Level III IR Certification or must obtain within first year	• QEW or Electrician	5%	100%
Total			**100%**	

Asset Inspections-Qualification Improvement Plans

ICS and PSPS processes have been recently incorporated into the apprentice curriculum and into the annual Environmental & Safety Compliance Management Program (ESCMP) training for Electrical Regional Operations. Additionally, FTEs receive specific training related to SDG&E's fire plan in ESP 113.1 and the Cleveland National Forest (CNF) Operations and Maintenance Fire Prevention Plan.

The SDG&E's Skills Training Center recently made advancements within the Apprentice Program to utilize a structured curriculum obtained from the National Utility Industry Training Fund (NUITF), which is a product of the Electrical Training Alliance and the IBEW. The program emphasizes theory, design, and engineering standards, along with practical hands-on scenarios in the SDG&E modernized training yard, as well as integrating with learning systems and online training modules. This comprehensive program adds consistency and efficiency to the training. These modules are self-guided and can be completed in class and at home.

The Skills Training Center staff tailored the NUITF courses to SDG&E's workforce and work practices, aligning them with the phases of SDG&E's three-year apprenticeship program. Tests are conducted online, grades are always accessible, and instructors have the capability to connect with their students, and vice versa. This new technology, combined with SDG&E's strong hands-on training program, will ensure that SDG&E's workforce is fully prepared for the next stage of their careers.

Specific improvements to outreach and onboarding training programs included:

- Transitioned from paper training tools to MDTs, smart devices, and online learning
- Revised all aspects of the Troubleshooter and Fault Finding program and training curriculum to include integrated 2.5 D, E-Learning, videos and smart devices
- Built virtual reality into the CMP program and completed the physical infraction training yard at Skills to allow hands on training by inspectors
- Trained on GIS based tools for Construction Supervisor, Electric Trobleshooters, Fault Finding Specialist, Working Foreman, and Field Patrols
- Trained Electric Troubleshooters on infrared guns to help perform more thorough inspections and patrols on overhead circuits, including PSPS patrol teams.

4. Grid Hardening

Table 5-8, Table 5-9, Table 5-10, and Table 5-11 list 1) worker titles, 2) minimum qualifications, 2a-c) special certification requirements, 3) percent of FTEs in target roles and 4) percent of FTEs with special certification. Plans to improve worker qualifications (5) are discussed separately.

Grid Hardening is discussed in Section 7.3.3 Grid Design and System Hardening.

Table 5-8: Workforce Planning and Limited Resources-Grid Hardening – Distribution (SDG&E)

1 Worker Titles	2 Minimum Qualifications	2a, b, c Special Certification Requirements	3 Percent FTE in Target Role	4 Percent FTEs with Special Certification
Apprentice Lineman	• 9 months' experience as Line Assistant • Valid California driver's license • Must have held previous position for at least 9 months	• No special certification required	17%	n/a
Construction Manager-Electric	• Bachelor's Degree or equivalent experience • 8 years' experience	• No special certification required	2%	n/a

1 Worker Titles	2 Minimum Qualifications	2a, b, c Special Certification Requirements	3 Percent FTE in Target Role	4 Percent FTEs with Special Certification
Construction Supervisor-Electric	• H. S. Diploma/GED • years' experience • Complete 2-day program at Skills Training Center or complete outside program	• No special certification required	9%	n/a
District Manager	• H. S. Diploma/GED • 10 years' experience	• No special certification required	11%	100%
Electric Troubleshooter	• Complete 7-week RETS class and pass written and practical exams	• Journeyman Lineman	10%	10%
Fault Finder	• Complete 4-week RFF class and pass written and practical exams	• Journeyman Lineman	2%	100%
Line Assistant (non QEW)	• Successfully pass Company administered aptitude and skills tests • Valid California Class A driver's license • Pass a Department of Motor Vehicles (DMV) physical examination and Department of Transportation (DOT) drug screen • Must have held previous position for at least 9 months	• No special certification required	12%	n/a
Distribution Lineman	• Complete the minimum 3-year 6000-hour Lineman Apprentice program at the Skills Training Center and assigned Districts • Complete a 3-year, 480-hour college-level program to be qualified to take the Journeyman Lineman's test • Pass the Journeyman Lineman test	• QEW	37%	100%
Working Foreman-Electric Distribution	• 6 months' experience in both overhead and underground electric during the past three years • Valid California Class A driver's license • Class A Medical Certificate • Must have held previous position for at least 9 months	• QEW	9%	100%
Total			**100%**	

Table 5-9: Workforce Planning and Limited Resources-Grid Hardening – Distribution (Contractors)

1 Worker Titles	2 Minimum Qualifications	2a, b, c Special Certification Requirements	3 Percent FTE in Target Role	4 Percent FTEs with Special Certification
Field Construction Advisor (FCA)	• Journeyman Lineman	• QEW	7%	100%
Apprentice Lineman	• n/a	• No special certification required	15%	n/a
Journeyman Lineman	• Journeyman Lineman	• QEW	48%	100%
Foreman	• Journeyman Lineman	• QEW	17%	100%
Groundman	• n/a	• No special certification required	2%	n/a
Cable Splicer	• Journeyman Lineman	• QEW	9%	100%
Foreman (Splicing)	• Journeyman Lineman	• QEW	2%	100%
Total			**100%**	

Table 5-10: Workforce Planning and Limited Resources-Grid Hardening – Transmission (SDG&E)

1 Worker Titles	2 Minimum Qualifications	2a, b, c Special Certification Requirements	3 Percent FTE in Target Role	4 Percent FTEs with Special Certification
Construction Manager-Electric	• Bachelor's Degree or equivalent experience • 8 years' experience	• QEW	7%	100%
Construction Supervisor-Electric	• H. S. Diploma/GED • 6 years' experience	• No special certification required	21%	n/a
Line Assistant (non QEW)	• Successfully pass Company administered aptitude and skills tests • Valid California Class A driver's license • Pass a DMV physical examination and DOT drug screen • Must have held previous position for at least 9 months	• No special certification required	17%	n/a
Team Lead	• Bachelor's Degree or equivalent experience • 5 years' experience • Professional Engineer License	• No special certification required	3%	n/a

1 Worker Titles	2 Minimum Qualifications	2a, b, c Special Certification Requirements	3 Percent FTE in Target Role	4 Percent FTEs with Special Certification
Transmission Lineman	• Complete the minimum 3-year 6000-hour Lineman Apprentice program at the Skills Training Center and assigned Districts • Complete a 3-year, 480-hour college-level program to be qualified to take the Journeyman Lineman's test • Pass the Journeyman Lineman test	• QEW	34%	100%
Transmission Patroller	• Valid California Class A driver's license • Class A Medical Certificate • 18 months experience in overhead and underground transmission construction and maintenance within the past 3 years • Must reside within SDG&E's service territory	• QEW	7%	100%
Working Foreman-Electric Transmission	• Valid California Class A driver's license • Class A Medical Certificate • 18 months' experience in transmission construction and EHV hotline maintenance within the past 5 years • Must have held previous position for at least 9 months	• QEW	14%	100%
Total			**100%**	

Table 5-11: Workforce Planning and Limited Resources-Grid Hardening – Transmission (Contractors)

1 Worker Titles	2 Minimum Qualifications	2a, b, c Special Certification Requirements	3 Percent of FTEs in Target Role	4 Percent FTE s with Special Certification
Field Construction Advisor (FCA)	Journeyman Lineman	QEW	24%	100%
Apprentice Lineman	n/a	No special certification required	4%	n/a
Journeyman Lineman	Journeyman Lineman	QEW	45%	100%
Foreman	Journeyman Lineman	QEW	14%	100%

Groundman	n/a	No special certification required	2%	n/a
Cable Splicer	Journeyman Lineman	QEW	0%	100%
Foreman (Splicing)	Journeyman Lineman	QEW	0%	100%
Operator	Crane license, if operating a crane	No special certification required	11%	n/a
Total			**100%**	

Grid Hardening-Qualification Improvement Plans

SDG&E maintains ESP 113.1 for Wildland Fire Operations and Maintenance specific to Wildland Fire Prevention. The intent of ESP 113.1 is to formalize procedures and routine practices to assist employees, contractors, and consultants in their understanding of the wildfire prevention and to improve their ability to prevent the start of any fire. Updates to ESP 113.1 are done on an annual basis which are communicated to employees, contractors, and consultants.

In addition, Grid Hardening enhances the training and qualifications of their workers by providing a constant feedback loop on the job. This is done through post construction inspections and true-ups of as-builts using LiDAR technology.

The QA/QC teams complete post construction inspections, which compares the project build to the SDG&E Design Preference Guide (DPG). Any errors, omissions, or craftsmanship improvements are provided back to the workers to enhance their knowledge and skills for future projects.

The true-up of as-builts using LiDAR technology compares the project build to the Power Line Systems – Computer Aided Drafting and Design (PLS-CADD) design, which models the as-built condition. Any discrepancies between the as-built model and the as-built are reviewed with workers to identify lessons learned to update the DPG when appropriate.

5. Risk Event Inspection

Table 5-5 lists 1) worker titles, 2) minimum qualifications, 2a-c) special certification requirements, 3) percent of FTEs in target roles and 4) percent of FTEs with special certification. Plans to improve worker qualifications (5) are discussed separately.

Risk event inspections are performed in conjunction with asset management and vegetation management inspections, discussed in Section 7.3.4 Asset Management and Inspections and Section 7.3.5 Vegetation Management and Inspections respectively.

Table 5-12: Workforce Planning and Limited Resources-Risk Event Inspection (SDG&E Employees)

1 Worker Titles	2 Minimum Qualifications	2a, b, c Special Certification Requirements	3 Percent FTE in Target Role	4 Percent FTEs with Special Certification
Troubleshooter	• Journeyman Lineman who completed an accredited apprenticeship program • IBEW Journeyman Lineman status in good standing • Complete 7-week RETS class and pass the associated written and practical exams	• QEW	100%	100%
Total			**100%**	

Risk Event Inspection-Qualification Improvement Plans

Ssee Asset Inspections Qualification Improvement Plans)

6. Service Restoration

The employee information in Table 5-13 demonstrates adequacy of size of service restoration workforce (requirement 8386(c)(15)).

Table 5-13: Service Restoration Workforce (SDG&E Employees)

Role	Description	Employee Quantity
Planner	Planners are responsible for fielding and designing electric distribution facilities.	33
Construction Supervisor	Construction supervisors are responsible for prioritizing work and directing the field crews.	53
Electric Troubleshooter	Electric Troubleshooters are the first responders to outages or damages to SDG&E facilities. They are responsible for assessing the damage, making the scene safe, and requesting follow-up repairs.	42
Working Foreman	The working foreman is a QEW that leads the crew by assigning work amongst crew members, holding safety tailgates, and ensuring construction and switching is done according to plan.	39
Lineman	A lineman is a QEW that has completed the Lineman Apprentice Program and passed the Journeyman Lineman test. They are part of the crew that performs restoration construction and switching.	142
Apprentice Lineman	Apprentice Linemen are currently in the SDG&E Apprentice program. An Apprentice Lineman may be qualified to only work on secondary voltages (up to 600V) or on primary voltages depending on where they are in their apprenticeship. They can work on electrical facilities for which they are qualified under the supervision of a QEW.	68

Role	Description	Employee Quantity
Line Assistant	Line assistants are not qualified to work on electrical facilities. They assist with obtaining and preparing materials for the crew.	49

To demonstrate adequacy of size of service restoration workforce (requirement 8386(c)(15)), SDG&E is providing contractor information below in Table 5-14, based on the following assumptions:

- SDG&E tracks its contract resources by crew.
- A crew typically consists of one Working Foreman, two to three Linemen, and one Apprentice Lineman or Line Assistant.
- SDG&E currently has 35 distribution crews available (if needed for the restoration)

Table 5-14: Service Restoration Workforce (Contractors)

Role	Contractor Quantity
Working Foreman	35
Lineman	104
Apprentice Lineman or Line Assistant	29

6 Performance Metrics and Underlying Data

Instructions: *Section to be populated from Quarterly Reports. Tables to be populated are listed below for reference.*

NOTE: Report updates to projected metrics that are now actuals (e.g., projected 2021 spend will be replaced with actual unless otherwise noted). If an actual is substantially different from the projected (>10% difference), highlight the corresponding metric in light green

6.1 Recent Performance on Progress Metrics, Last 7 Years

Instructions for Table 1 of Attachment 3: *In the attached spreadsheet document, report performance on the following metrics within the utility's service territory over the past seven years as needed to correct previously reported data. Where the utility does not collect its own data on a given metric, each utility is required to work with the relevant state agencies to collect the relevant information for its service territory, and clearly identify the owner and dataset used to provide the response in the "Comments" column.*

Table 1: Recent Performance on Progress Metrics, last 7 years is provided in Attachment B.

6.2 Recent Performance on Outcome Metrics, Annual, Last 7 Years

Instructions for Table 2 of Attachment 3: *In the attached spreadsheet document, report performance on the following metrics within the utility's service territory over the past seven years as needed to correct previously reported data. Risk events and utility-related ignitions are normalized by wind warning status (RFW & HWW). Where the utility does not collect its own data on a given metric, the utility is required to work with the relevant state agencies to collect the relevant information for its service territory, and clearly identify the owner and dataset used to provide the response in "Comments" column.*

Provide a list of all types of findings and number of findings per type, in total and in number of findings per circuit mile.

Table 2: Recent Performance on Outcome Metrics, last 7 years is provided in Attachment B.

6.3 Description of Additional Metrics

Instructions for Table 3 Attachment 3: *In addition to the metrics specified above, list and describe all other metrics the utility uses to evaluate wildfire mitigation performance, the utility's performance on those metrics over the last seven years, the units reported, the assumptions that underlie the use of those metrics, and how the performance reported could be validated by third parties outside the utility, such as analysts or academic researchers. Identified metrics must be of enough detail and scope to effectively inform the performance (i.e., reduction in ignition probability or wildfire consequence) of each preventive strategy and program.*

Table 3: List and Description of Additional Metrics, last 7 years is provided in Attachment B

6.4 Detailed Information Supporting Outcome Metrics

Instructions for Table 4 Attachment 3: *In the attached spreadsheet document, report numbers of fatalities attributed to any utility wildfire mitigation initiatives, as listed in the utility's previous or current WMP filings or otherwise, according to* *the type of activity in column one, and by the victim's relationship to the utility (i.e., full-time employee, contractor, of member of the general public), for each of the last five years as needed to correct previously reported data. For fatalities caused by initiatives beyond these categories, add rows to specify accordingly. The relationship to the utility statuses of full-time employee, contractor, and member of public are mutually exclusive, such that no individual can be counted in more than one category, nor can any individual fatality be attributed to more than one initiative.*

Table 4: Fatalities Due to Utility Wildfire Mitigation Initiatives, last 7 years is provided in Attachment B.

Instructions for Table 5 Attachment 3: *In the attached spreadsheet document, report numbers of OSHA-reportable injuries attributed to any utility wildfire mitigation initiatives, as listed in the utility's previous or current WMP filings or otherwise, according to the type of activity in column one, and by the victim's relationship to the utility (i.e., full-time employee, contractor, of member of the general public), for each of the last seven years as needed to correct previously reported data. For members of the public, all injuries that meet OSHA-reportable standards of severity (i.e., injury or illness resulting in loss of consciousness or requiring medical treatment beyond first aid) must be included, even if those incidents are not reported to OSHA due to the identity of the victims.*

For OSHA-reportable injuries caused by initiatives beyond these categories, add rows to specify accordingly. The victim identities listed are mutually exclusive, such that no individual victim can be counted as more than one identity, nor can any individual OSHA-reportable injury be attributed to more than one activity.

Table 5: OSHA-Reportable Injuries Due to Utility Wildfire Mitigation Initiatives, last 7 years is provided in Attachment B.

6.5 Mapping Recent, Modelled, and Baseline Conditions

Instructions: *Underlying data for recent conditions (over the last five years) of the utility service territory in a downloadable shapefile GIS format, following the special reporting schema.[42] All data is reported quarterly, this is a placeholder for quarterly spatial data.*

Refer to SDG&E's Quarterly Data Report (QDR) submitted concurrently herewith.

6.6 Recent Weather Patterns, Last 7 Years

Instructions for Table 6 Attachment 3: *In the attached spreadsheet document, report weather measurements based upon the duration and scope of NWS Red Flag Warnings, High wind warnings and upon proprietary Fire Potential Index (or other similar fire risk potential measure if used) for each year. Calculate and report 5-year historical average as needed to correct previously reported data.*

Table 6: Weather Patterns, last 7 years is provided in Attachment B.

6.7 Recent and Projected Drivers of Ignition Probability

Instructions for Table 7 Attachment 3: *(Table 7.1) In the attached spreadsheet document, report recent drivers of outages according to whether or not risk events of that type are tracked, the number of incidents per year (e.g., all instances of animal contact regardless of whether they caused an outage, an ignition, or neither), the rate at which those incidents*

[42] https://energysafety.ca.gov/wp-content/uploads/energy-safety-gis-data-reporting-standard_version2.1_09072021_final.pdf

(e.g., object contact, equipment failure, etc.) cause an ignition in the column, and the number of ignitions that those incidents caused by category, for each of last seven years as needed to correct previously-reported data. Calculate and include 5-year historical averages. This requirement applies to all utilities, not only those required to submit annual ignition data. Any utility that does not have complete 2021 ignition data compiled by the WMP deadline is required to indicate in the 2021 columns that said information is incomplete. (Table 7.2) Similar to Table 7.1, but for ignition probability by line type and HFTD status, according to if ignitions are tracked

Table 7.1: Key Recent and Projected Drivers of Ignition Probability, last 7 years and projections is provided in Attachment B.

Table 7.2: Key Recent and Projected Drivers of Ignition Probability by HFTD Status, last 7 years and projections is provided in Attachment B.

Conductor damage or failure-related ignitions filed in Table 7.2 of the 2018 and 2020 WMP were updated via the Quarter 1 non-spatial QDR in May 2021.

Table 6-1: Corrected Conductor Damage or Failure-Related Ignitions

	2015	2016	2017	2018	2019	2020
Conductor damage or failure-Distribution Ignitions	2	3	1	**1**	0	**1**

The ignition projection count due to conductor damage or failure is determined using an average of the last 5-year ignitions (2015-2019) of 1.4, broken down by Tier, less estimated total ignition reduction from targeted mitigation activities. In this case, undergrounding, overhead hardening, covered conductor and drone inspections are considered in the conductor failure related projection. Each estimated ignition reduction is determined by Tier in the Risk Reduction Estimation Calculation (see Table 6-2).

Table 6-2: Estimated 2021 Ignition Projection Count due to Conductor Damage or Failure

Tier	Ignition Average by Tier	Estimated Ignition Reductions from Targeted Mitigations				Estimated Total Ignition Reduction	2021 Ignition Projection Count
		Undergrounding	Overhead hardening	Covered Conductor	Drone Inspections		
Non-HFTD	0.4	0	0.002	0	0	0.002	0.0398
Tier 2	0.6	0.0011	0.006	0.0001	0	0.0072	0.5928
Tier 3	0.4	0.0028	0.0051	0.0002	0.0487	0.0568	0.3432
Total	**1.4**						**1.334**

Most conductor related ignitions have other contributing factors. There are events where even though the conductor is documented as the cause of the fire there may have been other factors that initiated the event. With such a limited data set (see Table 6-1), one year of 2 ignitions creates a substantial swing in the predictive result. While SDG&E will continue to track and attempt to identify issues to reduce ignitions, the limited data means there needs to be caution around future ignition projections. The intent of SDG&E's Ignition Management Program (IMP)is to assist in the identification of the cause determination of near miss events, which can also be incorporated into the ignition projection count.

Reference Section 7.3.3.3 Covered conductor installation Section 7.3.3.16 Undergrounding of electric lines and/or equipment to see how the initiatives may affect ignitions due to conductor damage or failure.

6.8 Baseline State of Equipment and Wildfire and PSPS Event Risk Reduction Plans

6.8.1 Current Baseline State of Service Territory and Utility Equipment

Instructions for Table 8 of Attachment 3: *In the attached spreadsheet document, provide summary data for the current baseline state of HFTD and non-HFTD service territory in terms of circuit miles; overhead transmission lines, overhead distribution lines, substations, weather stations, and critical facilities located within the territory; and customers by type, located in urban versus rural versus highly rural areas and including the subset within the Wildland-Urban Interface (WUI) as needed to correct previously reported data.*

The totals of the cells for each category of information (e.g., "circuit miles (including WUI and non-WUI)") would be equal to the overall service territory total (e.g., total circuit miles). For example, the total of number of customers in urban, rural, and highly rural areas of HFTD plus those in urban, rural, and highly rural areas of non-HFTD would equal the total number of customers of the entire service territory.

Table 8: State of Service Territory and Utility Equipment is provided in Attachment B.

6.8.2 Additions, Removal, and Upgrade of Utility Equipment by End of 3-Year Plan Term

Instructions for Table 9 of Attachment 3: *In the attached spreadsheet document, input summary information of plans and actuals for additions or removals of utility equipment as needed to correct previously reported data. Report net additions using positive numbers and net removals and undergrounding using negative numbers for circuit miles and numbers of substations. Report changes planned or actualized for that year – for example, if 10 net overhead circuit miles are added in 2020, then report "10" for 2020. If 20 net overhead circuit miles are planned for addition by 2022, with 15 being added by 2021 and 5 more added by 2022, then report "15" for 2022 and "5" for 2021. Do not report cumulative change across years. In this case, do not report "20" for 2022, but instead the number planned to be added for just that year, which is "5".*

Table 9: Location of actual and planned utility equipment additions or removal year over year is provided in Attachment B.

Instructions for Table 10 of Attachment 3: *Referring to the program targets discussed above, report plans and actuals for hardening upgrades in detail in the attached spreadsheet document. Report in terms of number of circuit miles or stations to be upgraded for each year, assuming complete implementation of wildfire mitigation activities, for HFTD and non-HFTD service territory for circuit miles of overhead transmission lines, circuit miles of overhead distribution lines, circuit miles of overhead transmission lines located in Wildland Urban Interface (WUI), circuit miles of overhead distribution lines in WUI, number of substations, number of substations in WUI, number of weather stations and number of weather stations in WUI as needed to correct previously-reported data. If updating previously reported data, separately include a list of the hardening initiatives included in the calculations for the table.*

Table 10: Location of Actual and Planned Utility Infrastructure Upgrades Year over Year is provided in Attachment B.

7 Mitigation Initiatives

7.1 Wildfire Mitigation Strategy

Describe organization-wide wildfire mitigation strategy and goals for each of the following time periods, highlighting changes since the prior WMP:

1. *By June 1 of current year*
2. *By September 1 of current year*
3. *Before the next Annual WMP Update*
4. *Within the next 3 years*
5. *Within the next 10 years*

SDG&E's near-term goals, by June 1 of 2022, by September 1 of 2022, and before the next Annual WMP Update, are provided in Table 7-1. Longer-term goals for the 3-year and 10-year timeframes are discussed in Section 5.2 The Objectives of the Plan. Additionally, a year-by year breakdown for each wildfire mitigation strategy initiative through 2030 is presented in Attachment A. Wildfire mitigation strategy is further discussed in Section 7.3 Detailed Wildfire Mitigation Programs.

Table 7-1: SDG&E's Near-Term Strategy and Goals by WMP Category

Category	By June 1, 2022	By September 1, 2022	Before 2023 WMP Update
Risk Assessment and Mapping	• Complete review of 2021 PSPS events and identify any enhancements required before the 2022 Santa Ana wind season. • Expand and integrate academic partnerships. • Migrate existing models to Amazon Web Services Cloud. • Evaluate updates on WiNGS-Planning model and finalize methodology. • Evaluate updates on existing PoI models and finalize methodology	• Operationalize the WRRM-Ops platform into a single visual and configurable live map that can be utilized to support operational decisions, including with respect to PSPS. • Enhance WRRM with new observations methodologies and datasets. • Integrate PoI models in WiNGS-Planning and WiNGS-Ops • Develop user interface/visualization tool for WiNGS-Planning • Develop visualization tool (proof of concept) for WiNGS-Ops	• Enhance POI models in IMP. • Integrate and align with SDG&E Climate Vulnerability Assessment. • Incorporate WRRM-Ops enhancements into MAVF in the determination of risk consequences. • Initiate third-party model reviews • Upgrade High-Performance Computing Infrastructure. • Execute risk models in the Cloud environment • Introduce egress in wildfire risk modeling
Situational Awareness and Forecasting	• Finalize location selection for any additional situational awareness tools. • Acquire next generation High Performance Computing Clusters (HPCC). • Open fully operational FSI Lab. • Install NDVI cameras and Air Quality Index (AQI) sensors at key locations. • Operationalize AI based smoke detection from cameras. • Finalize Fire Science & Climate Adaptation (FS&CA) Tuition Reimbursement Program details with benefits department	• Finalize installations of additional equipment to support 2022 fire season activities. • Engage academic community in the FS&CA Tuition Reimbursement Program and establish internal oversite committee to administer the program.	• Continue developing AI-based forecasting models to support PSPS decisions. • Expand weather network to include additional equipment in strategic locations. • Utilize imagery to observe fuel moisture and enhance the understanding of fire potential. • Have fully implemented FS&CA Tuition Reimbursement Program available to incentivize scientific advancement.
Grid Design and System Hardening	• Continue implementing overhead and underground grid hardening initiatives and programs across the HFTD. • Continue equipment installation and replacement programs including hot line clamp, lightning arrestor, WFI, expulsion fuse and PSPS sectionalizing devices.	• Continue implementing overhead and underground grid hardening initiatives and programs across the HFTD. • Continue equipment installation and replacement programs including hot line clamp, lightning arrestor, WFI, expulsion fuse and PSPS sectionalizing devices	• Continue implementing overhead and underground grid hardening initiatives and programs across the HFTD. • Continue equipment installation and replacement programs including hot line clamp, lightning arrestor, WFI, expulsion fuse and PSPS sectionalizing devices.

Category	By June 1, 2022	By September 1, 2022	Before 2023 WMP Update
			• Complete installation or replacement of all branch expulsion fuses in the HFTD to CAL FIRE-approved power
Asset Management and Inspections	• Continue maintenance and inspection of facilities consistent with the scope and schedule of CPUC GOs. • Complete drone assessments of transmission structures within the HFTD.	• Continue to evaluate drone inspections in HFTD Tier 2 and find ways to perform them more efficiently.	• Expand distribution inspection program practice of expediting fire safety infraction repairs into HFTD Tier 2 • Identify the appropriate cycle, locations, and/or types of structures to utilize drones as part of routine inspection programs. • Assess wildfire reduction benefit cost effectiveness after drone pilot assessments complete • Explore virtual reality/augmented reality opportunities to enhance electric first responder training program • Build electric first responder testing into Learning Management System (LMS) • Finish electric distribution drone inspections for Tier 2 • Prepare for implementation of risk-based prioritized inspections by developing workflows, processes, and procedures, and updating systems to convert current QC inspections (approx. 13000) distribution pole inspections performed on a 3-year cycle in Tier 3 HFTD) to risk-based inspections across the entire HFTD. These inspections would be over and above the time-based 5-year inspections required by GO 95
Vegetation Management Plan	• Further engage supercomputing for predictive analysis and prioritization of activities • Continue participation in the joint IOU study of enhanced vegetation clearances	• Develop improved reporting capabilities	• Expand fuel management activities in vegetation management operations • Enhance VRI modeling • Develop work management system for unplanned vegetation management activities

Category	By June 1, 2022	By September 1, 2022	Before 2023 WMP Update
	• Engage third-party analysis of clearance and outage data		• Develop training curriculum to address audit deficiencies • Source native tree stock from nursery vendors •
Grid Operations and Protocols	• Continue to disable reclosing in the HFTD • Establish a qualified roster for upcoming fire season for use of staffing Infrastructure Protection Team	• Continue to enable sensitive/fast protection settings on days with FPI of Extreme • Take ownership of an additional air suppression resource	• Continue to leverage fire suppression resources to accompany crews performing work in the HFTD during elevated FPI • Launch predictive and fault signature AI for development of real-time operations predictive equipment failure analytics • Develop as-switched system model to mobile NMS App (OMA)
Data Governance	• Implement data platform architecture capable of collecting disparate information sources into a CR • Deploy advanced analytics solutions and leverage reporting tools to drive utility wildfire mitigation decisions • Enhance ability to ingest and share weather data using real-time API protocols with stakeholders • Enhance risk event PoI Models in IMP	• Document central repository of data sources, assumptions, and algorithms into a single document • Document data governance for data models and predictive analytics • Enhance publicly available tools to visualize fire-weather data, collected via sensors	• Implement OEIS GeoDatabase schema • Deliver data governance education program • Continue to assess data governance implementation using internal audits • Utilize methodology to inform 2023 WMP
Resource Allocation Methodology	• Integrate new PoI modeling capabilities	• Expand the investment prioritization prototype development to electric distribution projects, including wildfire-driven projects • Explore new methodologies to other mitigations including asset management and vegetation management	• Complete WiNGS-Ops Cloud migration and automation for advanced analytics • Initiate egress analysis and explore ways to incorporate into WiNGS-Planning model • Incorporate life cycle cost analysis into WiNGS-Planning model • Initiate proof of concept for electric distribution portfolio optimization approach • Initiate third-party model review

Category	By June 1, 2022	By September 1, 2022	Before 2023 WMP Update
			• Develop associated business processes to implement the portfolio optimization tool with electric distribution business units • Develop proof of concept (PoC) for electric distribution portfolio optimization approach • Utilize methodology to inform 2023 WMP
Emergency Planning and Preparedness	• Conduct review of the emergency preparedness plan with stakeholders • Complete new Emergency Operations Center (EOC) and place in service • Complete bi-annual internal/external stakeholder plan review and audit • Complete bi-annual First Responder Utility Incident Command System (UICS)/PSPS emergency response training • Build depth in Utility Incident Commander position • Implement night fly firefighting program with CAL FIRE approval • Complete annual AAR metrics report	• Adopt emergency preparedness plan revision	• Update emergency plans • Further refine the K2 system to identify jurisdictions / adjacencies to support public safety partner notifications • Complete Event Emergency Plan & Company integration process with Fire and Law Enforcement Chief Officer and Dispatch Services UICS/PSPS workshops and meetings • Complete bi-annual AAR review and revision • Complete AAR program alignment/ integration with Safety Management System • Develop AAR content management system • Conduct ICS functional field exercise with Eastern Zone fire agencies
Stakeholder Cooperation and Community Engagement	• Launch PSPS and wildfire safety public education campaigns (year-round) • Survey customers to understand needs and communication preferences and to establish baseline for public education campaign awareness. • Schedule and finalize webinars and community fairs • Optimize partnerships with 40 HFTD-focused CBOs and increase and enhance CBO partnerships in key areas (e.g., healthcare) for promotion and amplification of PSPS to vulnerable populations.	• Adapt PSPS and wildfire safety public education campaigns based on customer and stakeholder feedback. • Complete webinars and community fairs, gathering stakeholder feedback • Promote and amplify PSPS, wildfire, and readiness messaging through CBO partnership activities • Assess and resolve any customer support and communications gaps identified through AFN stakeholders • Enhance communication channels and utilize technology to create more accessibility	• Survey customers, particularly affected customers, to assess campaign effectiveness and communication preferences and to inform development of 2023 campaigns. • Survey customers, community organizations, and community partners to understand the needs of AFN customers on an ongoing basis • Strengthen and expand AFN CBO partnerships • Continuously refine and enhance protocols based on stakeholder feedback • Continue to conduct additional working sessions with the International Wildfire Risk

Category	By June 1, 2022	By September 1, 2022	Before 2023 WMP Update
	• Launch second campaign driving customers to self-identify as AFN • Incorporate key feedback received from state and local AFN councils, customers, and other stakeholders into 2022 protocols and practices		Mitigation Consortium (IWRMC) and fire suppression agencies • Enhance PSPS Mobile App and develop Public Safety Partner Mobile App

7.1.1 Approach to Managing Wildfire Risk

A. Discuss the utility's approach to determining how to manage wildfire risk (in terms of ignition probability and estimated wildfire consequence) as distinct from managing risks to safety and/or reliability. Describe how this determination is made both for (1) the types of activities needed and (2) the extent of those activities needed to mitigate these two different groups of risks. Describe to what degree the activities needed to manage wildfire risk may be incremental to those needed to address safety and/or reliability risks.

Wildfire is the top risk in SDG&E's Enterprise Risk Management assessment. As such, wildfire prevention and mitigation activities are a key component in keeping customers, employees, and communities safe. Generally, wildfire mitigation activities are focused on electrical assets which have the potential to cause fires as opposed to assets with the potential to cause a safety or reliability issue unrelated to wildfires. However, improved reliability is often an ancillary benefit of wildfire mitigation work because system hardening, fire science, and weather technology help prevent forced outages.

To reduce the risk of catastrophic wildfires caused by electric power lines, mitigation activities encompass infrastructure hardening, undergrounding, vegetation management, fuels management, inspections and patrols focused on high-risk fire areas, customer outreach and education, and support for customers with AFN, in conjunction with leveraging fire science and weather technology.

Wildfire mitigation activities are focused in the HFTD and WUI and are often complimentary to activities associated with safety and reliability outside of the HFTD. Some of these activities include increased inspections, infrastructure hardening, undergrounding, operational measures such as patrols prior to RFW days, post-PSPS patrols prior to restoration of outages, additional vegetation management inspections, and increased clearance of tree pruning. Situational awareness-related activities are also focused in the HFTD and WUI. These activities include forecasting weather, monitoring wind, fuel, and relative humidity to understand wildfire risk, monitoring fire cameras, and collaborating with outside entities such as the National Weather Service.

Activities surrounding public outreach and collaboration with public service partners differ in the HFTD and WUI compared to other areas in the service territory. Each year, community outreach and education events are conducted to better prepare customers for PSPS events and to raise awareness of wildfire risk. Throughout the year, SDG&E works to strengthen collaboration with its public service partners and to determine additional ways to support its customers. A key component is developing resources for customers with AFN and driving awareness to the right customers.

In addition to mitigations developed to reduce the risk of catastrophic wildfires, activities are implemented to reduce the impact of PSPS on customers. Mitigations such as PSPS Sectionalizing Enhancements, Microgrids, and the GGP are implemented to reduce the scope of PSPS to customers. Other mitigations, such as undergrounding, serve the dual purpose of reducing the risk of wildfire while reducing the scope of PSPS events for customers.

Wildfire mitigation-related activities are separate from activities that focus on reliability. For example, outreach and communication with customers is focused on customer satisfaction and mitigating the impacts of outages. Outside the HFTD and WUI, system upgrades are not driven by wildfire risk but by improving the impacts of outages to customers and reducing risks unrelated to wildfires. An example is the underground cable replacement program that improves reliability for customers.

7.1.2 Use of Risk Modeling Outcomes to Inform Decisions

> *B. Discuss how risk modeling outcomes are used to inform decision-making processes and used to prioritize mitigation activities. Provide detailed descriptions including clear evaluation criteria[43] and visual aids (such as flow charts or decision trees). Provide an appendix (including use of relevant visual aids) with specific examples demonstrating how risk modeling outcomes are used in prioritizing circuit segments and selecting mitigation measures.*

Utilization of Risk Modeling Outcomes to Inform Decision Making and Prioritize Mitigation Activities.

As discussed in Section 4.5.1.7 Wildfire Next Generation System-Planning, the WiNGS-Planning model is utilized to obtain segment risk ranking, segment RSE analysis, and portfolio analysis. This informs scoping for higher capital programs, including grid hardening initiatives in the HFTD.

To address the recommendations in action statement SDGE-21-09 (see Section 4.6 Progress Reporting on Key Areas of Improvement), flowcharts of the three largest categories of work were created. These flowcharts show at a high level the decision-making process and how work is implemented for the following categories:

1. Grid Hardening: See Section 4.5.1.7 Wildfire Next Generation System-Planning and Figure 7-4 for decision-tree flowcharts highlighting how the WiNGS-Planning model is used along with other factors to inform scoping and selection of underground versus covered conductor projects.
2. Asset Management and Inspections: See Figure 7-5, Figure 7-6, and Figure 7-7 for decision-tree flowcharts documenting the general process, highlighting how remediation is prioritized based on findings from inspections.
3. Vegetation Management and Inspections: See Figure 7-9, Figure 7-10, and Figure 7-11 for decision-tree flowcharts documenting the general process, highlighting how remediation is prioritized based on inspection findings.

7.1.3 Summary of Achievements, Implementation Wildfire Mitigation Initiatives, and Lessons Learned

> *C. Include a summary of achievements of major investments and implementation of wildfire mitigation initiatives over the past year, lessons learned, changed circumstances during the 2020-2022 WMP plan cycle, and corresponding adjustment in priorities for the current year. Organize summaries of initiatives by the wildfire mitigation categories listed in Section 7.3.*

A summary of achievements and implementation of wildfire mitigation initiatives over the past year is provided in Table 7-2. Program metrics (planned and actual) by wildfire mitigation categories are provided in Section 5.3 Plan Program Targets. Lessons learned by wildfire mitigation categories are provided in Section 4.1 Lessons Learned: How Tracking Metrics on the 2020 and 2021 Plans Informed the 2022 Plan Update.

[43] "Evaluation criteria" should include all points of considerations including any thresholds and weights that may affect the outcome of their decision, as well as a descriptor of how it is evaluated (i.e., given a risk score, using SME expertise to determine that score, using a formula).

Table 7-2: SDG&E's 2021 Achievements and Major Investments by WMP Category

Category	2021 Achievements
Risk Assessment and Mapping	Updated the fire growth algorithms and the LFM data in the model to improve the accuracy of consequence modeling in WRRM and WRRM-Ops. Began automation of WiNGS-Planning and developed PoC tool to visualize WiNGS-Planning and enable interactive scenario analysis. Developed a model to predict conductor-related failures and ignitions, and preliminary models for predicting ignitions from vehicle contacts, vegetation contacts, animal contacts, and balloon contacts.
Situational Awareness and Forecasting	Completed sensor selection and purchased 6 AQI sensors. The sensors interface with the Weather Station Network. Completed an operational update that included an adjustment to the weather matrix which determines the overall weather component (dryness and winds). Conducted an analysis with a Capstone Team at the SDSC to look at the variables incorporated into the FPI and future opportunities for enhancements. Future variables that would continue to refine the FPI could include solar radiation and fuel temperatures.
Grid Design and System Hardening	Participated in covered conductor effectiveness workstream in collaboration with other utilities. Progress is expected on comparing covered conductor to alternatives, determining covered conductor's ability to reduce the need for PSPS (in comparison to alternatives), and developing an initial assessment of the differences in costs. Completed temporary configuration (conventional generators) for 4 microgrids deployed in 2020. The permanent renewable solution and completed land acquisitions on two microgrid sites – one home to a Feeding America distribution center that requires electricity to power the refrigeration of perishable food items. The Feeding America center had a mobile battery storage solution implemented to avoid the impacts of PSPS events to this customer. Completed an infrastructure assessment feasibility of PSPS impacted communities (Related to Action Statement SDGE 21-10). Completed contracting and design for an off grid (box power) solution for a cathodic protection water system that has a 2-mile line through the HFTD Construction commenced on the CNF Program in late 2016 and was completed in 2021
Asset Management and Inspections	Utilized previously processed LiDAR to proactively model transmission lines that were identified by Meteorology as likely to experience high winds during red flag events. Additionally, Transmission requested new LiDAR for 50 miles of transmission in HFTD Tier2 for our 230kV system. Expedited repairs for some conditions found in the Tier 3 of the HFTD (including the design, engineering, and construction of the new structures) faster than the 6-month or 12-month timeframe required by the CPUC's GOs. This will reduce the risk of wildfire on an accelerated schedule within the highest risk areas Transitioned the DIAR Program from a pilot program to a more defined initiative through development of workflows and process and procedure documents In August 2021, QEWs completed 5 days of flights to look at all 69kV tie lines within Tier 3 of the HFTD. The goal to complete all 69kV lines prior to September 1, 2021, which is typically the beginning of fire season, was accomplished. In addition, these flights looked at key 230kV and 500kV tie lines within Tier 3 of the HFTD. Completed visual patrols on all transmission lines in the system. At the end of August, an additional set of visual patrols was completed on transmission lines in Tier 3 of the HFTD. Infrared patrols were also completed prior to multiple RFWs to verify the integrity of the system in the potential impact areas prior of the event.
Vegetation Management Plan	Engaged a third certified vendor that processes 100 percent of material received into recyclable streams, resulting in an increase in the amount of material diverted from landfills and in a

	further reduction of the carbon footprint related to tree trimming efforts. Current percentage of total green waste diverted to recycling facilities is approximately 46 percent. Continued to collaborate with the SDSC to model tree data. The project's goal was to use Vegetation Management's highly rich inventory tree data and outage history to develop a predictive risk analysis tool. Results from study corroborate SDG&E's premise and practice of obtaining greater clearance to reduce the frequency of tree-related outages. Continued offering customers trees that are compatible to plant near power lines ss part of the tree removal/replacement program and "Right Tree, Right Place" initiative. Beginning in 2021, as part of the company sustainability initiative, SDG&E set an annual goal of providing and distributing 10,000 trees. By Quarter 4 2021, over 11,000 trees were provided in collaboration with a multitude of stakeholders including customers, counties, cities, tribal lands, and state and federal agencies. Implemented next generation mobile application (Epoch) of PowerWorkz. The new system was designed, developed, and tested before going live. Improvements included new mapping interface, more robust software performance, enhancements to data capture, streamlined mapping, and associated reporting.
Grid Operations and Protocols	Deployed technology solutions to increase efficiency in post-PSPS restoration efforts that improved documentation of post-event patrols. This software supports forms to document damage found on post-event patrols and provides photos of damage per CAL FIRE's recommendations. Additionally, utilized drone support in areas where terrain was difficult for foot patrols to access, or wind conditions made it difficult for helicopters to access. Created a partnership with CAL FIRE for night firefighting. While the demands and requirements are determined by CAL FIRE, SDG&E began night currency and proficiency flights for pilots to gain confidence and familiarity with night operations. Increased hangar space for maintenance and security of aerial firefighting assets. Maintenance can now be performed indoors, and secure indoor storage is provided when the helicopters are not in use. Took ownership of a Sikorsky S-70M (Firehawk), which will serve as a lead aerial firefighting resource once it is outfitted with firefighting capability. Operations with Firehawk will be more capable and safer compared to the current Blackhawk due to advanced safety systems and enhanced performance characteristics. The Firehawk will also have a 1000-gallon water drop capacity.
Data Governance	Developed DGFs for Vegetation Management, FC&SA, Asset GIS, Asset Inspections (Distribution, Transmission, Substations), Outages (Distribution, Transmission), Safety, PSPS, Financial, and the CR as well as other WMP program initiatives. Completed internal DGF audits, including recommendations for management corrective actions for Vegetation Management, FS&CA, Asset Inspections (Distribution, Transmission), and Outages (Distribution, Transmission). Developed data glossaries for Vegetation Management, FS&CA, GIS, Asset Inspections (Distribution, Transmission, Substations), Outages (Distribution, Transmission), Safety, PSPS, Financial, and the CR as well as other WMP program initiatives. Integrated data sources with the CR for Vegetation Management, Fire Science & Climate Adaptation, Asset GIS, Asset Inspections (Transmission), Transmission Outages, and Safety. Many of these data sources include data from sensored portions of electric lines, equipment, Vegetation Management, and Safety. Developed a central catalog and documentation standard for all WMP table metrics. Enabled data quality visibility by developing Data Quality/Availability Scorecards for transmission and distribution inspection data Ignition Management Program continued to solidify processes for informing mitigation owners and gathering ignition and near ignition data. Ignition/near ignition event sources have been focused within the categories identified by the CPUC Decision 14-02-015. Automation of the data gathering process coupled with refinement of information workflows continued in 2021 and will continue in the future. Steps taken in 2021 include automating processing and working

	to centralize data. Data was then leveraged in the Probability of Ignition (POI) models to create foundational knowledge for wildfire risk mitigation initiatives.
Resource Allocation Methodology	**Investment Prioritization** Programed the investment prioritization prototype into a software solution as the capital portfolio allocation tool Sampled project entry sprint was conducted, identifying enhancements of the value framework for transmission and substation portfolio Started development of the next phase of the value framework electric distribution **WiNGS-Planning** Expanded application of the WiNGS-Planning tool, developing WiNGS-Ops to support real-time decision making during PSPS events Initiated a proof of concept for visualizing WiNGS-Planning and enabling dynamic scenario modeling Leveraged WiNGS-Planning in scoping and prioritization of future undergrounding and covered conductor work Began automation of elements of the WiNGS-Planning model Initiated lifecycle cost analysis and developed preliminary approach for incorporating it into RSE calculations In response to Action Statement SDGE 21-09, SDG&E has developed its decision-making flow chart. Such process flow charts are intended to provide greater clarity around how risk factors are considered in decision-making. See sections 5.4.1.7 and 7.3.3 for Grid Hardening, section 7.3.4 for Asset Management and Inspections and section 7.3.5 for Vegetation Management and Inspections.
Emergency Planning and Preparedness	Updated and modernization of the Electric Regional Operations STC. Update of all levels of QEW training such as ETS, fault finders, line assistants, and apprentices Developed the Senior Emergency Response Advisor to help assist in the STC integration under the guidance of Emergency Management Completed construction on a physical infractions test yard with infractions that will be changed regularly for Journeymen to identify and properly code Over 400 employees completed ICS training Working with the Indian Health Council and Southern Indian Health Council to identify needs during PSPS events, and partnering with these organizations to address those needs (e.g., generators, resiliency items, etc.). Partnered with two tribal consultants to advise on customized and culturally appropriate communications and outreach. Partnered with expand its Tribal and AFN campaigns to reach and communicate with a greater number of hard-to-reach vulnerable populations. Held drive-through Wildfire Safety Fairs that attracted over 2,400 HFTD residence. Enhanced notifications during an event to be more accessible by including a video with American Sign Language interpretation and an audio read-out. Continued focus outreach on the most vulnerable customers, including MBL customers. Added ENS notifications with an accessible format and videos with American Sign Language translation and audio read out. Reviewed the Mutual Assistance Plan annually, in accordance with GO 166.[44] Matured the AAR program to align and integrate processes with SDG&E's SMS. Where the AAR focuses on emergency incidents and events involving SDG&E's EOC, the SMS will provide an enterprise-wide approach to risk and safety and allow for cross-functional learning and information sharing on all events.

[44] GO 166, Standard 2. SDG&E is in the process of developing a formal Mutual Assistance training. SDG&E currently does what can be considered "just in time" training during the pre-deployment briefing on policies and procedures, including COVID-19 protocols

	Partnered with the Training and Exercise program to draft core capabilities for continuous quality improvement, performance management, and benchmarking of emergency response to wildfire incidents/events. Developed a Training & Exercise division to expand the program and continue to formalize processes. SDG&E has conducted or participated in 12 emergency exercises and over 25 trainings all of which have included a lessons learned component. SDG&E is expanding the After-Action Program to ensure it is comprehensive and lessons learned are cataloged into core capabilities for further benchmarking and analytics. Additionally, SDG&E has partnered with PG&E and SCE to develop a joint training committee to develop standardized training for CalOES EOC Credentials. SDG&E, through its Emergency Management and Fleet Services departments, implemented a program with Verizon Connect to track vehicles assigned to the HFTD. This program provides an additional level of safety to SDG&E's employees working in areas that do not have adequate radio or cell phone coverage, or both. Management and control of the Sole Worker Safety Program transitioned to SDG&E's Information Technology department, where 185 TracPlus devices have been implemented. Implemented an Aerial Mesh Network, which allows live high-definition video, infrared video, and shape files to be live streamed from equipped helicopters to several receive sites located throughout the service territory, and onto SDG&E's intranet for consumption by the EOC, aviation services, and external cooperators such as CAL FIRE. This video is used for real-time situational awareness in times of emergency (fires, earthquakes, large outages).
Stakeholder Cooperation and Community Engagement	Increased support by CBOs who serve the HFTD during PSPS and expanded direct CBO partnerships to provide AFN support during PSPS. Expanded its public education and outreach efforts associated with its PSPS Communications Plan. Offered online Webinars and Drive-Thru Wildfire Safety Fairs to customers and the general public. A large portion of these events provided information about PSPS and how to prepare for and remain resilient through the events. Record attendance was reached in 2021 and planning for future events will focus on expanding participation in future community events. At the beginning of September 2020, the PSPS Mobile App (Alerts by SDG&E) was launched and its capabilities were expanded in 2021. Emergency Management established a relationship with PS&E, a local and experienced HFE and HMI scientific company. PS&E secured a $1.4 million grant through DOE's SBIR Grant program to partner with a utility, SDG&E, to identify how the science of HFE/HMI could apply to the utility industry. This led to significant improvements in situational awareness and decision-making processes with PSPS events and Aviation Services flight coordination and tracking. SDG&E entered into a multi-year contract with PS&E to integrate this science into operations company-wide.

7.1.4 Limited Resource Challenges

D. List and describe all challenges associated with limited resources and how these challenges are expected to evolve over the next 3 years.

Given the continued high demand for utility tree crews throughout California, the possibility of contractor resource constraints continues into 2022. This will also be driven by the expected high workload of tree trimming and removal operations statewide. The ongoing COVID-19 pandemic may also have an impact on contractors' ability to maintain a consistent workforce.

Relay technician and SCADA technician resource constraints along with COVID-19 challenges made it more difficult to commission Advanced Protection work on circuits and substations and sectionalizing devices on circuits in 2021. These resource constraints are expected to continue in 2022.

In 2021, it was challenging to meet WMP goals related to strategic undergrounding work due to competing priorities across the IOUs for permitting, design, and construction resources. These constraints are expected to continue in 2022 and may be exacerbated by global and local workforce shortages. The permitting process for much of grid hardening work—especially for Strategic Undergrounding—is very challenging. Although, much of the routing can be in existing roads, this work requires environmental reviews and assessments and acquiring easements from private and public property owners. Permitting reviews can last several months to over a year before approval. Acquiring easements from property owners is further complicated by communications infrastructure provider assets that may remain above ground after the electric assets have been undergrounded. This is because communication providers (telecom and cable) have no provision for recovering the cost of undergrounding their existing overhead service lines. In some communities, the fact that communication lines are remaining overhead (thus losing any aesthetic benefit) has been enough to deny SDG&E easements to underground electric facilities for safety. The long duration for acquiring permits and easements exacerbates the resource constraints and makes it challenging to meet WMP targets and schedules for reasons entirely outside of SDG&E's control. These constraints are the main reason why the Strategic Underground target for 2022 was adjusted from 850 miles to 65 miles.

As the importance of risk assessment and development of risk models grows, data scientists and data analytics expertise has become more critical. The demand for well-trained science professionals is growing across the region and the entire energy sector, and as a result, finding these resources for wildfire risk work has become increasingly challenging. To help in addressing this issue, FS&CA is developing an employee Tuition Reimbursement Program designed to encourage and support employees' pursuit of higher education in areas considered to help wildfire mitigation efforts through the advancement of environmental science, fire science, climate science and/or data science. The primary goal of this program is to prepare a workforce trained to deal with the evolving needs associated with wildland fire management and climate change as it relates to power utilities. The most recent climate science indicates that wildfire mitigation will become increasingly challenging in the coming years and decades, and this program is designed to develop the workforce to face these issues.

Additionally, the global supply chain was significantly impacted in 2021, and material availability and deliverability will likely continue to be impacted in 2022. SDG&E plans to mitigate the impacts of labor and material constraint as much as possible by issuing work as early as possible and securing resources as early in the year as possible.

7.1.5 Impact of Technologies and Innovations on Wildfire Mitigation Strategy

E. Outline how the utility expects new technologies and innovations to impact the utility's strategy and implementation approach over the next 3 years, including the utility's program for integrating new technologies into the utility's grid. Include utility research listed above in Section 4.4.

New technologies and innovations will be leveraged to refine, improve, and advance wildfire mitigation strategy in the coming years. These technologies are summarized below and discussed Section 4.4 Research Proposals and Findings and Section 7.3 Detailed Wildfire Mitigation Programs.

Distribution Communications Reliability Improvements

A robust communication network is foundational for the success of advanced protection technologies on the electric distribution system (e.g., FCP). SDG&E's Distribution Communications Reliability Improvements (DCRI) program (discussed in Section 7.3.3.18.1 Distribution Communications Reliability Improvements) is currently deploying a privately-owned Long-Term Evolution (LTE) network in the service territory using licensed radio frequency spectrum. Use of private LTE technology yields benefits such as:

- Provide enhanced cybersecurity capabilities
- Reduce cybersecurity risk
- Apply enhanced failover and redundancy capabilities and yield high availability and reliability
- Provide forward-looking technology lifecycle with global adoption
- Provide solutions that are upgradable over time and adaptable for new utility use cases and requirements.

Advanced Protection

Early Fault Detection (EFD) uses radio frequency monitoring of potential discharges from primary conductors to find damaged components which can be replaced or repaired before they fail. EFD installs monitors for each phase at 4 km intervals along a circuit. Data is collected continuously and backhauled on commercial cell communication networks to web servers. Software analysis eliminates spurious signals and isolates signals which are generated by the electrical facilities. Comparing the timing of the signal arrival at two adjacent monitors allows the location of the equipment generating the signal to be determined within 10 meters on the path between the monitors. The developer analyses the data and provides monthly reports showing low-medium-high risk ratings for each structure on the path allowing targeted inspections of the facilities to find the damaged equipment generating the signal.

Wire Down Detection

Wire Down Detection (WDD) focuses on detecting the location of an equipment caused de-energization event, indicating a wire down, within a brief period based on existing Advanced Metering Infrastructure (AMI) data. Extensive research and the implementation of a set of analytics-based AMI data that can detect in near time high impedance faults and single-phase faults has previously been conducted at other utilities deploying a similar AMI system. WDD deploys the same types of analytics to demonstrate the near-time identification of previously undetected fault events that can result in a wildfire.

Vegetation Risk Index

Historical meteorological data, the inventory tree database, and tree-caused outage information was used to develop a VRI of the highest risk trees in the service territory. Vegetation Management uses the VRI as situational awareness and as a management tool for decision-making regarding enhanced vegetation management work. The VRI is also a factor in decision-making during PSPS events.

VRI data, along with circuit segments that are most at risk of tree impacts, is displayed in the GIS layer (shapefile) of the MDTs used by Vegetation Management. Associated wind speeds along the circuit segments are also a factor within the VRI to aid in current and future operational decisions. Additionally, prior tree caused outage information is contained within the tree inventory record which can help determine if tree removal is a more proper application. The VRI is further discussed in Section 4.5.1.2 Vegetation Risk Index and Section 8.2 Protocols on Public Safety Power Shut-off.

PSPS App and Other Customer Communication Tools

In 2021, SDG&E enhanced its PSPS website to provide real-time status updates, and a dedicated landing page for customers with AFN. The website enhancements were built based on feedback from key stakeholders, and directs customers to locations for all support programs and services.

Intelligent Image Processing

SDG&E has created an image capture, centralized storage, and processing engine known as Intelligent Image Processing (IIP). In 2021, IIP harnessed digital capabilities to accelerate machine learning and AI, cutting-edge data acquisition technologies, and human/machine workflows to support wildfire mitigation and compliance. In 2021, IIP analyzed over 400 thousand images for fire risks utilizing AI damage detection models in support of the DIAR program. IIP also developed in-house capabilities to upload, store, and retrieve LiDAR project files, which is being utilized as part of SDG&E's ongoing HFTD LiDAR data capture.

7.1.6 GIS Layer Showing Wildfire Risk

F. Provide a GIS layer[45] showing wildfire risk (e.g., MAVF); data should be as granular as possible.

The geospatial map file is titled:

2022_02_05_SDGE_2022_WMP Update_GIS Layer_71F.zip

7.1.7 GIS Layers for Grid Hardening Initiatives

G. Provide GIS layers[46] for following grid hardening initiatives: covered conductor installation;[47] undergrounding of electrical lines and/or equipment; and removal of electrical lines. Features must have the following attributes: state of hardening, type of hardening where known (i.e., undergrounding, covered conductors, or removal), and expected completion date. Provide as much detail as possible (circuit segment, circuit level, etc.). The layers must include the following:

a. Hardening planned for 2022
b. Hardening planned for 2023
c. Hardening planned for 2024

The geospatial map file is titled:

[45] GIS data that has corresponding feature classes in the most current version of Energy Safety GIS Data Reporting Standard will utilize the format for submission. GIS data that does not have corresponding feature classes shall be submitted in an ESRI compliant GDB and include a data dictionary as part of the metadata.

[46] Energy Safety acknowledges potential security concerns regarding aggregating and presenting critical electrical infrastructure in map form. Utilities may provide maps or GIS layers required by these Guidelines as confidential attachments when necessary.

[47] For a definition of "covered conductor installation" see Section 9 of Attachment 2.

2022_02_05_SDGE_2022_WMP Update_GIS Layer_7G.zip

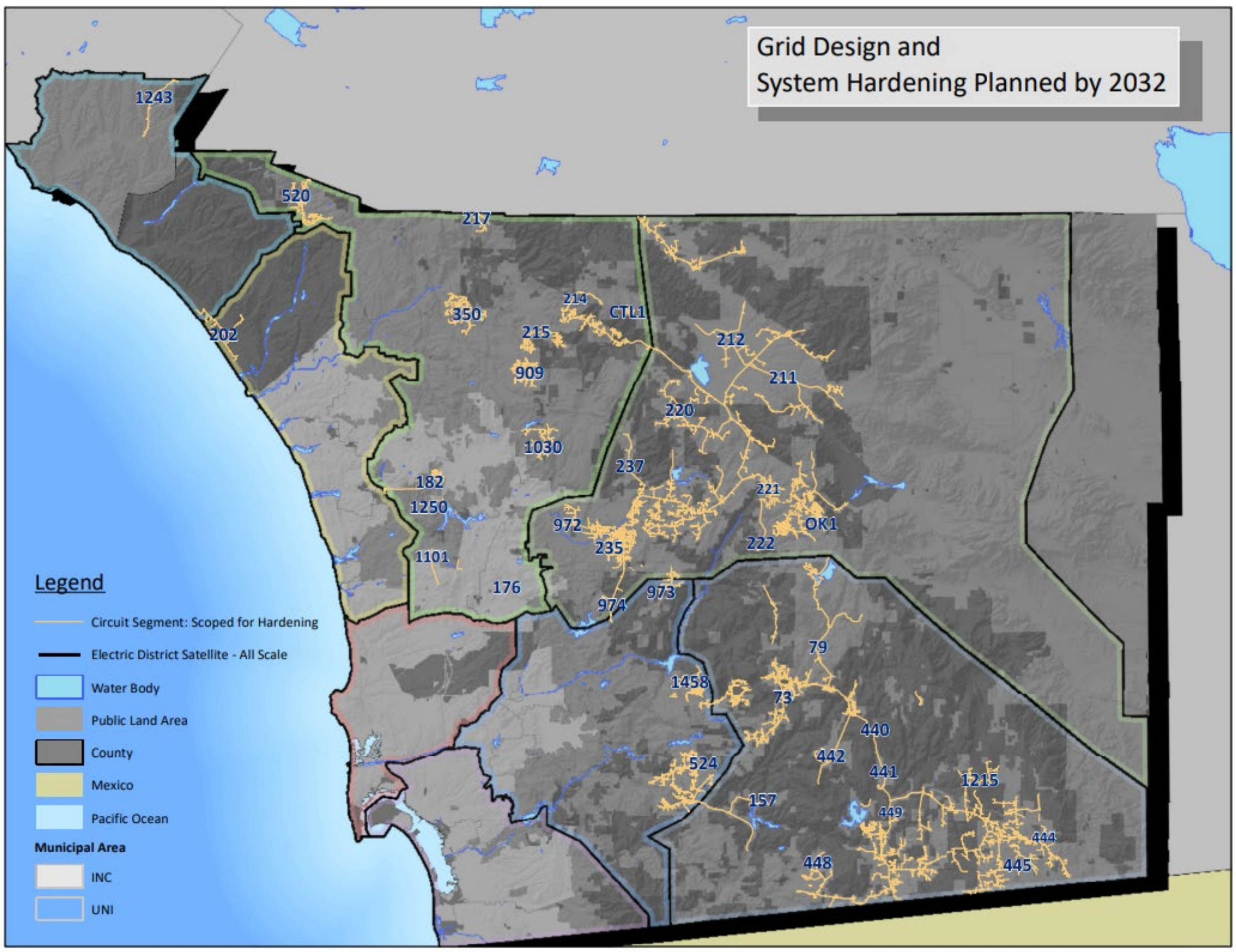
Hardening planned for 2024 includes 100 miles of covered conductor and 150 miles for strategic undergrounding. Because 2024 work is in the process of being scoped, precise planning locations are modelled, with the understanding that they may change.

7.1.8 Maps with Prioritization of Grid Design and System Hardening Initiatives

H. Provide static (either in text or in an appendix), high-level maps of the areas where the utility will be prioritizing Grid Design and System Harding initiatives for 2022, 2023, and by 2032.

Figure 7-1 shows Grid Design and System Hardening planned through 2032.

Figure 7-1: Grid Design and System Hardening planned by 2032



7.1.9 GIS Layer for Planned Asset Management and Inspections

I. Provide a GIS layer for planned Asset Management and Inspections in 2022. Features must include the following attributes: type, timing, and prioritization of asset inspection. Inspection types must follow the same types described *in Section 7.3.4, Asset Management and Inspections, and as applicable, should not be limited to patrols and detailed inspections.*

The geospatial map files are titled:

2022_02_05_SDGE_2022_WMP Update_GIS Layer_71I_Distribution.zip

2022_02_05_SDGE_2022_WMP Update_GIS Layer_71I_Transmission.zip

7.1.10 GIS Layer Illustrating Enhanced Clearances

J. Provide a GIS layer illustrating where enhanced clearances (12 feet or more) were achieved in 2020 and 2021, and where the utility plans to achieve enhanced clearances in 2022. Feature attributes must include clearance distance greater than or equal to 12 feet, if such data is available, either in ranges or as discrete integers (e.g., 12-15 feet, 15-20 feet, etc. OR 12, 13, 14, 15, etc.)

The geospatial map file is titled:

2022_02_05_SDGE_2022_WMP Update_GIS Layer_71J.zip

7.2 Wildfire Mitigation Plan Implementation

Describe the processes and procedures the electrical corporation will use to do all the following:

7.2.1 Monitor and Audit WMP Implementation

A. Monitor and audit the implementation of the plan. Include what is being audited, who conducts the audits, what type of data is being collected, and how the data undergoes quality assurance and quality control.

The electrical corporations' implementation of their WMPs is monitored through the OEIS Quarterly Initiative Update (QIU), QDR, Quarterly Notification Letter (QNL), Annual Changer Order Reports, bi-weekly meetings with Energy Safety's Compliance Division, and the annual WMP Update filing. In addition, SDG&E's Wildfire Mitigation business unit, in collaboration with other SDG&E business units, implemented metric dashboards which monitor key mitigation initiatives. The dashboards track actuals against initiative targets and indicate if a program is on track, complete, or delayed. A weekly report summarizing the dashboards is provided to stakeholders, including senior management. Any items not on track are brought to the attention of the Fire Directors for resolution.

A WMP DGF was established to define a repeatable set of standards, policies, processes, and controls for wildfire-related data associated with WMP initiatives. Business units who contribute data to the WMP measures and metrics are required to document their compliance with the DGF on an annual basis. The DGF includes the following policies: Data Definition, Data Collection, Data Processing, Data Storage and Retention, Data Access, and Data Quality.

On a bi-annual basis, SDG&E conducts audits on each business unit contributing data and assisting with the implementation of the WMP to assess if DGF controls were designed appropriately and if they are operating effectively. A significant amount of information is collected during the DGF audits which may include data dictionaries and taxonomies, standard operating procedures, access control matrices, reporting processes, and quality control procedures. These audits identify control issues and business enhancements which provide recommendations for management and corrective actions. The DGF compliance documentation and audits are conducted by a third party, independent auditor.

The WMP DGF includes a specific Data Quality policy addressing accuracy, completeness, timeliness, integrity, and authorization of the data through the data life cycle. Each business unit is required to document their compliance with this policy and provide evidence of quality assurance and quality controls during the DGF audits completed. The WMP data assurance and quality processes and controls cover a broad scope of procedures completed by employees and independent contractor auditors that complete inspections in the field.

In addition to the DGF audits, the WMP business units and related data are audited by other external regulatory agencies such as California Independent System Operator (CAISO) and by the Sempra Energy Audit Services department (Audit Services).

Audit Services uses a "risk-based" approach to determine the areas in which an internal audit will be conducted, as well as the extent and frequency of internal audits. The annual audit plan is based on an assessment of risk and exposures facing the organization. Audit Services uses various information sources in its risk assessment including internal knowledge and expertise, interviews with executive and director-level management, and coordination with company risk management functions to identify potential enterprise-wide, business unit, and process-level risk factors. An audit plan is created annually and reported to the Audit Committee.

SDG&E management is provided a report of the audit findings along with recommended management corrective actions (MCAs). The audit report and related MCAs are tracked by Audit Services for satisfactory completion. A monthly report is sent by Audit Services to maintain management's attention on issues until they are resolved.

7.2.2 Identify and Correct any Deficiencies in the WMP or its Implementation

B. Identify any deficiencies in the plan or the plan's implementation and correct those deficiencies

SDG&E believes that its WMP is a comprehensive, robust, and strategic guide to help reduce the potential for catastrophic wildfires caused by electrical infrastructure and protect the safety of its customers, workforce, and the communities served. To that end, the WMPs should not be seen as a static document, but subject to refinement and revision consistent with developments and improvements in data and information. SDG&E continues to innovate and look for further opportunities to enhance and refine its wildfire mitigation initiatives.[48]

In accordance with Public Utilities Code (PUC) Section 8389(a), SDG&E's 2021 WMP Update was evaluated by the CPUC's WSD. During the evaluation process, the WSD functions transitioned to the OEIS under the California Natural Resources Agency on July 1, 2021. The OEIS issued a Final Action

[48] In its evaluation of SDG&E's 2021 WMP Update, the WSD determined there were deficiencies. These are discussed in Section 4.6.

Statement addressing SDG&E's 2021 WMP Update identifying areas of significant progress and eleven key areas for improvement and remedies. SDG&E submitted a remediation plan to the Final Action Statement on November 1, 2021, which is summarized in Section 4.6 Progress Reporting on Key Areas of Improvement, including progress on each improvement area.

7.2.3 Monitor and Audit Effectiveness of Inspections

> *C. Monitor and audit the effectiveness of inspections, including inspections performed by contractors, carried out under the plan and other applicable statutes and commission rules.*

For electric asset inspection and maintenance programs, once inspections and repairs are reported as complete, an audit is conducted to ascertain the effectiveness of the inspections. This audit is managed by the Operation and Engineering managers who are responsible for each operating district. Auditors randomly select 1.5 percent of combined (overhead and underground) electric inspections and assess their conditions to see if the appropriate improvements have been properly carried out.

Multiple QA/QC programs monitor and audit the effectiveness of inspection programs, including LiDAR inspections (Section 7.3.4.7 LiDAR inspections of distribution electric lines and equipment and 7.3.4.8 LiDAR inspections of transmission electric lines and equipment), HFTD Tier 3 inspections (Section 7.3.4.9.1 HFTD Tier 3 distribution pole inspections), and drone assessments (Section 7.3.4.9.2 Drone assessments of distribution infrastructure). See referenced sections for information relating to the effectiveness of inspections completed.

A third-party contractor performs quality assurance audits of all vegetation management activities to measure work quality, contractual adherence, compliance, and to determine the effectiveness of each component of the Vegetation Management Program. Audits are performed by Certified Arborists using a representative 15 percent sample of completed work for all activities. Because audits are performed after the activities are completed, audits on activities that occur later in the calendar year are audited the following year. Table 7-3 shows the number of audits performed in 2020 and 2021 for the pre-inspection activity and for enhanced tree trimming. The average audit rate in 2020 and 2021 was 14.5 percent and 12.4 percent respectively. The audit rate for work performed in 2021 will increase as more audits are performed in early 2022.

Table 7-3: Audit Rate for Vegetation Management Activities

	2020		2021	
	Units Audited	Audit Rate	Units Audited	Audit Rate
Pre-Inspection	68,100	14.1%	70,627	14.1%
Enhanced Tree Trim	27,911	15.0%	18,602	10.7%
Average Audit Rate		**14.5%**		**12.4%**

Additionally, Vegetation Management attempts to audit 100 percent of all completed tree trimming work resulting from the additional off-cycle inspections performed on all trees located within the HFTD. This target may not be achieved in some instances due to inaccessibility of worksites. During the tree trimming audit activity a 100 percent inspection of all lines is also performed within the Vegetation Management Areas (VMAs) in the HFTD to ensure compliant conditions until the next routine-scheduled pre-inspection activity.

In addition to these internal audits, in 2020 the WSD Compliance Branch begun auditing both SDG&E's completed electric distribution asset work and Vegetation Management Program.

Audit Services may also audit inspection activities within an audit based on the outcome of audit planning.

7.2.4 Ensure Format Report Consistency

> *D. Ensure that across audits, initiatives, monitoring, and identifying deficiencies, the utility will report in a format that matches across WMPs, Quarterly Reports, Quarterly Advice Letters,[49] and annual compliance assessment.*

SDG&E implemented several processes to ensure audits, initiatives, monitoring, and identification of deficiencies are in a format that can be tracked against WMPs, QDR, QNLs, and annual compliance assessments.

This WMP follows the OEIS WMP Guidelines and Performance Metrics Data template. Using a master metric definition user guide, each performance metric is assigned a unique metric ID, along with a version, to track data sources, definitions, and logic year over year. Additionally, each metric is mapped to a DGF which outlines who is responsible for the data ownership and how the data is governed. When deficiencies are identified, they are mapped to the relevant WMP section for remediation.

7.3 Detailed Wildfire Mitigation Programs

> ***Instructions:*** *In this section, describe how specific wildfire and PSPS mitigation initiatives execute the strategy set out in Section 5. The initiatives are divided into 10 categories, with each providing a space for narrative descriptions of the utility's initiatives. The initiatives are organized by the following categories provided in this section:*
>
> 1. *Risk assessment and mapping*
> 2. *Situational awareness and forecasting*
> 3. *Grid design and system hardening*
> 4. *Asset management and inspections*
> 5. *Vegetation management and inspections*
> 6. *Grid operations and protocols*
> 7. *Data governance*
> 8. *Resource allocation methodology*
> 9. *Emergency planning and preparedness*
> 10. *Stakeholder cooperation and community engagement*
>
> *It is not necessary for a utility to have every initiative listed under each category*

[49] General Rule for filing Advice Letters are available in General Order 96-B: https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M023/K381/23381302.PDF

Financial Data on Mitigation Initiatives

> ***Instructions:*** *Report actual and projected WMP expenditure, as well as the risk-spend-efficiency (RSE), for each initiative by HFTD tier (territory-wide, non-HFTD, HFTD zone 1, HFTD tier 2, HFTD tier 3) in Table 12 of Attachment 3.*

Attachment B, Table 12 describes financial data on mitigation initiatives. If an actual is substantially different from the projected (greater than 10 percent difference), the corresponding metric is highlighted in light green.

Detailed Information on Mitigation Initiatives by Category and Activity

> ***Instructions:*** *Report detailed information for each initiative. For each initiative, organize details under the following headings:*
>
> *1. Risk to be mitigated / problem to be addressed*
>
> *2. Initiative selection ("why" engage in initiative) – include reference to and description of a risk informed analysis and/or risk model on empirical (or projected) impact of initiative in comparison to alternatives and demonstrate that outcomes of risk model are being prioritized*
>
> *3. Region prioritization ("where" to engage initiative) – include reference to a risk informed analysis in allocation of initiative (e.g., veg clearance is done for trees tagged as "high-risk") and demonstrate that high-risk areas are being prioritized*
>
> *4. Progress on initiative since the last WMP submission and plans, targets, and/or goals for the current year*
>
> *5. Future improvements to initiative – include known future plans (beyond the current year) and new/novel strategies the utility may implement in the next 5 years (e.g., references to and strategies from pilot projects and research detailed in Section 4.4).*
>
> *List of initiative activities by category - Detailed definitions for each mitigation initiative are provided in the appendix.*

7.3.1 Risk Assessment and Mapping

SDG&E continues to develop its risk assessment and mapping models and is refining a primarily automated risk assessment and mapping methodology. The aim of the risk assessment effort is to quantify the risk of wildfire and the impacts of PSPS events more effectively to identify optimal solutions that target risk reduction of both elements across the system. Working with Technosylva and others, SDG&E is implementing innovative approaches to leverage these models for the evaluation of hardening projects and for the safe operation of the system. Proposed grid hardening projects and emergency actions are also evaluated and prioritized from the standpoint of reducing or eliminating fire risk potential from overhead electric facilities and reducing the impact of PSPS to customers.

7.3.1.1 A summarized risk map showing the overall ignition probability and estimated wildfire consequence along electric lines and equipment

1. Risk to be mitigated

Without sufficient awareness, it is difficult to target long-term system hardening efforts to the areas of greatest wildfire risk. This awareness also aids in identifying the risk and impacts of potential fires of consequence that could occur in the service territory, which requires sufficient data.

2. Initiative selection

To mitigate the problem, several models were developed to enhance awareness and inform work.

WRRM and WRRM-Ops

The WRRM model was developed in collaboration with fire behavior experts and leverages 30 years of high-resolution weather data to establish climate scenarios and failure rates of SDG&E's assets, establishing risk maps showing the overall ignition probability and estimated wildfire consequence along electric lines and equipment. This model was further enhanced into an operational system, WRRM-Ops, by developing a fully-automated process to ingest daily weather and fuel moisture data and to re-calculate risk levels to support emergency operations.

SMEs, including fire coordinators and fire scientists, analyze the model's performance for all wildfires on the landscape, identifying deviations from the risk and propagation modeling. These findings drive future development of the model and will result in more specific quantifiable outcomes, allowing for better decision making in the overall hardening effort. See Section 4.5.1.3 Wildfire Risk Reduction Model and 4.5.1.4 Wildfire Risk Reduction Model – Operations for details on WRRM and WRRM-Ops.

WiNGS-Planning and WiNGS-Ops

The WiNGS-Planning model was developed to aid with the allocation of grid hardening initiatives across HFTD segments based on an assessment of both wildfire risk and PSPS impacts. WiNGS-Planning is built upon the MAVF framework in RAMP and evaluates both wildfire and PSPS impacts at the sub-circuit/segment level. Information is used to inform investment decisions by determining and prioritizing mitigation based on RSEs, improving wildfire safety, and limiting the impact of PSPS on customers. Additionally, WiNGS-Ops model, a real-time risk assessment model, helps quantify the wildfire risk and PSPS risk in real-time as a function of wind and provides a range of wind gusts where the fire risk is likely greater than the PSPS risk based on a wind curve. This information will provide an additional data point for consideration during PSPS events. See Section 4.5.1.7 Wildfire Next Generation System-Planning and 4.5.1.8 Wildfire Next Generation System-Operations for details on WiNGS-Planning and WiNGS-Ops.

Probability of Ignition (PoI)

In 2021, more granular PoI models at the asset and ignition source level were developed in collaboration with the FS&CA department and Technosylva, who helped gather data on significant ignitions, ignition sources, and weather. These include models that capture the ignition risk associated to specific ignition drivers, including conductor failure, vegetation contact, balloon contact, vehicle contact, and animal contact. The PoI models are built upon outputs from two separate models, PoF and conditional PoI_F. The PoI models also take into account failure-related data sets to compute the component PoF model, such as outage history and equipment failures. The models are developed at the span level and are additionally aggregated to the segment/sub-circuit level for available analysis at multiple levels of granularity. This level of granularity will provide an understanding of the different ignition risk drivers, assisting in the selection of mitigation measures and effective operational decision making. See Section 4.5.1.1 POI Model for further details on these models.

Risk Reduction Estimation Methodology

This initiative does not have a Risk Reduction Estimation because it is considered foundational to supporting wildfire mitigation efforts. Quantifying a Risk Reduction Estimation would be difficult and not beneficial because it cannot be directly tied to reducing a risk driver and measuring the effectiveness of that reduction. Instead, this initiative supports various mitigation efforts by providing better information to make risk-informed mitigation decisions

3. Region prioritization

WRRM and WRRM-Ops were developed for the entire service territory. The models are now being deployed by other utilities broadly across the state of California, enhancing the information available for making decisions on whether and how to update the models. The WiNGS-Planning model was developed for Tier 2 and Tier 3 of the HFTD service territory and for circuit-segments with historical PSPS event occurrences, to focus on the highest wildfire and PSPS risk areas. WiNGS-Ops and PoI were developed to be utilized across the entirety of the service territory, as needed.

4. Progress on initiative

WRRM and WRRM-Ops

Enhancements and progress made in 2021 include:

- Updated the software platform to increase ease of use
- Updated the LFM data in the model to improve consequence modeling
- Updated the fire growth algorithms to improve the accuracy of consequence modeling

Enhancements planned for 2022 include:

- Upgrade fuel moisture inputs into the fire behavior modeling
- Upgrade the forecaster interface
- Incorporate the data into a PSPS decision support tool

WiNGS-Planning and WiNGS-Ops

Enhancements and progress made to WiNGS in 2021 include:

- Began automation of WiNGS-Planning
- Developed proof of concept tool to visualize WiNGS-Planning and enable interactive scenario analysis
- Developed WiNGS-Ops

Enhancements planned for 2022 include:

- Complete WiNGS-Planning automation
- Develop user interface/visualization tool for WiNGS-Planning
- Improve WiNGS-Planning and WiNGS-Ops model with new data and models such as PoI models
- Develop visualization (PoC) tool for WiNGS-Ops
- Integration of Technosylva and weather data in WiNGS-Ops

PoI

To address the OEIS Action Statements regarding Risk Assessments and Mapping,[50] SDG&E developed PoI models to better understand and predict ignitions from various sources. These models will improve the way in which ignition sources are accounted for in decision-making models such as WiNGS-Planning (Section 4.5.1.7 Wildfire Next Generation System-Planning) and WiNGS-Ops (Section 4.5.1.8 Wildfire Next Generation System-Operations). Enhancements and progress made to PoI in 2021 include:

- Developed a model to predict conductor-related failures and ignitions
- Developed preliminary models for predicting ignitions from vehicle contacts, vegetation contacts, animal contacts, and balloon contacts
- Initiated the migration of the balloon contact model to the cloud
- Integrated the Conductor model into the PSPS dashboard

Enhancements planned for 2022 include:

- Continue iteration and improvement of PoI models
- Migration of models to the cloud
- Initiation of third-party review of the models

Consistency of Risk Modeling Amongst Electrical Corporations

With respect to ongoing collaboration amongst the utilities to increase consistency of wildfire risk modeling, in response to Action Statement SDG&E 21-01, the utilities are collaborating through the working group with Energy Safety and stakeholders and have already dedicated and will continue to dedicate substantial time and resources to the working group. The utilities believe that there will be increased transparency for Energy Safety and stakeholders through the working group process.

On November 17, 2021, December 8, 2021, and January 12, 2022, meetings were held to discuss fire consequence, likelihood of asset risk events and ignitions, and likelihood of vegetation risk events and ignitions, respectively. Energy Safety provided an agenda before each meeting which listed discussion topics and tentative time allotments. The meetings followed the agenda in a “Question and Answer” discussion format with utility SMEs.

The utilities look forward to future sessions with Energy Safety and stakeholders to promote continued collaboration, incorporate additional expert input, and increase transparency in order to help better realize our shared goal of reducing wildfire and PSPS risks.

Refer to Section 4.6 Progress Reporting on Key Areas of Improvement and Attachment D for Detailed Progress Report on Key areas of Improvement.

Actual performance for 2021 and targets for 2022 for this initiative are provided in Attachment B, Table 12.

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[50] See Section 4.6 for the response to Action Statement SDGE 21-01 (Inadequate transparency in accounting for ignition sources in risk modeling and mitigation selection) regarding transparency of ignition sources.

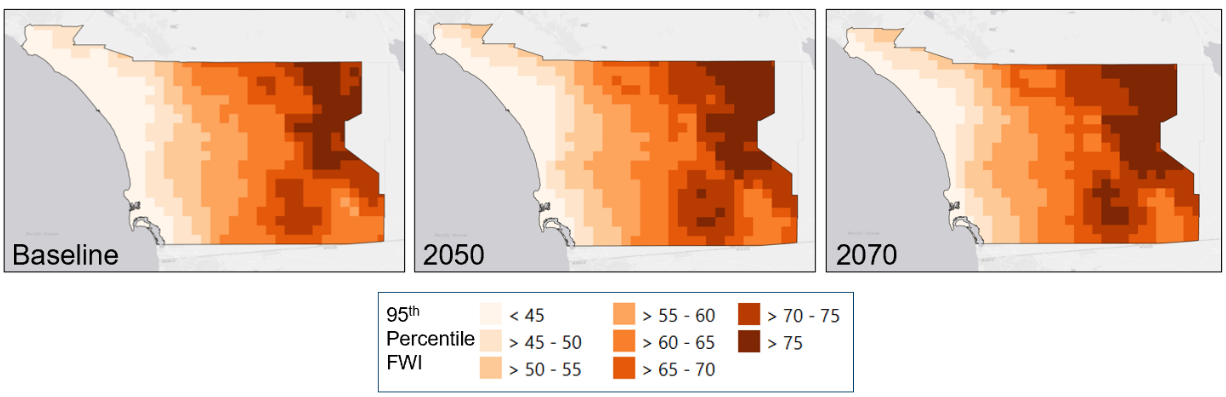
5. Future improvements to initiative

SDG&E strives to further enhance the risk assessment processes and tools through development of more granular machine learning PoI models, improvement of existing consequence and expected outcome models, expansion of modeling to further assets and failure modes, and further enhancement of PSPS modeling. All wildfire risk modeling will be migrated into the cloud to enable the models to be more dynamic, flexible, granular, modular, scalable, and expandable. Automation of modeling across all models will be sought where possible, to increase frequency and efficiency of modeling updates.

7.3.1.2 Climate-driven risk map and modelling based on various relevant weather scenarios

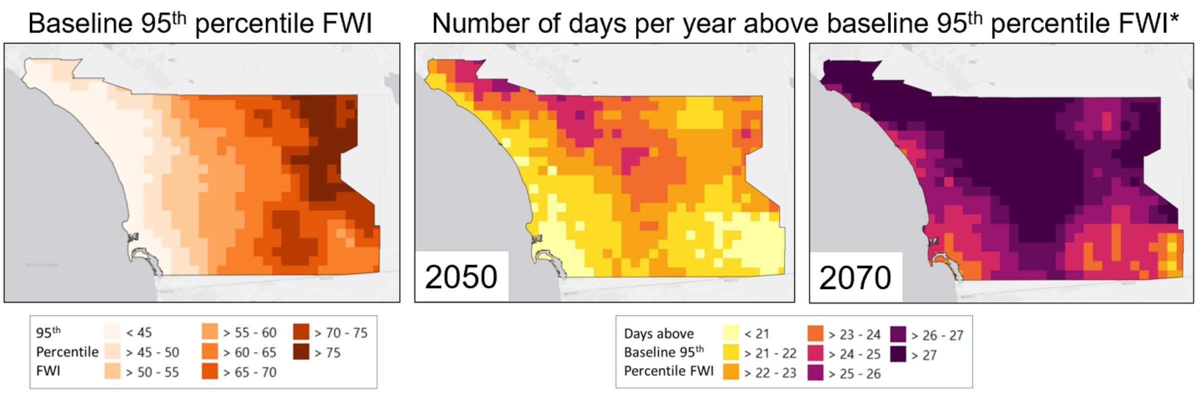
SDG&E is conducting a system-wide climate change vulnerability assessment looking at mid- and end-of-century climate change projections. As a part of this assessment, projected 95th percentile Fire Weather Index (FWI) values and the number of future days above the current baseline 95th percentile FWI are modeled (note that FWI values are unitless). Figure 7-2 and Figure 7-3 show maps outlining these projected changes.

Figure 7-2: Historical and Projected 95th Percentile FWI



Note that FWI is unitless

Figure 7-3: Projected Days Per Year Above Baseline 95th Percentile FWI



*Relative to 18 days per year during the baseline time period. Subtract 18 from projected day totals in the figures above to evaluate projected *increases* in the number of days above the baseline 95th percentile FWI.

7.3.1.3 Ignition probability mapping showing the probability of ignition along the electric lines and equipment

Ignition probability mapping is referenced within the PoI model.

Refer to Section 7.3.1.1. A summarized risk map showing the overall ignition probability and estimated wildfire consequence along electric lines and equipment and 4.5.1.1 POI Model for details on PoI.

7.3.1.4 Initiative mapping and estimation of wildfire and PSPS risk-reduction impact

Initiative mapping and estimation of wildfire and PSPS risk-reduction impact takes place within the WiNGS-Planning model.

Refer to Section 7.3.1.1 A summarized risk map showing the overall ignition probability and estimated wildfire consequence along electric lines and equipment and Section 4.5.1.7 Wildfire Next Generation System-Planning for details on WiNGS-Planning.

7.3.1.5 Match drop simulations showing the potential wildfire consequence of ignitions that occur along the electric lines and equipment

Match drop simulations are conducted within WRRM-Ops.

Refer to Section 7.3.1.1 A summarized risk map showing the overall ignition probability and estimated wildfire consequence along electric lines and equipment and Section4.5.1.4 Wildfire Risk Reduction Model – Operations for details on WRRM-Ops.

7.3.2 Situational Awareness and Forecasting

There is growing evidence that changing climate conditions are contributing to an increase in wildfire potential throughout California. As a result, SDG&E established the FS&CA in 2018. The FS&CA is comprised of meteorologists, community resiliency experts, fire coordinators, and project management personnel. Its purpose is responding to and strategizing for SDG&E's fire preparedness activities and programs.

In addition to providing subject matter expertise in meteorology, wildland fire coordination and response, and community resiliency, the FS&CA department is leading the creation of a FSI Lab that will bring together leading thinkers and problem solvers in academia, government, and the community to create forward-looking solutions to help prevent ignitions, mitigate the impacts of fires, and ultimately help build a more resilient region. See Section 4.4.1.1 Environmental Impacts of Wildfires vs Wildfire Mitigation Measures for details on the FSI Lab.

7.3.2.1 Advanced weather monitoring and weather stations

1. Risk to be mitigated

There is a lack of specific information regarding the location and severity of weather events that may impact SDG&E's system. Weather events have the potential to cause damage to electrical infrastructure, which may lead to an ignition.

2. Initiative selection

To increase situational awareness and obtain foundational data for operational and mission critical activities, SDG&E developed a Weather Station Network. Existing weather stations continue to be replaced and/or updated to improve weather data and ultimately provide more accurate forecasting. When developing the Weather Station Network, the alternative of using pre-existing weather stations was considered, however, the existing data generated did not have the granularity needed to support emergency operations during PSPS events.

<u>Risk Reduction Estimation Methodology</u>

This initiative does not have a Risk Reduction Estimation because it is considered foundational to supporting wildfire mitigation efforts. Because it cannot be directly tied to reducing a risk driver and therefore effectiveness cannot be measured, quantifying a Risk Reduction Estimation for such a mitigation would not be beneficial. Instead, this initiative supports various other initiatives by providing better information to make risk-informed mitigation decisions.

3. Region prioritization

Weather stations are placed throughout the territory with a focus on the HFTD. At least one station is associated with each circuit in the HFTD, with multiple stations on larger circuits. Region prioritization is also determined by the presence of strong winds and/or the ability to mitigate PSPS impacts.

4. Progress on initiative

Weather Station Network targets for 2021 were met and 2022 targets have been set.

Enhancements in 2022 will include:

- Add a second charging regulator to SCADA battery systems.
- Install additional sensors to better measure and validate fuel moisture conditions across the region

Actual performance for 2021 and targets for 2022 for this initiative are provided in Attachment B, Table 12.

5. Future improvements to initiative

Data intensive initiatives will be enhanced through additional information integration, automation, and strategic partnerships.

7.3.2.2 Continuous monitoring sensors

7.3.2.2.1 Air Quality Index

1. Risk to be mitigated

Particulates contained in wildfire smoke are hazardous to employees and the public. In addition, the Division of Occupational Safety and Health (Cal/OSHA) Protection from Wildfire Smoke Program (Title 8 CCR Section 5141.1) requires employers to notify employees when the AQI for Particulate Matter 2.5 microns or smaller in diameter ($PM_{2.5}$) exceeds 150 or exceeds 500 during wildfires.

2. Initiative selection

In order to mitigate this risk, the AQI Program will install particulate sensors and an automatic notification system. This program is built on the backbone of an existing best-in-class weather network. Real-time AQI values for townships in San Diego County will be available on the FS&CA App. The app will also have the option of sending alerts of poor air quality to personnel once dangerous levels are detected.

Currently, AQI is determined through manual collections performed by Safety team members. San Diego county has AQI monitoring stations, however, stations are limited in quantity and do not accurately represent the service territory. Additionally, AQI data published by the Environmental Protection Agency (EPA) and local air districts varies and is delayed.

<u>Risk Reduction Estimation Methodology</u>

This initiative does not have a Risk Reduction Estimation because it is considered foundational to supporting wildfire mitigation efforts. Quantifying a Risk Reduction Estimation would be difficult and not beneficial because it cannot be directly tied to reducing a risk driver and measuring the effectiveness of that reduction. Instead, it supports various initiatives by providing better information to make risk-informed mitigation decisions

3. Region prioritization

Locations in the HFTD areas are prioritized for sensor installation.

4. Progress on initiative

Enhancements and progress made in 2021 include:

- Completed sensor selection and purchased 6 AQI sensors. The sensors interface with the Weather Station Network.

- Selected six company locations for the initial program (Ramona, Kearny, El Cajon, Avocado substation, Valley Center substation, and Cameron substation).

Enhancements in 2022 include:

- Provide training on sensor calibration and maintenance
- Install AQI sensors at key locations
- Develop and implement a notification system
- Procure 12 additional sensors

5. Future improvements to initiative

Future improvements include expansion of the AQI Program in collaboration with local air districts to improve public safety and an EOC overlay interface to assist with employee/public safety and wildfire restoration staging area selection. The AQI Program will eventually expand to cover 18 locations.

7.3.2.2.2 Satellite-Based Remote Sensing

1. Risk to be mitigated

Wildfires continue to increase in frequency and intensity across the region. Fires need to be identified and suppressed as quickly as possible to mitigate potential impacts.

2. Initiative selection

Even though population density and a robust camera network of over 100 mountain top cameras enables near real-time reporting of fire ignitions in the SDG&E service territory, more can be done to achieve continuous situational awareness of this threat.

The SSEC at the University of Wisconsin-Madison is a world-class archive of satellite data, receiving, archiving, and redistributing most geostationary weather satellite data produced globally. SSEC and SDG&E partnered to increase situational awareness of wildfire ignitions in the service territory. In 2021, GOES 16/-17 and the ABI were utilized to operationalize fire detection and characterization at a spacial resolution of 2 km and temporal resolutions of 5 minutes, in some circumstances 1 minute or faster. FDC is accomplished with the WFABBA adopted for ABI-class sensors. Hotspots are rated in six fire categories based on confidence in the FRP, size, and temperature estimates.

In partnership with the SDSC, space-based fire alerts are sent to SDSC in real time where they are archived and processed for relevance within established boundary conditions and filtered for false positives. The ignition data is then sent to SDG&E as an email with a link to a web-based map of the area with camera images auto triangulated on the fire.

<u>Risk Reduction Estimation Methodology</u>

This initiative does not have a Risk Reduction Estimation because it is considered foundational to supporting wildfire mitigation efforts. Quantifying a Risk Reduction Estimation would be difficult and not beneficial because it cannot be directly tied to reducing a risk driver and measuring the effectiveness of that reduction. Instead, it supports various initiatives by providing better information to make risk-informed mitigation decisions.

3. Region prioritization

Satellite-based alerts are used to monitor the service territory with a focus on the HFTD.

4. Progress on initiative

Satellite-based alerts were implemented in 2021, achieving the goal for the initiative. In 2022, a continued effort to coordinate the alerts with the ground-based camera network will be pursued.

5. Future improvements to initiative

As technological advancements permit, SDG&E plans to update algorithms in cooperation with the University of Wisconsin to better measure and validate fire ignitions across the region to further understand the effects on wildfire ignition.

7.3.2.3 Fault indicators for detecting faults on electric lines and equipment

1. Risk to be mitigated

When a system failure occurs, the precise area of the failure needs to be determined in order to restore power. Additionally, operational measures initiated during times of elevated or extreme wildfire risk, such as the disabling of automatic reclosing and the use of sensitive and fast protection settings that limit the heat energy produced by a fault, increase the duration of outages due to a lack of circuit coordination that makes faults and damaged assets more difficult to locate.

2. Initiative selection

To mitigate this risk, SDG&E established the WFI Program. WFIs are a proven, cost-effective technology that helps determine where a system failure has occurred so search areas can be identified and crews can be dispatched.

If an outage occurs during a time of heightened wildfire risk, all infrastructure is patrolled for damage prior to restoring power. In instances where large areas are de-energized due to sensitive protective relay settings, WFIs are used to concentrate focus on a smaller portion of the electric circuit, which allows for a faster response in the event of an ignition; a greater chance of determining and correcting a fault cause when damage on the overhead electric system is not immediately obvious; and potentially faster power restoration which could offset customer reliability impacts caused by wildfire mitigation measures.

<u>Risk Reduction Estimation Methodology</u>

To calculate the benefits of WFIs, the 5-year customer minute impacts of risk event data set was used (see Table 7 in Attachment B). The average duration and customer impact was calculated for Tier 3 HFTD, Tier 2 HFTD, and non-HFTD. The installation of WFIs was assumed, by SME's, to reduce the duration of an outage by 10 minutes. Customer minutes were calculated using the 10-minute reduction per outage. Customer minutes are then converted to annual SAIDI and the savings per HFTD Tier were calculated. Finally, the number of WFI circuit installations was compared to the number of total installations to assess what percentage of benefits would be realized in the 2020-2022 period of the plan. The total SAIDI benefit of WFI's for the WMP timeframe is estimated at 0.734 SAIDI minutes.

A summary of the calculation is shown in Table 7-4.

Table 7-4: Risk Reduction Estimation for the WFI Program

5-year total SAIDI Non-HFTD	25.75
5-year total SAIDI Tier 2	8.73
5-year total SAIDI Tier 3	5.08
5-year total SAIDI Non-HFTD with WFIs	24.28
5-year total SAIDI Tier 2 with WFIs	8.38
5-year total SAIDI Tier 3 with WFIs	4.89
SAIDI Minutes saved Non-HFTD	25.75 – 24.28 = 1.47
SAIDI Minutes saved Tier 2	8.73-8.38=0.35
SAIDI Minutes saved Tier 3	5.08-4.89=0.19
Circuits Non HFTD	1437
Circuits Tier 2	300
Circuits Tier 3	173
Circuits planned for WFIs (2020-2022) Non HFTD	186
Circuits planned for WFIs (2020-2022) Tier 2	300
Circuits planned for WFIs (2020-2022) Tier 3	173
SAIDI minutes saved Non-HFTD	1.47 x 186/1437 = 0.19 minutes
SAIDI minutes saved Tier 2	0.35 x 300/300 = 0.35 minutes
SAIDI minutes saved Tier 3	0.019 x 173/173 = 0.019 minutes
Total SAIDI minutes saved	0.19+0.35+0.019 = 0.734 minutes

3. Region prioritization

Results of sensitive relay outages are routinely reviewed to identify where new WFIs are most needed, with a focus on the HFTD. The program began by targeting Tier 3 installations, followed by Tier 2, and then expanding into the non-HFTD WUI. Typically, WFIs are placed on bifurcations in the system or midway on a section of conductor that does not have SCADA devices to provide real-time notification of loss of current or faults downstream. For example, a location where a feeder splits but only has a SCADA switch in one direction downstream. In this case, adding WFIs to the conductors in the other direction will provide information on faults occurring on all conductors downstream. WFIs are also placed at locations where facilities enter areas of high fuel concentrations, areas that are difficult to patrol, or transitions between HFTD tiers. Overhead to underground and underground to overhead unfused transitions and downstream of non-SCADA substations are also locations that benefit from the placement of WFIs.

4. Progress on initiative

The WFI Program has met its targets for 2021 and has set targets for 2022. In 2022, the Program will expand into the WUI.

Actual performance for 2021 and targets for 2022 for this initiative are provided in Attachment B, Table 12.

5. Future improvements to initiative

As technology changes and new innovations are introduced into the industry, SDG&E will continue to evaluate products to enhance its system and potentially incorporate new devices with optimum features. Such new devices may lead to modifications and a request for future installations.

7.3.2.4 Forecast of a fire risk index, fire potential index, or similar

7.3.2.4.1 Fire Potential Index

1. Risk to be mitigated

In order to promote safety and reliability, the year-round wildfire risk needs to be understood to better inform daily operations.

2. Initiative selection

To mitigate this risk, the FPI model was developed to calculate the wildfire potential on any given day, assisting in safe and reliable operations. It establishes daily operating conditions (i.e., Normal, Elevated, Extreme, and RFW), which inform operational decisions such as recloser settings, restrictions on the type of work being performed in high-risk locations, and the use of contract firefighting resources (CFRs). It is also used as an input for PSPS decision making. See Section 4.5.1.5 Fire Potential Index for details on the FPI.

<u>Risk Reduction Estimation Methodology</u>

This initiative does not have a Risk Reduction Estimation because it is considered foundational to supporting wildfire mitigation efforts. Quantifying a Risk Reduction Estimation would be difficult and not beneficial because it cannot be directly tied to reducing a risk driver and measuring the effectiveness of that reduction. Instead, it supports various initiatives by providing better information to make risk-informed mitigation decisions.

3. Region prioritization

The FPI generates wildfire potentials throughout the service territory, with a focus on high-risk areas.

4. Progress on initiative

Enhancements and progress made in 2021 include

- Completed an operational update that included an adjustment to the weather matrix which determines the overall weather component (dryness and winds).
- Conducted an analysis with a Capstone Team at the SDSC to look at the variables incorporated into the FPI and future opportunities for enhancements. Future variables that would continue to refine the FPI could include solar radiation and fuel temperatures.

In 2022 partnerships with academia will continue to work to advance fire science and weather science.

5. Future improvements to initiative

Operational decision making will continue to integrate of the FPI in operations in order to mitigate wildfire potential. Additionally, the accuracy and efficacy of the model will continue to be improved.

7.3.2.4.2 Santa Ana Wind Threat Index

1. Risk to be mitigated

In order to operate reliably and safely, the year-round wildfire risk needs to be understood to better inform daily operations.

2. Initiative selection

To mitigate this risk, the SAWTI was developed to calculate the potential for large wildfire activity based on strength, extent, and duration of wind, dryness of air, dryness of vegetation, and greenness of grasses. The SAWTI provides a greater understanding of the risk of a potential ignition growing into a catastrophic wildfire by looking historically at all Santa Ana winds. The SAWTI is shared with fire agencies and the general public through the Predictive Services Unit at the U.S. Forest Service. See Section 4.5.1.6 Santa Ana Wildfire Threat Index for details on the SAWTI.

Risk Reduction Estimation Methodology

This initiative does not have a Risk Reduction Estimation because it is considered foundational to supporting wildfire mitigation efforts. Quantifying a Risk Reduction Estimation would be difficult and not beneficial because it cannot be directly tied to reducing a risk driver and measuring the effectiveness of that reduction. Instead, it supports various initiatives by providing better information to make risk-informed mitigation decisions.

3. Region prioritization

The SAWTI generates data for all of southern California.

4. Progress on initiative

No significant changes were made to the SAWTI model in 2021, though the data delivery process to the U.S. Forest Service was modernized. In 2022, the resolution of the modeling used to generate the SAWTI will be increased, which will require re-coding of the software that processes the weather and fuels data.

5. Future improvements to initiative

SDG&E will continue to work with academia and the fire agencies to further develop fire science for integration into SAWTI.

7.3.2.4.3 High-Performance Computing Infrastructure

1. Risk to be mitigated

Models that have been developed to mitigate wildfire risk require an increasing number of compute cores to run in a timely manner to support utility operations.

2. Initiative selection

To address this issue, high-performance computing clusters generate high-quality weather data that is incorporated directly into operations. Collectively, nearly 2,000 compute core hours of high-performance computing are used per day to generate operational products, including the SAWTI, FPI, and WRRM-Ops. The forecast data generated by these supercomputers is shared with researchers and various stakeholders, including the U.S. Forest Service, which disseminates the data through their public website and the National Weather Service. APIs enable public access to WMP-related datasets by authorized users for use in fire modeling.

<u>Risk Reduction Estimation Methodology</u>

This initiative does not have a Risk Reduction Estimation because it is considered foundational to supporting wildfire mitigation efforts. Quantifying a Risk Reduction Estimation would be difficult and not beneficial because it cannot be directly tied to reducing a risk driver and measuring the effectiveness of that reduction. Instead, it supports various initiatives by providing better information to make risk-informed mitigation decisions.

3. Region prioritization

The HPCCs integrate data from across the service territory and generate forecasts for the entire service territory.

4. Progress on initiative

No changes were made to the HPCCs in 2021. In 2022, two new HPCCs will be added.

Actual performance for 2021 and targets for 2022 for this initiative are provided in Attachment B, Table 12.

5. Future improvements to initiative

SDG&E will continue the production and sharing of forecast products as well as the prioritization of data analytics and modeling. Working with the SDSC, data science advancements will be monitored to ensure that this technology can provide the advanced analytics required to maximize operations.

7.3.2.5 Personnel monitoring areas of electric lines and equipment in elevated fire risk conditions

1. Risk to be mitigated

The problem this initiative addresses is the lack of real-time situational awareness, especially during elevated fire risk conditions.

2. Initiative selection

To mitigate this risk, observers are deployed to the field during high-risk situations. In addition to monitoring weather conditions from the Weather Station Network, input from the field is an important factor when considering the potential need for PSPS. In advance of each high-risk fire weather event, SMEs provide a list of areas within the service territory where the combination of high winds and vegetation could lead to potential threats to public safety. These areas are prioritized for placing observers. Throughout the duration of a high-risk event, observers are moved and deployed to areas where winds are shown to be increasing according to the Weather Station Network.

Risk Reduction Estimation Methodology

Since this activity is part of a high-risk weather event response, the Risk Reduction Estimation is grouped with PSPS events and mitigation of PSPS impacts (see Section 7.3.6.6 PSPS events and mitigation of PSPS impacts).

3. Region prioritization

Observers are placed throughout the service territory as informed by the FPI and other models and based on wildfire risk, with a focus on the HFTD.

4. Progress on initiative

The process of sending observers into the field was improved in 2021 through the introduction of tablets with digital maps for field personnel to use during patrols and observations. These digital maps allow the user to zoom in and obtain more detail on the circuits when performing their patrols. This also cuts down on time when shifting from one circuit to the next as the users don't need to report back to the operating center to retrieve new paper maps. Additional consistencies in updating these digital maps and enhancements to field navigation will be reviewed for implementation in 2022.

5. Future improvements to initiative

SDG&E will continue to integrate the latest risk assessments and scientific understanding to the deployment of observers during high-risk events to try to place observers in the best place to mitigate risk.

7.3.2.6 Weather forecasting and estimating impacts on electric lines and equipment

See Section 7.3.2.4 Forecast of a fire risk index, fire potential index, or similar.

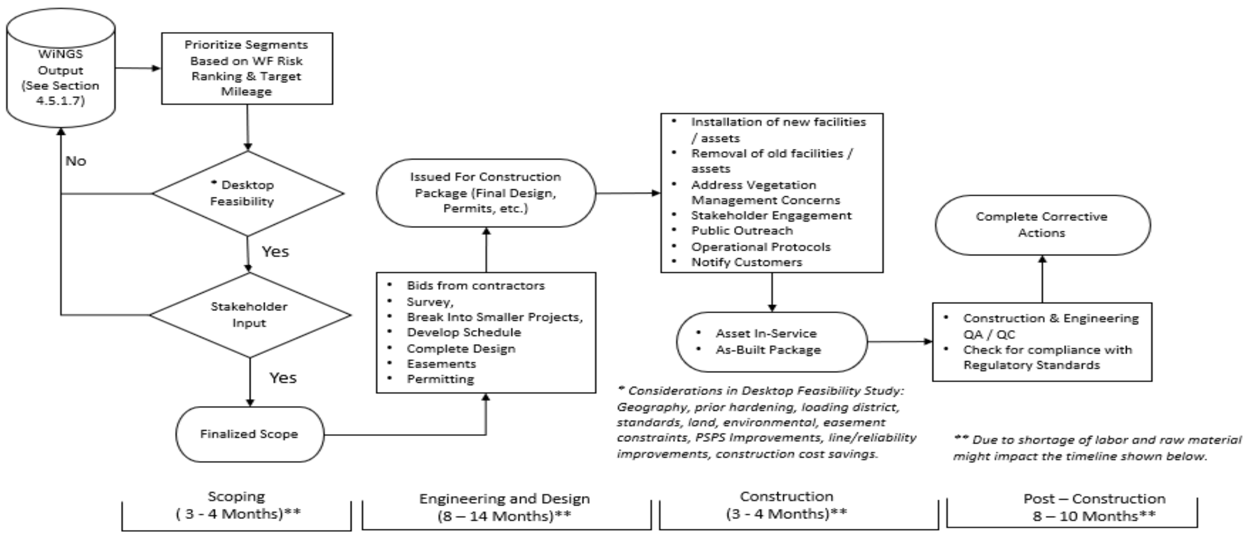
7.3.3 Grid Design and System Hardening

SDG&E's grid hardening programs are aimed at reducing wildfires caused by utility equipment and minimizing impacts to customers from mitigations such as PSPS. Protection and equipment programs including advanced protection, the expulsion fuse replacement program, and the lightning arrestor program do not prevent risk events from occurring, but instead reduce the chance that a risk event will result in an ignition by utilizing protection settings and/or equipment that addresses a specific failure mode known to lead to the ignition. Other programs reduce PSPS impacts to customers, including the PSPS sectionalizing program, microgrid and generator programs. Strategic undergrounding—a system hardening effort—reduces the need for mitigations such as PSPS while also reducing the risk of utility caused wildfires.

Figure 7-3 shows the flowchart for the Grid Hardening decision tree, highlighting how WiNGS-Planning is used to inform scoping, selection, and implementation of underground and covered conductor projects. Traditional hardening areas are descoped through modeling and review processes. See section 4.5.1.7 Wildfire Next Generation System-Planning for details on WiNGS-Planning and Section 4.5.1.8 Wildfire Next Generation System-Operations for details on WiNGS-Ops.

Figure 7-4: Grid Hardening Flowchart

Grid Hardening (Decision Tree)



Grid Hardening: Scoping, Engineering & Design and Construction		
Step #	**Workflow Steps**	**Description**
1	WiNGS Output	See Section 4.5.1.7
2	Prioritize Segments Based on WF Risk Ranking & Target Mileage*	This kicksoff the Scoping phase of the project. The scoping team receives a summary spreadsheet of relevant WiNGS information for each circuit segment. These segments are ranked by Wildfire Risk. The order of segments identifies the riskiest segments, and these are selected first to apply the mitigation. Additional segments in that circuit with WiNGS solutions are brought into scope. To meet annual target mileage the quantity of existing hardening projects and known constraints are accounted for.
3	** Desktop Feasibility	Once the segments and mitigation types are known, the circuits are edited in our Future Scope App and this tool is used to evaluate the feasibility of the selected mitigation and determine ideal routes. In this stage we consider geography, prior hardening, loading district, standards, land, environmental, easement constraints, PSPS Improvements, line/reliability improvements, construction cost savings. This is also where stakeholder feedback is gathered and incorporated.
4	Stakeholder Input	In this stage the scope is reviewed by stakeholders within SDG&E. This is the opportunity for other operations, engineering, and planning teams to provide comments and design inputs on the proposed scope.
4	Finalized Scope	The scoped circuits in the Future Scope App are finalized and the team produces the Design Input Transmittal (DIT) which includes a summary of stakeholder inputs, a scoping map, a pole list, shapefiles, and KMZ files of the project for the design and engineering teams.
5	• Bids from contractors • Survey, • Break Into Smaller Projects, • Develop Schedule • Complete Design • Easements • Permitting	This kicksoff Engineering & Design phase of the project. During this phase, finalized scope is received to get the project on track for construction. This starts by getting survey (if required) and engineering & design bids. Once these contracts are awarded, the PPM group is engaged to develop schedules. Land and environmental input is incorporated into the design. The design goes through several iterations until it is suitable to construct. Land and environmental take these completed designs to obtain new easements and permits (if required).
6	Issued For Construction Package	Once the design package is complete, and all relevant permits and easements are obtained. The deliverables are then provided to the construction team.
7	• Installation of new facilities / assets • Removal of old facilities / assets • Address Veg Mgmt Concerns • Stakeholder Engagement • Public Outreach • Operational Protocols	This kicksoff the Construction phase of the project. The construction team fields the job to identify any errors / omissions, or any changes needed in the job package. Public outreach is done to notify customers regarding pending construction activities. Survey Staking is conducted. Short lead time material is placed on order. Vegetation management addresses access and clearance requirements to accommodate new construction. Civil construction starts pole hole, anchors, underground trench, conduits and sub structures. Customers are notified of pending outages and then electrical crew installs electrical equipment including pole, conductor, cable, anchors, guys, equipment (transformers, fuses, capacitors, regulators, etc.). Lastly the old equipment is removed.
8	• Asset In-Service • As-Built Package	The asset is placed in service. Construction team completes As-Built package that documents what is installed. Additionally, for overhead construction projects, external construction team will provide their own QA/QC documentation.
9	• Construction & Engineering QA / QC • Check for compliance with Regulatory Standards	For overhead construction projects, post construction inspection is performed by SDG&E QA/QC inspection team consisting of qualified electrical workers. In parallel, post construction LiDAR survey is performed on the overhead construction projects. Post engineering analysis is performed (aka true up) to check to compliance with GO 95 standard requirements.
10	Complete Corrective Actions	Post construction inspection findings are remediated.

7.3.3.1 Capacitor maintenance and replacement program

1. Risk to be mitigated

Current capacitors are designed to provide continuous voltage and power factor correction for the distribution system. During a failure of a capacitor from either mechanical, electrical, or environmental overstress, an internal fault is created resulting in internal pressure and the potential to rupture the casing. This rupture of molten metal has the potential to be an ignition source. Capacitor faults are currently protected through fusing, which is not always effective at preventing this high-risk failure from becoming an ignition source.

2. Initiative selection

To mitigate this risk, the SCADA Capacitors Program was developed to replace existing non-SCADA capacitors with a more modern SCADA switchable capacitor or to remove non-SCADA capacitors if not required for voltage or reactive support. These modernized capacitors have a monitoring system to check for imbalances and isolate internal faults before they become catastrophic. In addition, SCADA capacitors have the capacity for remote isolation and monitoring of the system which provides additional situational awareness during extreme weather conditions. The SCADA Capacitors Program prioritizes replacing or removing fixed capacitors from service and then addresses capacitors with switches. Both types of capacitors will be modernized to a SCADA switchable capacitor. While this program will not reduce capacitor faults, the advanced protection equipment is designed to detect and isolate issues before a capacitor rupture occurs, reducing the failure mode most likely to lead to an ignition.

<u>Risk Reduction Estimation Methodology</u>

Capacitors currently cause an average of 0.2 ignitions annually in the HFTD based on ignition data from 2015-2019. It is estimated that the SCADA Capacitors Program will reduce capacitor-caused HFTD ignitions by an estimated 0.16 per year. This estimate is derived by evaluating historical data on faults that could cause ignitions to determine ignition rates and estimating a reduction in ignition rates as a result of capacitor replacements.

A summary of the risk reduction estimation methodology is provided in Table 7-5.

Table 7-5: Risk Reduction Estimation for SCADA Capacitors Program

Risk Events Tier 3 (average 2015 – 2019)	0.4
Risk Events Tier2 (average 2015 – 2019)	0.8
Risk Events Non-HFTD (average 2015-2019)	7.6
Average Ignition Rate Tier 3	2.69%
Average Ignition Rate Tier 2	3.29%
Average Ignition Rate Non-HFTD	1.46%
Effectiveness Estimate	80%
Ignition Reduction Estimate Tier 3	0.4 x 2.69% x 80% = 0.0086
Ignition Reduction Estimate Tier 2	0.8 x 3.29% x 80% = 0.021

Ignition Reduction Estimate Non-HFTD	7.6 x 1.46% x 80% = 0.089
Total Capacitors	101
Capacitors in the Tier 3 HFTD (2020-2022)	41
Capacitors in the Tier 2 HFTD (2020-2022)	48
Capacitors in the Non-HFTD WUI (2020-2022)	12
Ignitions reduced Tier 3 HFTD	0.0086 x (41 ÷ 101) = 0.0035
Ignitions reduced Tier 2 HFTD	0.021 x (48 ÷ 101) = 0.010
Ignitions reduced Non-HFTD	0.089 x (12 ÷101) = 0.011
Ignitions reduced	0.0035 + 0.010 + 0.011 = 0.024

3. Region prioritization

SDG&E plans to remove or replace all non-SCADA capacitors within the WUI and HFTD, prioritizing Tier 3, followed by Tier 2, and then proceeding to the WUI.

4. Progress on initiative

The SCADA Capacitors Program is meeting its targets for 2021 and has set targets for 2022. No changes were made to this Program in 2021 and none are expected to be made in 2022.

Actual performance for 2021 and targets for 2022 for this initiative are provided in Attachment B, Table 12.

5. Future improvements to initiative

SCADA capacitors will be monitored to ensure effectiveness of reducing ignition risk and to improve equipment as necessary if issues are identified. As more work is done to understand the risk in the WUI, the program could potentially expand to those areas.

7.3.3.2 Circuit breaker maintenance and installation to de-energize lines upon detecting a fault

See Section 7.3.4.15 Substation inspections.

7.3.3.3 Covered conductor installation

1. Risk to be mitigated

SDG&E operates and maintains nearly 3,500 miles of overhead distribution circuit miles within the HFTD. This infrastructure was originally designed to meet GO 95 requirements of an 8 pounds-per-square-foot (psf) or 55 mph transverse wind load for elevations below 3,000 ft and 6 psf or 48 mph transverse wind load with a half inch of radial ice on conductor for elevations above 3,000 feet. With the effects of climate change and changing conditions in the service territory, wind speeds can reach 85 mph to 111 mph in certain areas of the HFTD during extreme Santa Ana conditions. Aging infrastructure, combined with these extreme weather conditions, can increase the possibility of equipment failure on these lines. Further, high winds and outdated design techniques make these lines more vulnerable to foreign object in line contacts, both risk events that could lead to ignitions.

2. Initiative selection

To mitigate this risk, SDG&E has three main hardening programs: bare conductor hardening, which has been the most historically utilized mitigation; strategic undergrounding, which began in 2019; and the Covered Conductor Program. Alternatives to covered conductor installation include undergrounding and bare conductor hardening.

Covered conductor is a widely accepted term to distinguish from bare conductor. The term indicates that the installed system utilizes conductors manufactured with an internal semiconducting layer and external insulating ultraviolet-resistant layers to provide incidental contact protection. The Covered Conductor Program has the potential to raise the threshold for PSPS events to higher wind speeds compared to bare conductor hardening; however, as of the end of 2021 the threshold for PSPS events has not been raised on any circuits with covered conductor installed as there have not yet been any circuit segments fully hardened with covered conductor. The WiNGS-Planning model is utilized to both evaluate mitigation alternatives and prioritize the deployment of mitigations at the circuit segment level (see Section 4.5.1.7 Wildfire Next Generation System-Planning for details on WiNGS-Planning).

<u>Risk Reduction Estimation Methodology</u>

Over the 3-year period of the 2020 WMP cycle, covered conductor is expected to reduce 0.21 ignitions annually. This estimate is derived by evaluating different causes of ignitions using 5-year ignition data from 2015-2019 and estimating a potential reduction in each cause based on estimates of effectiveness of covered conductor (e.g., ignitions caused by animal contact, balloon contact, and vegetation contact have an estimated reduction of approximately 90 percent while ignitions caused by vehicle contact have an estimated reduction of 0 percent). This results in an overall estimated effectiveness of 65 percent. This is described in further detail in Section 4.6 Progress Reporting on Key Areas of Improvement and Attachment H the joint IOU response to Action Statement SDGE-21-03.

A summary of the risk reduction estimation methodology is provided in Table 7-6.

Table 7-6: Risk Reduction Estimation for Covered Conductors

Pre-mitigation risk events per 100 miles Tier 3	6.48
Pre-mitigation risk events per 100 miles Tier 2	7.02
Effectiveness Estimate	64.50%
Post-mitigation risk events per 100 miles Tier 2	6.48 - (64.5% x 6.48) = 2.3
Post-mitigation risk events per 100 miles Tier 4	7.02 - (64.5% x 7.02) = 2.49
Ignition rate in Tier 3	2.69%
Ignition rate in Tier 2	3.29%
Pre-mitigation Tier 3 ignitions per 100 miles	6.48 x 2.69% = 0.17
Pre-mitigation Tier 2 ignitions per 100 miles	7.02 x 3.29% = 0.23
Post-mitigation Tier 3 ignitions per 100 miles	2.3 x 2.69% = 0.06
Post-mitigation Tier 2 ignitions per 100 miles	2.49 x 3.29% = 0.08
Ignitions reduced in Tier 3 per 100 miles	0.17 - 0.06 = 0.112

Ignitions reduced in Tier 2 per 100 miles	0.23-0.08 = 0.15
Miles of mitigation in Tier 3 (2020-2022)	59.455
Miles of mitigation in Tier 2 (20202-2022)	22.895
Ignitions reduced in Tier 3 Post Mitigation	59.455 x (0.112 ÷ 100) = 0.07
Ignitions reduced in Tier 2 Post Mitigation	22.895 x (0.15 ÷ 100) = 0.034
Total Ignition Reduction Estimate	0.07 + 0.034 = 0.104

3. Region prioritization

Covered conductors are installed in the HFTD. However, given the significant mileage that exists, RSE calculations developed in the WiNGS-Planning model are utilized to prioritize installation within the HFTD. For further discussion regarding the prioritization of covered conductor, see response to Action Statement 21-10 in Section 4.6 Progress Reporting on Key Areas of Improvement and Attachment E.

4. Progress on initiative

The Covered Conductor Program meet its targets for 2021 and has set a target of 60 miles for 2022.

In 2021 SDG&E participated in the covered conductor effectiveness workstream in collaboration with other utilities. The goal of the workstream collaboration is to provide an initial common effectiveness value for covered conductor and a long-term plan to continually update the data sets that inform this value in the respective WMPs. Progress is also expected on comparing covered conductor to alternatives, determining covered conductor's ability to reduce the need for PSPS (in comparison to alternatives), and developing an initial assessment of the differences in costs. For further discussion regarding the effectiveness of covered conductor, see response to Action Statement 21-03 in Section 4.6 Progress Reporting on Key Areas of Improvement and Attachment H.

Actual performance for 2021 and targets for 2022 for this initiative are provided in Attachment B, Table 12.

5. Future improvements to initiative

As covered conductor becomes a larger part of the system, SDG&E will continue to monitor and measure performance indicators that impact the efficacy of this mitigation, including the measured effectiveness (number of faults per operating year per mile relative to the unhardened system averages) and the cost per mile. SDG&E will also continue to participate in the joint IOU covered conductor workstreams to further develop the estimated and calculated effectiveness of covered conductor.

7.3.3.4 Covered conductor maintenance

See Section 7.3.4.1 Detailed inspections of distribution electric lines and equipment for information on the maintenance of distribution overhead equipment. SDG&E's inspection programs are structure based. When an inspection is performed on a structure, the inspector is will review the condition of the structure and all associated equipment (crossarms, transformers, switches, etc.)

7.3.3.5 Crossarm maintenance, repair, and replacement

See Corrective Maintenance Program inspections in Section 7.3.4.1 Detailed inspections of distribution electric lines and equipment. SDG&E's inspection programs are structure based. When an inspection is performed on a structure, the inspector is will review the condition of the structure and all associated equipment (crossarms, transformers, switches, etc.).

7.3.3.6 Distribution pole replacement and reinforcement, including with composite poles

1. Risk to be mitigated

Aging and/or damaged poles are at an increased risk of failure which may cause an ignition.

2. Initiative selection

To mitigate this problem, the Pole Replacement and Reinforcement Program replaces deteriorated wood distribution poles and other asset-related components identified through inspection programs (e.g., CMP and HFTD Tier 3 Inspections) in an effort to reduce the risk of ignitions. Replaced poles are constructed to SDG&E's improved site-specific design criteria (e.g., wood poles will be replaced with steel poles that meet the known local wind conditions of a particular area). PLS-CADD modeling is used to design pole replacement work in the HFTD. In addition, Pole Loading Calculations are reviewed by a designated engineering team.

For poles identified in Tier 3 of the HFTD, replacement is accelerated faster than the 6-month timeframe required by the CPUC's GO 95. In addition to poles, any other identified issues are remediated to clear potential infractions and vulnerabilities in the system. All pole replacements are audited by Civil/Structural Engineering. Any issues found are routed back to the district or contractor who performed the work for resolution.

<u>Risk Reduction Estimation Methodology</u>

This initiative does not have its own Risk Reduction Estimation Methodology because it is part of the various asset inspection programs. Risk Reduction Estimation Methodology for those programs are provided in Section 7.3.4 Asset Management and Inspections.

3. Region prioritization

The Pole Replacement and Reinforcement Program replaces poles and remediates other identified issues throughout the service territory as they are identified through various inspection programs, with a focus on expediting those in the HFTD.

4. Progress on initiative

The Pole Replacement and Reinforcement Program does not have specific targets set as all replacement work is reactive and based on findings from the various asset inspection programs in Section 7.3.4 Asset Management and Inspections. No changes were made to this Program in 2021 and none are expected to be made in 2022.

5. Future improvements to initiative

Mandated and enhanced inspection programs will continue over the next 10 years. Expected structure replacement forecasts are adjusted annually based on the latest inspection data results and the location and number of assets contained in specific inspection cycles.

7.3.3.7 Expulsion fuse replacement

1. Risk to be mitigated

When the distribution system experiences a fault or overcurrent, there are fuses connected to the system to protect its integrity and isolate the fault. These expulsion fuses are designed to operate by creating a significant expulsion within the fuse, resulting in the fuse opening and isolating the fault, and in turn limiting further damage to other equipment. Because of this internal expulsion, the fuses are equipped with a venting system that sends a discharge of energy out of the fuse and into the atmosphere. This external discharge has the potential to ignite flammable vegetation.

2. Initiative selection

To mitigate this risk, the Expulsion Fuse Replacement Program replaces existing expulsion fuses with new, more fire safe expulsion fuses that are approved by CAL FIRE. These new expulsion fuses reduce the discharge expelled into the atmosphere, reducing the chance of a fuse operation leading to an ignition. See Section 4.4.2.4 CAL FIRE Approved Expulsion Fuses vs Other Expulsion Fuses for research findings on CAL FIRE Approved Expulsion Fuses vs Other Expulsion Fuses.

<u>Risk Reduction Estimation Methodology</u>

Over the 3-year period of the 2020 WMP cycle, mitigation done by the Expulsion Fuse Replacement Program is expected to reduce ignitions by 0.52 annually. Based on preliminary study results (see Section 4.4.2.4), work done by the program to install CAL FIRE-approved fuses is 100 percent effective at reducing ignition risk. Because SDG&E plans to complete this mitigation, replacing all expulsion fuses within the HFTD by 2022, SDG&E estimates that all ignitions from this cause will be mitigated.

A summary of the risk reduction estimation methodology is provided in Table 7-7.

Table 7-7: Risk Reduction Estimation for the Expulsion Fuse Replacement Program

Expulsion Fuse Operation Tier 3 (5-year average)	80
Expulsion Fuse Operation Tier 2 (5-year average)	104.2
Average ignition rate Tier 3	0.11%
Average ignition rate Tier 2	0.11%
Pre mitigation ignitions Tier 3	80 x 0.11% = 0.088
Pre mitigation ignitions Tier 2	104.2 x 0.11% = 0.115
Number of fuses installed Tier 3 (2020-2022)	1,361
Number of fuses installed Tier 2 (2020-2022)	5,632
Fuses to be replaced Tier 3	1,573
Fuses to be replaced Tier 2	6,483

Ignition Reduced Tier 3	(1,361/1,573) x 0.088 = 0.076
Ignition Reduced Tier 2	(5,632/6,483) x 0.115 = 0.10
Ignition Reduction HFTD	0.076 + 0.10 = 0.176

3. Region prioritization

The Expulsion Fuse Replacement Program replaces fuses throughout the HFTD. Prioritization started with Tier 3 then moved to Tier 2. Due the high volume of replacements, projects are bundled based on geographic proximity for construction efficiency and to reduce outages when required.

4. Progress on initiative

The Expulsion Fuse Replacement Program has met the 2021 target. Installations in Tier 3 are 98 percent complete, and Tier 2 is 91 percent complete. Targets are set for 2022. No changes were made to this Program in 2021 and none are expected to be made in 2022.

Actual performance for 2021 and targets for 2022 for this initiative are provided in Attachment B, Table 12.

5. Future improvements to initiative

As technology changes and new innovative ideas are introduced into the industry, SDG&E will continue to evaluate products to enhance its system and potentially incorporate new devices that can improve performance. Such new devices may lead to modifications for future installations.

7.3.3.8 Grid topology improvements to mitigate or reduce PSPS events

7.3.3.8.1 PSPS sectionalizing enhancements

1. Risk to be mitigated

PSPS events can have negative customer impacts and should be limited as much as feasible to the specific areas that are experiencing the extreme risk. This is especially important for critical facilities providing firefighting resources and life-saving services for AFN customers who may require medical devices to be powered 24 hours a day, seven days a week. SDG&E initiates PSPS events as a last resort mitigation during extreme weather conditions, utilizing other tools to mitigate PSPS risk.

2. Initiative selection

To mitigate PSPS risk, the PSPS Sectionalizing Enhancement Program installs switches in strategic locations, improving the ability to isolate high-risk areas for potential de energization. For example, switches are installed on circuits that have significant sections undergrounded, allowing customers with this lower-risk infrastructure to remain energized during weather events. Another example is combining weather stations with sectionalizing devices to de-energize only sections of circuits that are experiencing extreme wind events.

<u>Risk Reduction Estimation Methodology</u>

Over the 3-year period of the SDG&E's 2020 WMP cycle, the PSPS Sectionalizing Enhancement Program has the potential to reduce PSPS impacts by a total of 28,147 customers. The total potential reduction represents 15,088 customers in 2020 and 8,111 customers in 2021, and an estimated 4,948 customers for the proposed 2022 projects.

These numbers were calculated per project by comparing the number of customers de-energized when the previously used PSPS device was in place with the number of customers de-energized when sectionalizing is completed. Because sectionalizing customer savings vary due to weather-dependency and resulting differences in switch plans, the effectiveness of this mitigation is estimated to be 50 percent.

3. Region prioritization

Historical PSPS data is used to identify and prioritize locations for switches. This typically means installing switches in the HFTD, however, as recent weather patterns have become more extreme and widespread, switches are placed in both the HFTD and the wildland urban interface.

4. Progress on initiative

The PSPS Sectionalizing Enhancement Program has met its targets for 2021 and has set targets for 2022. No changes were made to this Program in 2021 and none are expected to be made in 2022.

Actual performance for 2021 and targets for 2022 for this initiative are provided in Attachment B, Table 12.

5. Future improvements to initiative

SDG&E will continue the PSPS Sectionalizing Enhancement Program using additional data from any additional PSPS events with the goal of reducing PSPS impacts using the most relevant data

7.3.3.8.2 Microgrids

1. Risk to be mitigated

PSPS events can have negative customer impacts and should be limited as much as feasible to the specific areas that are experiencing extreme risk. This is especially important for critical facilities providing firefighting resources and life-saving services for and AFN customers who may require medical devices to be powered 24 hours a day, seven days a week. SDG&E initiates PSPS events as a last resort mitigation during extreme weather conditions, utilizing other tools to mitigate PSPS risk.

2. Initiative selection

To mitigate this risk, the Microgrid Program designs and builds microgrids that can be electrically isolated during a PSPS event, thereby maintaining electric service to customers who would otherwise be affected. While alternative hardening solutions, such as strategic undergrounding, may be better at simultaneously mitigating wildfire risk, those options are not always technically feasible or cost-effective. For instance, customers who are located far away from a substation or central source of generation would require additional mileage of undergrounding that can be cost-prohibitive. Additionally, undergrounding may not be feasible, whether due to hard rock, environmental, or cultural concerns.

Risk Reduction Estimation Methodology

Over the 3-year period of the SDG&E's 2020 WMP cycle, microgrids are expected to reduce PSPS impacts to a total of 662 customers. This number is calculated based on the locations of microgrids and the customers they serve and is used to estimate the reduction in PSPS impact to calculate the RSE (see Attachment B Table 12). Because microgrids are designed to keep customers energized throughout the duration of a PSPS event, the effectiveness of the mitigation is estimated to be 100 percent.

3. Region prioritization

A combination of data including the risk of wildfire from overhead infrastructure, feasibility of traditional overhead hardening solutions, alternative solutions such as undergrounding distribution infrastructure, and historical PSPS impact data is used to guide the installation of microgrids. Additional information such as identification of critical facilities or AFN customers is incorporated into prioritizing targeted locations for a potential microgrid project. The majority of microgrid installations are in the HFTD.

4. Progress on initiative

Enhancements and progress made in 2021 include:

- Completed temporary configuration (conventional generators) for four microgrids deployed in 2020. The permanent renewable solution is planned to be in service by early 2022, which will include Cameron Corners and Ramona Air Attack Base microgrids.
- Campo is a low-income community in Tier 3 of the HFTD and is home to a Feeding America distribution center that requires electricity to power the refrigeration of perishable food items. In 2021, The Feeding America center had a mobile battery storage solution implemented to avoid the impacts of PSPS events to this customer.
- Identified additional locations for further evaluation
    - Rincon Circuit 217 is an HFTD circuit that is frequently impacted by PSPS events. A new microgrid location that can reduce PSPS potential to 78 customers is being studied for potential implementation in 2023.
    - A microgrid location on Santa Ysabel Reservation is being developed that will reduce PSPS impacts to four customers is being studied for potential implementation in 2022.

Enhancements for 2022 will include:

- Completing the permanent renewable solution for the four microgrids deployed in 2020.
- Implementing the off grid (box power) solution for a cathodic protection water system that has a 2-mile line through the HFTD.
- Installing new non-toxic, non-flammable iron and saltwater batteries. These batteries will be 500 kWh per container, enhancing battery life compared to the current batteries.

Actual performance for 2021 and targets for 2022 for this initiative are provided in Attachment B, Table 12.

5. **Future improvements to initiative**

- Utilize the WiNGS-Planning model to explore potential use of segment-level risk analysis to inform identification of additional microgrid sites as a potential alternative to other initiatives such as grid hardening.
- Upgrade iron and saltwater batteries as new technology is developed. It is anticipated that they can be upgraded to 600 kWh, which will power microgrids for a longer period of time.

7.3.3.9 Installation of system automation equipment

1. **Risk to be mitigated**

SDG&E operates and maintains nearly 3,500 miles of overhead distribution circuit miles within the HFTD. This infrastructure was originally designed to meet GO 95 requirements of an 8 psf or 55 mph transverse wind load, however winds can reach 85 to 111 mph in certain areas of the HFTD during extreme Santa Ana conditions. Aging infrastructure also makes the remaining lines more suspectable to equipment failures and outdated design techniques makes these lines more vulnerable to foreign object in line contacts during high winds, all of which could lead to ignitions.

2. **Initiative selection**

The Advanced Protection Program (APP) develops and implements advanced protection technologies within electric substations and on the electric distribution system. It aims to prevent and mitigate the risks of fire incidents, provide better transmission and distribution sectionalization, create higher visibility and situational awareness in fire-prone areas, and allow for the implementation of new relay standards in locations where protection coordination is difficult due to lower fault currents attributed to high impedance faults.

More advanced technologies, such as microprocessor-based relays with synchrophasor/phasor measurement unit (PMU) capabilities, real-time automation controllers, auto-sectionalizing equipment, line monitors, direct fiber lines, and wireless communication radios comprise the portfolio of devices that are installed in substations and on distribution circuits to allow for a more comprehensive protection system and greater situational awareness in the fire-prone areas of the HFTD. Advanced technology protection systems implemented include:

- FCP designed to trip distribution and transmission overhead circuits before broken conductors can reach the ground energized
- Sensitive Ground Fault Protection for detecting high impedance faults resulting from downed overhead conductors that result in very low fault currents
- Sensitive Profile Relay Settings enabled remotely on distribution equipment during red flag events to reduce fault energy and fire risk
- High Accuracy Fault Location for improved response time to any incident on the system
- Remote Event Retrieval and Reporting for real-time and post-event analysis of system disturbances or outages
- SCADA Communication to all field devices being installed for added situational awareness.

- Increased Sensitivity and Speed of Transmission Protection Systems to reduce fault energies and provide swifter isolation of transmission system faults
- Protection Integration with DCRI as a means of facilitating the communication infrastructure needs
- EFD is a demonstration project that proactively monitors the distribution system to detect failing overhead equipment before it can permanently fail and cause an outage/ignition
- WDD is a demonstration project that assesses the effectiveness of software functionality to detect energized wire downs utilizing existing AMI data

The APP replaces aging substation infrastructure such as obsolete 138 kV, 69 kV, and 12 kV substation circuit breakers, electro-mechanical relays, and Remote Terminal Units (RTUs). New circuit breakers incorporating microprocessor-based relays, RTUs, and the latest in communication equipment are also installed in substations within the HFTD. On distribution circuits within the HFTD, APP coordinates with the overhead system hardening programs to strategically install or replace sectionalizing devices, line monitors, direct fiber lines, and communication radios to facilitate the requirements of SDG&E's advanced protection systems. These upgrades with increased sectionalization can also lead to reduced PSPS impacts. The reduction in PSPS impacts is directly related to the greater number of sectionalizing devices installed on the system as a part of this program. This reduces the customer counts between sectionalizing devices, which can reduce the number of customers de-energized during weather events.

<u>Risk Reduction Estimation Methodology</u>

FCP can sense a break in conductor and isolate a fault before it occurs and is focused on mitigating risk events associated with wire downs. To calculate the benefit of this mitigation, SDG&E utilized the 5-year average of wire down activities unmitigated by other mitigations such as hot line clamps, the ignition percentages within the Tier 2 and Tier 3 HFTD, and the percent of circuits that would be enabled with FCP by the end of the 2022 WMP period. This results in an expected 0.294 ignitions reduced per year based on the current deployment forecast after the 3-year period of the plan.

Details of the calculation are provided in Table 7-8.

Table 7-8: Risk Reduction Estimation for FCP

Tier 3 wire downs (2015-2019 average)	14.4
Tier 2 wire downs (2015 – 2019 average)	17.4
Wire down with connection failures Tier 3	4
Wire down with connection failures Tier2	3.5
Wire Down Mitigated Tier 3	14.4 - 4.0 = 10.4
Wire Down Mitigated Tier 2	17.4 - 3.5 = 13.9
Ignition rate Tier 3 (2015 – 2019 average)	2.69%
Ignition rate Tier 2	3.29%
Ignitions reduced Tier 3	10.4 x 2.69% = 0.280
Ignitions reduced Tier 2	13.9 x 3.29% = 0.457

Tier 3 circuits enabled (2020-2022)	18
Tier 2 circuits enabled (2020-2022)	0
Total Tier 3 circuits	28
Total Tier 2 circuits	54
Ignitions reduced Tier 3	(18 ÷ 28) x 0.28 = 0.294
Ignitions reduced Tier 2	(0 ÷ 54) x 0.457 = 0
Total Ignitions reduced	0.294 + 0 = 0.294

Reliability event data and ignition data is tracked for both transmission and distribution lines. The APP is designed to reduce the risk of transmission or distribution events leading to an ignition. To evaluate the effectiveness of this mitigation, SDG&E would expect to see the ratio of faults leading to ignition to decrease over time.

3. Region prioritization

The APP implements advanced protection technology throughout the service territory with a focus in the HFTD.

4. Progress on initiative

Enhancements and progress made in 2021 include

- Added WDD and EFD as demonstration projects

Enhancement in 2022 will include

- Expand the functionality of WDD and EFD demonstration projects based on initial results
- Enhance the coordination with expanding initiatives such as strategic undergrounding and covered conductor to refine scoping of APP circuits, thereby optimizing the deployment schedule for both Tier 2 and Tier 3.

Actual performance for 2021 and targets for 2022 for this initiative are provided in Attachment B, Table 12.

5. Future improvements to initiative

Beyond 2022, the APP will continue improving advanced protection technology, including expanding FCP to include two-phase and single-phase distribution circuits. The APP will also begin migrating new FCP communication designs, utilizing LTE communication to improve wireless network coverage, increase path resiliency, and optimize deployment cost.

Capitalizing on substation enhancements being made with new relays and communication via direct fiber, the Transmission Falling Conductor Protection (TFCP) will be deployed on transmission lines in the HFTD, with the goal of deployment on all single conductor HFTD transmission lines to reduce transmission-energized wire down wildfire risk.

7.3.3.10 Maintenance, repair, and replacement of connectors, including hotline clamps

1. Risk to be mitigated

Connectors that have been connected directly to overhead primary conductors, known as hotline clamps (HLCs), are associated with creating a weak connection which could result in a wire down event. This in turn could lead to an energized wire either coming into contact with the ground or a foreign object where it could become a source of ignition.

2. Initiative selection

To mitigate the problem, the HLC Replacement Program replaces HLC connections that are connected directly onto the overhead primary conductors with compression connections to eliminate the risk of the wire down failure and the associated wildfire risk.

<u>Risk Reduction Estimation Methodology</u>

To estimate the risk reduction, data from historical wire downs associated with connection failures, ignition percentages within the HFTD, and the amount of replacements expected completed by the end of 2022 was gathered. Using the calculations shown in Table 7-9, ignitions were shown to be reduced by 0.045 ignitions per year over the 3-year WMP period.

Table 7-9: Risk Reduction Estimation for the HLC Replacement Program

Tier 2 wire downs (2015-2019 average for connector failures)	1
Tier 3 wire downs (2015-2019 average for connector failures)	1.2
Ignition rate Tier 2 (2015 – 2019 average)	3.29%
Ignition rate Tier 3 (2015 – 2019 average)	2.69%
Total Hotline Clamps in the network Tier 2	5426
Total Hotline Clamps in the network Tier 3	3094
Hotline clamps replaced (2020-2022) Tier 2	5426
Hotline clamps replaced (2020-2022) Tier 3	1118
Ignition Reduced Tier 2	1 x (5426 ÷ 5426) x 3.29% = 0.033
Ignition Reduced Tier 3	1.2 x (1118 ÷ 3094) x 2.69% = 0.012
Ignition Reduced HFTD	0.033 + 0.012 = 0.045

3. Region prioritization

The HLC Replacement Program focuses on the HFTD portion of the service territory. Within the HFTD, Tier 3 is prioritized over Tier 2 areas. Due to the high volume of replacements, projects are bundled based on geographic proximity for construction efficiency and to reduce outages when required.

4. Progress on initiative

The HLC Replacement Program has met its targets for 2021 and has set targets for 2022. No changes were made to this Initiative in 2021 and none are expected to be made in 2022.

Actual performance for 2021 and targets for 2022 for this initiative are provided in Attachment B Table 12.

5. Future improvements to initiative

As new innovative ideas are introduced into the industry, SDG&E will continue to evaluate products to enhance its system and potentially incorporate new devices. Such new devices may lead to modifications for future installations.

7.3.3.11 Mitigation of impact on customers and other residents affected during PSPS events

7.3.3.11.1 Generator Grant Program

1. Risk to be mitigated

PSPS events can have negative customer impacts and should be limited as much as feasible to the specific areas that are experiencing the extreme risk. This is especially important for customers who may require medical devices to be powered 24 hours a day, 7 days a week. SDG&E initiates a PSPS event as a last resort mitigation during extreme weather conditions, utilizing other tools to mitigate risks associated with PSPS events.

2. Initiative selection

The GGP focuses on enhancing resiliency among the most vulnerable customer segments in the service territory. This program was previously referred to as the Resiliency Grant Program.

The GGP offers portable battery units with solar charging capacity to customers, leveraging cleaner, renewable generator options to give vulnerable customers a means to keep small devices and appliances charged and powered during PSPS events. The GGP, launched in 2019, focuses on the needs of MBL customers in addition to other customers with access and functional needs in Tiers 2 and 3 of the HFTD who have experienced a PSPS outage. In 2021, Eligible customers were proactively contacted and educated about the GGP.

In 2021, a reserve of backup batteries was established specifically for expedited delivery during active PSPS events. These units are pre-charged and delivered within 1-4 hours of eligible requests to customers who call into SDG&E's Customer Care Centers or 211 in need of emergency power backup that cannot be met through other AFN services such as hotel stays and accessible transportation. SDG&E also partnered with Indian Health Councils to promote the availability of these backup battery units to vulnerable customers in tribal nation communities.

To further support customers, the Resiliency Audit program was launched in 2021. Customers in the HFTD were invited to participate in an online survey to assess and enhance their readiness for potential PSPS shutoffs and evacuations. Based on their responses, customers receive information about backup power solutions and programs, as well as relevant preparedness resources from community partners including Red Cross, County of San Diego, and more.

<u>Risk Reduction Estimation Methodology</u>

Over the 3-year period of the 2020 WMP cycle, the GGP is expected to reduce PSPS impacts to a total of 6,730 customers. This number is calculated based on the count of customers likely to receive generators and is used to estimate the reduction in PSPS impact to calculate the RSE (see Attachment B Table 12). Because the generators provided to customers as a part of this program are not whole-facility solutions, the effectiveness of the mitigation is estimated to be 40 percent.

3. Region prioritization

Historical PSPS impact data guides which regions are targeted for resilience-focused solutions. Customers located in Tier 3 of the HFTD are the highest priority, followed by customers in Tier 2 of the HFTD, targeting those who have experienced PSPS events in prior years. Customers with other types of AFN and vulnerable customers within tribal communities are also prioritized.

4. Progress on initiative

Enhancements and progress made in 2021 include:

- Established a dedicated reserve of backup battery units to deliver during active PSPS events
- Targeted all MBL customers in HFTD Tier 2 and Tier 3 that experienced a PSPS event in either 2019 or 2020
- Established a streamlined process with the Indian Health Council to reach eligible customers in the tribal communities

Enhancement in 2022 will include:

- Strengthen the process of promoting participation and delivering resources in partnership with tribal community partners
- Develop plans to offer to additional AFN population and tribal communities

Actual performance for 2021 and targets for 2022 for this initiative are provided in Attachment B, Table 12.

5. Future improvements to initiative

The GGP will continue to focus on MBL customers and those on life support as the primary customer criteria, while expanding the reach to additional populations within the broader AFN community.

7.3.3.11.2 Standby Power Programs

1. Risk to be mitigated

PSPS events are utilized as a last resort mitigation during extreme weather conditions, however, PSPS events leave impacted customers without power.

2. Initiative selection

The Standby Power Programs target customers and communities that will not directly benefit from other grid hardening programs. These customers reside in the backcountry and are widely distanced from one another, so grid hardening initiatives will not reduce PSPS impacts. Currently, the Standby Power Programs consist of the Fixed Backup Power (FBP) Program and the Mobile Home Park Resilience Program (MHRP).

In 2020, SDG&E introduced the FBP Program, formally known as the Whole House Generator Program. This program assists backcountry residences, businesses, and local communities in the HFTD that may not benefit from near or long-term traditional hardening initiatives. Other hardening initiatives in these communities would be ineffective and costly, with no guarantee that powerlines would not be shut off during a PSPS event. Instead, providing standby generators is the most efficient remedy for certain rural customers that are likely to experience PSPS events.

Depending on site requirements, feasibility, and cost, a customer could receive a fixed installation backup generator, a business could receive a critical facility generator on a temporary basis during an active PSPS event (previously known as the Critical Facility Generator Program per the 2020 WMP), or a clubhouse or central community building at a mobile home park could receive a solar panel and battery backup system.

Risk Reduction Estimation Methodology

Over the 3-year period of the 2020 WMP cycle, the Standby Power Program is expected to reduce PSPS impacts for over 900 customers (See Section 8.3 Projected Changes to PSPS Impact). This number is calculated based on how many customers would receive generators and is used to estimate the reduction in PSPS impacts to calculate the RSE (see Attachment B Table 12). Because the generators provided to customers as a part of this program are whole-facility solutions that are expected to keep the customers energized throughout a PSPS event, the effectiveness of the mitigation is estimated to be 100 percent.

3. Region prioritization

Historical PSPS impact data guides which regions are targeted for resilience-focused solutions. Customers located in Tier 3 of the HFTD are the highest priority, followed by customers in Tier 2 of the HFTD. Additional priority is given to regions that are fed by circuits with higher historical PSPS impacts. Beginning in 2021, WiNGS-Planning is used to prioritize regions and specific customers based on risk profile and cost effectiveness of various solutions (see Section 4.5.1.7 Wildfire Next Generation System-Planning for more information on WiNGS-Planning).

4. Progress on initiative

Enhancements and progress made in 2021 include:

- 2021 was the first full year of program implementation.
- Program reached 86% of 2021 target goal (355 installed generators).
  - A total of 406 generators were set in the ground, with 355 completing the final safety inspection.
  - Generated a significant number of projects in the pipeline from 2021 that will be finalized in 2022.
- Streamlined residential permitting from 4-8 weeks to 3-4 weeks.
- Enhanced customer enrollment, project approval, and status tracking processes.
- Installation delays occurred due to supply chain issues and changes in local agency inspection standards.

Enhancements in 2022 will include:

- Continuing to reduce permitting times by beginning projects earlier in the year, learning and adjusting to the more stringent and increased safety standards, and building and maintaining relationships with the County to ensure a natural flow of communication.
- Continuing to streamline program planning by identifying a larger target audience and creating a marketing schedule to ensure customers are invited earlier and more often. Additionally, projects that began in 2021 will continue in early 2022.
- Collaborating with program contractor to codesign marketing material and customer information pieces, staff up certified installers to accommodate larger customer pipeline, and sending project leads earlier and more often.
- Developing a customer survey to better understand customer needs and potential gaps in program experience.
- Utilizing WiNGS-Planning to prioritize regions and specific customers.

Actual performance for 2021 and targets for 2022 for this initiative are provided in Attachment B, Table 12.

5. Future improvements to initiative

SDG&E will continue to explore enhancements of customer initiatives through evaluation of customer feedback and lessons learned. Additionally, SDG&E will dive into the complexities of this new program by identifying and further understanding the bottlenecks of the program process. SDG&E will also continue to streamline and eliminate manual processes while ensuring compliant operations and better project tracking. Lastly, as mentioned above, SDG&E will continue to build and maintain relationships with the County to ensure better understanding of permitting procedures.

7.3.3.11.3 Generator Assistance Program

1. Risk to be mitigated

PSPS events are utilized as a last resort mitigation during extreme weather conditions, however, PSPS events leave impacted customers without power.

2. Initiative selection

The Generator Assistance Program (GAP) focuses on enhancing resiliency for all customers who reside in the HFTD and may be impacted by PSPS events. While the Generator Grant Program addresses the needs of the most medically vulnerable and Standby Power Programs focus on customers that do not have other grid hardening initiatives planned in their area, GAP expands resilience opportunities to the general market in the HFTD and beyond. This program was previously referred to as the Resiliency Assistance Program.

The GAP was launched in 2020 and is the first ever program to offer point-of-sale rebates for portable generators. Using a similar model to Energy Efficiency rebates offered on customer programs promoting products like programmable thermostats, the GAP offers rebates for a wide array of dual-fuel (gas-propane) portable generators and portable power stations that are available in local “big box” stores. To streamline the process, customers who are invited to the program can download a coupon online, choose a retailer, then choose between direct delivery to their home, order with store pickup, or standard in-store shop and purchase.

The program offers a $300 rebate to customers who meet the basic eligibility criteria of residing in an HFTD zone and experiencing a recent outage. In addition, for CARE customers meeting these criteria, an enhanced rebate amount of $450 is offered, providing a 70 to 90 percent discount on average portable generator models.

In 2021, the GAP was marketed to customers in the HFTD who had experienced a PSPS event in either 2019 or 2020. Through a series of email and letter invitations to customers in the summer and fall of 2021, customers were educated, engaged, and offered new options to enhance their own personal emergency preparedness plans for PSPS events.

<u>Risk Reduction Estimation Methodology</u>

Over the 3-year period of the SDG&E's 2020 WMP cycle, the GAP is expected to reduce PSPS impacts to a total of 3,290 customers. This number is based on how many customers are expected to purchase generators through the rebate program and is used to estimate the reduction in PSPS impact to calculate the RSE (see Attachment B Table 12). Because generators purchased through this program vary depending on the customer's preferences, the effectiveness of the mitigation is estimated to be 75 percent.

3. Region prioritization

Historical PSPS impact data guides which regions are targeted for resilience-focused solutions. Customers located in Tier 3 of the HFTD are the highest priority, followed by customers in Tier 2 of the HFTD. Additional priority is also given to well pump customers.

4. Progress on initiative

Enhancements and progress made in 2021 include:

- Provided 735 rebates in 2021, exceeding the updated target of 600.
- Reduced 2021 target from 1250 to 600 in OEIS Change Order Report based on program participation trends.
- Determined program performance was reduced due to fewer PSPS events.
- Deployed targeted marketing during early forecast stages of November PSPS event to ensure impacted customers had program information as the event was activated.
- Expanded program eligibility and marketing to include well pump customers.
- Updated product qualification list to include more generators and portable power stations to the program.
- Resolved point-of-sale rebate system issue impacting customer rebate redemption process.

Enhancements in 2022 will include:

- Continue to evaluate rebate process options to maximize customer options and program quality assurance ensure program customers options to customers.

- Identify additional portable battery and power station options for the program.
- Continue pursuing additional marketing and outreach channels.

Actual performance for 2021 and targets for 2022 for this initiative are provided in Attachment B, Table 12.

5. Future improvements to initiative

SDG&E will continue to pursue new ways to educate and inform customers about the Generator Assistance Programs and will continue to refine programs.

7.3.3.12 Other corrective action

See Section 7.3.4.1 Detailed inspections of distribution electric lines and equipment for detailed inspections of distribution electric lines and equipment.

7.3.3.13 Pole loading infrastructure hardening and replacement program based on pole loading assessment program

See Section 7.3.3.6 Distribution pole replacement and reinforcement, including with composite poles and 7.3.3.17.1 Distribution overhead system hardening.

7.3.3.14 Transformers maintenance and replacement

See Section 7.3.4.1 Detailed inspections of distribution electric lines and equipment.

7.3.3.15 Transmission tower maintenance and replacement

See Section 7.3.4.2 Detailed inspections of transmission electric lines and equipment

7.3.3.16 Undergrounding of electric lines and/or equipment

1. Risk to be mitigated

SDG&E operates and maintains nearly 3,500 miles of overhead distribution circuit miles within the HFTD. This infrastructure was originally designed to meet GO 95 requirements of an 8 psf or 55 mph transverse wind load, however winds can reach 85 to 111 mph in certain areas of the HFTD during extreme Santa Ana conditions. Aging infrastructure also makes the remaining lines more susceptible to equipment failures during high winds and outdated design techniques makes these lines more vulnerable to foreign object in line contacts, all of which could lead to ignitions.

2. Initiative selection

Strategic undergrounding converts overhead systems to underground, providing the dual benefits of nearly eliminating wildfire risk and the need for PSPS events in these areas.

A primary downside of undergrounding is the cost. It is the most expensive major hardening alternative on a per mile basis, therefore undergrounding is strategically deployed.

<u>Risk Reduction Estimation Methodology</u>

To calculate the wildfire risk reduction for strategic undergrounding, data on historical ignitions associated with underground equipment, pre-mitigation overhead system risk event rate and ignitions rates, and underground mileage to be completed within the 3-year period were analyzed. Specifically, the effectiveness of undergrounding was measured by taking total CPUC-reportable ignitions associated with underground and dividing by total ignitions. Based on this analysis, strategic undergrounding is expected to reduce ignitions per year by 0.192 and mitigate PSPS impacts to 7,192 customers by the end of 2022. Calculations are summarized in Table 7-10.

Table 7-10: Risk Reduction Estimation for Strategic Undergrounding

Pre-mitigation risk events per 100 miles Tier 3	6.48
Pre-mitigation risk events per 100 miles Tier 2	7.02
Undergrounding effectiveness	98%
Ignition rate in Tier 3	2.69%
Ignition rate in Tier 2	3.29%
Pre-mitigation Tier 3 ignitions per 100 miles	6.48 x 2.69% = 0.174
Pre-mitigation Tier 2 ignitions per 100 miles	7.02 x 3.29% = 0.23
Post-mitigation Tier 3 ignitions per 100 miles	0.174 x (1-98%) = 0.0035
Post-mitigation Tier 2 ignitions per 100 miles	0.23 x (1-98%) = 0.0046
Ignitions reduced in Tier 3 per 100 miles	0.174 - 0.0035 = 0.17
Ignitions reduced in Tier 2 per 100 miles	0.23 - 0.0046= 0.227
Miles of mitigation in Tier 3	79.62
Miles of mitigation in Tier 2	27.23
Ignitions reduced in Tier 3	0.17 * (79.62/100) = 0.136
Ignitions reduced in Tier 2	0.227* (27.23/100) = 0.0617
Total Ignition Reduction Estimate	0.136 + 0.0617= 0.192

3. Region prioritization

Strategic undergrounding is deployed in the HFTD as well as in areas where substantial PSPS-event reductions can be gained through strategic installation of underground electric system.

Data on historic PSPS events, wind conditions, and others are reviewed to determine where undergrounding will have the largest impact. Constraints such as environmental, permitting, and design are also taken into consideration (See Section 7.1.4 Limited Resource Challenges for a discussion of constraints associated with significant construction projects). RSE calculations developed in WiNGS-Planning (see Section 4.5.1.7 Wildfire Next Generation System-Planning) are utilized to prioritize undergrounding within the HFTD.

See Section 4.6 Progress Reporting on Key Areas of Improvement and Attachment D for a response to action statement SDGE 21-10 regarding the prioritization of undergrounding and covered conductor mitigation efforts.

4. Progress on initiative

Enhancements and progress made in 2021 include

- Utilized WiNGS-Planning to evaluate mitigation alternatives and prioritize strategic undergrounding
- Completed an infrastructure assessment feasibility of PSPS impacted communities (Related to Action Statement SDGE 21-10)
- Undergrounding services up to customer panel which provides a safe and more reliable service (currently the only utility company in state offering this service as a part of Wildfire Mitigation)
- Process Efficiency
  - Planned and streamlined processes procedures
  - Conducted field constructability reviews
  - Performed strategic bidding/bundling of projects
  - Coordinated with the County to avoid repaving conflicts
- Technology Alignment
  - Implemented new trench method
  - Established a standard for Breakaway Technology
  - Strategically placed equipment
  - Used innovative approach in construction by using HDD and Jack and Bore
  - Conduit diameter adjustment from 5 inches to 4 inches where permitted
- Organization Agility
  - Centralized support
  - Streamlined reporting
  - Defined Roles and Responsibilities
- Demand Management
  - Conducted material forecasting
  - Determined location and timing of acquisition for Laydown yards
- Business Effectiveness
  - Collaborated with internal team and external agencies
  - Partnered with design firms
  - Built relationship with the County and their inspectors
  - Re-evaluated program contracting strategy

Enhancements in 2022 will include:

- Reduce trench dimensions where possible to reduce costs and schedule impacts
- Create permitting strike team to manage and expedite WMP-related permitting and agency approvals.

- Re-evaluate Strategic Undergrounding program contracting strategy to address resource constraints and workload increase

Actual performance for 2021 and targets for 2022 for this initiative are provided in Attachment B, Table 12.

5. Future improvements to initiative

Over the next 10 years, strategic underground scope will significantly increase as the understanding of costs and constraints improve. Installations in the HFTD remain challenging due to difficult terrain, environmental constraints, permitting timelines, and acquisition of easements. SDG&E also hopes to facilitate productive engagement with stakeholders in the telecommunication field to streamline resources and obtain more support for undergrounding efforts. Lessons learned from each year's undergrounding accomplishments will help alleviate these constraints through process improvements and stakeholder engagement.

7.3.3.17 Updates to grid topology to minimize the risk of ignition in HFTD

7.3.3.17.1 Distribution overhead system hardening

1. Risk to be mitigated

SDG&E operates and maintains nearly 3,500 miles of overhead distribution circuit miles within the HFTD. This infrastructure was originally designed to meet GO 95 requirements of an 8 psf or 55 mph transverse wind load, however winds can reach 85 to 111 mph in certain areas of the HFTD during extreme Santa Ana conditions. Aging infrastructure makes lines more suspectable to equipment failures and outdated design techniques makes these lines more vulnerable to foreign object in line contacts during high winds, all of which could lead to ignitions.

2. Initiative selection

To mitigate this risk, in 2021 the FiRM, PRiME, and WiSE programs were combined into the ESH Program. The scope of this program includes the replacement of wood poles with steel, replacement of conductor with uncovered or covered conductor, and in some cases permanent removal of overhead facilities.

The consolidation of hardening programs into the ESH Program resulted in the execution of projects based on a circuit-by-circuit approach that weighs risk inputs alongside the need to reduce PSPS impacts, rather than scoping projects based on specific wire or at-risk poles. Combining overhead distribution hardening programs makes project engineering, design, construction, and management more efficient and minimizes impacts to customers during job walks, construction, and post construction close-out activities.

<u>Risk Reduction Estimation Methodology</u>

To determine the estimated ignition reduction for overhead system hardening, data on average historical pre-mitigation risk events, mitigation effectiveness, historical ignition rates, and the amount of overhead hardening planned to be completed in the 2020-2022 timeframe was analyzed. Based on this analysis, the Distribution Overhead System Hardening Program is estimated to reduce ignitions by 0.217 per year by the end of 2022. Calculations are shown in Table 7-11.

Table 7-11: Risk Reduction Estimation for Overhead System Hardening

Pre-mitigation risk events per 100 miles Tier 3	6.48
Pre-mitigation risk events per 100 miles Tier 2	7.02
Pre-mitigation risk events per 100 miles Non HFTD	13.5
Effectiveness Estimate	45%
Ignition rate in Tier 3	2.69%
Ignition rate in Tier 2	3.29%
Ignition rate Non HFTD	1.46%
Ignitions reduced in Tier 3 per 100 miles	6.48 x 45% x 2.69% = 0.078
Ignitions reduced in Tier 2 per 100 miles	7.02 x 45% x 3.29% = 0.103
Ignitions reduced in Non HFTD per 100 miles	13.5 x 45% x 1.46% = .088
Miles of mitigation in Tier 3	99.92
Miles of mitigation in Tier 2	101.03
Miles of mitigation in Non HFTD	4.03
Ignitions reduced in Tier 3	99.92 x (0.078 ÷ 100) = 0.078
Ignitions reduced in Tier 2	101.03 x (0.103 ÷ 100) = 0.104
Ignitions reduced in Non HFTD	4.03 x .088 ÷ 100 = 0.035
Total Ignition Reduction Estimate	0.078 + 0.104 + 0.035 = 0.217

3. Region prioritization

The ESH Program targets fire prone areas including the HFTD and wildland urban interfaces. In 2021, the WiNGS-Planning model was introduced, and as previously started work is completed, the program will transition fully to the WiNGS-Planning strategy by 2022 (see Section 4.5.1.7 Wildfire Next Generation System-Planning).

4. Progress on initiative

Enhancements and progress made in 2021 include

- Utilizing WiNGS-Planning to determine projects for the ESH Program

Enhancements in 2022 will include

- Fully transition the ESH project prioritization process to WiNGS-Planning

Actual performance for 2021 and targets for 2022 for this initiative are provided in Attachment B, Table 12.

5. Future improvements to initiative

Legacy traditional hardening projects will continue to be closed out in the future.

7.3.3.17.2 Transmission Overhead System Hardening Program

1. Risk to be mitigated

SDG&E operates and maintains approximately 1,995 miles of transmission infrastructure, including 994 miles of overhead transmission infrastructure in the HFTD. Aging infrastructure makes lines more suspectable to equipment failures and outdated design techniques make these lines more vulnerable to foreign object in line contacts during high winds, all of which could lead to ignitions.

2. Initiative selection

To mitigate this risk, the Transmission Overhead System Hardening Program utilizes enhanced design criteria to replace wood poles with steel poles, replace aging conductors with high strength conductors, and increase conductor spacing in the HFTD to reduce the chance of risk events and ignitions.

Risk Reduction Estimation Methodology

To determine the estimated ignition reduction for transmission overhead system hardening, data on average historical transmission risk event data, average historical transmission ignition rates, the measured effectiveness of hardened transmission lines, and the amount of hardening expected to be completed in the 2020-2022 timeframe was analyzed. For the distribution underbuilt components, historical information used for distribution hardening was applied to the miles of distribution underbuilt on transmission. For the underground component of transmission hardening, a 100 percent effectiveness rating was assumed, as underground transmission does not have pad mounted equipment that could be struck by vehicles. Utilizing this methodology, a reduction of 0.244 transmission ignitions and 0.001 distribution ignitions for the associated underbuilt was estimated. Calculations are shown in Table 7-12, Table 7-13, and Table 7-14.

Table 7-12: Risk Reduction Estimation for Overhead Transmission Hardening

Pre-mitigation risk events per 100 miles	6.27
Effectiveness Estimate	83%
Post-mitigation risk events per 100 miles	6.27 x (1-83%) = 1.07
Transmission Ignition Rate HFTD	9.00%
Pre-mitigation HFTD ignitions per 100 miles Tier 3	6.27 x 9% = 0.564
Pre-mitigation HFTD ignitions per 100 miles Tier 2	6.27 x 9% = 0.564
Post-mitigation HFTD ignitions per 100 miles Tier 3	1.07 x 9% = 0.096
Post-mitigation HFTD ignitions per 100 miles Tier 2	1.07 x 9% = 0.096
Ignitions reduced Tier 3	0.564 - 0.096 = 0.468
Ignitions reduced Tier 2	0.564 - 0.096 = 0.468
Miles of mitigation Tier 3	0
Miles of mitigation Tier 2	52.13
Ignitions reduced Tier 3	0.468 x (0 ÷ 100) = 0.0
Ignitions reduced Tier 2	0.468 x (52.13 ÷ 100) = 0.244

Total Ignitions reduced OH	0 + 0.244 = 0.244

Table 7-13: Risk Reduction Estimation for Underground Transmission Hardening

Pre-mitigation risk events per 100 miles Tier 3	6.27
Effectiveness Estimate Tier 3	100%
Transmission Ignition Rate HFTD	9.00%
Pre-mitigation risk events per 100 miles Tier 2	6.27
Effectiveness Estimate Tier 2	100%
Transmission Ignition Rate HFTD	9.00%
Pre-mitigation HFTD ignitions per 100 miles Tier 3	6.27 x 9% = 0.564
Pre-mitigation HFTD ignitions per 100 miles Tier2	6.27 x 9% = 0.564
Post mitigation risk events per 100 miles Tier 3	6.27 x (1-100%) =0
Post mitigation risk events per 100 miles Tier 2	6.27 x (1-100%) =0
Post-mitigation HFTD ignitions per 100 miles Tier 2	0 x 9%=0
Post-mitigation HFTD ignitions per 100 miles Tier 2	0 x 9%=0
Ignitions reduced HFTD per 100 miles	0.564
Miles of mitigation Tier 2	5.5
Miles of mitigation Tier 3	0
Ignitions reduced Tier 2	0.564 x (5.5 ÷ 100) = 0.031

Table 7-14: Risk Reduction Estimation for Overhead Transmission-Distribution Underbuilt

Ignition rate in Tier 3	2.69%
Ignition rate in Tier 2	3.29%
Pre-Mitigation Risk Events per 100 miles Tier 3	6.48
Pre-Mitigation Risk Events per 100 miles Tier 2	7.02
Effectiveness Estimate	45%
Post-Mitigation Risk Events per 100 miles Tier 3	3.60
Post-Mitigation Risk Events per 100 miles Tier 2	3.89
Pre-mitigation Tier 3 ignitions per 100 miles	7.02 x 2.69% = 0.19
Pre-mitigation Tier 2 ignitions per 100 miles	6.48 x 3.29% = 0.21
Post-mitigation Tier 3 ignitions per 100 miles	3.60 x 2.69% = 0.10
Post-mitigation Tier 2 ignitions per 100 miles	3.89 x 3.29% = 0.13
Ignitions reduced in Tier 3 per 100 miles	0.19 – 0.10 = 0.09
Ignitions reduced in Tier 2 per 100 miles	0.21 – 0.13 =0.08

Miles of mitigation in Tier 3	0
Miles of mitigation in Tier 2	15.5
Ignitions reduced in Tier 3	0 x (0.09÷100) = 0
Ignitions reduced in Tier 2	15.5 x (0.08÷100) = 0.01
Total Ignition Reduction Estimate	0.00 + 0.01 = 0.01

3. Region prioritization

The Transmission Overhead System Hardening Program prioritizes hardening activity in the HFTD, starting with Tier 3 and moving into Tier 2.

4. Progress on initiative

No changes were made to this Program in 2021 and none are expected to be made in 2022.

Actual performance for 2021 and targets for 2022 for this initiative are provided in Attachment B, Table 12.

5. Future improvements to initiative

Grid hardening of the transmission system within Tier 3 is expected to be completed in 2022, and hardening in Tier 2 is scheduled to be completed by 2027. Projects for the remaining unhardened lines have been identified and the process of being scoped and approved has begun.

7.3.3.17.3 CNF MSUP Powerline Replacement Program

1. Risk to be mitigated

SDG&E operates and maintains nearly 3,500 miles of overhead distribution circuit miles within the HFTD. This infrastructure was originally designed to meet GO 95 requirements of an 8 psf or 55 mph transverse wind load, however winds can reach 85 to 111 mph in certain areas of the HFTD during extreme Santa Ana conditions. Aging infrastructure makes lines more suspectable to equipment failures and outdated design techniques makes these lines more vulnerable to foreign object in line contacts during high winds, all of which could lead to ignitions.

2. Initiative selection

To mitigate this risk, the CNF Master Special Use Permit (MSUP) Powerline Replacement Program was created to address various recommendations for fire prevention and the U.S. Forest Service's environmental requests. Using an analytical matrix reflecting elements of fire risks and environmental concerns, SDG&E and the U.S. Forest Service collaborated to determine which sections of the electric system should be upgraded. Each segment required a custom solution based on factors such as customer location, topography of the land, and various biological, cultural, and environmental factors.

Under this program, grid hardening activities are designed to handle wind speeds of 85 to 111 mph, exceeding GO 95 requirements. In addition, steel structures, stronger conductor, and increased wire spacing are used to decrease the likelihood of wire-to-wire contact or arcing as the result of contact by flying debris.

Risk Reduction Estimation Methodology

To estimate the ignitions reduced for the 2020-2022 timeframe, data on average historical transmission risk events, average historical transmission ignition rates, measured effectiveness of hardened transmission lines, and the amount of hardening expected to be completed as part of the CNF Project were analyzed. For the distribution components, historical information used for distribution hardening was applied to the miles of distribution that were planned for completion as part of the CNF Project. For the distribution underground component of the CNF Project, the same historical pre-mitigation failure and ignition rates were used and the underground effectiveness calculation discussed in strategic undergrounding was leveraged. Utilizing this methodology, a reduction of 0.135 transmission ignitions and 0.139 distribution ignitions for the associated underbuilt was estimated. Calculations are shown in Table 7-15.

Overhead system hardening was found to reduce the risk of possible ignition by 83 percent (see Section 4.4.2.3 Impact of Overhead Distribution Hardening at Reducing Overhead Faults for study details).

Table 7-15: Risk Reduction Estimation for CNF Overhead System Hardening

CNF Overhead Transmission Hardening	
Pre-mitigation risk events per 100 miles HFTD	6.27
Effectiveness Estimate Tier 3	83%
Post-mitigation risk events per 100 miles Tier 3	6.27 x (1-83%) = 1.07
Post-mitigation risk events per 100 miles Tier 2	6.27 x (1-83%) = 1.07
Transmission Ignition Rate HFTD	9.00%
Pre-mitigation HFTD ignitions per 100 miles Tier 3	6.27 x 9% = 0.564
Pre-mitigation HFTD ignitions per 100 miles Tier 2	6.27 x 9% = 0.564
Post-mitigation HFTD ignitions per 100 miles Tier 3	1.07 x 9% = 0.096
Post-mitigation HFTD ignitions per 100 miles Tier 2	1.07 x 9% = 0.096
Ignitions reduced Tier 3	0.564 - 0.096 = 0.468
Ignitions reduced Tier2	0.564 - 0.096 = 0.468
Miles of mitigation Tier 3	29
Miles of mitigation Tier 2	0
Ignitions reduced Tier 3	0.468 x (29 ÷ 100) = 0.136
Total Ignitions reduced	**0.136**
CNF Overhead Distribution Hardening	
Pre-mitigation risk events per 100 miles Tier 3	6.48
Pre-mitigation risk events per 100 miles Tier 2	7.02
Effectiveness Estimate Tier 3	45%
Post-mitigation risk events per 100 miles Tier 3	6.48 - (45% x 6.48) = 3.6
Post-mitigation risk events per 100 miles Tier 2	7.02 - (45% x 7.02) = 3.9
Distribution Ignition Rate Tier 3	2.69%

Distribution Ignition Rate Tier 2	3.29%
Pre-mitigation HFTD ignitions per 100 miles Tier 3	6.48 x 2.69 = 0.174
Pre-mitigation HFTD ignitions per 100 miles Tier 2	7.02 x 3.29% = 0.231
Post-mitigation HFTD ignitions per 100 miles Tier 3	3.6 x 2.69% = 0.097
Post-mitigation HFTD ignitions per 100 miles Tier 2	3.9 x 3.29% = 0.128
Ignitions reduced Tier 3	0.174 - 0.097 = 0.078
Ignitions reduced Tier2	0.231 - 0.128 = 0.103
Miles of mitigation Tier 3	53.61
Miles of mitigation Tier 2	0
Ignitions reduced Tier 3	0.078 x (53.61 ÷ 100) = 0.042
Total Ignitions reduced	**0 + 0.042 = 0.042**
CNF Distribution Undergrounding	
Pre-mitigation risk events per 100 miles Tier 3	6.48
Pre-mitigation risk events per 100 miles Tier 2	7.02
Effectiveness Estimate	98%
Distribution Ignition Rate Tier 3	2.69%
Distribution Ignition Rate Tier 2	3.29%
Pre-mitigation HFTD ignitions per 100 miles Tier 3	6.48 x 2.69 = 0.174
Pre-mitigation HFTD ignitions per 100 miles Tier 2	7.02 x 3.29% = 0.231
Post-mitigation HFTD ignitions per 100 miles Tier 3	0.174 x (1-98%) = 0.0035
Post-mitigation HFTD ignitions per 100 miles Tier 2	0.231 x (1-98%) = 0.0046
Ignitions reduced per 100 miles Tier 3	0.174 - 0.0035 = 0.171
Ignitions reduced per 100 miles Tier2	0.231 - 0.0046 = 0.226
Miles of mitigation Tier 3	14.77
Miles of mitigation Tier 2	0
Ignitions reduced Tier 3	0.171 x (14.77 ÷ 100) = 0.025
Total Ignitions reduced	**0 + 0.025 = 0.025**

3. Region prioritization

The CNF MSUP Powerline Replacement Program encompasses the hardening of facilities and select undergrounding of several existing 12kV and 69kV electric facilities spread throughout an approximately 880-square-mile area in the eastern portion of San Diego County located in the HFTD. The existing electric lines located within CNF also extend outside of CNF boundaries.

4. Progress on initiative

Construction commenced on the CNF Program in late 2016 and was completed in 2021.

5. Future improvements to initiative

The CNF project was completed in Q1 of 2021. All construction and close out activities such as QA/QC reviews were also completed in 2021, however post project environmental work will be completed in the future.

7.3.3.18 Other

7.3.3.18.1 Distribution Communications Reliability Improvements

1. Risk to be mitigated

The current communication system within the HFTD does not have the bandwidth to support some of the technologies deployed as wildfire mitigations, including the APP and the FCP. In addition, there are gaps in coverage of third-party communication providers in the rural areas of eastern San Diego County that limit the ability to communicate with field personnel during Red Flag Crew deployments and EOC activations.

2. Initiative selection

To mitigate this risk, the DCRI Program was developed to deploy a privately-owned LTE network using licensed radio frequency spectrum, enhancing the reliability of the communication network. A reliable communication network is necessary for many initiatives that require continuous communication. An LTE network provides the ability to reliably enable and disable sensitive settings, enable or disable reclosing, or remotely operate a switch during a high-risk weather event.

<u>Risk Reduction Estimation Methodology</u>

This initiative does not have a Risk Reduction Estimation because it is considered foundational to supporting wildfire mitigation efforts. Quantifying a Risk Reduction Estimation would be difficult and not beneficial because it cannot be directly tied to reducing a risk driver and measuring the effectiveness of that reduction.

3. Region prioritization

Installation of protection and communications equipment in the HFTD are prioritized with the help of the APP team.

4. Progress on initiative

Enhancements and progress made in 2021 include

- Acquired second spectrum licensing
- Completed RF design for the entire HFTD territory
- Continued developing site design standards for attachment to distribution assets
- Continued developing integrated LTE/Distribution build process
- Completed siting surveys, land rights, and environmental analysis
- Planned community outreach and communications
- Completed 10 base stations

- Completed further use case testing and validation

Enhancements in 2022 will include

- Install additional base stations

Actual performance for 2021 and targets for 2022 for this initiative are provided in Attachment B, Table 12.

5. Future improvements to initiative

As the DCRI Program progresses, initial build sites will be analyzed and deployment strategies will be adjusted based on the analysis.

7.3.3.18.2 Lightning arrestor removal and replacement

1. Risk to be mitigated

Lightning arrestors are a piece of electrical equipment designed to mitigate the impact of transient overvoltage on the electric system. If the overvoltage duration is too long or too high, the arrestor can become thermally overloaded, causing these units to fail in a way where they can become an ignition source.

2. Initiative selection

To mitigate this risk, a new type of lightning arrestor was introduced that received CAL FIRE approval. These lightning arrestors are equipped with an external device that operates prior to the arrestor overloading, dramatically reducing the potential of becoming an ignition source. As part of the Lightning Arrestor Replacement Program, the first of these devices were installed in 2021, and arrestors are being replaced in strategic locations within the HFTD.

Risk Reduction Estimation Methodology

The ignitions reduced by 2022 was calculated using the 5-year average risk events caused by lightning arrestors, the 5-year average ignitions caused by lightning arrestors, the assumed effectiveness of 80 percent, and the number of planned lightning arrestor installations for the WMP timeframe. The mitigation will have an estimated 80 percent reduction in ignitions based on the technology and what the product is designed to accomplish. Based on this data, a reduction of 0.024 and 0.005 ignitions in Tier 3 and Tier 2, respectively, are expected by the end of 2022. Calculations are shown in Table 7-16.

Table 7-16: Risk Reduction Estimation for Lightning Arrestor Replacement

Lighting Arrestor risk events Tier 3 (5-year average)	5.2
Lighting Arrestor risk events Tier 2 (5-year average)	5.8
Pre-mitigation ignitions Tier 3 (5-year average)	0.4
Pre-mitigation ignitions Tier 2 (5-year average)	0.2
Effectiveness	80%
Pre mitigation ignition rate Tier 3	0.4 ÷ 5.2 = 7.69%
Pre mitigation ignition rate Tier 2	0.2 ÷ 5.8 = 3.33%

Post mitigation ignition rate Tier 3	7.69% x (1-80%) = 1.54%
Post mitigation ignition rate Tier 2	3.33% x (1-80%) = 0.67%
Post-mitigation ignitions Tier 3	5.2 x 1.54% = 0.08
Post-mitigation ignitions Tier 2	5.8 x 0.67% = 0.04
Ignitions reduced Tier 3	0.4-0.08 = 0.32
Ignitions reduced Tier 2	0.2-0.04 = 0.16
Total Arrestors Tier 3	30,000
Total Arrestors Tier 2	43,000
Arrestors Tier 3 (2020-2022)	2,239
Arrestors Tier 2 (2020-2022)	1,405
Ignitions reduced Tier 3	0.32 x (2,239 ÷ 30,000) = 0.024
Ignitions reduced Tier 2	0.16 x (1,405 ÷ 43,000) = 0.005

The effectiveness of this program can be evaluated as new lightning arrestors begin to protect the electric system under overvoltage conditions.

3. Region prioritization

Lightning arrestors are installed on the distribution system throughout the service territory. Some locations have more installations than others based on the increased probability of lightning strikes in order to protect other major equipment from abnormal surges and failing. Replacement started in areas of typically high lightning activity and in Tier 3 of the HFTD. Due to the volume of the work, projects are bundled together based on geographic location to increase construction efficiency and reduce the number of construction outages for the project.

4. Progress on initiative

Enhancements and progress made in 2021 include

- Finalized construction standards and construction at test sites
- Installed lightning arrestors to meet the 2021 target

No changes are expected for the program in 2022.

Actual performance for 2021 and targets for 2022 for this initiative are provided in Attachment B, Table 12.

5. Future improvements to initiative

Based on information provided from outage and possible ignition events, timelines and prioritization may change to fit the need. Installation may be ramped up to potentially replace all at-risk locations in 10 years.

7.3.3.18.3 Avian Mitigation

1. Risk to be mitigated

Certain bird contacts with electrical lines and equipment can lead to potential ignition sources, as well as harm to avian species.

2. Initiative selection

SDG&E's Avian Protection Program involves installing avian protection equipment on distribution poles in the service territory to prevent electrocution of birds and to facilitate compliance with Federal and State Laws.[51] The project is aimed at reducing the risk of faults and wire-down events associated with avian contact that can lead to ignitions and improve reliability.

This is a new initiative in the Wildfire Mitigation Plan for 2022. In 2021 and prior years, avian protection equipment throughout the service territory was installed and tracked outside of the WMP. However, due to the increase in work being performed in the HFTD including hot line clamp replacements, fuse replacements, and lightning arrester replacements, SDG&E has found that many of these poles need avian protection installed in concurrence with these projects to bring the equipment up to current standards. If avian protection is not installed or replaced at the same time, the risk of avian contact remains and crews will need to revisit the pole in the future to install the avian protection at a later date resulting in additional outages or impacts to customers.

<u>Risk Reduction Estimation Methodology</u>

The estimated percent reduction in wildlife ignitions due to the installation of avian covers is 90 percent. This is based on field observations in the Tier 3 area.

The ignitions reduced by 2022 was calculated using the 5-year average risk events caused by animal contact, the 5-year average ignitions caused by animal contacts, and number of planned Avian Protection installations for the WMP timeframe. Based on this data, a reduction of 0.00046 and 0.0061 ignitions in Tier 3 and Tier 2, respectively, are expected by the end of 2022. Calculations are shown in the below table.

Table 7-17: Risk Reduction Estimation for Avian Covers

Animal Contact Tier 3 - 5 yr avg (2015-2019)	20.6
Animal Contact Tier 2 - 5 yr avg (2015-2019)	22.4
Animal Contact Non-HFTD - 5 yr avg (2015-2019)	35
Animal Contact 5 yr avg Ignition Tier 3	0.2
Animal Contact 5 yr avg Ignition Tier 2	0.4
Animal Contact 5 yr avg Ignition Non-HFTD	0.4
5 Yr Avg Ignition Rate Tier 3	0.97%
5 Yr Avg Ignition Rate Tier 2	1.79%

[51] Migratory Bird Treaty Act (16 U.S.C. §§ 703-712), Bald and Golden Eagle Protection Act (16 U.S.C. §§ 668-668d), and California Fish and Game Code (Cal. Fish and Game Code §§ 3503, 3503.5, 3511, 3513)

5 Yr Avg Ignition Rate Non-HFTD	1.14%
Total Avian Protection In The Network Tier 3	39,575
Total Avian Protection In The Network Tier 2	46,955
Total Avian Protection In The Network Non HFTD	136,835
2022 Avian Protection actuals to be repaired or replaced Tier 3	91
2023 Avian Protection actuals to be repaired or replaced Tier 2	711
2024 Avian Protection actuals to be repaired or replaced Non HFTD	45
Ignition Reduced Tier 3	20.6 x (91/3,975) x 0.97% = 0.000459886
Ignition Reduced Tier 2	22.4 x (711 ÷ 46955) x 1.79% = 0.006056863
Ignition Reduced Non-HFTD	35 x (45 ÷136835) x 1.14% = 0.000131545

3. Region prioritization

Avian protection equipment will be installed concurrently with other asset replacement initiatives across the HFTD.

4. Progress on initiative

Targets for 2022 for this initiative are provided in Attachment B, Table 12.

5. Future improvements to initiative

SDG&E will evaluate progress on the bundling of avian protection work with other initiatives to ensure all required items are being addressed at each structure.

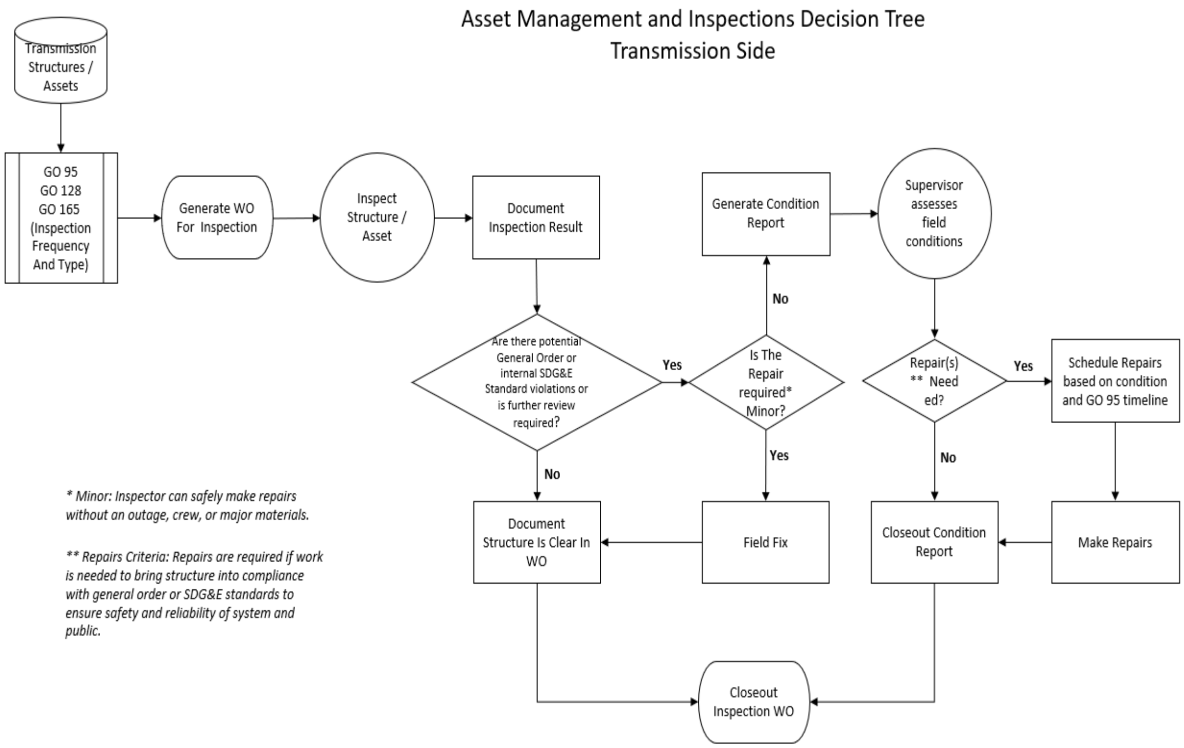
7.3.4 Asset Management and Inspections

SDG&E's asset management and inspection programs are designed to promote safety for the general public, SDG&E personnel, and contractors by providing a safe operating and construction environment while maintaining system reliability. Established inspection and maintenance programs identify and repair conditions and components to reduce potentially defective equipment on the electric system to minimize hazards and maintain system reliability.

Asset management and inspection programs continue to look for ways to improve the safety of the electric system. This includes development of new programs such as the distribution and transmission drone programs and a continued focus on existing programs such as the routine and detailed inspections performed for substation, distribution, and transmission assets.

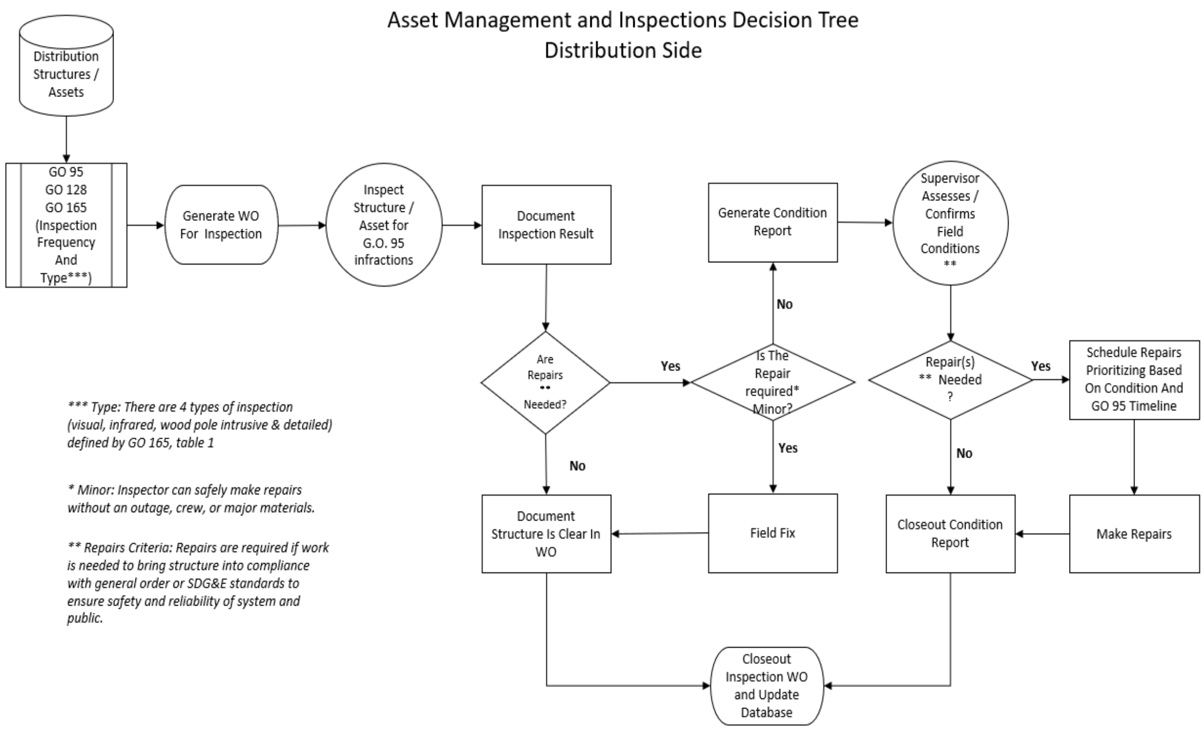
Figure 7-5, Figure 7-6, and Figure 7-7 show the high-level process for implementation of Asset Management and Inspections programs. Each flowchart represents a different asset in Asset Management and Inspections to show how SDG&E incorporates risks and makes decisions to prioritize the work performed on transmission, distribution, and substation assets.

Figure 7-5: Asset Management and Inspections Decision Tree: Transmission



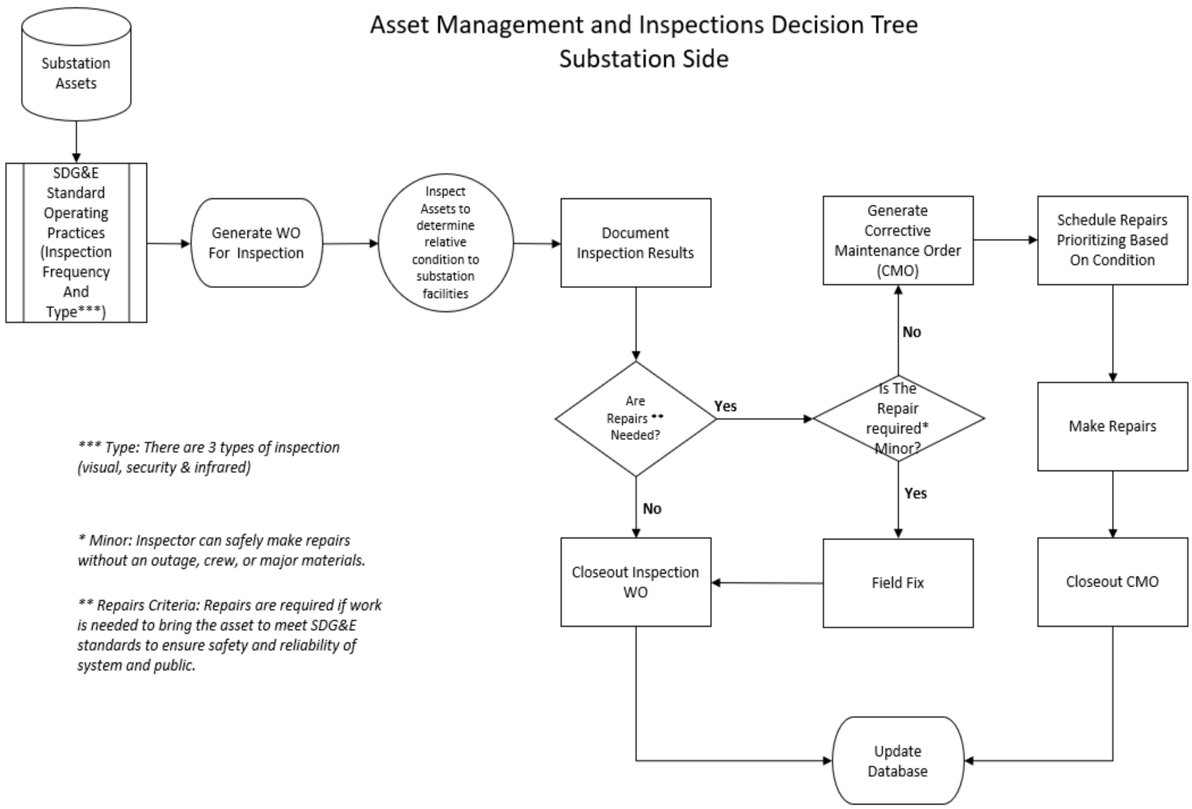
Transmission Side		
Step #	**Workflow Steps**	**Description**
1	Transmission Structures / Assets	All structures and components on those structures including conductor that are at a transmission level voltage.
2	GO 95, GO 128, GO 165 (Inspection Frequency And Type)	Inspection frequency and types are defined in SOP TCM807. Timelines and types of inspections for transmission were set to meet or exceed those required for distribution in Table 1 in GO165.
3	Generate WO For Inspection	An inspection workorder is generated by an analyst and deployed to the Transmission Patroller or Thermographer for the tieline and/or structures which have entered their compliance window.
4	Inspect Structure / Asset for G.O. 95 infractions	The assets are inspected or patrolled by a Transmission Patroller or Thermographer for compliance with general orders to ensure safety/reliability of system.
5	Document Inspection Result	For inspections, each structure is either noted as complete with no findings which marks it as complete on the work order or necessary conditions are inputted for the structure which can then be marked complete on the work order.
6	Are there potential General Order or internal SDG&E Standard violations or is further review required?	As noted in Document Inspection Step, conditions are entered.
7	Is The Repair required* Minor?	Transmission Patroller will review if they can safely make repairs without an outage, crew, or major materials.
8	Generate Condition Report	If condition repair would require an outage, crew, or major materials, transmission patroller or thermographer enters a condition with a severity from 2-5 which sets timelines for supervisors to assess field conditions identified.
9	Supervisor Assesses / Confirms Field Conditions **	Supervisor will field assess severity 2-5 conditions to determine how to implement corrective actions.
10	Repair(s) ** Needed?	During field assessment, supervisor will determine if repairs are required by determining if work is needed to bring structure into compliance with general order or SDG&E standards to ensure safety and reliability of system and public.
11	Schedule Repairs Prioritizing Based On Condition And GO 95 Timeline	After fielding job, construction supervisors will write up jobs for repair and will schedule.
12	Make Repairs	A crew is assigned a maintenance job and repairs are made by the crew.
13	Closeout Condition Report	The crew returns the job package and signs report with all conditions cleared by crew and analyst closes open conditions.
14	Field Fix	Transmission Patroller will make necessary repair.
15	Document Structure Is Clear In WO	Transmission Patroller will add a condition for the item repaired and assign a severity code 0 to the condition. This will show the structure has had a completed patrol and the severity 0 conditions require no follow-up but allow internal tracking of completed conditions.
16	Closeout Inspection WO and Update Database	When all structures have had completed inspection, work order is completed, and database is synched. As conditions are completed, they are completed in the maintenance database which is continually synched.

Figure 7-6: Asset Management and Inspections Decision Tree: Distribution



Distribution Side		
Step #	**Workflow Steps**	**Description**
1	Distribution Structures / Assets	All structures and components on those structures including conductors and any attachments that are at the distribution level and below.
2	GO 95, GO 128, GO 165 (Inspection Frequency And Type***)	Timelines and types of inspections for transmission were set to meet or exceed those required for distribution in Table 1 in GO165.
3	Generate WO For Inspection	An inspection workorder is generated by SAP-PM
4	Inspect Structure / Asset for G.O. 95 infractions	The assets are inspected or patrolled by a distribution CMP inspector for compliance with general orders to ensure safety/reliability of system.
5	Document Inspection Result	The distribution CMP inspector will document any findings, or no repairs needed for all structures and equipment on the inspection workorder.
6	Are Repairs ** Needed?	If there are any infractions entered by the distribution CMP inspector that was set to "pending", then repairs are needed
7	Is The Repair required* Minor?	If the infraction is minor, the distribution CMP inspector will remediate the infraction at the time of inspection if possible. If not, then additional follow up is required.
8	Generate Condition Report	The district office personnel will generate the CMP backlog to identify the list of repairs needed.
9	Supervisor Assesses / Confirms Field Conditions **	The Construction Supervisor will visit the structure based on the CMP backlog to determine/validate the extent of repairs, list of materials, and any specifics needed to complete the repairs.
10	Repair(s) ** Needed?	The Construction Supervisor will determine if repairs are needed, and will move forward accordingly
11	Schedule Repairs Prioritizing Based On Condition And GO 95 Timeline	The Construction Supervisor will design and plan the job accordingly and send the job to be scheduled within our compliance timeframe.
12	Make Repairs	The crew is assigned the electronic repair workorder and the crew will complete the repairs
13	Closeout Condition Report	The foreman of the crew will confirm the repairs were completed, and then complete the electronic workorder and as-built.
14	Field Fix	The distribution CMP inspector will repair the minor infraction.
15	Document Structure Is Clear In WO	The distribution CMP inspector will enter No Repairs Needed for the structure(s) in the WO
16	Closeout Inspection WO and Update Database	The data from the inspection and maintenance WO is then sent to SAP-PM and updates the inspection and maintenance records

Figure 7-7: Asset Management and Inspections Decision Tree: Substation



Substation		
Step #	**Workflow Steps**	**Description**
1	Substation Assets	All equipment and facilities within a substation. Substation major equipment and inspections are documented in the Substation Maintenance Management System (SMMS) database.
2	SDG&E Standard Operating Practices (Inspection Frequency And Type)	Inspection frequency and type are defined in SOP 510.004 Substation Maint Practice (Non-ISO Operational Control)
3	Generate WO For Inspection	An inspection Work order is generated to perform routine inspections by a KMO Substation Electrician at a particular substation location for all (or most of) equipment items at site.
4	Inspect Assets to determine relative condition to substation facilities	The assets are inspected to determine Severity Code. Severity Code 1 is used to identify a significant and immediate risk to the reliability and/or safety of personnel or equipment within a substation. Severity Code 2 is used to identify corrective action that is necessary. but does not pose an immediate risk to personnel or equipment within a substation.
5	Document Inspection Results	Visual and Infra-red inspections are documented in the Substation Maintenance Management System (SMMS)
6	Are Repairs Needed?	When repairs are needed, Severity Code 1 items are resolved within 7 days. Severity Code 2 items are resolved within 12 months.
7	Closeout Inspection WO	Inspection WO are closed upon completion of inspection.
8	Is The Repair required* Minor?	Assigned Severity Code 2, resolved within 12 months.
9	Field Fix	A field fix is performed by the inspector and documented in the inspection report.
10	Generate Corrective Maintenance Order (CMO)	New corrective work orders are opened for items needing attention.
11	Make Repairs	A crew is assigned the corrective maintenance work order. Repairs are made by the crew.
12	Schedule Repairs Prioritizing Based On Severity Code	Corrective maintenance orders are assigned to crews by the inspector opening the corrective maintenance work order. Severity Code 1 items are resolved within 7 days. Severity Code 2 items are resolved within 12 months.
13	Closeout CMO	Upon completion of the corrective maintenance order, it is documented in SMMS and closed
14	Update Database	Database is synced.

7.3.4.1 Detailed inspections of distribution electric lines and equipment

1. Risk to be mitigated

CPUC GO 165 requires SDG&E to perform a service territory-wide inspection of its electric distribution system, generally referred to as the CMP. Without regular inspections, equipment is at a risk of failure which can lead to electrical faults and potentially ignitions.

2. Initiative selection

The CMP helps mitigate wildfire risk by providing additional information about the condition of the electric distribution system, including in the HFTD. With this information, potential infractions can be addressed before they develop into a possible issue.

GO 165 establishes inspection cycles and record-keeping requirements for utility distribution equipment. In general, utilities must patrol their systems once a year in urban areas and in HFTD Tier 2 and Tier 3 (see Section 7.3.4.10 Other discretionary inspection of transmission electric lines and equipment, beyond inspections mandated by rules and regulations for details). In addition to patrols, utilities must conduct detailed inspections at a minimum of every 3 to 5 years, depending on the type of equipment. The 5-year detailed inspections are mandated by GO 165.

Risk Reduction Estimation Methodology

The studies discussed in Section 4.4.2.6 Impact of Inspection Programs at Finding and Repairing Equipment Issues and Section 4.4.2.7 Impact of Distribution and Transmission Inspection Program on Faults Avoided Due to Fire Risk Infractions Repaired describe the methodology to estimate the risk reduced by inspection and maintenance programs. For existing programs, a 5-year historical average of hit rates (number of issues found at a given priority level divided by total inspections) was calculated and utilized to forecast future years based on the number of inspections in the HFTD for these programs. Failure rate calculations (i.e., how many risk events would occur within a year if there were no inspections or repairs within the prescribed timeframes) are described in the study and utilized to convert issues found into risk events. Finally, the average distribution ignition rates broken down by HFTD Tier were utilized to calculate ignitions avoided due to the program. The ignitions avoided is calculated on an annual basis and can change annually depending on the inspection cycle, which determines which structures are scheduled for inspections within the HFTD. For 2022, an estimated 0.589 ignitions would occur if inspections and repairs were not completed in the prescribed timeframes as part of the 5-year detailed distribution inspection program. Calculations are shown in Table 7-18.

Table 7-18: Risk Reduction Estimation for CMP

5-year average hit rate Emergency (0-3 days)	0.002
5-year average hit rate Priority (4-30 days)	0.001
5-year average hit rate Non - Critical	0.060
2022 Inspection Total Tier 3	6530
2022 Inspection Total Tier 2	11647
Emergency Tier 3	0.002 x 6530=13.08
Emergency Tier 2	0.002 x 11647=23.33

Priority Tier 3	0.001 x 6530=4.82
Priority Tier 2	0.001 x 11647=8.60
Non-Critical Tier 3	0.060 x 6530=392.52
Non-Critical Tier 2	0.060 x 11647=700.10
Fail Rate Emergency	41%
Fail Rate Priority	4%
Fail Rate Non-Critical	0.34%
Risk events Avoided Tier 3	13.08 x 41% + 5 x 4% + 392.52 x 0.34% = 6.88
Risk events Avoided Tier 2	23.33 x 41% + 8.6 x 4% + 700.095 x 0.34% = 12.27
Distribution Ignition rate Tier 3	2.69%
Distribution Ignition rate Tier 2	3.29%
Ignitions Avoided Tier 3	6.88 x 2.69%=0.186
Ignitions Avoided Tier 2	12.27 x 3.29%=0.404
Total Ignitions avoided	0.186 + 0.404=0.589

3. Region prioritization

Inspections and patrols are performed throughout the service territory. The inspections and patrols reported within the WMP are only those inspections that occur within the HFTD.

4. Progress on initiative

SDG&E will complete inspections on a cycle and continue to comply with GO 165.

Actual performance for 2021 and targets for 2022 for this initiative are provided in Attachment B, Table 12.

5. Future improvements to initiative

Results from LiDAR inspections (discussed in Section 7.3.4.7 LiDAR inspections of distribution electric lines and equipment) and high-definition imagery from drone inspections (discussed in Section 7.3.4.9.2 Drone assessments of distribution infrastructure) will be reviewed to provide feedback and enhance ground GO 165 detailed overhead visual inspections and patrols.

7.3.4.2 Detailed inspections of transmission electric lines and equipment

1. Risk to be mitigated

Without regular inspections, equipment is at a risk of failure or malfunction which can lead to electrical faults and potentially ignitions.

2. Initiative selection

To mitigate this risk, SDG&E has implemented a comprehensive, multi-faceted transmission inspection and patrol program. The transmission inspection program consists of visual patrols (discussed in Section 7.3.4.12 Patrol inspections of transmission electric lines and equipment), infrared patrols (discussed in

Section 7.3.4.5 Infrared inspections of transmission electric lines and equipment), detailed patrols (discussed in this section), and other various specialty patrols, inspections, and assessments. Inspections and patrols of all structures, attachments, and conductor spans are performed to identify facilities and equipment that may not meet Public Resources Code §§ 4292 and 4293 or GO 95 and GO 128 rules.

For detailed inspections, experienced, internal lineman (patrollers) physically visit every structure scheduled for the year, looking at all components of the structure and conductor. By physically visiting the structures, patrollers can assess the structure for current and future maintenance requirements. As conditions are identified, internal severity codes are established to ensure supervisors properly prioritize corrections. This prioritization considers the component identified, the location of the structure and surrounding terrain, and the severity of the condition to set this prioritization. It also ensures that conditions are corrected in timeframes which meet or exceed GO 95 requirements.

Risk Reduction Estimation Methodology

The studies discussed in Section 4.4.2.6 Impact of Inspection Programs at Finding and Repairing Equipment Issues and Section 4.4.2.7 Impact of Distribution and Transmission Inspection Program on Faults Avoided Due to Fire Risk Infractions Repaired describe the methodology to estimate the risk reduced by inspection and maintenance programs. For existing programs, a 5-year historical average of hit rates (number of issues found at a given priority level divided by total inspections) was calculated and utilized to forecast future years based on the number of inspections in the HFTD for these programs.

Failure rate calculations (i.e., how many risk events would occur within a year if there were no inspections or repairs within the prescribed timeframes) are described in the study and utilized to convert issues found into risk events. Finally, the average transmission ignition rate for risk events and ignitions in the HFTD was used to convert risk events avoided to ignitions avoided. The ignitions avoided is calculated on an annual basis and can change annually depending on the inspection cycle, which determines which structures are scheduled for inspections within the HFTD. For 2022, an estimated 0.139 ignitions would occur if inspections and repairs were not completed in the prescribed timeframes as part of the detailed transmission inspection program. Calculations are shown in Table 7-19.

Table 7-19: Risk Reduction Estimation for Transmission Inspection and Maintenance Programs

5-year average hit rate Emergency (0-3 days)	0
5-year average hit rate Priority (4-30 days)	0.012
5-year average hit rate Non - Critical	0.77
2022 Inspection Total Tier 3	644
2022 Inspection Total Tier 2	1443
Emergency Tier 3	0 x 644=0
Emergency Tier 2	0 x 1443=0
Priority Tier 3	0.012 x 644=7.73
Priority Tier 2	0.012 x 1443=17.31
Non-Critical Tier 3	0.077 x 644=49.59

Non-Critical Tier 2	0.077 x 1443=111.11
Fail Rate Emergency	41%
Fail Rate Priority	4%
Fail Rate Non-Critical	0.34%
Risk events Avoided Tier 3	0+(7.73 x 4%) + (49.59 x 0.34%)=0.48
Risk events Avoided Tier 2	0+(17.31 x 4%)+(111.11 x 0.34%)= 1.07
Transmission Ignition rate HFTD	9%
Ignitions Avoided Tier 3	0.47 x 9%=0.043
Ignitions Avoided Tier 2	1.07 x 9%=0.096
Total Ignitions avoided	0.043+0.096=0.139

3. Region prioritization

Detailed inspections are currently completed on a 3-year cycle for all structures in the HFTD. In addition, prior to the first event of the current year's wildfire season and as conditions allow, an additional set of visual inspections is completed on transmission lines located within Tier 3 of the HFTD which are likely to be impacted by high winds. This additional patrol looks for potential fire conditions within the high-risk Tier 3 HFTD environment which, if identified, take immediate priority.

4. Progress on initiative

Detailed inspections on all transmission structures are completed on a 3-year cycle. This has been a successful historical practice that will be continued in subsequent years. With the continuation of this program and interval, detailed tie line inspections on 2,087 structures on 37 tielines will be completed in 2022.

Actual performance for 2021 and targets for 2022 for this initiative are provided in Attachment B, Table 12.

5. Future improvements to initiative

While this initiative will continue, SDG&E does not currently plan on implementing any improvements to this initiative. All structures are physically visited on a 3-year cycle with additional patrols (such as visual, infrared, and additional Tier 3 patrols) used to supplement these inspections.

7.3.4.3 Improvement of inspections

See Section 7.3.4.9 Other discretionary inspection of distribution electric lines and equipment, beyond inspections mandated by rules and regulations.

7.3.4.4 Infrared inspections of distribution electric lines and equipment

1. Risk to be mitigated

There is a risk of issues arising from electrical connections and equipment that cannot be seen during traditional visual inspections. Connections are difficult to fully assess from the ground or air as it is not possible to visually see the electrical flow. If connections look secure but are not truly tight, the electrical flow may all follow one path resulting in potential premature failure of a connection. Left undetected, these issues could cause an equipment failure that could lead to an ignition.

2. Initiative selection

To mitigate this risk, the Distribution Infrared Inspection demonstration project was developed. Thermographers utilize infrared technology to look at the radiation emitted by the connections to determine if there are potential issues with a connection prior to failure.

Distribution Infrared Inspection demonstration project findings will be tracked to evaluate the risk reduction potential. At this time, findings have been discovered utilizing infrared technology that would not have been seen through traditional visual inspections. The issues identified to date are conditions that could pose a fire or public safety risk.

Risk Reduction Estimation Methodology

Because the Distribution Infrared Inspection program is new, results from 2020 were utilized to forecast future years. Due to the technology dependency of this inspection type, it was assumed that any issue found would lead to a risk event. Other inspection cycles or patrols would be unable to identify these issues as they are performed visually and cannot detect hot connections (which cannot be seen with the naked eye). The 2020 results showed an estimated 0.0002 ignitions reduced in the Tier 3 HFTD. Calculations are shown in Table 7.

Table 7-20: Risk Reduction Estimation for Distribution Infrared Inspections

2020 Inspections completed Tier 2	0
Emergency Tier 2 Actuals	0
Priority Tier 2 Actuals	0
Non-Critical Tier 2 Actuals	0
2020 Inspections completed Tier 3	13077
Emergency Tier 3 Actuals	0
Priority Tier 3 Actuals	2
Non-Critical Tier 3 Actuals	0
Fail Rate Emergency	41%
Fail Rate Priority	4%
Fail Rate Non-Critical	0.34%
Faults Avoided Tier 3	0 + 2 + 0 = 2
Distribution Ignition rate Tier 3	2.69%
Fault Reduced Tier 3	(0 x 41%)+(2 x 4%)+(0 x 0.34%)=0.08
Ignition Reduced	0.08 x 2.69%=0.002

3. Region prioritization

The initial focus of the demonstration project in 2020 was on distribution circuits located within Tier 3 of the HFTD. Circuits were initially selected within Tier 3 based on the historical fault counts. Based on initial results and a comparison to visual findings for a similar region, the prioritization of the demonstration project was changed for 2021. Infrared inspections in 2021 were performed on more urban circuits within Tier 2 of the HFTD based on location and customer count.

4. Progress on initiative

Based on the results from 2020 and 2021, work in 2022 will be a mix of Tier 2 and Tier 3 inspections. Circuits will be prioritized utilizing the same methods but targeting structures and conductors which were not already captured in the previous year's patrols. This project will be assessed to determine if it will be continued after 2022. (See section 7.1 Wildfire Mitigation Strategy for program metrics).

Actual performance for 2021 and targets for 2022 for this initiative are provided in Attachment B, Table 12.

5. Future improvements to initiative

Future plans for the Distribution Infrared Inspection demonstration project will be assessed based on results from 2020, 2021, and 2022 data.

7.3.4.5 Infrared inspections of transmission electric lines and equipment

1. Risk to be mitigated

There is a risk of issues with electrical connections and equipment that cannot be seen during traditional visual inspections. Connections are difficult to fully assess from the ground or air as it is not possible to visually see the electrical flow. If connections look secure but are not truly tight, the electrical flow may all follow one path resulting in potential premature failure of a connection. Left undetected, these issues could cause an equipment failure that could lead to an ignition.

2. Initiative selection

To mitigate this risk, the Transmission Infrared Inspection demonstration program was developed. Thermographers utilize infrared technology which looks at the radiation emitted by the connections to determine if there are potential issues with a connection prior to failure.

Historically, patrols performed on all transmission lines do not provide the same quantity of GO 95 infractions as does the detailed inspection program. However, the conditions reported are often extremely elevated equipment connection temperatures which pose a fire or public safety risk. The conditions noted through the program are typically conditions that would not have been seen through the visual or detailed patrols and are often only able to be seen through infrared showing the positive impact of the program. Additional infrared patrols completed in conjunction with visual patrols are also performed as needed on potentially impacted transmission lines prior to major events such as RFWs.

<u>Risk Reduction Estimation Methodology</u>

The studies discussed in Section 4.4.2.6 Impact of Inspection Programs at Finding and Repairing Equipment Issues and 4.4.2.7 Impact of Distribution and Transmission Inspection Program on Faults

Avoided Due to Fire Risk Infractions Repaired describe the methodology to estimate the risk reduced by inspection and maintenance programs. To review, for existing programs, a 5-year historical average of hit rates (number of issues found at a given priority level divided by total inspections) was calculated and utilized to forecast future years based on the number of inspections in the HFTD for these programs. Due to the technology dependency of this inspection type, it was assumed that any issue found would lead to a risk event, as another inspection cycle or patrol would be unable to identify this issue as they are visual and could not detect hot connections. Finally, the average ignition rate for transmission risk events and ignitions in the HFTD was utilized to convert from risk events avoided to ignitions avoided. The ignitions avoided is calculated on an annual basis, and can change annually depending on the inspection cycle, which determines which structures are scheduled for inspections within the HFTD. For 2022, an estimated 0.083 ignitions would occur should SDG&E stop completing inspections and repairs in the prescribed timeframes as part of the transmission infrared protection program. Calculations are shown in Table 7-21.

Table 7-21: Risk Reduction Estimation for the Transmission Infrared Inspection Demonstration Program

5-year average hit rate Emergency (0-3 days)	0
5-year average hit rate Priority (4-30 days)	0.00004
5-year average hit rate Non - Critical	0.0001
2022 Inspection Total Tier 3	1993
2022 Inspection Total Tier 2	4161
Emergency Tier 3	0
Emergency Tier 2	0
Priority Tier 3	0.00004 x 1993 = 0.080
Priority Tier 2	0.00004 x 4161 = 0.166
Non-Critical Tier 3	0.0001 x 1993 = 0.199
Non-Critical Tier 2	0.0001 x 4161 = 0.446
Risk events Avoided Tier 3	0.0805 + 0.199 = 0.279
Risk events Avoided Tier 2	0.166+0.446 = 0.612
Transmission Ignition rate HFTD	9.00%
Ignitions Avoided Tier 3	0.279 x 9% = 0.025
Ignitions Avoided Tier 2	0.612 x 9% = 0.055

Total Ignitions avoided	**0.055+0.025 = 0.080**

3. Region prioritization

Infrared patrols on transmission lines are most effective during higher loading conditions and therefore they typically begin in the warmer months prior to San Diego's peak fire season. As corrosion, rust, and other structural impacts may cause hotspots on structures and equipment, all energized transmission lines are targeted by this program. Additional patrols performed prior to events are targeted based on meteorological data. Wind speed, FPI, and other factors are also analyzed to determine where best to patrol prior to Red Flag Warning or other events.

4. Progress on initiative

In 2021, infrared patrols were completed on all energized transmission lines in its system. In 2022, an additional set of infrared patrols will be performed on all energized transmission lines in the HFTD resulting in infrared patrols on over 6,154 structures on approximately 112 tielines as well as additional patrols prior to events as needed.

Actual performance for 2021 and targets for 2022 for this initiative are provided in Attachment B, Table 12.

5. Future improvements to initiative

SDG&E does not currently plan on implementing any improvements to this initiative. All structures are inspected on an annual basis. Additional infrared patrols completed in conjunction with visual patrols are also performed as needed on potentially impacted transmission lines prior to major events such as RFWs.

7.3.4.6 Intrusive pole inspections

1. Risk to be mitigated

Poles can fail due to internal degradation prior to identification of the issue via visual inspections and replacement of the pole. A pole failure can lead to a fault on the system, a wire down event, and a potential ignition.

2. Initiative selection

The Wood Pole Intrusive Program mitigates this risk. GO 165 requires 1) all wood poles over 15 years of age are intrusively inspected within 10 years, and 2) all poles which previously passed intrusive inspection are to be inspected intrusively again on a 20-year cycle. Wood pole intrusive inspections are performed on a 10-year (average) cycle.

An intrusive inspection normally involves an excavation around the pole base and/or a sound and bore of the pole at ground-line. Depending on the cavities found or the amount of rot observed, an estimate of the remaining pole strength is determined utilizing industry-wide standards. Depending on the severity of the deterioration, the pole either passes, is reinforced with a steel truss to provide it another five to ten years of useful life, or is replaced. This replacement and reinforcement process is described in Section 7.3.3.6 Distribution pole replacement and reinforcement, including with composite poles.

Risk Reduction Estimation Methodology

The studies discussed in Section 4.4.2.6 Impact of Inspection Programs at Finding and Repairing Equipment Issues and Section 4.4.2.7 Impact of Distribution and Transmission Inspection Program on Faults Avoided Due to Fire Risk Infractions Repaired describe the methodology to estimate the risk reduced by inspection and maintenance programs. To review, for existing programs, a 5-year historical average of hit rates (number of issues found at a given priority level divided by total inspections) was calculated and utilized to forecast future years based on the number of inspections in the HFTD for these programs. Failure rate calculations (i.e., how many risk events would occur within a year if inspections and repairs were not performed within the prescribed timeframes) are described in the study and utilized to convert issues found into risk events. Finally, the average distribution ignition rates broken down by HFTD tier were utilized to calculate ignitions avoided due to the program. The ignitions avoided is calculated on an annual basis, and can change annually depending on the inspection cycle and which structures are scheduled for inspections within the HFTD. The 10-year intrusive program in particular can vary from year to year, as some cycles do not involve many inspections in the HFTD, and some cycles can be over 90% within the HFTD. Given the inspection cycle for 2022, an estimated 0.011 ignitions would be avoided in relation to the 10-year intrusive wood pole inspection program. Calculations are shown in Table 7-22.

Table 7-22: Risk Reduction Estimation for Wood Pole Intrusive Inspection Programs

5-year average hit rate Emergency (0-3 days)	0.0015
5-year average hit rate Priority (4-30 days)	0.0013
5-year average hit rate Non - Critical	0.0350
2022 Inspection Total Tier 3	0
2022 Inspection Total Tier 2	350
Emergency Tier 3	0.002 x 0 = 0
Emergency Tier 2	0.0015 x 350 = 0.525
Priority Tier 3	0.001 x 0 = 0
Priority Tier 2	0.0013 x 350 = 0.455
Non-Critical Tier 3	0.035 x 0 = 0
Non-Critical Tier 2	0.035 x 350 = 12.2
Fail Rate Emergency	41%
Fail Rate Priority	4%
Fail Rate Non-Critical	0.34%
Risk events Avoided Tier 3	0
Risk events Avoided Tier 2	(0.525 x 41%) + (0.455 x 4%) + (12.2 x 0.34%) =0.28
Distribution Ignition rate Tier 3	2.69%
Distribution Ignition rate Tier 2	3.29%
Ignitions Avoided Tier 3	0

Ignitions Avoided Tier 2	0.28 x 3.29% = 0.009
Total Ignitions avoided	**0.009**

3. Region prioritization

Intrusive wood pole inspections are performed on all wood poles throughout the service territory. Intrusive wood pole inspections that occur in the HFTD are reported in the WMP.

4. Progress on initiative

The Wood Pole Intrusive Inspection program is slightly below its targets for 2021 and has set targets for 2022. SDG&E did not fully complete the initial target of 9,796 inspections due to planned intrusive inspections being completed early in 2020. Of the 14,450 intrusive inspections performed in 2020, 700 of those were planned for 2021, but completed in 2020 through our special request process. These inspections were canceled for 2021, resulting in a reduced target that was not discovered until after the change order deadline of November 1, 2021 had passed. Using the modified target of 9,096 intrusive inspections, SDG&E would be 96 percent complete with this initiative in 2021.

No changes were made to this program in 2021 and none are expected to be made in 2022.

Actual performance for 2021 and targets for 2022 for this initiative are provided in Attachment B, Table 12.

5. Future improvements to initiative

SDG&E does not currently plan on modifying or enhancing this program.

7.3.4.7 LiDAR inspections of distribution electric lines and equipment

1. Risk to be mitigated

Hanging field conditions, if not assessed, can lead to potential failures and ignitions.

2. Initiative selection

To mitigate this risk, LiDAR inspections are used. Unlike other inspection programs, LiDAR inspections on distribution lines are primarily used to support grid hardening design efforts rather than for identifying issues. LiDAR surveys have evolved into a foundational component for overhead distribution line engineering analysis and design. Starting in 2013 with the development of the FiRM program, LiDAR was utilized for analysis of the distribution system for clearance and structural adequacy. Distribution systems are often changing with joint use additions, customer relocations, compliance, reliability and maintenance modifications, conductor creep and pole settling, external development, and other potential hazards which can impact electric line design to mitigate the risk of wildfires.

LiDAR surveys provide a cost effective, scalable, and accurate solution for overhead power line analysis, increasing both system reliability and safety. Priority for LiDAR spend is as follows: post-construction survey (including auditing contractor activities), pre-construction design, and vegetation analysis.

Risk Reduction Estimation Methodology

This initiative does not have a Risk Reduction Estimation because it does not directly reduce wildfire risk. LiDAR inspections on distribution and transmission lines are primarily used for grid hardening design efforts rather than for identifying issues like the other inspection programs. As such, quantifying a reduction in ignition risk for these inspections is not applicable.

3. Region prioritization

LiDAR is utilized for distribution hardening programs, which are primarily being designed and constructed in the HFTD.

4. Progress on initiative

In 2022, all circuits within the HFTD will be completed. Captured data will be used to implement vegetation risk analysis within the HFTD. Additionally, Results of these analyses will be used for emergency operations during red flag and other extreme events. As system hardening projects continue to roll out, additional pre-LiDAR and post-LiDAR design and analysis will follow.

Actual performance for 2021 and targets for 2022 for this initiative are provided in Attachment B, Table 12.

5. Future improvements to initiative

LiDAR inspections will continue to supplement grid hardening efforts and post-construction analysis. The LiDAR data will also be evaluated as a tool to enhance vegetation management inspections and check for changes to vegetation throughout the HFTD.

7.3.4.8 LiDAR inspections of transmission electric lines and equipment

1. Risk to be mitigated

Changing field conditions, if not assessed, can lead to potential failures and ignitions.

2. Initiative selection

The NERC FAC-003-4 Transmission Vegetation Management established a standard for utilities to evaluate their transmission system for clearance compliance. This standard, along with the emergence of LiDAR survey and PLS-CADD, allowed utilities to rapidly deploy and model transmission systems for clearance and structural adequacy.

LiDAR surveys are primarily used for grid hardening design efforts rather than for identifying issues. They provide a cost effective, scalable, and accurate solution for overhead power line analysis, increasing both system reliability and safety while mitigating the risk of wildfires. Over time, LiDAR surveys have evolved into a necessary function for overhead transmission line engineering analysis and design.

Transmission and distribution systems are often changing with joint use additions, customer relocations, compliance, reliability and maintenance modifications, conductor creep and pole settling, and external development. Rural transmission lines, particularly in the HFTD, require attentive vegetation analysis. As such, it is important that LiDAR surveys are current and field verified to ensure conditions of the line have not changed. Priority for LiDAR spend is as follows: post-construction survey, pre-construction design, and vegetation analysis.

Risk Reduction Estimation Methodology

This initiative does not have a Risk Reduction Estimation because it does not directly reduce wildfire risk. Because LiDAR inspections on distribution and transmission lines are primarily used for grid hardening design efforts rather than for identifying issues like the other inspection programs, quantifying a reduction in ignition risk for these inspections is not applicable.

3. Region prioritization

LiDAR survey and PLS-CADD design are utilized for all overhead hardening projects, the majority of which are being designed and constructed in the HFTD.

4. Progress on initiative

Previously processed LiDAR was utilized to proactively model transmission lines that were identified by Meteorology as likely to experience high winds during red flag events. Additionally, Transmission requested new LiDAR for 50 miles of transmission in HFTD Tier2 for SDG&E’s 230kV system. This is an ongoing initiative.

5. Future improvements to initiative

LiDAR inspections will continue to supplement grid hardening efforts and post-construction analysis. The LiDAR data will also be evaluated as a tool to enhance vegetation management inspections and check for changes in vegetation throughout the HFTD. Results of these analyses will also be used for emergency operations during red flag and other extreme events.

7.3.4.9 Other discretionary inspection of distribution electric lines and equipment, beyond inspections mandated by rules and regulations

7.3.4.9.1 HFTD Tier 3 distribution pole inspections

1. Risk to be mitigated

HFTD Tier 3 Inspections of overhead electric distribution poles in high-risk fire areas are performed with a focus on identifying areas where maintenance would improve fire safety and reliability, with a goal of mitigating the probability that the overhead electric system, facilities, and equipment would be the source of ignition for a fire.

2. Initiative selection

Additional HFTD Tier 3 distribution pole inspections were conducted from 2010 through 2016 as a result of a settlement agreement adopted in D.10-04-047. In 2017, SDG&E decided to proactively continue the HFTD Tier 3 QA/QC inspections as part of its normal program. In addition to these HFTD Tier 3 inspections, a system maintenance patrol (as specified by GO 165) is performed for the entire overhead electric distribution system in the HFTD on an annual basis. Safety-related issues identified on those patrols are scheduled for follow-up repair.

Risk Reduction Estimation Methodology

The studies discussed in Sections 4.4.2.6 Impact of Inspection Programs at Finding and Repairing Equipment Issues and Section 4.4.2.7 Impact of Distribution and Transmission Inspection Program on Faults Avoided Due to Fire Risk Infractions Repaired describe the methodology to estimate the risk reduced by inspection and maintenance programs. To review, for existing programs, a 5-year historical average of hit rates (number of issues found at a given priority level divided by total inspections) was calculated and utilized to forecast future years based on the number of inspections in the HFTD for these programs. Failure rate calculations (i.e., how many risk events would occur within a year if inspections and repairs were not performed within the prescribed timeframes) are described in the study and utilized to convert issues found into risk events. Finally, the average distribution ignition rates broken down by HFTD tier were utilized to calculate ignitions avoided due to the program. The ignitions avoided is calculated on an annual basis, and can change annually depending on the inspection cycle, which determines which structures are scheduled for inspections within the HFTD. For 2022, an estimated 0.231 ignitions would occur if inspections and repairs were not performed in the prescribed timeframes as part of the 3-year Tier 3 HFTD distribution inspection program. Calculations are shown in Table 7-23.

Table 7-23: Risk Reduction Estimation for HFTD Tier 3 Distribution Pole Inspection Program

5-year average hit rate Emergency (0-3 days)	0.0013
5-year average hit rate Priority (4-30 days)	0.0053
5-year average hit rate Non - Critical	0.026
2022 Inspection Total Tier 3	12268
2022 Inspection Total Tier 2	18
Emergency Tier 3	0.0013 x 12,268 = 15.95
Emergency Tier 2	0.0013 x 18=0.023
Priority Tier 3	0.0053 x 12268 = 65.02
Priority Tier 2	0.0053 x 18=0.095
Non-Critical Tier 3	0.026 x 12268 = 318.97
Non-Critical Tier 2	0.026 x 18 =0.468
Fail Rate Emergency	41%
Fail Rate Priority	4%
Fail Rate Non-Critical	0.34%
Risk events Avoided Tier 3	(15.95 x 41%) + (65.02 x 4%) + (318.97 x 0.34%) = 10.22
Risk events Avoided Tier 2	(0.023 x 41%) + (0.095 x 4%) +(0.468 x 0.34%) = 0.0148
Distribution Ignition rate Tier 3	2.69%
Distribution Ignition rate Tier 2	3.29%
Ignitions Avoided Tier 3	10.22 x 2.69% = 0.275
Ignitions Avoided Tier 2	0 .0148 x 3.29%=0.00049
Total Ignitions avoided	**0.275**

3. Region prioritization

In 2018, when the CPUC adopted the current statewide fire threat map, SDG&E began applying the QA/QC three-year cycle to the newly defined HFTD Tier 3[52]. From 2016 to 2018 HFTD Tier 3 Inspections were performed on an average of 15,000 poles annually (approximately one-third of the distribution poles in the HFTD Tier 3) in then-existing "extreme" and "very high" fire threat areas.

4. Progress on initiative

Repairs for some conditions found in Tier 3 of the HFTD (including the design, engineering, and construction of the new structures) were completed faster than the 6-month or 12-month timeframe required by applicable General Orders. This approach aims to address the highest first risk areas on an accelerated schedule. No changes were made to the inspection process in 2021 and none are expected to be made in 2022.

Targets have been met for HFTD Tier 3 inspections in 2021. Actual performance for 2021 and targets for 2022 for this initiative are provided in Attachment B, Table 12.

5. Future improvements to initiative

No specific improvements are planned in the future for this initiative.

7.3.4.9.2 Drone assessments of distribution infrastructure

1. Risk to be mitigated

Some issues on distribution infrastructure are difficult or impossible to identify from the ground using traditional inspection methods.

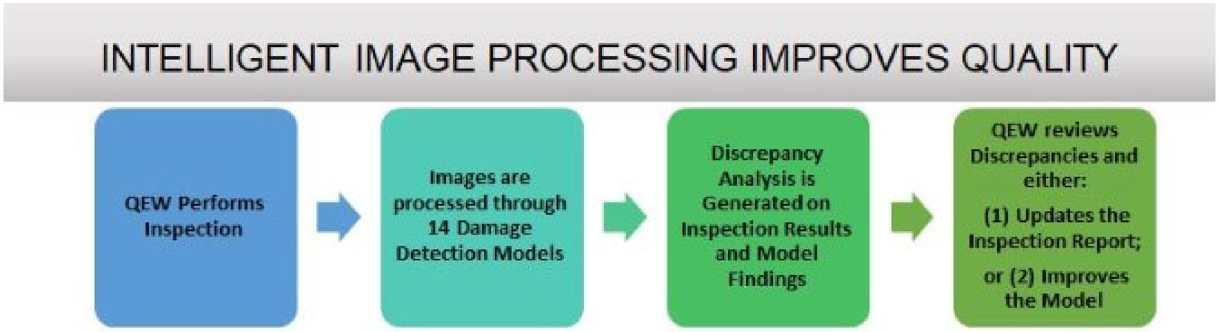
2. Initiative selection

To mitigate this risk, the use of drones was implemented to provide a "birds-eye" view of distribution electric facilities and capture high-resolution imagery which can be used to identify issues, build a library of images for machine learning, and improve risk-based inspection methodology. The DIAR Program involves flight planning, drone flight and image capture, image assessment and determination of issues, and repair. Imagery collected by the drones improves identification of potential fire hazards related to certain types of issues or where conditions such as terrain and vegetation density make full detailed inspections difficult. Issues that are more readily observed by the DIAR Program include damaged arrestors, damaged insulators, issues with pole top work, issues with armor rods, crossarm or pole top damage, exposed connections, loose hardware, improper splices, and damaged conductors.

Images are also used to build damage detection models that allow intelligent image processing (i.e., machine learning or artificial intelligence) technology to process the image data and improve the quality of the DIAR assessments (see Figure 7-8).

[52] See: https://www.arcgis.com/apps/webappviewer/index.html?id=5bdb921d747a46929d9f00dbdb6d0fa2

Figure 7-8: Intelligent Image Processing Improves Quality



These models are generally associated with the pole, crossarm, insulator, and transformer. SDG&E prioritized the types of models it developed to focus on the highest risk items and highest frequency issues.

<u>Risk Reduction Estimation Methodology</u>

The studies discussed in Section 4.4.2.6 Impact of Inspection Programs at Finding and Repairing Equipment Issues and Section 4.4.2.7 Impact of Distribution and Transmission Inspection Program on Faults Avoided Due to Fire Risk Infractions Repaired describe the methodology to estimate the risk reduced by inspection and maintenance programs. To review, for existing programs, a 5-year historical average of hit rates (number of issues found at a given priority level divided by total inspections) was calculated and utilized to forecast future years based on the number of inspections in the HFTD for these programs. Failure rate calculations (i.e., how many risk events would occur within a year if inspections and repairs were not performed within the prescribed timeframes) are described in the study and utilized to convert issues found into risk events. Finally, the average distribution ignition rates broken down by HFTD tier were utilized to calculate ignitions avoided due to the program. The ignitions avoided is calculated on an annual basis, and can change annually depending on the inspection cycle and which structures are scheduled for inspections within the HFTD.

For the DIAR Program, the actual hit rate is significantly higher than the 5-year average. This was expected as the program evaluates infrastructure, at a high level of detail, from the top-down as opposed to the bottom-up method of traditional inspections. Once all poles in each of the respective areas have been inspected, the hit rate is expected to reduce to the 5-year average values. In 2020, only poles in Tier 3 had been inspected by the DIAR program. In 2021 the focus shifted to primarily Tier 2 poles and the remainder of Tier 3 that was not completed previously. In 2022, the inspections are entirely in Tier 2. Based on the data and assumptions, the DIAR Program reduced 3.21 ignitions in the HFTD Tier 3 in 2020. For 2021, the DIAR Program reduced 0.168 ignitions in HFTD Tier 3 and 3.65 ignitions in the HFTD Tier 2 and will reduce 2.99 ignitions in the HFTD Tier 2 in 2022. Calculations are shown in Table 7-24.

Table 7-24: Risk Reduction Estimation for the DIAR Program (Distribution)

2021 Inspections completed Tier 3	520
Emergency Tier 3 Actuals	10

Priority Tier 3 Actuals	45
Non-Critical Tier 3 Actuals	100
2021 Inspections completed Tier 2	8131
Emergency Tier 2 Actuals	87
Priority Tier 2 Actuals	1314
Non-Critical Tier 2 Actuals	6730
Fail Rate Emergency	41%
Fail Rate Priority	4%
Fail Rate Non-Critical	0.34%
Faults Avoided Tier 2	87+1314+6730=8131
Distribution Ignition rate Tier 2	3.29%
Fault Reduced Tier 2	(87 x 41%) + (1314 x 4%) +(6730 x 0.34%) = 111
Ignition Reduced Tier 2	111 x 3.29%=3.65
Faults Avoided Tier 3	10+45+100=155
Distribution Ignition rate Tier 3	2.69%
Fault Reduced Tier 3	(10 x 41%) + (45 x 4%) +(100 x 0.34%) = 6.26
Ignition Reduced Tier 3	6.26 x 2.69%=0.168
Total Ignitions Reduced	**3.65 + 0.168 = 3.818**

3. Region prioritization

The DIAR Program collects images and performs inspections in the HFTD portion of the service territory. Circuits are prioritized according to circuit risk indices that consider pole age, pole material type, local weather conditions, and vegetation communities.

4. Progress on initiative

Enhancements and progress made in 2021 include

- Transitioned the DIAR Program from a pilot program to a more defined initiative through development of workflows and process and procedure documents
- Developed and refined damage detection models including 22 damage conditions within a range of 65-97 percent accuracy.
- Added QEW inspector teams in the field with the drone pilot so image assessments could happen in the field, allowing a reduction of the number of images needed

Enhancements for 2022 will include

- Continue to refine and expand damage detection models
- Streamline the process of gaining government agency authorizations from California State Parks, as well as coordination with sensitive customers

- Develop processes and procedures to incorporate the use of drones into SDG&E's routine inspection program

Actual performance for 2021 and targets for 2022 for this initiative are provided in Attachment B, Table 12.

5. Future improvements to initiative

Assessment results will be utilized as a baseline to improve models related to PoF. When the potential for failure is better understood, inspection efforts can be better focused, creating efficiencies and reducing the potential for ignition events, outages, and failures from occurring.

The intelligent image processing models will be enhanced and expanded to allow for improved damage detection using drones and other methods such as fleet and mobile device image capture. The ability to process large amounts of data will help drive inspections to a more predictive or prevention-based focus. For example, damage detection models deployed on a fleet vehicle could identify a potential issue on an asset not scheduled for inspection in that cycle or could help detect less severe issues that would not require a repair at the time of inspection but would indicate a follow-up inspection should be conducted in a reduced timeframe. Similarly, the risk models could indicate what facilities might need less frequent inspection. This data would ultimately allow for more efficient maintenance practices to be implemented from inspection to repair.

7.3.4.10 Other discretionary inspection of transmission electric lines and equipment, beyond inspections mandated by rules and regulations

7.3.4.10.1 Drone assessment of transmission

1. Risk to be mitigated

Some issues on transmission infrastructure are difficult or impossible to identify from the ground using traditional inspection methods.

2. Initiative selection

To mitigate this risk, the use of drones was implemented to capture high-resolution imagery which can be used to identify issues. The DIAR Program is discussed in detail in Section 7.3.4.9.2 Drone assessments of distribution infrastructure. The primary difference between distribution and transmission inspections is that transmission already performs aerial patrols of its lines on a routine basis; therefore, the value associated with the use of drones to provide a top-down look and high-resolution images at the structures was unknown.

<u>Risk Reduction Estimation Methodology</u>

The studies discussed in Section 4.4.2.6 Impact of Inspection Programs at Finding and Repairing Equipment Issues and Section 4.4.2.7 Impact of Distribution and Transmission Inspection Program on Faults Avoided Due to Fire Risk Infractions Repaired describe the methodology to estimate the risk reduced by inspection and maintenance programs. To review, for existing programs, a 5-year historical average of hit rates (number of issues found at a given priority level divided by total inspections) was calculated and utilized to forecast future years based on the number of inspections in the HFTD for these programs. Failure rate calculations (i.e., how many risk events would occur within a year if inspections and repairs were not performed within the prescribed timeframes) are described in the study and utilized to convert issues found into risk events. Finally, the average distribution ignition rates broken down by HFTD tier were utilized to calculate ignitions avoided due to the program. The ignitions avoided is calculated on an annual basis, and can change annually depending on the inspection cycle and which structures are scheduled for inspections within the HFTD.

The transmission DIAR Program included aerial flights and assessments for approximately 1,200 structures within the Tier 3 HFTD in 2021. Forecasts for future years will be based off the additional assessment results allowing the use of historical averages. Issues found and the failure rate calculations discussed in Section 4.4.2.7 Impact of Distribution and Transmission Inspection Program on Faults Avoided Due to Fire Risk Infractions Repaired were leveraged to determine the estimated ignitions reduced by this program on the transmission system within the Tier 3 HFTD. Based on the results from the transmission DIAR Program in 2021, an estimated 0.053 ignitions would be reduced annually. Calculations are shown in Table 7-25.

Table 7-25: Risk Reduction Estimation for the DIAR Program (Transmission)

2021 Inspections completed Tier 2	37
Emergency Tier 2 Actuals	0
Priority Tier 2 Actuals	7
Non-Critical Tier 2 Actuals	3
2021 Inspections completed Tier 3	768
Emergency Tier 3 Actuals	0
Priority Tier 3 Actuals	3
Non-Critical Tier 3 Actuals	49
Fail Rate Emergency	41%
Fail Rate Priority	4%
Fail Rate Non-Critical	0.34%
Faults Avoided Tier 3	0+3+49=52
Distribution Ignition rate HFTD	9.00%
Fault Reduced Tier 3	(0 x 41%) + (3 x 4%) + (49 x 0.34%) = 0.29
Ignition Reduced Tier 3	0.29 x 9% = 0.026
Faults Avoided Tier 2	0+7+3=10
Distribution Ignition rate HFTD	9.00%
Fault Reduced Tier2	(0 x 41%) + (7 x 4%) + (3 x 0.34%) = 0.30
Ignition Reduced Tier 2	0.30 x 9% = 0.027
Total Ignitions Reduced	**0.026 + 0.027 = 0.053**

3. Region prioritization

This initiative focuses on select higher-risk transmission structures in the HFTD such as older wood structures in high wind areas, areas subject to PSPS events, and Western Energy Coordinating Council (WECC) tie lines.

4. Progress on initiative

Enhancements and progress made in 2021 include

- Completed initial pilot program for drone assessment of transmission assets.
- Reduced the target for 2021 transmission drone flights to focus on the distribution system and select higher-risk transmission structures such as older wood structures in high wind areas, areas subject to PSPS events, and WECC tie lines.

Enhancements in 2022 include:

- Continue to refine transmission DIAR Program based on consequence of failure and probability of failure
- Expand intelligent image processing to build models for transmission facilities asset identification and damage detection in 2022 using the images collected.

Actual performance for 2021 and targets for 2022 for this initiative are provided in Attachment B, Table 12.

5. Future improvements to initiative

The drone inspection data collected for transmission facilities will continue to improve understanding of the transmission facility risk and how frequently inspections using different methods are necessary. For example, the inspection data from drone assessments combined with traditional inspections may aid SDG&E in identifying the types of issues that should be inspected via drone, such as loose hardware or conductor damages. Focusing on those issues could better prevent failures from occurring.

The intelligent image processing models will be enhanced and expanded to help reduce future costs associated with inspections to address the increasing need to consume and process data.

7.3.4.10.2 Additional Transmission Aerial 69kV Tier 3 Visual Inspection

1. Risk to be mitigated

During San Diego's peak fire season, it is imperative that tie lines and equipment do not have any major issues which may pose a fire concern. Issues, if not corrected, may lead to the possibility of ignition.

2. Initiative selection

To mitigate this risk, visual inspection flights are performed just prior to the start of San Diego's peak fire season. The timeliness of these patrols is critical to mitigating potential risk. Flights are performed by QEWs who are responsible for performing inspections and patrols throughout the year. Aerial visual patrols are performed on all tie lines starting in the first quarter of the year to check for major issues. Additional patrols are completed on tie lines in Tier 3 of the HFTD to check for potential fire conditions on these structures. Prior to September 1 of each year, flights are performed to check for these conditions and work is prioritized to ensure any conditions found are corrected before the season for extreme wind, RFW, or Santa Ana events occurs. This reduces the risk for potential wildfires by ensuring these potential conditions are checked and corrected.

Due to the scope of these patrols and their timing before fire season, all repair conditions found are critical to mitigate risks.

Risk Reduction Estimation Methodology

The studies discussed in Section 4.4.2.6 Impact of Inspection Programs at Finding and Repairing Equipment Issues and Section 4.4.2.7 Impact of Distribution and Transmission Inspection Program on Faults Avoided Due to Fire Risk Infractions Repaired describe the methodology to estimate the risk reduced by inspection and maintenance programs. For existing programs, a 5-year historical average of “hit rates” (number of issues found at a given priority level divided by total inspections) was calculated and utilized to forecast future years based on the number of inspections in the HFTD for these programs. Failure rate calculations (i.e., how many risk events would occur within a year if inspections and repairs were not performed within the prescribed timeframes) are described in the study and utilized to convert issues found into risk events. Finally, the average ignition rate for transmission risk events and ignitions in the HFTD was utilized to convert from risk events avoided to ignitions avoided. The ignitions avoided is calculated on an annual basis. For 2022, an estimated 0.005 ignitions would occur if inspections and repairs are not performed in the prescribed timeframes as part of the additional transmission aerial patrol program. Calculations are shown in Table 7-26.

Table 7-26: Risk Reduction Estimation for Transmission Aerial 69kV Tier 3 Visual Inspections

5-year average hit rate Emergency (0-3 days)	0
5-year average hit rate Priority (4-30 days)	0.00084
5-year average hit rate Non-Critical	0
2022 Inspection Total Tier 3	1654
Emergency Tier 3	0 x 1654 = 0
Priority Tier 3	0.00084 x 1654 = 1.3894
Non-Critical Tier 3	0 x 1654 = 0
Fail Rate Emergency	41%
Fail Rate Priority	4%
Fail Rate Non-Critical	0.34%
Risk events Avoided Tier 3	1.3894 x 4% = 0.0556
Transmission Ignition rate HFTD	9.00%
Ignitions Avoided Tier 3	**0.0556 x 9% = 0.005**

3. Region prioritization

Patrols are focused on 69 kV tie lines located in Tier 3 of the HFTD, as 69 kV tie lines typically have less spacing and ground clearance than higher voltages. Patrollers also utilize these flights to get another visual on the components and equipment of the 230 kV and 500 kV structures to further mitigate these risks.

4. Progress on initiative

In August 2021, 5 days of flights were completed by QEWs to look at all 69 kV tie lines within Tier 3 of the HFTD. The goal to complete all 69 kV lines prior to September 1, 2021, which is typically the beginning of peak fire season, was accomplished. In addition, these flights looked at key 230 kV and 500 kV tie lines within Tier 3 of the HFTD. These same flights will be completed prior to September 1, 2022.

Actual performance for 2021 and targets for 2022 for this initiative are provided in Attachment B, Table 12.

5. Future improvements to initiative

In addition to the aerial patrols on the 69 kV tie lines in Tier 3 of the HFTD, Patrols will be completed on the 230 kV and 500 kV tie lines in the same area.

7.3.4.11 Patrol inspections of distribution electric lines and equipment

1. Risk to be mitigated

Patrol inspections mitigate the risk of equipment failure by identifying equipment deterioration and facilitating repair and/or replacement before failures occur. Equipment failure can lead to electrical faults, which can lead to ignitions.

2. Initiative selection

In general, utilities must patrol their systems once a year in urban areas and in Tier 2 and Tier 3 of the HFTD. Patrol inspections in rural areas outside of the HFTD are required to be performed once every two years. As a long-standing practice, however, SDG&E performs patrol inspections in all areas on an annual basis. In addition to the patrol inspections, utilities must conduct detailed inspections at a minimum every three to five years, depending on the type of equipment.

The patrol inspections are mandated by GO 165. SDG&E tracks the issues identified and their remediation which demonstrates their effectiveness.

<u>Risk Reduction Estimation Methodology</u>

The studies discussed in Section 4.4.2.6 Impact of Inspection Programs at Finding and Repairing Equipment Issues and Section 4.4.2.7 Impact of Distribution and Transmission Inspection Program on Faults Avoided Due to Fire Risk Infractions Repaired describe how SDG&E developed a methodology to estimate the risk reduced by inspection and maintenance programs. To review, for existing programs, a five-year historical average of hit rates (number of issues found at a given priority level/total inspections) was calculated and utilized to forecast future years based on the number of inspections in the HFTD for these programs. SDG&E's failure rate calculations (i.e., how many risk events would occur within a year should SDG&E not have inspected and repaired issues within the prescribed timeframes) are described in the study and utilized to convert issues found into risk events. Finally, the average distribution ignition rates broken down by HFTD tier were utilized to calculate ignitions avoided due to the program. The ignitions avoided is calculated on an annual basis. For 2022, an estimated 0.621 ignitions would occur should SDG&E stop completing inspections and repairs in the prescribed timeframes as part of the annual patrol distribution inspection program. A summary of the calculation is provided in Table 7-27.

Table 7-27: Risk Reduction Estimation for Patrol Inspections of Distribution Equipment

5-year average hit rate Emergency (0-3 days)	0.00054
5-year average hit rate Priority (4-30 days)	0.0005
5-year average hit rate non-Critical	0.0038
2022 Inspection Total Tier 3	39,550
2022 Inspection Total Tier 2	46,940
Emergency Tier 3	0.00054 x 39,550 = 21.36
Emergency Tier 2	0.00054 x 46,940 =25.35
Priority Tier 3	0.0005 x 39,550 = 19.76
Priority Tier 2	0.0005 x 46,940 = 23.47
Non-Critical Tier 3	0.0038 x 39,550 = 150.29
Non-Critical Tier 2	0.0038 x 46,940 = 178.329
Fail Rate Emergency	41%
Fail Rate Priority	4%
Fail Rate Non-Critical	0.34%
Risk events Avoided Tier 3	(21.36 x 41%) + (19.76 x 4%) + (150.29 x 0.34%) = 10.06
Risk events Avoided Tier 2	(25.35 x 41%) + (23.47 x 4%) + (178.37 x 0.34%) = 11.94
Distribution Ignition rate Tier 3	2.69%
Distribution Ignition rate Tier 2	3.29%
Ignitions Avoided Tier 3	10.06 x 2.69% = 0.271
Ignitions Avoided Tier 2	11.94 x 3.29% = 0.393
Total Ignitions avoided	**0.271 + 0.393 = 0.664**

3. Region prioritization

SDG&E performs patrol inspections throughout its service territory. Only the patrols associated with HFTD assets are reported within the WMP.

4. Progress on initiative

In 2021, all patrols on the electric distribution system have been completed in the service territory. In 2022, SDG&E will continue to comply with GO 165 and conduct the required patrol inspections.

Actual performance for 2021 and targets for 2022 for this initiative are provided in Attachment B, Table 12.

5. Future improvements to initiative

SDG&E does not plan any future improvements to this initiative.

7.3.4.12 Patrol inspections of transmission electric lines and equipment

1. Risk to be mitigated

Structures, conductor spans, and right of way encroachments can create issues or equipment deterioration that are not visible from the ground. Equipment failure can lead to electrical faults, which can lead to ignitions.

2. Initiative selection

To mitigate this risk, transmission visual patrols are conducted annually by helicopter on all overhead tie lines within the HFTD. The visual patrols provide an overhead view of structures and components in order to identify issues such as cracked pole tops or rust/corrosion and larger issues which pose a fire risk or risk to public safety.

<u>Risk Reduction Estimation Methodology</u>

The studies discussed in Section 4.4.2.6 Impact of Inspection Programs at Finding and Repairing Equipment Issues and Section 4.4.2.7 Impact of Distribution and Transmission Inspection Program on Faults Avoided Due to Fire Risk Infractions Repaired describe how SDG&E developed a methodology to estimate the risk reduced by inspection and maintenance programs. To review, for existing programs, a 5-year historical average of hit rates (number of issues found at a given priority level/total inspections) was calculated and utilized to forecast future years based on the number of inspections in the HFTD for these programs. SDG&E's failure rate calculations (i.e., how many risk events would occur within a year should SDG&E not have inspected and repaired issues within the prescribed timeframes) are described in the study and utilized to convert issues found into risk events. Finally, the average ignition rate for transmission risk events and ignitions in the HFTD was utilized to convert from risk events avoided to ignitions avoided. The ignitions avoided is calculated on an annual basis. For 2022, an estimated 0.018 ignitions are avoided as a result of the detailed transmission inspection program. A summary of the calculation is provided in Table 7-28.

Table 7-28: Risk Reduction Estimation for Patrol Inspections of Transmission Equipment

5-year average hit rate Emergency (0-3 days)	0
5-year average hit rate Priority (4-30 days)	0.00072
5-year average hit rate Non-Critical	0.00085
2022 Inspection Total Tier 3	1,993

2022 Inspection Total Tier 2	4,319
Emergency Tier 3	0 x 1,993 = 0
Emergency Tier 2	0 x 4319 = 0
Priority Tier 3	0.00072 x 1,993 = 1.43
Priority Tier 2	0.00072 x 4,319 = 3.11
Non-Critical Tier 3	0.00085 x 1,993 =1.69
Non-Critical Tier 2	0.00085 x 4,319 = 3.67
Fail Rate Emergency	41%
Fail Rate Priority	4%
Fail Rate Non-Critical	0.34%
Risk events Avoided Tier 3	0 + (1.43 x 4%) + (1.69 x 0.34%) = 0.063
Risk events Avoided Tier 2	0 + (3.11 x 4%) + (3.67 x 0.34%) = 0.137
Transmission Ignition rate HFTD	9.00%
Ignitions Avoided Tier 3	0.063 x 9% = 0.0057
Ignitions Avoided Tier 2	0.137 x 9% = 0.0123
Total Ignitions avoided	0.0057 + 0.0123 = 0.018

3. Region prioritization

All energized and de-energized transmission lines are patrolled on an annual basis. Additional flights prior to September 1 of each year in Tier 3 of the HFTD are specifically targeted to ensure fire safety prior to peak fire season. The locations for additional patrols performed prior to forecasted events are targeted based on meteorological data such as at wind speed, FPI, and other factors to determine where best to patrol prior to RFW or other events.

4. Progress on initiative

Progress for visual patrols is within 10 percent of the 2021 target and targets are set for 2022. No changes were made in 2021 and none are expected to be made in 2022.

Actual performance for 2021 and targets for 2022 for this initiative are provided in Attachment B, Table 12.

5. Future improvements to initiative

SDG&E does not currently plan on implementing any improvements to this initiative.

7.3.4.13 Pole loading assessment program to determine safety factor

See Section 7.3.3.6 Distribution pole replacement and reinforcement, including with composite poles and Section 7.3.3.17 Updates to grid topology to minimize the risk of ignition in HFTD for distribution overhead system hardening.

7.3.4.14 Quality assurance/quality control of inspections

1. Risk to be mitigated

Application of inspection protocols can be inconsistent and subject to human error, resulting in the potential to miss an infraction that could become a fire hazard.

2. Initiative selection

To mitigate this risk, CMP inspections are audited. Inspection audits are managed by Operation and Engineering managers who are responsible for audits in each of the operating districts. This process also allows field supervisors to evaluate the inspectors and ensure they are all aligned with SDG&E's protocols and procedures.

3. Region prioritization

The 1.5 percent of CMP inspections are audited in each region including inspections done in the HFTD.

4. Progress on initiative

All audits on SDG&E's detailed inspections and repairs have been completed for 2021. Audits for 2022 will occur as inspections and repairs are completed next year.

Actual performance for 2021 and targets for 2022 for this initiative are provided in Attachment B, Table 12.

5. Future improvements to initiative

SDG&E does not plan on implementing any improvements to this initiative.

7.3.4.15 Substation inspections

1. Risk to be mitigated

Substations have the risk of equipment failure which has the potential to cause ignitions,[53]

2. Initiative selection

To mitigate this risk, the Substation Inspection and Maintenance Program identifies Substation equipment deterioration in order to make repairs or replacements before a failure occurs, as mandated by GO 174. The program is conducted primarily for reliability; however, it also provides incidental wildfire mitigation benefits within the HFTD and the WUI. The Substation Inspection and Maintenance Program schedules routine inspections at reoccurring cycles. These inspections consist of a detailed monthly or bimonthly inspection where equipment is visualized and problems, such as oil leaks, are identified. When issues are identified during an inspection, corrective work orders are opened with a severity level of either immediate or within the next 12 months. While patrol inspections are primarily focused on the substation assets, switchyard vegetation removal corrective maintenance orders are part of the inspection findings.

[53] While substation equipment failure can cause ignition of equipment inside a substation, it is rare for it to travel outside of the substation.

Risk Reduction Estimation Methodology

This initiative does not have a Risk Reduction Estimation. Design and construction of substations include steel structures and a gravel and concrete base which makes it difficult for a fire to spread outside the substation.

3. Region prioritization

Patrol Inspections and Infrared Inspections are prioritized regardless of location within or outside of the HFTD. Priority 1 substations have an operating voltage above 200 kV or have a total of 4 or more transmission lines at or above 69 kV. All other substations are categorized as Priority 2. See Table 7-28 for inspection schedules.

Table 7-29: Patrol and Infrared Inspection Frequency

Inspection	Planned Frequency	Acceptable Frequency (per internal Standard Operating Procedures)
Substation Patrol Inspection	Priority 1 – Once per month Priority 2 - Once per two months	Priority 1 - 10 per every 12 months Priority 2 - 5 per every 12 months
Substation Infrared Inspection	Every 12-months	Every 15 months

4. Progress on initiative

The Substation Inspection and Maintenance Program is meeting its targets for 2021 and has set targets for 2022. No changes were made to this Program in 2021 and none are expected to be made in 2022.

Actual performance for 2021 and targets for 2022 for this initiative are provided in Attachment B, Table 12.

5. Future improvements to initiative

There are no current plans to change the Substation Inspection and Maintenance Program.

7.3.5 Vegetation Management and Inspections

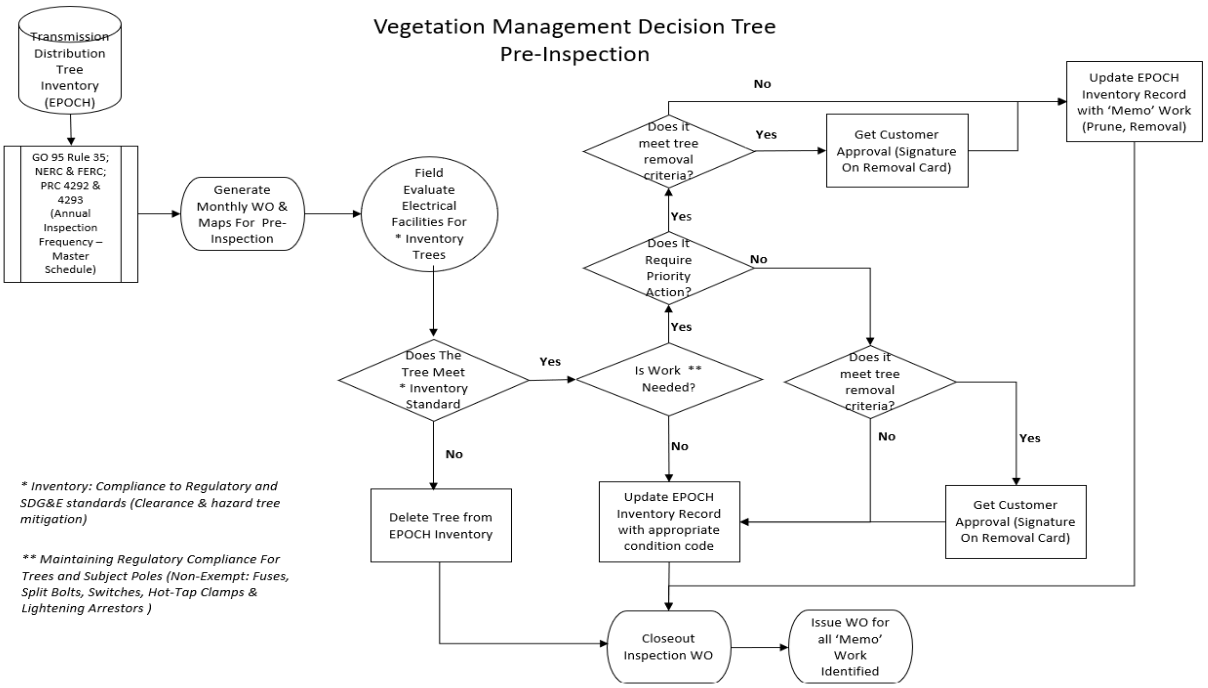
As part of its efforts to make its electric system more resistant to wildfires and to comply with relevant CPUC rules and state law, SDG&E's Vegetation Management Program was designed with the goal of keeping vegetation clear of electric infrastructure. It involves several components, including but not limited to tracking and maintaining a database of inventory trees and poles, routine and off-cycle inspections, pruning and removing hazardous trees, replacing unsafe trees with more situationally compatible species, pole brushing, and training first responders in electrical and fire awareness.

Figure 7-9 shows a high-level flowchart process for the various activities of the vegetation management program. Each flowchart represents a different activity of the program including pre-inspection, tree trimming/removal, pole brushing, and quality assurance and shows how SDG&E incorporates risks and makes decisions to prioritize the work performed. Tables below each flowchart include descriptions for each step shown in the flowchart.

Vegetation Management prioritizes tree work based on the urgency of the condition. Trees that are non-compliant with the minimum clearance requirement are referred to as “Memos” and can be classified as Level 1 inspection findings. Memos may be scheduled for trim the same day they are observed or up to a few weeks post observation depending on site-specific conditions. Trees that are not Memos are considered a routine priority and follow the Master Schedule of Vegetation Management activities. Routine inspection findings may be classified as Level 2. In 2020 there were 5,579 memos and 171,731 routine inspection trees. In 2021 there were 4,548 memos and 158,644 routine inspection trees. In response to QR Action-SDGE-31 (Class B), see Attachment J: Vegetation Management Inspection Findings by Vegetation Management Area (VMA) and Priority Level.

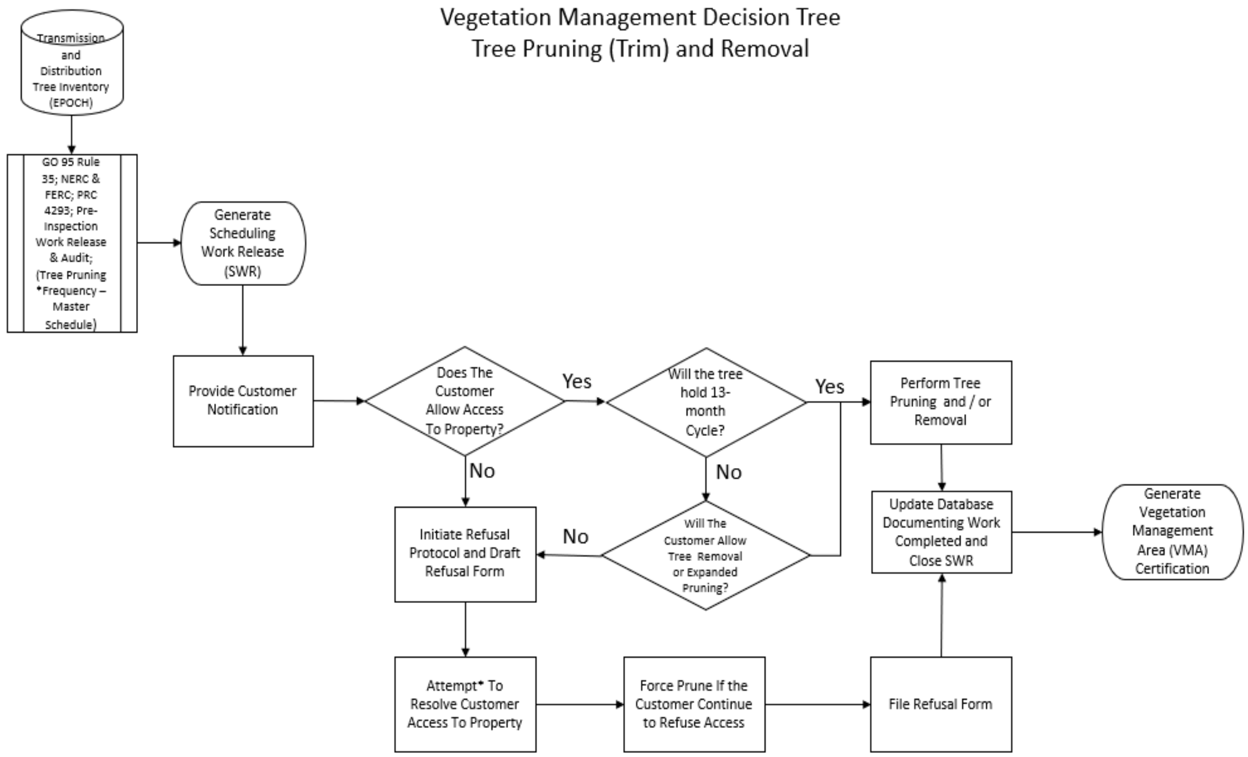
See Figure 7-10 for a high-level flowchart process for tree pruning and removal. Figure 7-11 shows a high-level flowchart process for pole brushing. Figure 7-12shows a high-level flowchart process for auditing.

Figure 7-9: Vegetation Management Decision Tree: Pre-Inspection



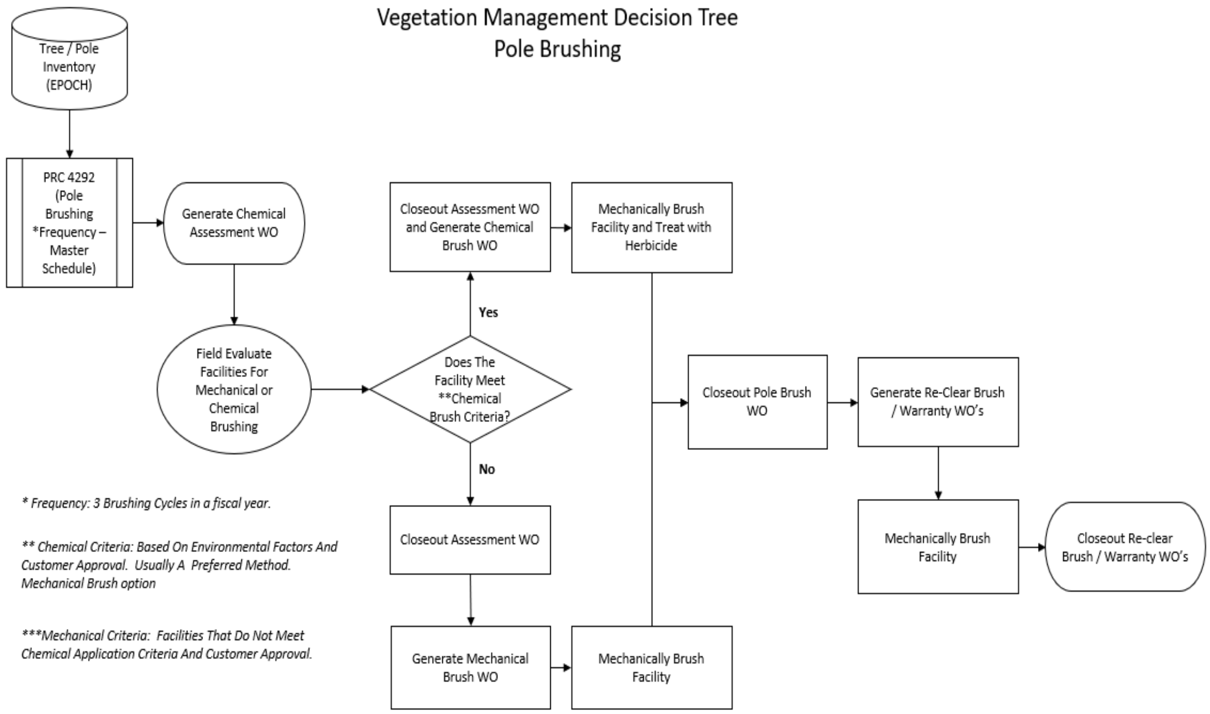
Vegetation Management - Pre-Inspection		
Step #	**Workflow Steps**	**Description**
1	Transmission Distribution Tree Inventory Database	Vegetation records are maintained utilizing relative positioning to a GIS layer of energized facilities.
2	GO 95 Rule 35; NERC & FERC; PRC 4292 & 4293 (Annual Inspection Frequency – Master Schedule)	Compliance requirements and SDG&E standards determine frequency and type of inspections. A routine annual inspection cycle is performed to maintain regulatory compliance and SDG&E standards. GO 95 Rule 35 is the 18" rule for vegetation clearances in areas that fire protection is managed locally (not Cal Fire) PRC 4292 is the regulatory statute stating the 10-foot radius around poles; PRC 4293 is the 4-foot rule clearance standard for areas that fire protection is Cal Fire in wild land areas. Master schedule is the start times plotted by month for Vegetation Management Areas (VMA's) regarding all work activities.
3	Generate Monthly WO & Maps For Pre-Inspection	Work orders (WOs) are electronically created for individual forester to effectively assign the inspection work along with maps of the Vegetation Management Areas (VMAs) being inspected to ensure all required facilities are inspected.
4	Field Evaluate Electrical Facilities For Inventory Trees	All vegetation is evaluated and potentially inventoried based on its clearance and potential threat to energized facilities. This is determined based on the voltage of the lines and the geographical layer the facilities reside in (I.e., LRA, SRA, HFTD).
5	Does The Tree Meet Inventory Standard	Vegetation is inventoried if it has the potential to grow out of compliance within 3 years, if it needs to be worked in the current cycle (such as a newly identified hazard tree). "Brush" records are also created and maintained for poles with non-exempt equipment in SRA (called "subject poles").
6	Is Work Needed?	Vegetation is flagged for pruning if it will become non-compliant within 14 months – the time until the next cycle's tree trim activity, if it is currently out of compliance, or if a tree represents a threat to the energized facilities from a partial or total tree failure. Such hazard trees are referred to as "reliability trees". Subject poles that meet the criteria for work according to PRC4292 and SDG&E standards are also flagged for clearing.
7	Does It Require Priority Action?	Vegetation is flagged for priority pruning (called memos) ahead of routine work if it is currently non-compliant, will not hold 2 months until routine tree trimming occurs, or represent an imminent threat of failing into the facilities.
8	Does it meet tree removal criteria?	Trees are considered good removal candidates if they are fast growers requiring annual pruning, they are palms growing near the lines, they are palms able to shed dead fronds onto the lines.
9	Get Customer Approval (Signature On Removal Card)	Signatures are required for all removals. The signature must be provided by the homeowner, property manager, or authorized agency (city, Caltrans, etc.).
10	Update EPOCH Inventory Record with 'Memo' Work (Prune, Removal)	Data is entered into each inventory record reflecting the current condition code of work required as well as tree, property, and customer details.
11	Delete Tree from EPOCH Inventory	Inventory records are removed if the vegetation has been removed or no longer represents a threat to energized facilities.
12	Update EPOCH Inventory Record with 'Routine' Work (Clear, Prune, Removal)	Data is entered into each inventory record reflecting the current condition code of work required as well as tree, property, and customer details.
13	Closeout Inspection WO	WOs managed by the pre-inspectors are sent back to their supervisors, triggering a certification process for each VMA for the current month.
14	Issue WO for all Memo Work Identified	Priority work is issued directly to the tree trim contractors on a daily, weekly, or end of the inspection month work order packet depending upon the threat level (i.e., proximity to the lines or hazard tree condition).

Figure 7-10: Vegetation Management Decision Tree: Pruning and Removal



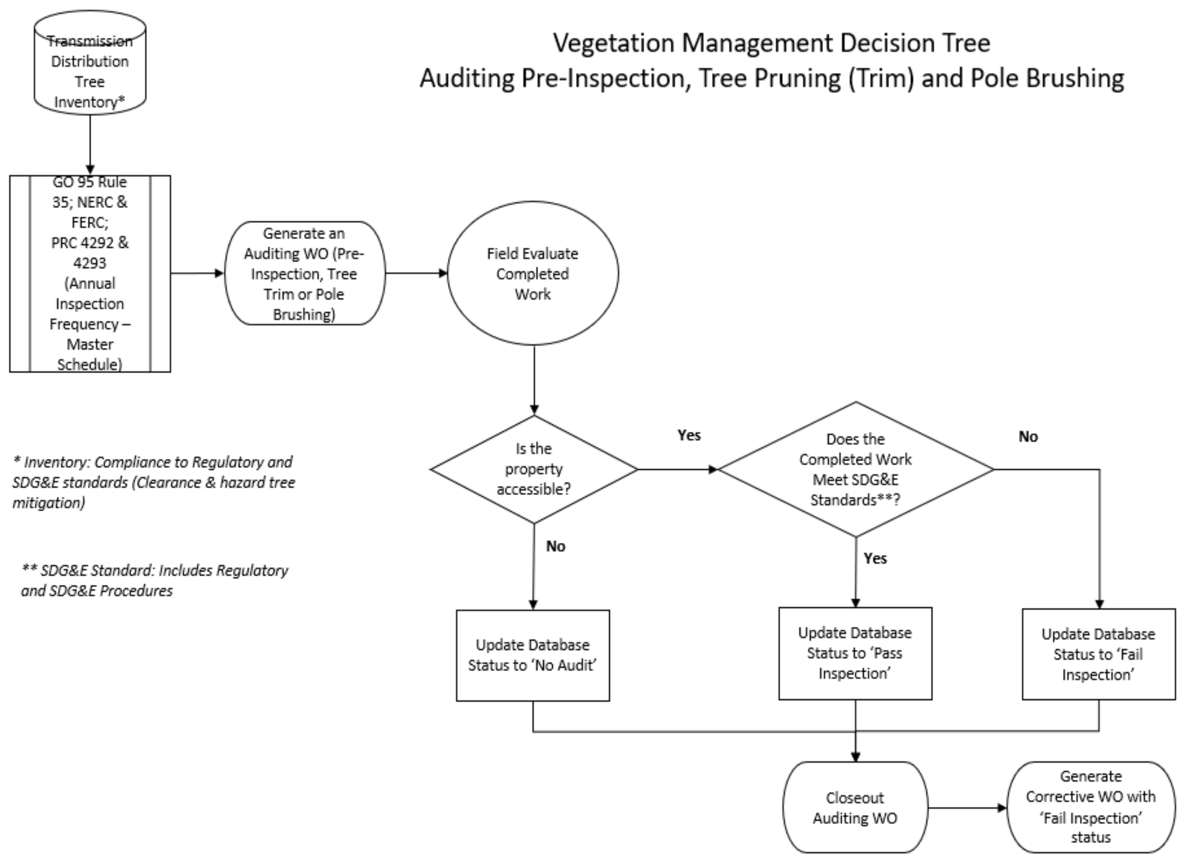
Vegetation Management - Tree Pruning and Removal		
Step #	Workflow Steps	Description
1	Transmission and Distribution Tree Inventory (EPOCH)	Vegetation records are maintained utilizing relative positioning to a GIS layer of energized facilities.
2	GO 95 Rule 35; NERC & FERC; PRC 4293; Pre-Inspection Work Release & Audit; (Tree Pruning *Frequency – Master Schedule)	Compliance requirements and SDG&E standards determine frequency and type of inspections. GO 95 Rule 35 is the 18" rule for vegetation clearances in areas that fire protection is managed locally (not Cal Fire) PRC 4292 is the regulatory statute stating the 10-foot radius around poles; PRC 4293 is the 4-foot rule clearance standard for areas that fire protection is Cal Fire in wild land areas. Master schedule is the start times plotted by month for Vegetation Management Areas (VMA's) regarding all work activities.
3	Generate Scheduling Work Release (SWR)	Active tree ID's (for pruning, removal, etc) are gathered in an electronic work package that is generated for each VMA.
4	Provide Customer Notification	Tree contractor attempts to make contact with each property owner / resident and waits 3 days before commencing work. Customer notification occurs via in person, door hanger or a phone call.
5	Does The Customer Allow Access To Property?	If the customer allows access, then crews proceed with required work.
6	Initiate Refusal Protocol and Draft Refusal Form	If the customer refuses access, then a Refusal Form is filled out by the crew and the customer signs (if willing to do so) and the form is given to their General Foreman.
7	Attempt* To Resolve Customer Access To Property	GF attempts to resolve, if unsuccessful then Refusal Form is updated and given to SDG&E Area Forester. A DRG Refusal Specialist is assigned by DRG Management to attempt resolution. If unsuccessful then Refusal Form is updated and given back to SDG&E Area Forester to attempt resolution.
8	Force Prune If the Customer Continue to Refuse Access	Customer is mailed a Certified Form Letter when necessary and the work is performed.
9	File Refusal Form	Refusal Form is updated and filed for a 3-year retention period.
10	Will the tree hold 13-month Cycle?	If SDG&E's required 10ft minimum post-prune clearances will not hold a 13-month cycle, then the tree must be pruned to a greater clearance or removed to comply with applicable GO 95 Rule 35; NERC & FERC; PRC 4293 regulations.
11	Will The Customer Allow Tree Removal or Expanded Pruning?	If customer refuses expanded clearance or tree removal, then a Refusal Form is filled out by the crew and the customer signs (if willing to do so) and the form is given to their General Foreman.
12	Perform Tree Pruning and / or Removal	If the customer allows removal or expanded pruning, then crews proceed with required work.
13	Update Database Documenting Work Completed and Close SWR	Contractor updates each individual tree record to an inactive work completed status and electronically closes the SWR.
14	Generate Vegetation Management Area (VMA) Certification	Reports are ran for VMA work completion statistics, required forms and documentation are prepared for submittal. Then a Certification package is generated and electronically sent to SDG&E for final review and retention.

Figure 7-11: Vegetation Management Decision Tree: Pole Brushing



Vegetation Management - Pole Brushing		
Step #	**Workflow Steps**	**Description**
1	Tree/Pole Inventory (Epoch)	Master Vegetation Management Asset Inventory System.
2	PRC 4292 Pole Brushing (Frequency – Master Schedule)	4 Phases in an Annual Cycle (Assessment/Notification; Chemical Brush; Mechanical Brush; Re-Clear/Chemical Warranty.
3	Generate Chemical Assessment WO	Generate Chemical Assessment Scheduling WO's and Issue to Contractor to Field Evaluate Facilities for Chemical Brushing and Mechanical Brushing Criteria.
4	Field Evaluate Facilities for Chemical or Mechanical Brushing	Physical Facility Site Evaluations of Facilities for Chemical Brushing Criteria or Mechanical Brushing Criteria and Updating the Facility Record Status.
5	Does the Facility Meet Chemical Brush Criteria?	Field Facility Site Evaluation Determinations Made by Examining Environmental Conditions and Customer Approval.
6	Chemical – Closeout Assessment WO and Generate Chemical Brush WO.	Closeout the Chemical Assessment WO's After All Facility Records have been Updated and Certify WO Completion. Generate Chemical Brush Scheduling WO's and Issue to Contractor for Facilities that Met the Chemical Brush Criteria During Assessment.
7	Chemical - Mechanically Brush Facility and Treat with Herbicide	The Physical Mechanical Clearing of a Facility and the Application of Herbicide to the Soil. The Facility Records are Updated to Completed Status.
8	Mechanical – Closeout Assessment WO	Closeout the Chemical Assessment WO's After All Facility Records have been Updated and Certify WO Completion.
9	Mechanical - Generate Mechanical Brush WO	Generate Mechanical Brush Scheduling WO's and Issue to Contractors for Facilities that Met the Mechanical Brush Criteria During Assessment.
10	Mechanical – Mechanically Brush Facility	The Physical Mechanical Clearing of a Facility (Without Herbicides). The Facility Records are Updated to Completed Status.
11	Closeout Pole Brush WO	Closeout Chemical and Mechanical Brush WO's After ALL Facilities Records have been Updated and Certify WO Completion.
12	Generate Re-Clear Brush/Warranty WO's	Generate Re-Clear Brush and Chemical Warranty Brush Scheduling WO's and Issue to Contractor.
13	Mechanically Brush Facility	The Physical Mechanical Re-Clearing of All Facilities from both the Mechanical Brush and Chemical Brush Cycles (Without Herbicides). The Facility Records are Updated to Completed Status.
14	Closeout Re-Clear/Warranty WO's	Closeout the Re-Clear Brush and Chemical Warranty Brush WO's After ALL Facilities have been Updated and Certify Completion.

Figure 7-12: Vegetation Management Decision Tree: Auditing



Vegetation Management - Auditing Pre-Inspection		
Step #	**Workflow Steps**	**Description**
1	Transmission Distribution Tree Inventory Database	Vegetation records are maintained utilizing relative positioning to a GIS layer of energized facilities.
2	GO 95 Rule 35; NERC & FERC; PRC 4292 & 4293 (Annual Inspection Frequency – Master Schedule)	GO 95 Rule 35 is the 18" rule for vegetation clearances in areas that fire protection is managed locally (not Cal Fire) PRC 4292 is the regulatory statute stating the 10-foot radius around poles; PRC 4293 is the 4-foot rule clearance standard for areas that fire protection is Cal Fire in wild land areas. Master schedule is the start times plotted by month for Vegetation Management Areas (VMA's) regarding all work activities.
3	Generate an Auditing WO	Work performed within Epoch/PowerWorkz are facilitated by work orders. Specific work orders contain assets that memorialize work by type. Audit WO are tied back to WO's of total work performed in order to perform sampling.
4	Field Evaluate Completed Pre-Inspection Results	This is validation of work performed by being at the specific assets updated.
5	Is the property accessible?	Some properties are inaccessible due to Refusals, Customer out of area, secured by fencing or Governmental access.
6	Does the Pre-Inspection Meet SDG&E Standards**?	There is a Pre-Inspection Guideline that is the standard for inspections
7	Update Database 'Pass Inspection'	When an asset or record is correct and accurate the auditor will "Pass" by selecting pass and updating.
8	Update Database 'Fail Inspection' And Update With Correct Data	When an asset or record is not correct and accurate either by information or status the auditor will "Fail" by selecting fail adding comment to explain reasoning and updating the record.
9	Update Database 'No Audit'	When a property cannot be accessed in a way to be able to view and judge the asset status and information the record will be updated "No Audit"
10	Closeout Auditing WO	Once all assets are updated and PI work evaluated the WO is closed, completing and locking in the data of performed work.

Vegetation Management - Auditing Tree Pruning and Removal		
Step #	Workflow Steps	Description
1	Transmission Distribution Tree Inventory Database	Vegetation records are maintained utilizing relative positioning to a GIS layer of energized facilities.
2	GO 95 Rule 35; NERC & FERC; PRC 4292 & 4293 (Annual Inspection Frequency – Master Schedule)	GO 95 Rule 35 is the 18" rule for vegetation clearances in areas that fire protection is managed locally (not Cal Fire) PRC 4292 is the regulatory statute stating the 10-foot radius around poles; PRC 4293 is the 4-foot rule clearance standard for areas that fire protection is Cal Fire in wild land areas. Master schedule is the start times plotted by month for Vegetation Management Areas (VMA's) regarding all work activities.
3	Generate an Auditing WO	Work performed within Epoch/PowerWorkz are facilitated by work orders. Specific work orders contain assets that memorialize work by type. Audit WO are tied back to WO's of total work performed in order to perform sampling.
4	Field Evaluate Completed Tree Pruning Results	This is validation of work performed by being at the specific assets where tree pruning was performed updated.
5	Is the property accessible?	Some properties are inaccessible due to Refusals, Customer out of area, secured by fencing or Governmental access.
6	Does the Tree Pruning Meet SDG&E Standards**?	Along with tree pruning guidelines does the pruning meet the following standards GO 95 Rule 35 is the 18" rule for vegetation clearances in areas that fire protection is managed locally (not Cal Fire) PRC 4292 is the regulatory statute stating the 10-foot radius around poles; PRC 4293 is the 4-foot rule clearance standard for areas that fire protection is Cal Fire in wild land areas. Master schedule is the start times plotted by month for Vegetation Management Areas (VMA's) regarding all work activities.
7	Update Database 'Pass Inspection'	When tree pruning is completed to specifications and the asset or record is correct and accurate the auditor will "Pass" by selecting pass and updating.
8	Update Database Status, 'Failed Tree Trim'	When an asset or record is not correct due to improper pruning and or accuracy the auditor will "Fail" by selecting fail adding comment to explain reasoning and updating the record.
9	Update Database 'No Audit'	When a property cannot be accessed in a way to be able to view and judge the asset status and completion of work performed or information the record will be updated "No Audit"
10	Closeout Auditing WO	Once all assets are updated and Tree pruning work evaluated the WO is closed, completing and locking in the data of performed work.
11	Generate WO for Re-Trim / Removal with 'Fail Inspection' status	Once all assets are updated and Tree Pruning work evaluated the WO is closed, completing and locking in the data of performed work. If there are fails that require rework a subsequent retrim work order is issued for rework that is performed at no additional cost to SDG&E

Vegetation Management - Auditing Pole Brushing		
Step #	Workflow Steps	Description
1	Transmission Distribution Tree Inventory Database	Vegetation records are maintained utilizing relative positioning to a GIS layer of energized facilities.
2	PRC 4292 (Pole Brushing *Frequency – Master Schedule)	Compliance requirements and SDG&E standards determine frequency and type of inspections. PRC 4292 is the regulatory statute stating the 10-foot radius around poles; Master schedule is the start times plotted by month for Vegetation Management Areas (VMA's) regarding all work activities.
3	Generate a Pole Brush Auditing WO	Work performed within Epoch/PowerWorkz are facilitated by work orders. Specific work orders contain assets that memorialize work by type. Audit WO are tied back to WO's of total work performed in order to perform sampling.
4	Field Evaluate Completed Pole Brush Results	This is validation of work performed by being at the specific assets where brushing was performed.
5	Is the property accessible?	Some properties are inaccessible due to Refusals, Customer out of area, secured by fencing or Governmental access.
6	Does the Pole Brush Meet SDG&E Standards**?	SDG&E standards equal the public resource code (PRC) 4292. PRC 4292 is the regulatory statute stating a 10-foot radius to bare soil, raising of limbs to 8-feet above ground and removing any dead wood to the height of the cross arm within the cylinder around poles.
7	Update Database 'Pass Inspection'	When pole brushing is completed to specifications and the asset or record is correct and accurate the auditor will "Pass" by selecting pass and updating.
8	Closeout Auditing WO	Once all assets are updated and pole brush work evaluated the WO is closed, completing and locking in the data of performed work.
9	Update Database 'No Audit'	When a property cannot be accessed in a way to be able to view and judge the asset status and completion of work performed or information the record will be updated "No Audit"
10	Update Database Status 'Fail Pole Brush'	When an asset or record is not correct due to improper pole brushing and or accuracy the auditor will "Fail" by selecting fail adding comment to explain reasoning and updating the record.
11	Generate WO for Re-Pole Brush with 'Fail Inspection' status	Once all assets are updated and pole brushing work evaluated the WO is closed, completing and locking in the data of performed work. If there are fails that require rework a subsequent retrim work order is issued for rework that is performed at no additional cost to SDG&E

7.3.5.1 Additional efforts to manage community and environmental impacts

1. Risk to be mitigated

Vegetation has the potential to come into contact with power lines and cause ignitions. The removal and trimming of trees, however, impacts the community and the environment in various ways.

2. Initiative selection

SDG&E aims to mitigate the environmental impacts of tree trimming and removals, as well as the impacts vegetation management practices have within the community. In part to achieve this goal, Vegetation Management provides outreach and education to customers and stakeholders to explain the value and necessity of vegetation management activities. Outreach and education also promote buy-in, collaboration, and investment from customers in the safety and fire prevention benefits of vegetation management practices.

Outreach and education include community events that focus on the utility vegetation management industry standards of "Right Tree-Right Place," proper planting near power lines, maintaining safe clearances, and fire safety. SDG&E also participates in Arbor Day events and engages a non-profit vendor to educate the public and school-age children on electrical awareness and safe and proper management of trees near power lines. Outreach efforts are coordinated through Public Affairs and the WMP Outreach teams. Since 2020, efforts have been modified to conform with COVID-19 social distancing mandates.

Customer engagement activities are continually developed and updated to improve customer outreach and awareness of various wildfire mitigation efforts. Pre- and post-event customer research is also conducted to obtain feedback on the quality of messaging and communication tactics that are employed.

SDG&E created a 30-minute documentary about wildfire safety efforts and advancements and community engagement, including vegetation management practices, that is broadcast on local TV stations and with trailers shown in strategically located movie theaters. Collateral materials were also developed to further educate customers about the need for and value of vegetation management. These materials provide tips and recommendations to help customers manage vegetation and defensible space around their homes and businesses. Additionally, SDG&E's tree safety website is shared with numerous stakeholders and agencies. SDG&E also utilizes its contract workforce of professional arborists and tree trimmers to directly engage with customers on the positive benefits of safe and proper utility line clearance operations.

Vegetation management operations are conducted with an eye toward their environmental impacts and in accordance with all applicable rules and regulations, including protocols of the wildlife agency-approved Natural Communities Conservation Plan (NCCP). Under this plan, company activities are previewed by SDG&E's Environmental Services Department to ensure habitat and species protection. Mitigation measures may include specific constraints, schedule modification, monitoring, and other steps to limit negative impact to species. SDG&E also works with land agencies such as the U.S. Forest Service and California State Parks to identify and implement best practices to protect habitat and species and follows State Forest Practice Rules in the dispersal and removal of green waste associated with tree pruning and removal operations. As a standard operating procedure, smaller wood debris associated with pruning operations is chipped and removed from the site. Wood of larger diameter (approximately 6 inches and greater) that cannot be rendered safely in a chipper is left on site and cut into manageable size. All debris is removed from watercourses to prevent flow restriction or channeling and to prevent flooding or erosion.

Planting utility-compatible trees improves safety, reliability, and compliance, and minimizes the probability of vegetation-related outages and ignitions. As part of the "Right Tree, Right Place" initiative, Vegetation Management offers customers replacement trees as an incentive to allow abatement (removal or heavy pruning) of incompatible trees/shrubs growing near power lines, and/or pole brushing and fuels management activities. The replacement trees are more compatible with the native environment and pose less threat to utility infrastructure.

Tree planting initiatives are also an integral component of SDG&E's approach to sustainability. Forests and trees play a vital role in our planet's overall health, providing critical ecosystem services that allow Earth's natural cycles to function and as important carbon sinks. Climate change and wildfires threaten this relationship. In geographically diverse California, forests are facing climate risks from extreme heat, drought, and wildfires. 2020 was one of the worst years in California wildfire history, with an estimated 1.75 million acres of forest burned and approximately 90 million metric tons of carbon dioxide released from the burning of forests.[54] According to the California Air Resources Board, our natural and working lands have now become a source of carbon emissions.[55]

Recognizing that tree mitigation efforts have an impact on area vegetation and overall tree population, SDG&E has expanded its tree planting initiatives to include planting and distributing up to 10,000 trees annually. The 10,000-tree initiative expands the tree planting approach beyond the replacement of removed trees as a customer courtesy to promote safe tree planting throughout the service territory, combating carbon emissions and promoting environmental stewardship. In working towards this goal, SDG&E emphasizes promoting native, utility-safe vegetation, following the industry-established Right-Tree-Right-Place approach. Where applicable, customers are assisted in the selection of compatible tree species with the goal of minimizing interference with electrical infrastructure and maximizing energy savings and environmental benefits.

3. Region prioritization

Vegetation management operations impact customers across the service territory, with routine scheduled and "off-cycle" activities targeted within the HFTD. To reach a broad segment of customers, online webinars are publicly available. Drive-through fairs are held annually in backcountry communities throughout the summer where customers are provided literature and information pertaining to vegetation management operations, proper tree planting, species selection, and wildfire preparedness. As the 10,000 tree initiative aims to safely plant trees compatible with the environment and mitigate tree removals throughout the service territory, tree distribution activities take place both in and outside of the HFTD. Customers are also encouraged to visit the SDG&E website for additional information and links to various related topics.

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[54] https://ww3.arb.ca.gov/cc/inventory/pubs/ca_ghg_wildfire_forestmanagement.pdf

[55] https://ww2.arb.ca.gov/sites/default/files/2020-10/draft-nwl-ip-040419.pdf

4. Progress on initiative

Enhancements and progress made in 2021 include:

- Established the 10,000 tree initiative, building upon the Right Tree Right Place program and promoting SDG&E's overall sustainability approach. This included the collaboration and partnership with agencies, municipalities, tribal lands, and private landowners to provide trees to enhance environmental quality, combat climate change, enrich customer relationships, and help cities reach climate action goals. Goal was achieved in Quarter 4 of 2021.
- Engaged a third certified vendor to processes 100 percent of material received into recyclable streams, resulting in an increase in the amount of material diverted from landfills and in a further reduction of the carbon footprint related to tree trimming efforts. Current percentage of total green waste diverted to recycling facilities is approximately 46 percent.
- Developed reporting and sustainability dashboard to track amount of green waste such as wood chips and ground cover delivered to customer properties.
- Participated in multiple community outreach events in 2021, including virtual online webinars and community fire-preparedness events, to reach a broader segment of customers and provide information regarding the importance of vegetation management in wildfire mitigation efforts.
- Collaborated with and participated in monthly meetings with California State Parks personnel to review vegetation management activities and scheduling.
- Initiated online customer survey to gauge public feedback on tree trimming operations.

Enhancements for 2022 will include:

- Grow the company sustainability initiative to provide 10,000 trees annually in collaboration with customers and local agencies.
- Implement a Tree Rebate Program targeted at underserved communities to promote the planting of trees where climate equity is compromised. The program will offer each applicant a rebate in the purchase of up to 5 trees. This initiative will help promote environmental awareness, teach sustainable tree planting, improve climate, and encourage community involvement. An interactive company website will be created to educate customers about the program and how they can participate.
- Develop and expand a customer survey regarding vegetation management operations to gather additional feedback on tree trimming operations.
- Develop internal, quarterly newsletters to engage internal business units and raise awareness of vegetation management operations.
- Continue to work collaboratively with state and federal agencies on the scope and effectiveness of sound vegetation management operations.

Actual performance for 2021 and targets for 2022 for this initiative are provided in Attachment B, Table 12.

5. Future improvements to initiative

Vegetation Management will continue to work with multiple internal departments and external stakeholders toward the goal of continuing to provide comprehensive outreach and education regarding its vegetation management activities including web content, specific literature, and public events. SDG&E will also continue to develop and promote tree planting and sustainability efforts as opportunities evolve.

7.3.5.2 Detailed inspections and management practices for vegetation clearances around distribution electrical lines and equipment

1. Risk to be mitigated

Vegetation around electric distribution lines and equipment poses potential risks for safety, compliance, and reliability.

2. Initiative selection

To mitigate this risk and to comply with CPUC rules and state and federal laws, the Vegetation Management Program includes annual routine and off-cycle inspection activities performed by IS Certified Arborists.

Routine Inspection

Vegetation management operations are driven by regulatory requirements and follow an annual, master schedule that includes pre-inspection, tree trimming, auditing, and pole brushing. During the annually scheduled routine inspection activity, all inventory trees are inspected to determine whether they require pruning for the annual cycle. Information for each inventory tree is recorded within the electronic inventory tree database (see Section 7.3.5.19 Vegetation management system). During routine pre-inspection within the HFTD all trees within the strike zone of transmission and distribution lines receive a "level 2" hazard evaluation. Trees tall enough to strike overhead electric lines are assessed for trimming or removal and include identification of dead, dying, and diseased trees, live trees with a structural defect, and conditions such as wind sway and line sag. The visual inspection includes a 360-degree hazard assessment of trees from ground level to canopy height to determine tree health, structural integrity, and environmental conditions. Where appropriate, sounding techniques or root examination may also be conducted. Where required, trees are trimmed or removed to prevent line-strike from either whole tree failure or limb break out.

Off-Cycle Patrols

Vegetation Management performs a second annual tree inspection activity within the HFTD referred to as the "off-cycle" patrol. The scope of the off-cycle patrol is similar to the routine inspection activity; all trees within the utility strike zone are assessed to determine whether a tree could encroach within the minimum clearance requirement or otherwise poses a threat to the overhead facilities. The off-cycle patrols are performed by SDG&E internal Patrollers and contractors who are ISA-Certified. Approximately 240,000 of SDG&E's 460,000 inventory trees are located within the HFTD. As described in Section 4.4.2.9 Impact of the Enhanced Vegetation Management Program and below, SDG&E's analysis demonstrates the risk reduction benefits of this program.

In addition, SDG&E performs additional annual inspections for Century plant and bamboo species due to their fast and unpredictable growth. Century plants (Agave) have a flowering stage at the end of their lifecycle that includes the growth of an elongated, vertical flower stalk. The stalk can grow to the height of power lines in a matter of weeks, and may pose an ignition threat. Bamboo are fast-growing species that, due to the growth rate, are difficult to manage for line clearance with a single annual trim cycle. Additional inspections of Century plant and bamboo have proven effective in intercepting the growth of these species and preventing contact and potential ignition.

The criteria for determining post-trim clearances includes factors such as species, height, growth rate, health, location of defect, site conditions, and proper cuts. Inspection strategy is tree-specific and the goal is to ensure that post-trim a tree cannot encroach power lines or make contact either by wind sway, branch breakout, or tree/root failure. The industry standard of directional pruning is followed to achieve this goal. If a tree cannot be mitigated by pruning, complete removal may be necessary. Emergency pruning may also occur when a tree requires immediate attention to clear an infraction, or if it poses an imminent threat to the electrical facilities (see Enhanced Clearances in Section 7.3.5.15 Identification and remediation of "at-risk species".)

Risk Reduction Estimation Methodology

To determine the effectiveness of the Vegetation Management program, historical vegetation contact data going back to 1995 before the formal vegetation management program was established in 1998 was reviewed. During this period, SDG&E increased its post trim clearance standards to 10-12 feet of clearance and saw dramatic reductions in vegetation contacts. Tree inventory location was then utilized as a method to approximate the location of risk events, and then the 5-year average ignition rates were utilized to estimate the ignitions avoided. Based on the calculations, 20.34 ignitions are avoided between 2020 and 2022 by completing vegetation management activities according to SDG&E's current process. Table 7-30 provides a summary of the calculation:

Table 7-30: Risk Reduction Estimation for Vegetation Management

Average vegetation risk events pre-mitigation (1995-1998)	402
Average vegetation risk events post mitigation (1999-2010)	66
Risk events reduced	336
Tier 3 Trees	109,535
Tier 2 Trees	135,340
Non-HFTD Trees	232,644
Total Trees	477,519
Risk events avoided Tier 3	336 x (109,535 ÷ 477,519) = 37
Risk events avoided Tier 2	336 x (135,340 ÷ 477,519) = 67.40
Risk events avoided Non-HFTD	336 x (232,644 ÷ 477,519) = 231.38

Ignition rate Tier 3	2.69%
Ignition rate Tier 2	3.29%
Ignition rate Non-HFTD	1.46%
Ignitions avoided Tier 3	37.22 x 2.69% = 1.002
Ignitions avoided Tier 2	67.40 x 3.29% =2.218
Ignitions avoided Non-HFTD	231.38 x 1.46% = 3.39
Number of Tree inspected Tier 3 (2020-2022)	345,114
Number of Tree inspected Tier 2 (2020-2022)	426,416
Number of Tree inspected Non HFTD (2020-2022)	703,935
Total Ignitions avoided (2020-2022)	**(345,114 ÷ 109,535) x 37 x 2.69%) + (426,416/135,340) x (67.4 x 3.29%) +(703,935/232,644) x 231.38 x 1.46%) = 20.34**

3. Region prioritization

SDG&E divides its service territory into 133 distinct zones known as VMAs which are determined by multiple factors including city boundary, SDG&E Districts, and other geographical features. Routine pre-inspection within each VMA follows an annual, master schedule. The off-cycle inspection activity is performed within all VMAs located partially or completely within the HFTD. An off-cycle inspection of every inventory Century plant is performed throughout the service territory in the spring when flowering typically occurs. Two off-cycle inspections of all inventory bamboo are performed, one in the spring and one in the fall.

4. Progress on initiative

Enhancements and progress made in 2021 include:

- Implemented the next generation of SDG&E's database work management system (Epoch). Enhancements to the new system include upgraded computer field hardware, software updates, and improvements to data entry, accuracy, and reporting.
- Integrated VRI GIS mapping layer into Epoch mobile application for user situational awareness during inspections.
- Engaged with a third party to study the correlation between enhanced tree trim clearances and reduction of vegetation-caused outages.
- SDG&E, PG&E, and SCE (jointly investor-owned utilities or IOUs) began collaboration on a vegetation clearance study to determine the effectiveness of expanded trim clearances on risk-event frequency (see Section 4.4.2.9 Impact of the Enhanced Vegetation Management Program), and Section 4.6 Progress Reporting on Key Areas of Improvement for progress on Action Statement SDG&E-21-04.

- Continued engagement with the SDSC to study the relationship between expanded clearances and reduction in tree-related outages.
- Hired four internal Forester Patroller positions to perform off-cycle, off-cycle tree inspections within the HFTD.
- Began the planning to proactively manage Century plants through the use of an EPA-approved herbicide to kill the plant before it enters it dangerous flowering stage. Planning activities are targeted within transmission corridors.

Enhancements in 2022 will include:

- Explore the use of the WiNGS-Planning risk model to evaluate the effectiveness of vegetation management operations risk models to support future prioritization and implementation of tree trimming
- Modify the annual schedule for off-cycle inspections within the HFTD to occur closer to the beginning of the region's peak fire season (September), while allowing enough time to complete any backlog items
- Continue to collaborate on multi-year vegetation management enhanced clearance study with the joint IOUs
- Further integrate VRI into inspection activities for the HFTD
- Engage third-party review of inspection activities to gauge the effectiveness and efficiency of scheduling
- Continue additional inspection activities throughout 2022 as they have proven to be extremely effective in mitigating the risk of outage, ignition, and wildfire.
- Proactively manage Century plants within transmission corridors through biological means (herbicide use).

Actual performance for 2021 and targets for 2022 for this initiative are provided in Attachment B, Table 12.

5. Future improvements to initiative

Future initiatives include the continued refinement of the VRI to enhance situational awareness, and to determine where additional inspections may be beneficial for situational awareness in advance of PSPS events.

Over the next 10 years, the use of LiDAR will be developed to augment inspection activities, equipment change detection, and auditing. SDG&E is also investigating inter-departmental processes that could automate notification when equipment is changed out that makes a pole subject to brushing.

Vegetation Management will continue to work with FS&CA to determine where to expand vegetation clearances around subject poles within high fire areas to mitigate the risk of ignitions that could occur outside the required clearances of Public Resources Code Section 4292.

7.3.5.3 Detailed inspections and management practices for vegetation clearances around transmission electrical lines and equipment

See Section 7.3.5.2 Detailed inspections and management practices for vegetation clearances around distribution electrical lines and equipment.

7.3.5.4 Emergency response vegetation management due to red flag warning or other urgent climate conditions

1. Risk to be mitigated

A process to respond to an emergency event or priority condition reduces the risk of service disruption and ignition.

2. Initiative selection

Vegetation Management response to emergency conditions such as RFW declarations and storm events are important to mitigate conditions that could increase outages and/or ignitions. Vegetation Management actively participates in emergency operations activities in advance of forecasted events through weather monitoring, contractor communication, and workforce preparation. In advance of forecasted RFWs or Santa Ana conditions, SDG&E will determine if additional vegetation management patrols are warranted to assess tree conditions. Vegetation Management coordinates with FD&CA to determine if and where this activity should occur.

In addition to elevated conditions such as storm and RFW events, Vegetation Management implements prioritization protocols when a tree is observed to be out of compliance with the minimum clearance requirement or if the tree poses an imminent threat to the power lines. A tree in this condition is considered a "Memo". When such a condition is identified, tree trimming may be performed the same day or scheduled within a few weeks depending on the severity and urgency of the condition.

3. Region prioritization

As a forecasted event approaches, tree crew resources are scheduled and coordinated for standby operations where requested. These crews are staged to be utilized for storm response and restoration activities. During elevated or extreme weather events, Vegetation Management contractors are kept informed of conditions in advance, allowing them time to relocate crews into safe work areas or to cease operations if required. In instances of emergency tree trimming during elevated fire conditions, additional fire equipment or support from contracted, professional fire resources may be utilized.

4. Progress on initiative

Vegetation Management was activated during multiple emergency events in 2021 including those associated with RFWs and winter storms; it also participated in SDG&E Emergency Operations training for improved situational awareness and resource coordination. Vegetation Management will continue to support emergency operations in 2022 and identify best practices for efficient and effective contractor resource allocation and management.

5. Future improvements to initiative

Targeted and timely tree inspections may help identify potential tree-line conflicts for trimming efforts in advance of a storm or RFW event. Vegetation Management will utilize internal contracted foresters to perform hazard tree inspections in high-risk areas prior to events.

7.3.5.5 Fuels management (including all wood management) and reduction of "slash" from vegetation management activities

1. Risk to be mitigated

Vegetation around electric facilities in the high fire risk areas and ROWs poses potential risks for safety, compliance, and reliability.

2. Initiative selection

To mitigate these risks, the Fuels Management Program consists of three activities: fuels treatment, vegetation abatement, and fuels reduction grants. Wildland fuel reduction involves the thinning, pruning, and in some cases, removal of vegetation for the purpose of minimizing source material that could ignite and propagate a wildfire.

The Fuels Management Program is administered under separate business units within SDG&E. The program consists of three activities:

- Fuels Treatment activity – Increased clearances around select structures (poles) that carry hardware that could possibly spark and ignite a fire. The scope of this activity entails the removal of dead or dying fine fuels at ground level within a 50-foot radius of selected poles. The Fuels Treatment activity was developed to reduce the risk of ignition in high fire risk areas that could occur from equipment or pole failure or a wire-down event. This activity is also intended to protect infrastructure in the event of a wildfire that originates beyond SDG&E facilities.

- Vegetation Abatement activity – Vegetation clearing within transmission ROWs. Vegetation Abatement activity was implemented to maintain SDG&E-owned parcels in a fire-safe manner as required by various municipal compliance ordinances, Fire Marshal directives, and community safety expectations. This activity is intended to reduce the fuel loading from overgrown vegetation that may propagate a fire if an ignition were to occur and consists primarily of the removal of ground level, non-native flashy fuels and the thinning of tree branches (to 6-8 feet) above ground on SDG&E-owned properties and ROW corridors. Typically, the same properties are abated annually or on a frequency based on vegetation growth. Depending on conditions such as plant species and rainfall frequency, inspection activities may occur monthly or weekly and may change depending on the season. Brush abatement activities are planned and scheduled in late February/early March each year near the end of the normal rain season and before the flush spring growth occurs.

- Fuels Reduction MOU & Grant activity – SDG&E-sponsored funding for memoranda of understandings (MOUs) and grants to external partners for the purpose of reducing fuels near electrical infrastructure and to enhance community wildfire prevention and safety. The Fuels Reduction MOU & Grant activity targets electric ROWs, evacuation routes, and community defensible space areas to reduce the risk of a fire of consequence and to strengthen community resiliency. Fuel reduction treatments can slow fire spread, assist in firefighting efforts, and reduce the impact of fires on a community. The Fuels Reduction MOU & Grant activity is a partnership with community organizations to help reduce the risk of catastrophic fire in their respective communities associated with electric infrastructure. The fuel reduction treatments follow industry best practice and target utility ROWs in high fire danger areas.

Vegetation debris (i.e., slash) generated from fuels management and vegetation management activities are typically completely removed from the project site unless it is determined that a portion of the debris can be used on site for soil cover or other purposes. This determination is made upon review by Environmental Services. Property owners may also request that debris be left on sight as chipped material for ground cover or landscaping (see Section 7.3.5.1 Additional efforts to manage community and environmental impacts).

Risk Reduction Estimation Methodology

Because SDG&E's Fuels Treatment activities are relatively new, the risk reduction methodology used is primarily based on subject matter expertise. As these activities mature and more data is gathered, it will be feasible to qualify and quantify future risk analysis.

3. Region prioritization

Fuels Treatment Activity

The Fuels Treatment activity is implemented within the HFTD and in portions of the State Responsibility Area (SRA) (boundary determined by CAL FIRE).

Vegetation Abatement Activity

Brush is abated as needed to create defensible space as outlined in the California Fire Code on company owned property (with the exception of environmentally sensitive areas). This activity is performed throughout the service territory including the HFTD Tiers 2 and 3.

Fuels Reduction Grant Activity

Fire Coordination fuels treatment projects use GIS analysis of Tier 2 and 3 areas of the service territory that meet certain criteria. The analysis focuses on areas impacted by significant wind events. The analysis then overlays areas where electric facilities, fuels, and topography have a direct association to fire ignition potential and growth and community protection.

4. Progress on initiative

Enhancements and progress made in 2021 include

- Modified Fuels Treatment activity to include target poles that already require brushing for Public Resource Code 4292 compliance.
- Streamlined the environmental review process to create efficiencies while also ensuring protection of species.
- Vegetation Abatement activity

    - Initiated a program that utilized prescribed goat grazing for brush abatement in a section of the Chula Vista Transmission corridor. After evaluation (including Environmental Services, Public Affairs, External Relations, and Community Relations), the activity was deemed a success.
    - Implemented enhanced reporting methods.
- Fuels Reduction Grant activity
    - In 2019, awarded $424,000 to 8 fuels treatment projects within the service territory including 5 Native American reservations, 2 community fire safe councils, and 1 roadside fuel treatment test project. All projects had direct benefit to electric infrastructure and public safety. Monitored progress and performed final review of the project work areas to ensure the work was completed in a timely manner and to the level described in the project proposals
    - In 2020, awarded a $500,000 fuels treatment grant and in 2021, awarded a $1 million fuels treatment grant to the Fire Safety Council of San Diego County. Grants will be used to treat wildland fuels in proximity to electric facilities with potential to impact communities during a wildland fire.

Enhancements in 2022 will include

- Fuels Treatment activity
    - Continue to assess cost/benefit as well as research alternatives such as use of fire retardants.
    - Engage third party to study the methodology and effectiveness of the fuels treatment activity.
    - Provide customer engagement and awareness earlier in the year to streamline authorization to perform.
- Vegetation Abatement activity
    - Expand the acreage to be abated by goat grazing in sections of the Transmission corridors within Chula Vista, Oceanside, Escondido and Harmony Grove.
- Fuels Reduction Grant activity
    - Treatment of wildland fuels in proximity to electric facilities will be completed.

Actual performance for 2021 and targets for 2022 for this initiative are provided in Attachment B, Table 12.

5. Future improvements to initiative

<u>Fuels Treatment Activity</u>

SDG&E continues to assess the cost/benefit of the Fuels Treatment Activity for efficiency and effectiveness.

Vegetation Abatement Activity

Future innovations may include improved sustainable brush abatement machinery technology (lower emissions and finely ground deck mulching spoils). All abatement spoils in excess of grassy vegetation will be chipped and field spread. Any collected debris (paper, plastic etc.) will be recycled in an appropriate manner through nominal methods.

Fuels Reduction Grant Activity

FS&CA will continue to monitor the success of the fuels treatment program and adjust funding and treatment locations, as well as continue to engage fire agencies, local, state, and federal governments, and community groups to coordinate and maximize all stakeholder efforts.

7.3.5.6 Improvement of inspections

See Section 7.3.5.2 Detailed inspections and management practices for vegetation clearances around distribution electrical lines and equipment.

7.3.5.7 Remote sensing inspections of vegetation around distribution electric lines and equipment

1. Risk to be mitigated

Without the implementation of new and existing technology, the ability to improve vegetation inspections and confirm clearances to mitigate ignitions or wildfire could be at risk.

2. Initiative selection

To mitigate this risk, remote sensing technologies such as LiDAR can be used for conditional awareness, outage investigation, and change detection. This technology can potentially augment and enhance vegetation inspection and auditing activities by providing highly accurate clearances between trees and power lines, thus providing another tool to prevent an outage or a non-compliant condition.

Vegetation Management is also currently reviewing the use of satellite imagery for conditional awareness, clearances, outage investigation, and change detection. The benefit of satellite imagery compared to LiDAR is the relative frequency of obtaining new information. Satellite imagery can be refreshed almost daily based on orbital satellite capture. Satellite imagery, however, does not provide the high level of detail and clearance accuracy of LiDAR point cloud data and three-dimensional modeling.

3. Region prioritization

Vegetation Management utilizes LiDAR in its vegetation inspection activities primarily within the HFTD and transmission corridors. Satellite technology is used in some of the HFTD areas in comparison to LiDAR to determine the relative benefits of both.

4. Progress on initiative

Enhancements and progress made in 2021 include

- In Quarter 2 the SDG&E Innovation Team completed its LiDAR PoC in anticipation of developing an enterprise-wide solution in its use of LiDAR. The team recently completed sprint reviews researching LiDAR visualization tools and platforms to validate the best tool for scaling the solution.

- In Quarter 3 the SDG&E Innovation Team completed the Final Readout on the LiDAR PoC for developing an enterprise-wide solution in its use of LiDAR and AI. This readout summarized analysis outcomes for vegetation clearance. Following the readout, the team collaborated with others to plan and frame the scaling of a solution to support storage, analysis, and visualization of critical LiDAR data.
- Vendor selection was made at the end of September on the service agreement for the enterprise wide-wide LiDAR data capture and modeling initiative.

Enhancements in 2022 will include

- With the recent LiDAR Foundation release, SDG&E and its contractors will develop a centralized enterprise repository where LiDAR data and associated files will be uploaded, stored, and accessed. This capability sets the stage for running analytics and Artificial Intelligence on the LiDAR data.
- Engage with other IOUs on their use and integration of remote sensing technologies within their vegetation management programs.
- Engagement with satellite vendors to determine current status of technology, and capabilities for augmentation and integration with vegetation management operations.

5. Future improvements to initiative

SDG&E will continue to evaluate the effectiveness of and cost/benefits of these technologies to determine how to best integrate into its routine vegetation management activities.

7.3.5.8 Remote sensing inspections of vegetation around transmission electric lines and equipment

See Section 7.3.5.7 Remote sensing inspections of vegetation around distribution electric lines and equipment.

7.3.5.9 Other discretionary inspection of vegetation around distribution electric lines and equipment, beyond inspections mandated by rules and regulations

See Section 7.3.5.2 Detailed inspections and management practices for vegetation clearances around distribution electrical lines and equipment.

7.3.5.10 Other discretionary inspection of vegetation around transmission electric lines and equipment, beyond inspections mandated by rules and regulations

See Section 7.3.5.9 Other discretionary inspection of vegetation around distribution electric lines and equipment, beyond inspections mandated by rules and regulations.

7.3.5.11 Patrol inspections of vegetation around distribution electric lines and equipment

See Section 7.3.5.2 Detailed inspections and management practices for vegetation clearances around distribution electrical lines and equipment.

7.3.5.12 Patrol inspections of vegetation around transmission electric lines and equipment

See Section 7.3.5.2 Detailed inspections and management practices for vegetation clearances around distribution electrical lines and equipment.

7.3.5.13 Quality assurance/quality control of vegetation management

1. Risk to be mitigated

Poor work quality and a lack of contractor oversight can lead to increased risk of non-compliant conditions as well as potential vegetation contacts.

2. Initiative selection

Documented QA/QC activities are a critical component of a utility's vegetation management program to measure contractor performance and to further safety, compliance, and reliability.

SDG&E utilizes a third-party contractor to perform quality assurance audits of vegetation management activities to measure work quality, contractual adherence, compliance, and to determine the effectiveness of each component of the program. These audits include a statistical analysis of a representative sample of all completed work. Auditing is performed by ISA Certified Arborists. A minimum random sampling of 15 percent of completed work is audited to determine compliance with scoping requirements.

SDG&E expanded its audit program by integrating "level 2" hazard tree assessments during the post-trim audit. These assessments are performed by the Certified Arborists performing the audit.

Safety, regulatory requirements, and service reliability dictate the vegetation management methodology of spend and resource allocation. SDG&E works with the audit contractor to determine the scope, frequency, and number of resources needed to complete all audit activities. During the post-trim audit, the Certified Arborist also performs an inspection of all power lines within the VMA for any trees that will not remain compliant with applicable regulatory requirements for the duration of the annual cycle. Results are reviewed to determine if any additional work is required.

3. Region prioritization

QA/QC activities are completed throughout the service territory. Within the HFTD, SDG&E aims to perform a 100 percent audit of tree trimming and removal work associated with the off-cycle secondary inspections within the HFTD.

4. Progress on initiative

Enhancements and progress made in 2021 include:

- Continued utilizing contracted audit resources to help perform off-cycle inspections in the HFTD.
- Continued the scope to audit 100 percent of all completed tree trimming and removal work associated with off-cycle, off-cycle inspections in the HFTD. SDG&E achieved less than 100 percent in some instances where access was prohibited or required work was modified in between inspection and trimming activities.
- Added five additional contracted auditors to perform vegetation management QA/QC activities.

- As part of the "doubling-down" initiative for fire preparedness in advance of fire season, Vegetation Management also performed a QA/QC audit on a sample of all FiRM project work completed in 2021. This audit identified zero non-compliant tree/line clearance findings.

Initiative targets for 2022 are provided in Table 5-2.

5. Future improvements to initiative

- Within the next two years SDG&E hopes to expand and integrate the use of LiDAR as an additional tool for QA/QC.
- Over the next 5 years, SDG&E will develop a comprehensive audit program to continue to assess and quantify the state of compliance of the Vegetation Management program with regulatory requirements. These audits will inform overall success of the program, state of compliance, and procedural integrity.

7.3.5.14 Recruiting and training of vegetation management personnel

1. Risk to be mitigated

Without proper recruiting and training, the Vegetation Management Program could not be successfully implemented which could lead to an increase in vegetation-related ignitions or wildfires.

2. Initiative selection

A trained, qualified, and professional workforce is imperative to efficiently and effectively manage operations to ensure safety, compliance, and reliability, and foster confidence in those who regulate these activities. SDG&E measures the success of contractor training and performance through metrics such as the number of customer complaints, outages, audit findings, claims, notice of violations, ignitions, and safety incidents. Vegetation management activities involve routine interactions with customers and vested internal and external stakeholders, often involving challenging issues. A professional, competent workforce instills trust and credibility that aids SDG&E in achieving vegetation management compliance and risk reduction.

Vegetation Management contractors are responsible for developing and conducting training of their personnel. SDG&E requires all contractors to perform annual training to address issues such as species identification, hazard tree assessment, customer engagement, fire preparedness, and environmental awareness/regulations. SDG&E personnel often attend and participate in contractor-led training modules. Through its service agreements, SDG&E requires professional certifications of many of the contract personnel based on activity type or employee level (i.e., Pre-inspectors, Auditors, General Foremen, Supervisors). The certifications include ISA-Certified Arborist and ISA-Utility Specialist. SDG&E provides training to contractors when scoping activities are changed or modified and documents changes via memorandum or procedural updates. See Section 4.6 Progress Reporting on Key Areas of Improvement for the response to action statement SDGE 21-05 regarding teaching species identification skills.

All contractors are required to develop a company Fire Plan and to train staff annually. In addition, all contractors must adhere to SDG&E's internal Fire Plan (ESP 113.1). Contractors are required to carry personal protective equipment (PPE), including all applicable fire PPE on their vehicles at all times and be trained in its safe and proper use. SDG&E also requires tree contractors to have fire PPE staged at each job site and at the ready for use.

Contractors must be enrolled in the ISNetworld safety clearinghouse that scores and tracks contractor safety performance and must meet minimum safety thresholds to remain a viable vendor and work for SDG&E. Contractors take annual conflict resolution training to deal with customers who pose a safety threat. Contractors must also document employee training and provide it to SDG&E upon request. Tree trim contractors must have a dedicated safety representative on property to conduct ongoing field observations, workforce training, and incident investigations.

To further develop a qualified workforce, SDG&E collaborated with the IOUs, Utility Arborist Association, industry professionals, and academia to develop and implement a "Utility Arborist Trainee" curriculum for community colleges throughout California. This initiative significantly reduces the training schedule, provides consistency in training, and develops a qualified employee upon completion of the curriculum. Upon completion of the 5-week curriculum and hands-on field training, trainees are eligible to obtain employment and status as a Line Clearance Qualified worker with SDG&E's contracted tree trimming companies.

SDG&E's Safety Department supports Vegetation Management by utilizing a third-party vendor to perform field safety observations. These observations are documented and reviewed by internal SDG&E personnel for safety adherence. SDG&E tracks the success and effectiveness of the contractors' safety program. The Safety Department utilizes predictive analytics software to record and anticipate contractor safety performance.

3. Region prioritization

Vegetation Management recruiting and training programs are consistent across the service territory.

4. Progress on initiative

Enhancements and progress made in 2021 and 2022 include

- The inaugural line-clearance tree trimming training class sponsored by SDG&E and the Utility Arborist Association was completed in Quarter 3 of 2021. Ten individuals currently employed with the California Conservation Corps successfully completed the course. The success of this program spurred the planning of additional local tree trimming training classes that will take place in the future. This program will also be expanded in Quarter 2 2022 to develop classroom and field curriculum courses for Pre-inspection.
- SDG&E will review their training programs to determine the applicability of species identification in conjunction with other vegetation activities and encourage personnel to identify genus/ species.
- Third-party pre-inspection auditing scope will be expanded to include validation of genus/ species.

5. Future improvements to initiative

SDG&E will collaborate with contractors on funding and developing additional training program and curriculums.

7.3.5.15 Identification and remediation of "at-risk species"

1. Risk to be mitigated

The ability to identify and remediate at-risk species will assist in mitigating vegetation-related risk-events and ignitions from occurring.

2. Initiative selection

SDG&E continues to focus on applying expanded post-trim clearances on targeted species identified as higher risk due to growth potential, failure characteristics, and relative outage frequency. Various criteria are used to determine targeted at-risk species. Correlation with higher outage frequency is a good indicator for species that pose higher risk to electrical infrastructure, however qualitative characteristics are also used to identify high-risk trees. Five primary "at-risk" species have been identified, including palm, eucalyptus, sycamore, pine, and oak, because they may exhibit one or more of the following criteria:

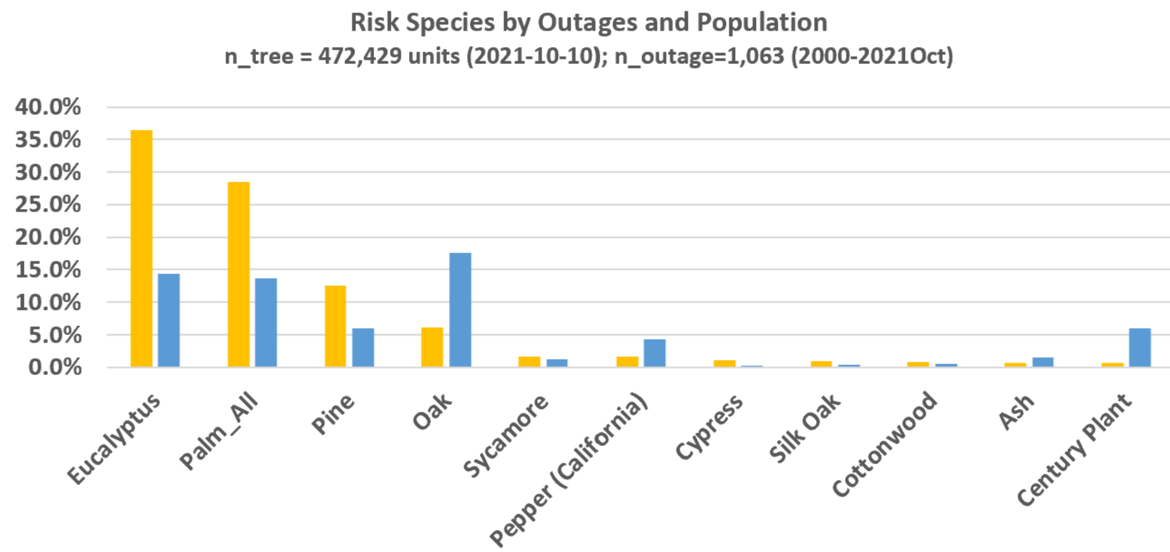
- Fast-growth pattern
- Branch structure and known propensity for branch failure
- History of high outage frequency relative to the total inventory tree population

It is important to note that SDG&E designates these species as "at risk" to facilitate targeted inspections. Species type is not a single determinant of whether enhanced clearances and/or removal is warranted. Clearances are determined by a holistic review of tree location, health, species, and growth pattern. Simply because a tree has been identified as requiring pruning or "at risk" does not mean it will require enhanced clearance.

Vegetation Management defines enhanced clearances as greater than or equal to 12 feet at time of trim, which is the CPUC-recommended post-trim clearance for distribution voltages in the HFTD. SDG&E aims to achieve clearances up to 25 feet where deemed to present the optimal risk mitigation approach. The determination of how much clearance is to be obtained at time of trim is based on several tree factors including minimum clearance requirement, voltage, species, location, branch structure, tree health, proper pruning practices, location of tree defect, etc. The tree contractor makes the determination of post-trim clearances in order to maintain compliance for the annual cycle, and to abate any structural hazard present in the tree.

SDG&E's methodology to determine "at -risk" species is based on the goal of reducing the total number of risk events (vegetation caused outages) to mitigate wildfire risk. As shown in Figure 7-12, the top 5 tree species identified by SDG&E as "at risk" are associated with 85.1 percent of all vegetation-caused outages, while the total amount of species units represents 52.9 percent of the entire inventory tree population. If the orange bar is taller than the blue bar, there is a disproportionate number of outages relative to the species' total population. These instances also represent the species that have higher outage risk per unit or per 1000 units.

Figure 7-13: Top 10 Risk Species by Percentage of Outages and Population



Note: the total inventory unit count is based on SDG&E's inventory tree database and reflects current tree inventory.

Oak and Sycamore can be categorized as species where the average number of outages per 1,000 inventory trees are not as high compared to other tree types. Vegetation Management also considers qualitative measures including anecdotal evidence, industry knowledge, and known species characteristics in its consideration of "at risk" species. For instance, oak and sycamore trees have a known propensity for branch failure, which could lead to increased chance of vegetation/line contact. Certified Arborists and line-clearance-qualified-tree-trimmers apply this knowledge when determining which species should be targeted for enhanced clearances and removal to prevent outages. As previously stated, however, while inspectors use this knowledge when assessing a tree for removal or trim, the ultimate determination regarding the need for enhanced clearance and/or removal is made at the time of trim, based on a wholistic review of the tree.

For additional information on "at-risk" species, see Action Statement SDGE-21-06 in Section 4.6 Progress Reporting on Key Areas of Improvement.

Risk Reduction Estimation Methodology

The effectiveness of the enhanced vegetation management program was measured using historical data and the methodology and results are described in detail in Section 4.4.2.9 Impact of the Enhanced Vegetation Management Program. Utilizing that information as a baseline, SDG&E combined the risk events reduced information from the study with the estimated number of enhanced trims to be completed through the WMP timeframe, the number of targeted species located within Tier 2 and Tier 3 to approximate where the risk reduction would occur, and finally the average ignition rates to calculate ignitions reduced. Based on these results, the enhanced vegetation management program is estimated to reduce 0.44 ignitions by the end of 2022. A summary of the calculation is shown in Table 7-31.

Table 7-31: Risk Reduction Estimation for Vegetation Management

Risk events reduced total from study	6.3
Trees Trimmed to enhanced levels Tier 3 (2020-2022)	16,254
Trees Trimmed to enhanced levels Tier 2(2020-2022)	26,554
Targeted species Tier 3	77,134
Targeted species Tier 2	73,672
Total Targeted species	150,806
Trees managed (2020-2022) Tier 3	6,633 + 4,095 + 5,526 = 16,254
Trees managed (2020-2022) Tier 2	10,800 + 8,456 +7,298 = 26,554
Ignition rate Tier 3	2.69%
Ignition rate Tier 2	3.29%
Risk events reduced Tier 3	6.3 x [(16,254/77,134) + (6,633/77,134)] x 2.69% + 6.3 x [(16,254/77,134) + (4,095/77,134)] x 2.69% + 6.3 x [(16,254/77,134) + (5,526/77,134)] x 2.69% = 0.1429
Risk events reduced Tier 2	6.3 x [(26,554/73,672) + (10,800/73,672)] x 3.29% + 6.3 x [(26,554/73,672) + (8,456/73,672)] x 3.29% + 6.3 x[(26,554/73,672) + (7,298/73,672)] x 3.29% = 0.299
Total ignitions reduced (2020-2022)	**0.143 + 0.299 = 0.44**

3. Region prioritization

Identification and remediation of at-risk species may be performed throughout the service territory. However, given the inherent risk and fire prone conditions, remediation of at-risk species is focused in the HFTD.

4. Progress on initiative

- SDG&E continued to refine its study of enhanced tree clearances and tree-related outages with updated data to better understand its assessment of targeted species. See Section 4.4.2.9 Impact of the Enhanced Vegetation Management Program for further information on this research study.
- Began collaboration on a multi-year vegetation management study with the joint IOUs. The study will benchmark vegetation management practices and data collection methodologies across IOUs to assist in the development of uniform standards, including but not limited to standardized definitions for “enhanced clearance”, “tree-caused risk event”, and “post-trim clearance”. See Attachment I.

- SDG&E continued to collaborate with the SDSC to model its tree data. The project's goal was to use Vegetation Management's inventory tree data and outage history to develop a predictive risk analysis tool. Results from study corroborate SDG&E's premise and practice of obtaining greater clearance to reduce the frequency of tree-related outages.
- Working with database developers to add genus/species identification within the inventory database tree records.

5. Future improvements to initiative

SDG&E will continue to refine its vegetation management practices for at-risk species based on research results.

7.3.5.16 Removal and remediation of trees with strike potential to electric lines and equipment

1. Risk to be mitigated

Hazard trees pose a risk to powerlines from branch contact, partial tree, or whole tree failure. The risks to be mitigated include electrical outage, property damage, personal injury, ignition and catastrophic fire.

2. Initiative selection

All trees are inspected under and adjacent to the lines to determine risk potential. The hazard tree strike zone is defined as the area where a tree is tall enough to hit the power lines if it were to fail at ground level.

SDG&E has fully integrated its team of internal company Patrollers to perform off-cycle hazard tree inspections within the HFTD. Successful hazard tree evaluation aims to prevent the risks associated with tree/power line conflicts. Inspections must be performed by qualified individuals skilled in tree species identification, diseases, tree biology and mechanics, hazard characteristics, and risk assessment. Hazard tree evaluation is a critical component of Vegetation Management Program operations to reduce tree-related outages and fire ignitions. SDG&E has a robust tree removal program that targets problematic species such as eucalyptus, palms, Century Plant, Bamboo, certain species of Pine, Oak, and Sycamore, before they become a danger. Because of the potential threat to the power lines from detached fronds, the removal of palms located outside SDG&E's ROW is also proactively pursued.

Trees are visually inspected from the ground to the upper canopy 360 degrees around. HFTD hazard tree inspections are performed by ISA Certified Arborists. Hazard tree trimming or removal is prioritized where necessary if failure is determined to be imminent.

Vegetation Management also uses its historical tree removal data to forecast the number of removals it may perform each year, including an analysis of known targeted species that are fast-growing and that have a propensity for branch or trunk failure. All hazard trees are assessed for risk and prioritized based on severity of condition and activity schedule. The hazard tree removal program is integrated within the routine inspection cycle and off-cycle patrols. ISA Certified Arborists trained in hazard tree evaluation perform these inspections, which include a critical look at any tree that could strike the power lines. In addition, tree trim contractors receive hazard tree training annually and perform a safety assessment before working on any tree to identify potential defects. A third-party contractor performs an audit on

100 percent of all trees removed to ensure work was completed per scope and contract including an assessment of the efficacy of stump treatment application and facility protection.

3. Region prioritization

Vegetation Management performs hazard tree inspections and abatement in all areas of the service territory where trees pose a potential threat to the power lines. Within the HFTD, hazard assessments of all trees located within the utility strike zone are performed twice annually.

4. Progress on initiative

The twice annual hazard assessment tree patrol in the HFTD is scheduled to occur 6 months ("mid-cycle") following the routine tree inspection activity. SDG&E has begun to refine the schedule of the annual HFTD patrol activity such that they occur within the quarter (June-Aug) before the Santa Ana wind season typically begins (September). This schedule adjustment will begin in 2022.[56] During routine inspection and special patrols within the HFTD, the team of Pre-inspectors and Patrollers continue to assess all trees within the strike zone for hazard characteristics that require trimming or removal to avoid conflict with the power lines.

As part of its tree removal/replacement program and it's "Right Tree, Right Place" initiative, SDG&E continues to offer customers replacement trees that are compatible to plant near power lines. Beginning in 2021, tree planting initiatives were expanded with a goal to plant and distribute 10,000 trees annually to promote sustainability and mitigate the impacts of climate change.

SDG&E engaged its Pre-inspection contractor to manage its tree planting initiative including more effective customer outreach and engagement, proper species selection, tracking tree health, and quantifying environmental benefits.

5. Future improvements to initiative

SDG&E plans to further evolve this program over the next 10 years by leveraging enhanced VRI and WiNGS-Planning modeling data to develop a more strategic approach to identify areas of high risk and prioritization of mitigation efforts. SDG&E will also utilize LiDAR to improve its assessment of hazard trees.

7.3.5.17 Substation inspections

See Section 7.3.4.15 Substation inspections.

7.3.5.18 Substation vegetation management

See Section 7.3.4.15 Substation inspections.

[56] In part, in response to Action Statement SDGE 21-07, based on a consensus agreement between SDG&E and Energy Safety in a meeting January 11, 2022, SDG&E will begin quantifying this initiative in the WMP 2022 Update by recording the number of off-cycle HFTD patrols completed before peak fire season within the Vegetation Management Areas (VMA) and associated HFTD line miles

7.3.5.19 Vegetation management system

1. Risk to be mitigated

A vegetation management system, including a tree inventory and work management features, helps mitigate the risk of non-compliance and tree-risk events.

2. Initiative selection

Vegetation Management maintains a robust electronic tree inventory and work management database that tracks the inspection, trimming, and auditing activity of its nearly 460,000 inventory trees.

The electronic tree inventory includes information such as species, height, diameter, growth rate, clearance, and activity history. SDG&E monitors all trees in its inventory using known species growth rates, tree and site-specific conditions, and past pruning practices. Each inventory tree is assigned a unique alpha-numeric identification number within the electronic database, which allows the activity history of each tree to be tracked. This database allows SDG&E to monitor and identify which trees to address in efforts to reduce vegetation-related ignitions. The tree inventory database enables a systematic and efficient approach to managing assets, scheduling, activity history, and resource allocation. The database and work management system provide a current view and status of all inventory trees and prioritizes work. All contractors work within the electronic system to provide real-time updates and scheduling as well as robust reporting functionality. SDG&E has a team of IT analysts, business control, and personnel to support the PowerWorkz management system. Contractors also have access to these personnel to support software and hardware functionality.

3. Region prioritization

The PowerWorkz management system includes an application where work orders are created and submitted to contractors, and the mobile application (Epoch) which is the GIS mapping interface where all asset (trees and poles) data is recorded. All inventory tree and pole brush records throughout the service territory are maintained in PowerWorkz. SDG&E defines an inventory tree as one that could encroach the minimum required clearance or otherwise impact the electrical facilities within three years of the inspection date.

4. Progress on initiative

Enhancements and progress made in 2021 include:

- Implemented next generation mobile application (Epoch) of PowerWorkz. The new system was designed, developed, and tested before going live. Improvements included new mapping interface, more robust software performance, enhancements to data capture, streamlined mapping, and associated reporting.
- Began to design enhancements in Epoch to record genus and species in the inventory tree records and outage investigations. See Section 4.6 Progress Reporting on Key Areas of Improvement for the response to SDGE 2021 WMP Action Statement: 21-05 regarding record keeping and identification of vegetation species.
- Added VRI GIS mapping layer to Epoch to provide greater situational awareness of where to engage in possible enhanced tree operations.

Enhancements in 2022 will include:

- Investigate the integration of the new work management system with other inter-departmental systems to streamline workflows. Research opportunities to share inventory data with external stakeholders for cross-activity initiatives.

5. Future improvements to initiative

- Continue enhancements to the PowerWorkz work management system to meet the evolving needs in the collection of data, work issuance, and process improvement. See Section 4.6 Progress Reporting on Key Areas of Improvement for the response to SDGE 2021 WMP Action Statement: 21-05 regarding record keeping and identification of vegetation species.
- Over the next three years, research and initiate future generation hardware for contract field personnel to interface with the electronic work management system.
- Continue to research industry best practices and work management software applications to further streamline and enhance its operations within the next 10 years.

7.3.5.20 Vegetation management to achieve clearances around electric lines and equipment

1. Risk to be mitigated

Vegetation growing near electrical equipment poses an ignition threat if not managed.

2. Initiative selection

Pole brushing is a fire prevention measure involving the removal of vegetation at the base of poles that carry specific types of electrical hardware that could cause sparking or molten material to fall to the ground. The clearance requirements in Public Resources Code § 4292 require the removal of all vegetation down to bare mineral soil within a 10-foot radius from the outer circumference of subject poles located within the boundary of the SRA. The requirement also includes the removal of live vegetation up to 8 vertical feet and the removal of dead vegetation up to conductor level within the clearance cylinder.

The same work management system is utilized to manage and track the inventory of all subject poles that require clearing. Approximately 34,000 distribution poles that have non-exempt subject hardware attached are brushed. Inspectors determine which poles require work and update the records in the database. Three separately scheduled pole brush activities are performed annually, including mechanical brushing, chemical application, and re-clearing. Pole brush inspection occurs in conjunction with the tree inspection activity.

Mechanical pole brushing is the clearing all vegetation around the base of a pole down to bare mineral soil for a radius of 10 feet from the outer circumference of the pole; removing all live vegetation within the cylinder up to a height of 8 feet above ground; and removing all dead vegetation up to the height of the conductors. Mechanical brushing is typically performed in the spring months.

On poles where environmentally safe and with customer consent, contractors will apply an EPA-approved herbicide. SDG&E treats approximately 10,000 poles with a pre-emergent herbicide to minimize vegetative re-growth and reduce overall maintenance costs. The chemical application is typically done just before the rainy season (during the fall and winter months) so the chemical is activated and effective.

Reclearing is a second mechanical activity performed on poles that are not cleared by a chemical application. During reclearing, vegetation which has grown into, or blown into, the required clearance area since the last maintenance activity is removed. The need to revisit a subject pole multiple times is not uncommon due to leaf litter cast or blown into the cleared area and vegetation regrowth that cannot controlled by mechanical or herbicide treatments.

Pole brushing follows a specific multi-activity, annual schedule to remain compliant year-round. The number of subject poles fluctuates minimally year-to-year so scheduling, spend, and resource allocation remain constant. An environmental review is performed in advance of all new pole brushing activities to assess impacts to protected species and habitat. Like all other vegetation management activities, a QA/QC audit is performed on a random, representative sample of all completed pole-brush work. Additionally, SDG&E conducts internal compliance audits for vegetation management on an annual basis.

Risk Reduction Estimation Methodology

To calculate the effectiveness of pole brushing in terms of ignitions prevented, SDG&E began by analyzing the 5-year historical risk event history focused on equipment failures within the HFTD that require pole brushing. Pole brushing does not prevent equipment failures, but if the energy/heat generated by a risk event occurs within the brushed area (no fuel) it is assumed an ignition is prevented. SDG&E is aware that pole brushing is not 100 percent effective as nearly 80 ignitions since 2014 have occurred near poles that have been brushed. However, how many more ignitions would have occurred if there was no pole brushing? If distance from pole to ignition origin was captured as a data point, SDG&E would have much more insight into the effectiveness of pole brushing, however, that data is not currently available and not always clear from ignition investigations. Instead utilized subject matter expertise was utilized to estimate that pole brushing is 40 percent effective at reducing the ignition rate of equipment failures associated with brushed poles. This assumption leads to an estimated 1.25 ignitions avoided from pole brushing annually. A summary of the calculation is provided in Table 7-32.

Table 7-32: Risk Reduction Estimation for Pole Brushing

Tier 2 equipment failures (average 2015-2019)	49
Tier 3 equipment failures (average 2015 -2019)	43
Ignition rate Tier 2	3.29%
Ignition rate Tier 3	2.69%
Assumed effectiveness	40%
Pre mitigation ignitions tier 3	49 x 3.29% = 1.63
Pre mitigation ignitions tier 4	43 x 2.69% = 1.16
Annual ignition avoided Tier 3	1.63 x 40% = 0.65
Annual ignition avoided Tier 2	1.16 x 40% = 0.463
Total poles each Tier 3	50,583

Total poles each Tier 2	42,678
Pole brushing actuals Tier 3	44,988
Pole brushing actuals Tier 2	48,297
Ignition reduced Tier 2	(48,297 ÷ 42,678) x 0.6529 = 0.739
Ignition reduced Tier 3	(44988 ÷ 50583) x 0.463 = 0.412

3. Region prioritization

SDG&E performs required pole brushing activities on subject poles located within the SRA per Public Resources Code Section 4292. The SRA where Public Resources Code Section 4292 applies does not align completely with the HFTD boundary. As an extra pre-cautionary measure, SDG&E brushes approximately 2,000 additional poles located outside SRA where Public Resources Code Section 4292 does not apply. These poles exist in areas of potentially flammable vegetation, on steep slopes, and/or in adjacent to areas where a fire may propagate

4. Progress on initiative

SDG&E will complete completed their scheduled pole brushing activities per its master schedule of activities to ensure compliance with PRC 4292. No changes were made to pole brushing in 2021 and none are expected to be made in 2022.

Actual performance for 2021 and targets for 2022 for this initiative are provided in Attachment B, Table 12.

5. Future improvements to initiative

Plans for future improvement include utilizing the vegetation management-contracted Quality Assurance team to field validate new pole-mounted hardware, and site-specific conditions for the need to perform pole brushing.

7.3.5.21 Vegetation management activities post-fire

1. Risk to be mitigated

Trees located near electrical infrastructure that are damaged or killed during a wildfire pose an ignition and risk potential if not inspected and mitigated.

2. Initiative selection

After a wildfire event a hazard assessment is performed on damaged trees located within the utility strike zone to determine risk and abatement.

SDG&E experienced very few fires in 2021 that required a post-event inspection of the power lines. In such instances Vegetation Management obtains fire perimeter maps from Fire Coordination, and Pre-inspection contractors and/or internal Patrollers perform a post fire inspection of trees under and adjacent to the facilities. When it is determined that a fire damaged tree could impact the power lines, the tree is topped to the point where it cannot strike the facilities or is felled completely. Property owners are notified of required work in advance, and mitigation measures are followed to protect habitat and avoid further environmental degradation.

3. Region prioritization

Post-fire tree inspections are performed throughout the service territory in response to small fires impacting single trees and in response to large, multi-acre wildfires where there is the potential of future threat to the power lines.

4. Progress on initiative

No changes were made to post-fire vegetation management process and scoping activities in 2021 and none are expected to be made in 2022.

5. Future improvements to initiative

Post-fire vegetation inspections will be continued where electrical infrastructure may be compromised to prevent ignitions caused by tree branch or tree failure onto the lines.

7.3.6 Grid Operations and Protocols

SDG&E’s grid operations and protocols consist of mitigations that reduce risk through changing the way SDG&E operates during periods of elevated and extreme wildfire risk. This includes the disabling of reclosing in the HFTD, the enabling of fast recloser settings, restricting work in the HFTD during extreme fire potential and RFWs, and sending contract fire resources (CFRs) with crews during elevated days in the HFTD. These operational protocols have led to reduced ignitions on the electric system and have reduced ignitions during operational periods where an ignition is more likely to lead to a catastrophic fire.

7.3.6.1 Automatic recloser operations

1. Risk to be mitigated

The recloser protocols mitigate the risk of wildfire by ensuring re-energization does not take place automatically, which potentially could lead to a wildfire ignition.

2. Initiative selection

Distribution reclosing capability on either circuit breakers or mid-circuit sectionalizing devices benefits customers by reclosing into faults to see if the disturbance to electric system was temporary or sustained. For example, a small branch could fall across electric lines causing the protection device to trip the line (a risk event and an outage), but that branch could fall to the ground, clearing the fault. With reclosing enabled, the device would automatically reclose the switch with the fault now cleared, restoring service to all customers and limiting the reliability impact from a sustained to a momentary outage. However, it is also possible that the risk event is more severe, like a downed power line. In this case, reclosing would close the switch two additional times, creating two more risk events with the potential to cause an ignition. This is especially dangerous in times of extreme FPI and in the HFTD, where the probability of ignition is high and the impact of an ignition could be catastrophic.

The chance of an ignition for circuits located within the HFTD is highest during extreme FPI days (see the research study in Section 4.4.2.1 Determination of Average Distribution Ignition Percentages by Location and Operating Risk Condition for details). A risk event occurring in the HFTD during those weather conditions is more likely to lead to an ignition than an event occurring on normal or elevated FPI days.

Grid Control has also developed protocols for disabling reclosers and testing tripped transmission lines for various defined operating conditions. While the Transmission Operators assume sole responsibility and authority when it comes to the safe and reliable operation of the Bulk Electric System, it is recognized that information from external departments such as Meteorology and Emergency Management can aid in operational decisions. To aid in the Transmission Operator's situational awareness for reclosers, custom EMS displays have been developed that capture all of the transmission lines that traverse the HFTD/National Weather Service fire weather zones that allow easy access to the recloser statuses and controls.

Risk Reduction Estimation Methodology

To measure the effectiveness of disabling reclosing, the six-year risk event data for all events isolated by reclosing devices was analyzed, filtered by HFTD locations and FPI. The research study outlined in Section 4.4.2.2 Understanding the Effectiveness of Recloser Protocols provides additional detail on results of the mitigation and how the benefits were measured, estimating that this mitigation prevents approximately 9 ignitions per year.

3. Region prioritization

Automated reclosing is disabled within the service territory.

4. Progress on initiative

SDG&E's internal operating procedure for automated reclosing is validated annually prior to the fire season. SCADA-controlled sectionalizing devices with specific anemometer locations are validated yearly to ensure all newly installed devices are updated on the procedure.

5. Future improvements to initiative

SDG&E's reclosing operations continue to represent a standard best practice for California utilities.

Wide Area Situational Awareness (WASA) Project

SDG&E has been developing a new situational awareness tool for Grid Control Operators and Electric Engineering users which provides higher sampled and time-aligned data via new micro-processor-based relays with synchrophasor/PMU capabilities. This system will provide Operators with new capabilities for detection, notification, and visualization of power system conditions for greater situational awareness. The implementation team has been working with Grid Control to develop training and documentation for the operations team. The WASA project is expected to go into production Quarter 1 of 2022.

7.3.6.2 Protective equipment and device settings

1. Risk to be mitigated

Sensitive/fast protective settings mitigate the risk of wildfire by reducing the amount of fault current it takes to trip a device while also reducing the time that device takes to isolate the fault. By isolating electric faults faster, the energy at the fault location can be vastly reduced; thereby reducing wildfire ignition risk.

2. Initiative selection

Protective relay settings are designed to operate as fast as possible to isolate electric faults, thereby reducing overall energy at the fault location. These settings are enabled on dynamic protective devices such as reclosers and circuit breakers when the FPI indicates an extreme risk and when the environmental conditions may warrant a PSPS event. By reducing the resultant energy of a fault, the probability of causing significant damage to the surrounding area is reduced by limiting additional sparks resulting from equipment damage. These sensitive relay settings improve both the sensitivity of fault detection and the speed at which faults are cleared.

Sensitive/fast protective settings can lead to unintended operations where the device incorrectly interprets load imbalance or load peaks as a risk event and operates, causing an outage. The lack of protection coordination with devices such as fuses also makes it more difficult to locate faults on the system, leading to longer outages. These impacts are lessened through the use of wireless fault indicators (see Section 7.3.2.3 Fault indicators for detecting faults on electric lines and equipment) and through the targeted deployment of sensitive/fast protective settings only during extreme FPI days and when a PSPS event is predicted, which have averaged around 15 days per year.

<u>Risk Reduction Estimation Methodology</u>

Data from this mitigation is too limited to be statistically significant, however, from 2015-2020 there were 62 fault events downstream of devices that were enabled with these fast protective relay settings on days with extreme FPI and zero of these fault events led to ignitions. Without mitigation, historical performance predicts approximately 6 ignitions for this time period. See Section 4.4.2.5 Impact of Sensitive Relay Settings at Reducing Ignitions from Risk Events for details on the research study measuring the benefits of sensitive/fast protection settings.

3. Region prioritization

Sensitive/fast protection settings are enabled within the service territory only on days with an FPI rating of Extreme and when conditions may trigger a PSPS event.

4. Progress on initiative

It is part of SDG&E's operating standards to enable these settings on remote sectionalizing devices located within the HFTD on days where the fire potential is extreme and when conditions may warrant a PSPS. SDG&E developed the settings and the operating standard around these settings in 2015.

Actual performance for 2021 and targets for 2022 for this initiative are provided in Attachment B, Table 12.

5. Future improvements to initiative

This program has synergies with the PSPS sectionalizing enhancement program and the Advanced Protection program. As more remote sectionalizing devices are deployed and upgraded with new system protection equipment being installed on the distribution system, these fast protection settings can be enabled on more devices within the HFTD.

7.3.6.3 Crew accompanying ignition prevention and suppression resources and services

1. Risk to be mitigated

Activities that occur in high-risk areas and/or during extreme weather events can result in an ignition.

2. Initiative selection

To mitigate this risk, CFRs are utilized during times of increased fire risk (e.g., during Extreme or RFW FPI days) and during at-risk work activities that are performed in areas adjacent to wildland fuels. Additional factors such as fuel moisture, weather, work activities, and fire activities in the region all play a role in determining the need for these prevention resources. CFRs are trained and equipped to notify the agency having jurisdiction of an ignition and can safely mitigate the impact of an ignition through suppressive action until first responders arrive.

<u>Risk Reduction Estimation Methodology</u>

The effectiveness of this mitigation is calculated in the study in Section 4.4.2.8 Impact of Other Special Work Procedures and Infrastructure Protection Teams at Reducing Personnel-Related Faults and Ignitions. The concept of the study was that because CFRs accompany crews during elevated or higher conditions within the HFTD, all crew caused risk events that met the criteria would not lead to a meaningful ignition, as the crews would be on scene to suppress an ignition that did occur. SDG&E utilized historical risk event data caused by employee/contractors and historical ignition rates to estimate the effectiveness in ignitions prevented per year.

3. Region prioritization

CFRs are utilized throughout the service territory in areas where at-risk work is being performed adjacent to wildland fuels during periods of time that have elevated fire risk.

4. Progress on initiative

No changes were made in 2021 and none are expected to be made in 2022

5. Future improvements to initiative

This program is regularly refined with the training qualifications of personnel serving on CFRs and utility activities are being reviewed annually.

7.3.6.4 Personnel work procedures and training in conditions of elevated fire risk

1. Risk to be mitigated

Personnel work procedures and training mitigate the risk an ignition while performing work activities that are necessary to maintain and operate the electric system.

2. Initiative selection

The safety of SDG&E's customers, personnel, and cooperating agencies are all considered during the development and subsequent refinements of personnel work procedures and training. The following summarizes the work activity guidelines for each of SDG&E's Operating Conditions:

- Normal Condition: normal operating procedures are followed with baseline tools and equipment
- Elevated Condition: certain at-risk work activities may require additional mitigation measures in order to proceed with work, such as welding or vegetation clearing.
- Extreme or RFW Condition: most overhead work activities will cease, except where not performing the work would create a greater risk than doing so. In those cases where at risk work needs to be performed, a Fire Coordinator is consulted and additional mitigation steps are implemented. Status of work, ceased or continued, is documented.

SDG&E has designated the type of work activities that may be performed in its service territory under certain Operating Conditions (e.g., Normal condition, Elevated condition, Extreme or RFW). As conditions increase in severity, activities that present an increased risk of ignition have additional mitigation requirements. Where risk cannot be mitigated, work activity might cease.

<u>Risk Reduction Estimation Methodology</u>

The effectiveness of this mitigation is calculated in the study above in Section 4.4.2.8 Impact of Other Special Work Procedures and Infrastructure Protection Teams at Reducing Personnel-Related Faults and Ignitions. Because SDG&E does not allow at risk work on extreme FPI days in the HFTD, SDG&E has no employee/ contractor caused ignitions in the five-year risk event data on extreme FPI days. To estimate the effectiveness, SDG&E calculated a daily annual rate of employee/crew caused risk events and extrapolated that value using the number of extreme FPI days. SDG&E then utilizes historical ignition rates to convert the risk events into ignitions avoided.

3. Region prioritization

The Operations and Maintenance Wildland Fire Prevention Plan (ESP 113.1) requires that all employees, contractors, and consultants that conduct activities in the wildland areas of the service territory receive this training on an annual basis. The training includes definitions of at-risk work, wildland areas, FPI, and a matrix that can be used to determine the minimum fire prevention requirements for at risk activities. Information is also provided related to working on or adjacent to wildland fires, reporting wildland fires, and guidance for taking fire suppression action.

4. Progress on initiative

SDG&E plans to continue to conducting training on fire prevention and refining procedures designed to prevent ignitions from SDG&E equipment or activities.

5. Future improvements to initiative

Procedures and training are reviewed annually with feedback from attendees are incorporated into future training.

7.3.6.5 Protocols for PSPS re-energization

1. Risk to be mitigated

SDG&E utilizes PSPS as a last resort mitigation during extreme weather conditions where the probability of ignition is much higher than normal and the consequences of ignitions due to high winds and dry conditions can be catastrophic. While power lines are de-energized, they are still exposed to extreme winds and weather and to the potential for damage. Once the wind has passed, conditions are typically still extremely dry and dangerous. Before re-energizing a line at the conclusion of a weather event and to ensure no damage has occurred to the line, post-event patrols must be completed to ensure ignitions will not occur upon re-energization.

2. Initiative selection

Restoration planning activities start prior to the PSPS event that mitigate potential damage that could delay restoration of service after a PSPS event. Pre-event patrols are utilized to find and repair damage on infrastructure that will be subject to high winds during the event. To ensure the correct infrastructure is patrolled, SDG&E has a dedicated PSPS prioritization team to ensure resources are matched to priorities. They receive a list of circuits from Meteorology that will see high wind during the event. The list includes circuits that are subject to high winds both in wind magnitude and in winds that will be statistically beyond historical performance. The high wind circuit list is also cross examined against other risk factors in the creation of their circuit pre-event patrol priorities.

The prioritization team in conjunction with Meteorology team, the EOC, and other operational units determines the orders-of-priority for inspection of circuits and re-energizing those circuits to restore power to customers. The prioritization team considers many data elements during the development of the prioritization plan, such as weather conditions, critical customers and facilities, field resource availability, impacts to electric infrastructure, and the duration of the outage. The prioritization team, in partnership with the Resource Coordination team, ensures appropriate resources are planned to support inspections, make critical repairs and restore customers in a safe manner.

Re-energization after PSPS events takes place after the Weather Station Network shows that wind speeds have decreased and the forecast does not indicate that the wind speeds will re-accelerate above certain thresholds. Four to eight hours of daylight are required for field crews to inspect lines to determine whether there is any damage and deem it safe to restore power. Crews look for safety hazards such as debris, downed lines, broken hardware, tree branches caught on the line, or issues related to communication wires. If there is any damage to the power lines or poles, repairs must be made first before power can be restored.

Both ground and aerial resources are utilized to patrol de-energized lines once a weather event concludes. While aerial resources are much faster at completing patrols, they cannot fly in elevated wind conditions, which often still exist after extreme wind events. Foot patrols utilize new technology to track patrol progress to support operation units in providing an outlook on restoration times and the allocation of field resources as needed. SDG&E strives to complete post-event patrols and restoring service within 24 hours from when the Utility Incident Commander determines it is safe to patrol. While SDG&E has been generally successful in restoring service within 24 hours, challenges such as lack of daylight hours or high winds impacting deployment of aerial resources may cause delays. The amount and severity of damage found during inspections may also affect restoration times. Once lines have been inspected and all damage has been repaired, the lines are then safely re-energized.

Risk Reduction Estimation Methodology

This initiative does not have a Risk Reduction Estimation because it is an activity that is foundational to supporting wildfire mitigation efforts and is part of core PSPS operations. Costs for protocols cannot be separated out and evaluating benefits for having protocols cannot be meaningfully measured.

3. Region prioritization

SDG&E patrols all lines that were proactively de-energized as part of a PSPS event. These events typically occur in the HFTD, however, depending on how widespread the weather event is and the extent of the real-time risk, some areas outside the HFTD could also be de-energized and patrolled.

4. Progress on initiative

In 2021, SDG&E deployed a technology solution to increase efficiency in post-PSPS-event restoration efforts that improved documentation of post-event patrols. This software supports forms to document damage found on post-event patrols and provides photos of damage per CAL FIRE's recommendations. Additionally, SDG&E utilized drone support in areas where terrain was difficult for foot patrols to access, or wind conditions made it difficult for helicopters to access.

SDGE will continue to refine protocols for PSPS re-energization in 2022.

5. Future improvements to initiative

SDG&E will continue to explore ways to reduce post-event patrol times in an effort to reduce the impacts of PSPS events on its customers.

7.3.6.6 PSPS events and mitigation of PSPS impacts

1. Risk to be mitigated

PSPS reduces wildfire risk by lowering the likelihood of a significant fire but introduces PSPS impacts. While the last resort utilization of this mitigation is necessary and the right thing to do for the safety of SDG&E's customers and communities, widespread power outages with longer than typical durations can have negative economic and societal impacts and should be limited as much as feasible to the specific areas that are experiencing the extreme risk.

2. Initiative selection

SDG&E utilizes PSPS as a last resort mitigation during extreme weather conditions where the probability of ignition is much higher than normal and the consequences of ignitions due to high winds and dry conditions can and have been catastrophic.

As discussed in Sections 7.3.3, 7.3.9, 7.3.10, and 8, multiple activities are utilized to reduce the impacts of PSPS events such as microgrid installations, customer generator programs, strategic undergrounding, installing additional sectionalizing switches, additional weather stations, and operational changes such as transferring sections of circuits to other circuits with less impacts from winds, customer support in emergencies, PSPS communication practices, and protocols on PSPS.

Risk Reduction Estimation Methodology

The effectiveness of the PSPS program is based on several factors and assumptions regarding wildfire and PSPS. The amount of wildfire risk reduced due to PSPS is estimated at 40 percent of overall wildfire risk. This value was estimated based on many factors, with special consideration of not double-counting risk reductions from various other programs. In other words, the Wildfire Risk score would be higher it wasn't for the PSPS activities bringing it down 40 percent to its current level.

The amount of risk introduced by PSPS is measured by historical PSPS events. For risk calculations, SDG&E defines a PSPS event as a "PSPS Activation" which is a contiguous span of time where at least one customer is experiencing PSPS. In 2019 there were 4 PSPS activations that fit that definition. SDG&E also knows the number of customers who were affected by each activation, the duration of their time affected, and certain customer characteristics such as medical baseline.

As discussed in PSPS Customer Impacts Valuation in Section 4.2 Understanding Major Trends Impacting Ignition Probability and Wildfire Consequence, there are assumptions regarding PSPS impacts for each of the attributes of safety, reliability, financial, and stakeholder impact across three distinct customer types. To calculate the PSPS impact under the current PSPS operational methods, the year 2019 was utilized.

The resulting formula for risk reduction due to PSPS is the following: (WF Reduced – PSPS Impact); and the Risk Spend Efficiency for PSPS is: (WF Reduced – PSPS Impact) / (cost of PSPS program). WF reduced is estimated to be 8,192 point and the PSPS impact is estimated to be 5,462. Therefore, the risk reduction from PSPS is the difference of 8,192 and 5,462, which is 2,730. Another way of saying is that the PSPS program lowers the Total Wildfire Risk Score by 2,730 points.

3. Region prioritization

Lessons learned from previous PSPS events are utilized across the service territory, but mitigations are prioritized in the areas most prone to PSPS events. The various activities used to mitigate PSPS impacts are focused on reducing the number of customers impacted by PSPS and the duration of PSPS events.

4. Progress on initiative

WiNGS-Planning modeling will allow SDG&E to have consider segment-based estimates around both the wildfire risk and the PSPS impacts. One important future enhancement is to understand more fully the relationship between the amount of PSPS and the amount of wildfire risk reduced.

In 2021, SDG&E completed additional hardening, installation of PSPS sectionalizing devices, as well as providing generators to customers as outlined in Table 12 of Attachment B. The estimated benefit of these projects is described in Section 8.3 Projected Changes to PSPS Impact.

5. Future improvements to initiative

SDG&E will continue refining the activities associated with reducing PSPS impacts as described in Section 8 Public Safety Power Shutoff (PSPS), including directional vision for PSPS and throughout this document.

7.3.6.7 Stationed and on-call ignition prevention and suppression resources and services

7.3.6.7.1 Aviation firefighting program

1. Risk to be mitigated

Under certain conditions, a wildfire that is not suppressed may grow rapidly and uncontrollably and endanger public safety and fire agencies could divert aerial resources to fight wildfires outside of SDG&E's service territory.

2. Initiative selection

To mitigate this risk, the aviation firefighting program serves as a wildfire suppression resource, ensuring aerial firefighting resources remain available in the region.

SDG&E has two firefighting helicopters available, an Erickson S-64 helitanker (Air Crane) and a Sikorsky UH-60 Blackhawk helitanker (Blackhawk). Both firefighting assets are Type 1 firefighting helicopters, which are defined as carrying over 700 gallons of water to fight fires. The Air Crane has the capability of dropping up to 2,650 gallons of water, and the Blackhawk has the capability of dropping up to 850 gallons of water. Additionally, the Blackhawk hardware is configured for night vision device flight and is capable of night firefighting with the appropriate crew, training, and CAL FIRE support.

SDG&E based its decision for these two resources on two missions. First, both resources provide exceptional fire suppression capability to the service territory. Second, SDG&E performs capital work in the more rural areas with access issues. In areas of difficult access, aerial resources are a necessary construction tool to be able to set structures. Both leased assets fit the requirement for SDG&E.

<u>Risk Reduction Estimation Methodology</u>

SDG&E's Aviation Program provides risk reduction not only to fires associated with SDG&E equipment but also to the entire community for all causes of wildfire. However, the risk reduction discussed here, and the RSE for the program, only focuses on wildfire risk associated to the utility. Similar to other risk-reducing programs, quantifying aviation risk reduction is complex. The goal is to understand how the aviation program reduces wildfire likelihoods and consequences.

From a likelihood standpoint, the Aviation Program is not focused on preventing CPUC reportable ignitions. As defined by D.14-02-015, a reportable ignition is one that starts at utility equipment and travels a meter in vegetation. The helicopters are not dispatched to an ignition site before the fire spreads one meter. As such, the ignition count will not be decrease.

The Aviation Program focuses on reducing the consequences of wildfires through suppression of fire spread and protection of assets. Thus, the risk reduction can be found in the CoRE portion of the risk score assessment.

The risk assessment asks the question of how much less impact do wildfires have with its aviation program versus without one. This is a complex question to solve. Each fire is different, and there is no known general rule to apply to SDG&E specific program. Fire behavior modeling is not accurate enough to suggest what would have happened without suppression activities compared to with. There is, however, anecdotal evidence that recent non-utility wildfires benefitted from aviation resources. Strong evidence of the benefit is reflected in the regularity that local fire agencies use the resource. This is specifically seen in the dispatch of assets to immediately get water on the small fire, avoiding the spread and minimizing the size.

What follows is a brief discussion on how the Aviation Program is effective against wildfires in different types of weather. It is known that on low wind days, aviation resources are excellent tools to prevent prolonged spread; and SDG&E's aviation resources are regularly dispatched in these situations. The effectiveness of aviation resources to assist general fire suppression activities is significant in these situations. However, most wildfire risk that exists to the community is not due to these calmer weather days. On the other end of the weather perspective, in high wind, the benefit of aviation resources is likely to have more constraints. On extremely windy days, wildfires can grow in size even in the first 10 minutes, and although aerial firefighting resources can arrive very quickly, the spread can become too great to overcome. Additionally, on extremely windy days, there are situations and locations when helicopters are not safe to operate. Generally, helicopters that drop water need to be relatively close to their target, and the stronger the wind the more dangerous it becomes to fly close to the ground. Importantly, strong winds can help dissipate the water from the aircraft and lead to ineffective water drops.

SDG&E will continue to analyze the most effective way to run its Aviation Program, and to determine the effectiveness of that program; using internal and external data to assist in the analysis. For the time being, SMEs believe that the program reduces overall wildfire consequence, and therefore wildfire risk, by approximately 4 percent; based solely on the knowledge of the equipment and operations, coupled with anecdotal evidence of recent history. Importantly, this 4 percent is only the measure of utility associated wildfires, and the overall benefit of the program is much larger than what that 4 percent represents.

3. Region prioritization

SDG&E has agreements with the County of San Diego, CAL FIRE, and the Orange County Fire Authority for aerial firefighting within the service territory. Dispatch of aviation firefighting assets is performed through CAL FIRE and these assets support the initial attack strategy to contain wildfires to less than 10 acres. SDG&E employs flight operations staff to assist in dispatching aerial assets 365 days per year, throughout the service territory. This allows the assets to be launched rapidly once dispatched by CAL FIRE.

4. Progress on initiative

Enhancements and progress made in 2021 include:

- Created a partnership with CAL FIRE for night firefighting. While the demands and requirements are determined by CAL FIRE, SDG&E began night currency and proficiency flights for pilots to gain confidence and familiarity with night operations.
- Increased hangar space for maintenance and security of aerial firefighting assets. Maintenance can now be performed indoors, and secure indoor storage is provided when the helicopters are not in use.
- Took ownership of a Sikorsky S-70M (Firehawk), which will serve as a lead aerial firefighting resource once it is outfitted with firefighting capability.

- Operations with Firehawk will be more capable and safer compared to the current Blackhawk due to advanced safety systems and enhanced performance characteristics. The Firehawk will also have a 1000-gallon water drop capacity.

Enhancements in 2022 will include:

- Continue to outfit the Firehawk to become a firefighting resource- expected to be in-service with SDG&E in late 2022.
- Installation of wire crossing hazard placards to increase the safety of helicopter patrols on distribution and transmission circuits within the HFTD.

Actual performance for 2021 and targets for 2022 for this initiative are provided in Attachment B, Table 12.

5. Future improvements to initiative

The Firehawk is expected to be in service in 2023, and the Blackhawk will be available as a backup resource. Over the next three to 10 years, SDG&E will continue to assess the effectiveness of its Aviation Firefighting program and will work with CAL FIRE on any changes for improved firefighting effectiveness.

7.3.7 Data Governance

7.3.7.1 Centralized repository for data

1. Risk to be mitigated

Management of programs and initiatives for mitigation of utility-related wildfires is a data driven process. It requires data from a variety of static and real time source systems to support operational needs, trend analysis, and predictive modeling. To ensure this data has high quality and integrity, the data must be governed through a set of standards and practices that uses people, process, and technology to ensure company data is complete, accurate, consistent, accessible, compliant, and safeguarded appropriately.

2. Initiative selection

To improve decision making in support, SDG&E determined an automated central repository for WMP measures and metrics data was needed to evaluate the effectiveness of utility-related wildfire mitigation programs. In addition, SDG&E determined a WMP DGF was needed to provide a structure for identifying and documenting repeatable processes and controls that govern the central repository data and the source systems of record.

Similar to the WSD's GIS Data Standards, the vision of SDG&E's CR and DGF is to make its wildfire-related data actionable, accessible, aligned, and auditable.

<u>Risk Reduction Estimation Methodology</u>

This initiative does not have a Risk Reduction Estimation because it is foundational to supporting wildfire mitigation efforts. Quantifying a Risk Reduction Estimation would be difficult and not beneficial because it cannot be directly tied to reducing a risk driver and measuring the effectiveness of that reduction.

3. Region prioritization

During the establishment of the WMP measures and metrics reporting process, SDG&E inventoried the required data metrics and identified numerous data owners and data sources. As the CR is being integrated with the source systems, the DGF principles are applied and evaluated.

4. Progress on initiative

Early in 2020, SDG&E established the initial structure for the CR, envisioning it would provide a "single source of truth" for wildfire-related data and be utilized by multiple internal and external stakeholders. In 2020, the DGF was developed and completed for Vegetation Management data sources, processes, and controls. In addition, a WMP audit framework was developed to assess the design and effectiveness of the processes and controls identified in the DGF.

During 2021, significant progress was made in implementing the DGF and automating the WMP metrics in the CR including the following:

- Development of DGFs for Vegetation Management, FS&CA, Asset GIS, Asset Inspections (Distribution, Transmission, Substations), Outages (Distribution, Transmission), Safety, Public Power Safety Shutoff, Financial, and the CR as well as other WMP initiatives.
- Completion of internal DGF audits, including recommendations for management corrective actions for Vegetation Management, FS&CA, Asset Inspections (Distribution, Transmission), and Outages (Distribution, Transmission).
- Development of data glossaries for Vegetation Management, FS&CA, GIS, Asset Inspections (Distribution, Transmission, Substations), Outages (Distribution, Transmission), Safety, Public Power Safety Shutoff, Financial, and the CR as well as other WMP initiatives.
- Integration of data sources with the CR for Vegetation Management, FS&CA, Asset GIS, Asset Inspections (Transmission), Transmission Outages, and Safety. Many of these data sources include data from sensored portions of electric lines, equipment, Vegetation Management, and Safety.
- Development of a central catalog and documentation standard for all WMP table metrics.
- Development of role-based training outlines for data owners and data stewards.

Early in 2021, the OEIS released the GIS Data Reporting Standard for California Electrical Corporations[57]. This reporting standard provided SDG&E with standards, schemas, guidance on data preparation and submittal, and a schedule for submission of GIS data to the OEIS in support of its assessment of SDG&E's WMP and compliance with the approved SDG&E WMP. Upon reviewing the requirements of this standard, SDG&E determined that many of the data sources required for metrics reporting and GIS reporting were common. As a result, data owners and technical teams are working on consolidating these data requirements into the CR.

During 2021, significant progress has been made in implementing the GIS data reporting standards including the following:

57 Geographic Information System (GIS) Data Reporting Standard for California Electrical Corporations

- Incrementally automating the data gathering process
- Processing additional data attributes for Asset Point, Asset Line, and Inspection Feature Classes
- Consolidating OEIS-required data in the SAP Hana data repository for Overhead Structures, Overhead Conductors, and Inspections
- Implementing tools for testing, development, and data quality/availability processes to incrementally automate the data submission process
- Enabling data quality visibility by developing Data Quality/Availability Scorecards for transmission and distribution inspection data

Implementation of the DGF and the GIS Data Standards will make the SDG&E CR scalable and sustainable to accommodate future regulatory requirements and enhance SDG&E's ability to utilize data to evaluate the effectiveness of utility-related wildfire mitigation programs.

Actual performance for 2021 and targets for 2022 for this initiative are provided in Attachment B, Table 12.

5. Future improvements to initiative

SDG&E plans to mature the data governance and CR capabilities including the following:

- Development of documentation for the central catalog of metric logics to provide improved transparency
- Implementation of DGF and documentation standards for data models and predictive analytics algorithms
- Implementation of the OEIS GeoDatabase schema
- Delivery of data governance education for data owners and data stakeholders
- Implementation of data monitoring and data remediation processes
- Sharing of best practices with other utilities in California
- Sharing of data in the cloud using real-time API protocols with a wide variety of internal and external stakeholders

7.3.7.2 Collaborative research on utility ignition and/or wildfire

1. Risk to be mitigated

To effectively mitigate wildfire risk, SDG&E and the overall community of wildfire stakeholders will need to continue to increase and enhance their understanding of weather science, fire science, and climate science. Participating in collaborative research will reduce the risk of duplication of efforts among the stakeholders, and allow sharing of data and modeling tools.

2. Initiative selection

SDG&E is engaging in this activity because the scientific reports released by the State of California in its Fourth Climate Assessment clearly indicate that the risk of wildfire will increase over time as a result of the changing climate. SDG&E has experienced first-hand the benefits of collaborative research with partnerships with academia and government agencies through the sharing of data and development of modeling tools that are now being leveraged to increase situational awareness across the state.

The integration of this increased understanding will help inform all aspects of wildfire mitigation from actions taken to anticipate and prepare for an event to recovering after a wildfire has impacted the region.

Risk Reduction Estimation Methodology

This initiative does not have its own Risk Reduction Estimation because it is foundational to supporting wildfire mitigation efforts. Quantifying a Risk Reduction Estimation would be difficult and not beneficial because it cannot be directly tied to reducing a risk driver and measuring the effectiveness of that reduction.

3. Region prioritization

SDG&E focuses its collaborative research locally across the service territory; however, SDG&E also collaborates with stakeholders throughout California and around the world.

4. Progress on initiative

See Section 4.4.1.1 Environmental Impacts of Wildfires vs Wildfire Mitigation Measures for information on collaborative research through Academic Partnerships. Through these partnerships, data is shared with the research community that addresses utility-ignited wildfire and risk reduction initiatives which can be abstracted to apply to other utilities.

5. Future improvements to initiative

SDG&E made strong progress in 2021 on this initiative despite restrictions as a result of COVID-19. Moving forward, there is an opportunity to establish even stronger partnerships with the academic community to sponsor ongoing wildfire mitigation-related data and collaborative research through internships programs where SDG&E further exposes graduate-level academic students to data driven wildfire mitigation within utility companies. This will serve as a mechanism to begin training the next generation of scientists to support this growing problem.

7.3.7.3 Documentation and disclosure of wildfire-related data and algorithms

See Section 4.5.1 Additional Models for Ignition Probability, Wildfire, and PSPS Risk.

7.3.7.4 Tracking and analysis of risk event data

7.3.7.4.1 Ignition management program

1. Risk to be mitigated

If ignition data is in disparate systems or unavailable, the ability to gain insights about ignition causes is more difficult, or could be uninformed.

2. Initiative selection

To mitigate this risk, the IMP was developed to track ignitions and potential ignitions and to perform root cause analysis on each ignition or potential ignition to detect patterns or correlations. When ignitions or near ignitions are identified through the IMP processes, the Electric Engineering failure analysis team is notified and a systematic analysis is conducted to determine the cause of the failure. When the cause of the failure is determined, the mode of failure is tracked for trends and reported to the mitigation owner to remedy the failure. Such ignition or potential ignition events are documented and analyzed. When patterns or correlations are identified, the outcomes are communicated and assigned to mitigation owners from the business unit most logically positioned to eliminate or reduce future events of a similar nature.

SDG&E has categorized this program as foundational, in which this activity alone does not mitigate the risk of wildfire but is critical in understanding the wildfire risk in general in relation to SDG&E equipment assets. This activity, in conjunction with the other foundational activities, allows for mitigation prioritization; the calculation of RSEs; and aids to effectively select and implement the right mitigations and controls to reduce the risk of wildfires.

3. Region prioritization

This program tracks all ignitions and near ignitions related to SDG&E equipment across the service territory.

4. Progress on initiative

In 2021, the IMP continued to solidify processes for informing mitigation owners and gathering ignition and near ignition data. Ignition/near ignition event sources were focused within the categories identified by the CPUC Decision 14-02-015. Automation of the data gathering process coupled with refinement of information workflows continued in 2021 and will continue in the future. Steps taken in 2021 include automating processing and working to centralize data. Data was then leveraged in the PoI models to create foundational knowledge for wildfire risk mitigation initiatives. The program continues to progress toward broader adoption and is based on the data gathering process that has been put in place and continues to be refined. Data, along with the events initiating the data, are being documented then filtered through the program and the program manager. The program has documented and followed up on over 500 reports with findings being communicated to the appropriate SME.

In 2022, further efforts will be taken to refine the ignition event information gathering process while also incorporating the lessons learned since 2019. The overall process of identifying an ignition or near ignition event, gathering the actionable information about the event, and then working to prevent future events through informed mitigations is unchanged. One area where SDG&E intends to make progress is in PoI. By gathering data on both ignitions and near ignition events and communicating that information to decision makers during project planning and during extreme fire weather events the IMP will enable more informed decisions to prevent ignitions and catastrophic fires from occurring.

5. Future improvements to initiative

Moving forward this program aims to further refine process documents and connect mitigation owners with data repositories.

7.3.7.4.2 Reliability database

1. Risk to be mitigated

Reliability outage data is necessary to better understand the drivers of faults and resulting ignitions, ultimately gaining a deeper understanding of risk events that could lead to ignitions.

2. Initiative selection

SDG&E tracks and maintains customer outage impact data for CPUC annual reporting, other internal and external reporting, and to analyze causes of electric system outages to use that information to optimize electric system reliability investments. The data tracked includes any outages in the primary voltage (i.e., 4 kV, 12 kV, 69 kV, 138 kV, 230 kV, 500 kV) electric systems that leads to customer impact. Planned outages and secondary voltage-related outages are not tracked within this database. The database tabulates results in terms of industry measurements such as Customers Impacted (CI), Customer Minutes interrupted (CMI), SAIDI, and SAIFI.

The Reliability database is audited on an annual basis. The outage data in the reliability database is used as a data source in the development of the PoI models discussed in Section 4.5.1.1 POI Model.

SDG&E has categorized this program as foundational, in which this activity alone does not mitigate the risk of wildfire but is critical in understanding the wildfire risk in general in relation to SDG&E equipment assets. This activity, in conjunction with the other foundational activities, allows for mitigation prioritization; the calculation of RSEs; and aids to effectively select and implement the right mitigations and controls to reduce the risk of wildfires.

3. Region prioritization

This program tracks and maintains outage data for the entire electric system.

4. Progress on initiative

The Reliability database will be migrated to an Oracle IT supported OUA application which allows for easier viewing of data by a broader internal audience.

5. Future improvements to initiative

In the future, the Reliability database and supporting processes will continue to be refined as broader internal audiences leverage the outage data.

7.3.8 Resource Allocation Methodology

SDG&E's enterprise risk management process, discussed in Section 4.2 Understanding Major Trends Impacting Ignition Probability and Wildfire Consequence, includes a step focused on risk-informed investment decision-making. The annual capital planning process prioritizes funding based on risk informed priorities and input from operations. Capital allocation planning sessions begin with input from each business unit manager as supported by their SMEs who perform high-level assessments of their capital allocation requirements based on achieving the highest risk mitigation at the lowest attainable costs. These requirements are presented to a cross-functional director team, which makes up the capital core planning team. This capital core planning team reviews the resource requirement submissions from all functional areas and projects are evaluated against priority by assessing a variety of metrics including safety, cost effectiveness, reliability, security, environmental, strategic, and customer experience. Recommendations for capital spending are then presented to a cross-divisional executive officers committee for approval. Once the capital allocations are approved, each individual operating organization is chartered to manage their respective capital needs within the capital allotted by the plan. This includes re-prioritizations as necessary to address imminent safety concerns as they arise.

7.3.8.1 Allocation methodology development and application

1. Risk to be mitigated

Without a consistent risk analysis there may not be a framework to evaluate various projects and prioritization of investments in different areas.

2. Initiative selection

Initiatives included in this category cover both an enterprise-wide initiative (Investment Prioritization) led by the Asset Management organization as well as a more focused initiative (WiNGS-Planning) led by the wildfire mitigation team to apply more granular analytics to grid hardening projects.

<u>Investment Prioritization</u>

SDG&E's Asset Management organization, under the Investment Prioritization workstream, worked on building the governance process, resource allocation methodology, and enabling tools to support the creation of long-term and short-term plans for capital investment, operation & maintenance, and asset retirement.

The strategic goal of Investment Prioritization is to incorporate an enterprise-wide, MAVF methodology to demonstrate appraisal of capital investments in a consistent, transparent, repeatable and standardized manner through a data-driven, quantitative risk- and safety-based lens with the appropriate review and approval committees. MAVF will utilize SDG&E's strategic values and determine standardized value-based metrics to quantitatively compare projects and thereby enhance the ability to cross-prioritize across portfolios and optimize investment decisions, including wildfire mitigation investments, while ensuring effective spend of ratepayer funds. A software solution from Copperleaf, called C55, is being implemented to improve investment prioritization capabilities. The purpose of the C55 implementation project is to develop business processes and a system for capital investment optimization using an objective, risk-informed value framework. The initial development of this value framework will be applied to electric transmission, substation and system protection assets and employ a phased approach applied to distribution and other assets supporting the electric system infrastructure.

<u>WiNGS-Planning and WiNGS-Ops</u>

While the Investment Prioritization Initiative described above focuses on enterprise-wide resource allocation, there was a need to develop a more granular application of the same type of modeling to tackle specific wildfire-related issues such as targeted grid hardening to reduce PSPS. To do that, the wildfire mitigation team developed the WiNGS-Planning model to quantify the impacts of wildfire and PSPS and identify more optimal solutions to target both wildfire risk reduction and PSPS reduction. The WiNGS-Planning model was developed internally with the support of third-party consultants to validate the methodology and provide external proxies to improve data used in the model. The current scope of

WiNGS-Planning covers preliminary prioritization concepts for grid hardening. A more operational focused model, WiNGS-Ops, was developed as a supporting tool for real-time PSPS decision-making.

The alternative of not pursuing these activities does not provide all the necessary enhancements to support risk-informed decision-making or meet the evolving regulatory requirements and expectations. These activities are also in response to Action Statement SDGE 21-09. See Section 4.6 Progress Reporting on Key Areas of Improvement for the response to Action Statement SDGE 21-09 regarding transparency in the decision-making process.

<u>Risk Reduction Estimation Methodology</u>

This initiative does not have a Risk Reduction Estimation because it is considered foundational to supporting wildfire mitigation efforts. Quantifying a Risk Reduction Estimation would be difficult and not beneficial because it cannot be directly tied to reducing a risk driver and measuring the effectiveness of that reduction. Instead, it supports various initiatives by providing better information to make risk-informed mitigation decisions.

3. Region prioritization

Investment Prioritization and WiNGS-Planning methodologies are implemented across the service territory to utilize as part of holistic risk-informed investment prioritization and risk-mitigation decision-making tool.

4. Progress on initiative

<u>Investment Prioritization</u>

Enhancements and progress made in 2021 include:

- Programed the investment prioritization prototype into a software solution as the capital portfolio allocation tool
- Conducted sample project entry sprint, identifying enhancements of the value framework for transmission and substation portfolio
- Began development of the next phase of the value framework electric distribution

Enhancements planned for 2022 include:

- Expand the investment prioritization prototype development to electric distribution projects, including wildfire-driven projects
- Develop PoC for electric distribution portfolio optimization approach
- Develop associated business processes to implement the tool with electric distribution business units.

<u>WiNGS-Planning</u>

Enhancements and progress made in 2021 include:

- Expanded application of the WiNGS-Planning tool, developed WiNGS-Ops to support real-time decision making during PSPS events

- Initiated a PoC for visualizing WiNGS-Planning and enabling dynamic scenario modeling
- Leveraged WiNGS-Planning in scoping and prioritization of future undergrounding and covered conductor work
- Began automation of elements of the WiNGS-Planning model
- Initiated lifecycle cost analysis and developed preliminary approach for incorporating it into RSE calculations
- In response to Action Statement SDGE 21-09, SDG&E developed its decision-making flowchart to provide greater clarity around how risk factors are considered in decision-making. See Section 7.3.3 Grid Design and System Hardening, Section 7.3.4 Asset Management and Inspections and Section 7.3.5 Vegetation Management and Inspections.

Enhancements planned for 2022 include:

- Complete WiNGS-Planning automation
- Develop user interface/visualization tool for WiNGS-Planning to enhance grid hardening planning process
- Improve WiNGS-Planning model with new data and models such as PoI models
- Migrate WiNGS-Planning model to the cloud for advanced analysis
- Initiate third-party model review
- Initiate egress analysis and explore ways to incorporate it into WiNGS-Planning model
- Incorporate lifecycle cost analysis into WiNGS-Planning

For additional information on RSE approaches and issues, see Action Statement SDGE 21-11 in Section 4.6 Progress Reporting on Key Areas of Improvement.

Actual performance for 2021 and targets for 2022 for this initiative are provided in Attachment B, Table 12.

5. Future improvements to initiative

As the Investment Prioritization matures, performance evaluation and continuous improvement capabilities will be developed. The performance evaluation capability will create business processes around identifying objectives and key performance indicators and will determine action plans to monitor the effectiveness of the Investment Prioritization. The continuous improvement capability will produce business processes on developing the approach and collaboration to address the recommended corrective or improvement actions. Additionally, the goal is to extend Investment Prioritization and C55 implementation across the SDG&E enterprise including IT, Facilities, and Fleet assets starting with a gap assessment of existing plans and processes.

SDG&E will continue to improve the data that is used in the WiNGS-Planning model used to evaluate risks at the segment level and will work on assessing the need and approach for expanding model use in grid hardening and potentially in other areas and initiatives such as enhanced vegetation management (EVM) and microgrids. EVM and Microgrid PoC elements are included in the WiNGS Planning model, however, the two mitigations have not been utilized by the model and cannot be compared across other evaluated initiatives. This is due to certain limitations inherent to each effort, including:

- Microgrids: Developing microgrids is a significantly more complicated activity compared to traditional mitigations such as covered conductor and undergrounding. There are many variables that cannot be considered in the current WiNGS-Planning modeling approach and too many unknowns such as number of customers, size of the microgrid, and financials variables, that cannot be reasonably estimated.
- EVM: There is very little overlap between the VMAs in which Vegetation Management work is conducted and the segment format that WiNGS-Planning interprets. This requires a separate exercise that could potentially result in an incomplete matching of Vegetation Management data to segments.

SDG&E will continue to improve WiNGS-Planning and WiNGS-Ops with new data and integration of new modeling elements and will assess the need and approach for expanding the use and feature capabilities of WiNGS across the system territory it covers.

7.3.8.2 Risk reduction scenario development and analysis

See Section 4.2 Understanding Major Trends Impacting Ignition Probability and Wildfire Consequence and SDG&E's 2019 RAMP[58].

7.3.8.3 Risk spend efficiency analysis – not to include PSPS

See Section 7.3.8.1 Allocation methodology development and application.

7.3.9 Emergency Planning and Preparedness

The mission of Emergency Management is to coordinate safe and effective emergency preparedness for SDG&E's customers and emergency response personnel. That mission extends to safely and efficiently preparing for, responding to, and recovering from all threats and hazards through strategic planning, training, and exercising, and to sustaining a Quality Assurance and Improvement process.

SDG&E manages emergencies in alignment with the state Standardized Emergency Management System (SEMS) and federal National Incident Management System (NIMS), to coordinate across all levels of utility, government, and agency activity. The Company utilizes a utility-compatible ICS structure as an all-hazards framework to manage emergency incidents and events.

The SDG&E Emergency Management department is responsible for coordinating emergency management activities and activation of the EOC. The department's mission is to support effective, efficient, and collaborative planning, preparedness, response, and recovery processes for all hazards and risks, including those associated with wildfire risk and Red Flag Warning incidents, enterprise wide. Collectively, this department leads efforts and strategies to prepare for, respond to, and recover from all risks, hazards, and incidents that may impact SDG&E operations.

The EOC serves as the location from which centralized emergency management is coordinated for the entire service territory. To respond and recover effectively from all hazards and threats, like wildfires, SDG&E established an EOC with cross-functional teams representing every major business line within the Company and functioning within a utility-compatible ICS. The activation of the EOC assembles the internal SMEs to assess and provide situational awareness to internal and external stakeholders,

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[58] https://www.sdge.com/rates-and-regulations/proceedings/sdge-ramp-report

overarching incident objectives, planning, anticipation, response, communications, and coordination. External Emergency Management partners, such as the County OES and CalOES, are provided with situational awareness up to 24-72 hours in advance or as soon as operationally feasible; additionally, those partners are embedded within the EOC during emergency conditions.

SDG&E has conducted or participated in emergency exercises and trainings, all of which have included a lessons-learned component. The AAR will be expanded to ensure it is comprehensive and lessons learned are cataloged into core capabilities for further benchmarking and analytics. Additionally, SDG&E has partnered with PG&E and SCE to develop a joint training committee to develop standardized training for CalOES EOC Credentials.

Future initiatives under Emergency Planning and Preparedness include a 24/7 Watch Command Desk and HFE.

The 24-hour, 7 day-a-week Watch Command Desk will ensure consistent and timely information monitoring of all hazards and real-time assessing of risk impacts to SDG&E's assets, customers, and employees. This program is the natural evolution of developing a world-class emergency management program by increasing Emergency Management's capacity to maintain around-the-clock situational awareness to rapidly respond to any risk posed to the service territory. It is quickly becoming an industry best practice to have a 24/7 Watch Command Desk; PG&E, SoCalGas and SCE currently have this capability. Beyond this trend, the impetus of this program is to reduce potential redundancies with multiple people gathering information, missed issues or information, or an inconsistent notification process. The current model for maintaining situational awareness through several on-duty position rotations is inefficient. To ensure more effective and efficient situational awareness across regional, national, and global information sources, SDG&E has included funding requests and resources in the upcoming General Rate Case to implement a 24/7 Watch Desk program.

SDG&E developed a Human-Machine Interface and decision-support concepts for real-time risk management and decision-making, called HFE in partnership with the DOE and PS&E Group. By weaving HFE into the design of PSPS decision-making tools, SDG&E has improved the safety, consistency, and timeliness of de-energization and re-energization decisions. HFE projects will be expanded to Electric Distribution Operations, Electric Regional Operations, Mission Control Grid Operations, and company-wide based on early successes. The business uses and benefits of HFE are exponential. To meet this need for efficiency and safety enhancements to the Company's technology, tools, and systems, SDG&E is proposing an expansion to the current PSE contract, then transitioning to two full-time HFE Scientists.

7.3.9.1 Adequate and trained workforce for service restoration

1. Risk to be mitigated

Employee and public safety are paramount to operations. For this reason, a comprehensive training program has been implemented to support outage restoration, patrols, inspections, and maintenance as part of SDG&E's CMP and QC program to reduce system impacts, promote public safety, and reduce the risk of wildfire.

2. Initiative selection

To better coordinate outage, storm (e.g., fire, rain, lightning, wind), and PSPS response, SDG&E's workforce must communicate and operate in sync with other first responders in the field (i.e., fire, police). The ICS includes an organizational structure to ensure proper communication. Training and tabletop exercises are also provided to operational leadership and field employees, including Electric Troubleshooters (ETS), Fault Finders, and Line Crews. These individuals respond to events impacting the electric system and may work side-by-side with other first responders (i.e., fire, police).

This ICS structure ensures employee and public safety, timely communication, and adequate resources during an event. Moving forward, ICS will not just be utilized during an event but also during "blue-sky" routine business. Utilizing ICS in this manner will facilitate a seamless transition for the workforce when faced with a system issue, PSPS, or storm event.

<u>Risk Reduction Estimation Methodology</u>

This initiative does not have a Risk Reduction Estimation because it is foundational to supporting wildfire mitigation efforts. Quantifying a Risk Reduction Estimation would be difficult and not beneficial because it cannot be directly tied to reducing a risk driver and measuring the effectiveness of that reduction.

3. Region prioritization

SDG&E's Electric Regional Operations group began integrating various levels of ICS training in support of storm response and PSPS into all aspects of Electric Operations, including Management and Supervisor ranks, as well as into the line assistant curriculum, lineman apprentice program, ETS, and Fault Finder training.

4. Progress on initiative

Enhancements and progress made in 2021 include:

- Updated and modernization of the Electric Regional Operations STC
  - Update of all levels of QEW training such as ETS, fault finders, line assistants, and apprentices
- Developed the Senior Emergency Response Advisor to help assist in the STC integration under the guidance of Emergency Management
- Completed construction on a physical infractions test yard with infractions that will be changed regularly for Journeymen to identify and properly code
- Over 400 employees completed ICS training

No changes are expected to be made in 2022.

Actual performance for 2021 and targets for 2022 for this initiative are provided in Attachment B, Table 12.

5. Future improvements to initiative

SDG&E continues to modernize and enhance training in the areas of storm response, process and documentation.

7.3.9.2 Community outreach, public awareness, and communication efforts

1. Risk to be mitigated

SDG&E customers and the general public are affected by wildfires, which are now a nearly year-long presence in California. Customers and the general public who are not educated about wildfire safety, emergency preparedness, and resiliency may be ill-prepared for a wildfire or a PSPS event.

2. Initiative selection

To mitigate this risk, SDG&E's comprehensive wildfire safety public education and outreach plan was developed with the intent of increasing community resiliency to wildfires and mitigating the impact of PSPS events. The plan is divided into 3 phases: prior to, during, and following a wildfire or PSPS event. Communication efforts before a wildfire focus on educating customers and the public about the measures and programs being implemented to reduce the threat of catastrophic wildfires, tactics they can employ to remain resilient and safe, and the community resources available. During a wildfire-related event, real-time awareness and updates about the event are provided along with information on how to remain safe and vigilant and the community resources available through the end of the event. After a wildfire, SDG&E examines communications and solicits customer and stakeholder feedback with the intent of refining and improving communication efforts.

<u>Wildfire Safety Communications Prior to Events</u>

SDG&E maintains a robust Wildfire Safety Community Awareness campaign to educate customers and the general public throughout its service territory. This campaign helps the community prepare for the risk of wildfires and PSPS events and encourages customers and the public to take preparedness measures such as updating their profile contact information and signing up for SDG&E notifications. Fundamental to the campaign's success is its collaborative framework—local public safety and community partnerships such as 211 San Diego, 211 Orange County, Facilitating Access to Coordinated Transportation (FACT), the San Diego County AFN Working Group, and American Red Cross help disseminate important information to potentially impacted and vulnerable communities.

Communication efforts also focus on AFN populations and other hard-to-reach communities. A dedicated paid AFN public-education campaign is activated every year leading up to and during peak wildfire season. The campaign informs customers and the public about available services through collaboration with local CBOs including 211 San Diego, 211 Orange County, FACT, and others. Key materials are produced in prevalent languages spoken in the region.

Some paid communications include:

- Promotion of community engagement events, emergency preparedness workshops, safety fairs and public participation meetings
- General Market TV
- Streaming TV
- General Market Radio
- Streaming Radio
- Radio Sponsorships (Traffic, News, Weather)

- Out-Of-Home (Bulletins/Posters/Transit)
- Digital (Banner Ads, Mobile Phone Ads, Online Video, Paid Search, Paid Social)
- Print Advertising
- Community newspapers in the HFTD and the service territory (Back Country, Spanish, Asian, African American, General Market)
- Educational information disseminated through a bill newsletter or special insert included in customer bills
- A series of wildfire safety and preparedness videos and new vignettes to help customers and the public prepare for wildfire and PSPS
- Distribution of an annual Wildfire Safety newsletter that is mailed to customers in the HFTD
- Promotion of weather information and system-outage status on SDGE.com
- Paid and organic social media messaging that includes platforms like Twitter, Facebook, and Nextdoor
- Partnership with a network of over 400 non-profit and community-based organizations who share fire safety and emergency communications with their networks

SDG&E will continue to solicit and utilize the customer feedback to refine and improve public education messaging and tactics listed above.

<u>Wildfire Safety Communications During PSPS Events</u>

During PSPS events, SDG&E uses notifications, media updates, in-community signage, and situational awareness postings across social media and shares social media kits with community partners to reach a broad audience. Additionally, SDG&E activates communications to provide affected customers and the public with the latest real-time updates during a PSPS event. Key communications are available in 21 prevalent languages.

During PSPS events, a dedicated AFN liaison is responsible for conveying real-time updates and talking points to AFN community partners. Communication platforms, including social media channels, broadcast and print media, and the SDG&E NewsCenter and website, are also used to share enhanced support services available for individuals with AFN. A digital document is also produced and distributed that lists communities affected by a PSPS event and shares it with local municipalities and agencies. This effort is intended to give additional context about PSPS events and help communities prepare.

In addition to mass media, SDG&E utilizes several communications channels geared towards individuals who may not be account holders (e.g., visitors, mobile home park residents, caretakers, etc.). These channels include SDG&E's PSPS Mobile App (Alerts by SDG&E), roadside electronic message signs placed in strategic, highly traveled locations, tribal casino marquees and flyers posted around impacted communities.

PSPS Notifications

PSPS notifications are sent to all impacted individuals as soon as possible through the ENS (recorded voice message, email and text message). In 2021, SDG&E worked with Deaf Link to convert all notifications into American Sign Language video, audio read-out, and written transcript. Address-level alerts are also enabled for customers and the general public through the Alerts by SDG&E app.

Annually SDG&E evaluates the content library of PSPS email, text and voice notifications for customers and non-accountholders. Feedback solicited from and provided by customers who have been notified and affected by PSPS events is used to simplify notification messaging and make content more representative of the conditions being experienced. During 2021, updated PSPS notifications were translated and recorded into 21 prevalent languages spoken in the region. Every year the SDG&E public-education campaign includes messaging about signing up for notifications prior to the start of peak fire season.

For MBL and Live Support Customers, results of each Enterprise Notification System campaign are reviewed to determine if a positive confirmation for MBL customers was received through a voice contact (landline or cell phone, based on the customer's preferred contact number). For any MBL customers that are not reached by voice contact, a list is provided to SDG&E's Customer Contact Center, who proactively call customers that have not been contacted. If they are unsuccessful in contacting the customer, a Customer Service Field representative is sent to the customer's service address to notify them. Customer Service Field representatives are trained on the County of San Diego's First Responder AFN Training Series to promote an empathetic and supportive approach for customers with AFN.

<u>Wildfire Safety Communications After an Event</u>

After a wildfire or PSPS event, communications to customers and the general public are reviewed and evaluated. Feedback is solicited from affected customers on communications related to the event. This feedback is then used to improve customer and public communications and outreach efforts for the following year.

<u>Risk Reduction Estimation</u>

This initiative does not have a Risk Reduction Estimation because it is considered foundational to supporting wildfire mitigation efforts. Quantifying a Risk Reduction Estimation would be difficult and not beneficial because it cannot be directly tied to reducing a risk driver and measuring the effectiveness of that reduction.

<u>Accessible Media Engagement</u>

SDG&E prioritizes accessibility for its websites and mobile apps, taking a proactive approach to meet Americans with Disabilities Act (ADA) and Web Content Accessibility Guidelines (WCAG) global web standards for accessibility.

2021 highlights include:

- Creation of an AFN landing page to allow customers to self-identify, as well as a one-stop location to get personified resources for AFN customers.
- Optimized Drupal (content management system) accessibility features including, search engine form and presentation, color contrast and intensity, image handling and form labeling.
- Implementation of AudioEye, service that continuously tests and remediates accessibility issues automatically and sends alerts for other potential issues.

- Work with the Center for Accessible Technology (CforAT) on testing and remediation of our digital properties.

While executing the development, implementation and maintenance of our digital properties, SDG&E always ensures that accessibility is a requirement and priority so all customers can access our information.

In 2022, SDG&E will continue to engage with local broadcast media and utilize various mediums to reach the public, including AFN communities, and Limited English Proficient residents, to provide them with wildfire safety and emergency preparedness information, PSPS awareness and PSPS education.

Per the U.S. Census Bureau, San Diego County is home to more than 3.3 million residents, approximately 1.1 million of which are Hispanic and Latino. SDG&E's service territory also borders Baja California, México, and is home to one of the busiest land border crossings in the world. In addition to providing communications in language, in 2021 SDG&E expanded its marketing and communications team with the addition of a dedicated Spanish communications manager and translates wildfire safety and PSPS-related news releases, social media and other communications pieces for the public and local Spanish broadcast media. SDG&E also provides critical PSPS and wildfire safety information in all prevalent languages.

Prior to a wildfire-related event, SDG&E will engage local broadcast media, including local Spanish media and multicultural niche outlets, early and often to reach customers and notify them of impending high fire risk conditions, the potential for a PSPS, where to go for more information and available resources. Local broadcast media, including designated emergency broadcast radio, will continue to amplify SDG&E's messaging during a wildfire or high fire risk weather conditions to keep our diverse customer base and the public informed.

3. Region prioritization

Public education and communication efforts target customers throughout the entire service territory due to the regional threat of potential wildfire. In particular, outreach efforts focus on the HFTD.

4. Progress on initiative

Enhancements and progress made in 2021 include:

- Worked with the Indian Health Council and Southern Indian Health Council to identify and address needs during PSPS events, (e.g., generators, resiliency items, etc.).
- Partnered with two tribal consultants to advise on customized and culturally appropriate communications and outreach.
- Held drive-through Wildfire Safety Fairs that attracted over 2,400 HFTD residence.
- Enhanced notifications during an event to be more accessible by including a video with American Sign Language interpretation and an audio read-out.

Enhancements for 2022 include:

- Integration of recommendations associated with SDG&E's Compliance Report Regarding Surveys and Metrics to Determine Effectiveness of 2021 Outreach[59] into planning efforts.
- Utilization of customer feedback solicited to inform its Compliance Report on Effectiveness of 2021 Outreach to refine and improve public education messaging and tactics
- Expansion of Tribal and AFN campaigns to reach and communicate with a greater number of hard-to-reach vulnerable populations
- Strengthen enhanced partnerships with Indian Health Councils and provide ongoing support to mitigate the impacts of PSPS events
- Expand and strengthen partnerships with CBOs. Many of these organizations target in-language communities and can help refine communications and further identify non-English speaking populations within the territory.
- Evaluate partnerships with local school districts to enhance public education efforts. Considerations include school newsletters and communications to parents, as well as leveraging established school communication platforms (emails, text messages and collateral materials).

Actual performance for 2021 and targets for 2022 for this initiative are provided in Attachment B, Table 12.

5. Future improvements to initiative

As the AFN support model continues to mature, SDG&E will refine its messaging and channels to optimize effectiveness. SDG&E will also continue proactively identifying customers with AFN in order to target outreach, education and solutions to these customers. Additionally, customized and culturally appropriate Tribal communications and communication channels will be an area of expanded focus.

7.3.9.3 Customer support in emergencies

1. Risk to be mitigated

Emergencies and wildfires often leave customers looking for support in many areas. Without this support, customers could suffer safety issues, economic hardship, and uncertainly to know where they can turn for assistance and information.

2. Initiative selection

To mitigate this risk, SDG&E provides assistance and resource access to those who are directly impacted by wildfires and/or PSPS events. Customers eligible for wildfire residential and non-residential customer protections are those identified as directly impacted by wildfires or who have self-reported as being impacted. Directly affected customers include those without electric service or those needing to re-locate (either temporarily or permanently) due to wildfire damage.

[59] Rulemaking (R.) 18-10-007, San Diego Gas & Electric Company Compliance Report Regarding In-Language Communications and Effectiveness of 2020 Outreach (December 31, 2020) (Compliance Report on Effectiveness of 2020 Outreach).

Emergency residential and non-residential customer protections are provided for wildfire victims, as ordered by the CPUC.[60] Examples of protections include billing adjustments, deposit waivers, extended payment plans, suspension of disconnection and nonpayment fees, and specific support for low-income and medical baseline customers.

Description of Adopted Customer Protections

In D.19-05-039 and D.19-07-015, the CPUC confirmed that SDG&E should continue to provide certain residential and non-residential customer protections for wildfires and other emergencies. Customer support in emergencies, including protocols for compliance with requirements adopted by the CPUC regarding activities to support customers during and after a wildfire, include:

- Outage reporting
- Support for low income and medical baseline customers
- Billing adjustments
- Deposit waivers
- Extended payment plans
- Suspension of disconnection and nonpayment fees
- Repair processing and timing
- Access to utility representatives

These customer protections apply to both residential and non-residential customers unless otherwise noted.

Outage Reporting

Throughout the lifecycle of an adverse weather event, it is important that the customer is adequately informed and prepared at all times. SDG&E's multi-channel approach utilizes the broadcast media (radio and TV), the SDG&E NewsCenter, dedicated PSPS landing page (sdge.com/ready), the SDG&E outage map (on sdge.com and the SDG&E app), and social media for real-time situational awareness. SDG&E's notification system, ENS, also provides notifications and updates directly to affected customers and community members who have signed up to receive PSPS alerts.

After high fire risk weather conditions are forecasted and the National Weather Service issues a RFW, SDG&E begins to coordinate with local government agencies, community-based organizations, and emergency responders approximately 72 hours prior to the event. Communications are then initiated with customers via SDG&E's ENS, broadcast media, and social media channels. These communications drive traffic to SDG&E's NewsCenter and/or dedicated PSPS landing page for more information and real-time situation updates.

The ENS system provides information in 21 languages (English, Spanish, Korean, Vietnamese, Mandarin, Cantonese, Tagalog, Russian, Arabic, Korean, French, German, Farsi, Japanese, Punjabi, Khmer, Somali, Armenian, Hindi, Portuguese, Thai, Mixtec, and Zapotec), with the additional option for American Sign Language available on SDGE.com. As the event progresses, these notifications become more specific and

[60] SDG&E filed Advice Letter 3177-E on January 26, 2018 in compliance with Resolution M-4835 dated January 11, 2018, which was made effective December 7, 2018. See also CPUC Decisions D.19-05-039 and D.19-07-015.

targeted to customers as the situation warrants. Along with outage updates, the channels listed above provide information related to wildfire safety, emergency preparedness, PSPS events, and CRCs.

Support for Low-Income Customers/Medical Baseline

In support of customer protections, SDG&E takes the following actions for all low-income customers in the wildfire-impacted areas within the service territory to align with the CARE and Energy Savings Assistance (ESA) programs as follows:

- Freeze all standard and high-usage reviews for CARE program eligibility standards and high-usage post enrollment verification (PEV) requests for all customers in the impacted areas within the service territory.
- Partner with the United Way, the administrator of its Neighbor-to-Neighbor program that provides emergency bill assistance, to increase the bill assistance cap amount for impacted customers from $200 to $400.
- Modify the ESA program by allowing impacted customers to self-certify if: 1) the customer states they lost documentation necessary for income verification of a wildfire, or 2) if the customer states that individuals displaced by the wildfires reside in the household.

Immediately following a wildfire, outreach representatives are deployed to the field to support American Red Cross and County of San Diego assistance centers. These outreach representatives help customers download the mobile outage map to stay up to date on estimated restoration times, promote and enroll them in programs like CARE and ESA, and connect them to the vast array of services provided by San Diego emergency services.

SDG&E also works with local CBOs to help connect customers with emergency-related information, outage information, and program information. These CBOs also help to refer customers in need to San Diego emergency services for further information and assistance. SDG&E will continue to work with the local CBOs to place emphasis on the additional measures available to low-income customers.

In addition to the protections for the low-income customers discussed above, SDG&E freezes all recertification for medical baseline customers in the impacted areas within SDG&E's service territory.

Billing Adjustments

When a wildfire has destroyed a customer's residential structure, SDG&E waives closing bills including charges from the previous regular read date up until the dates the wildfire occurred and charges from the prior month of billing. For non-residential customers whose structures have been destroyed, closing bill amounts from the previous regular read date up to the dates on which the wildfire occurred are waived. Non-residential customers are still held responsible for charges billed for any months prior to the wildfire. SDG&E stops estimated energy usage for billing purposes when a home/unit was unoccupied due to a wildfire.

Deposit Waivers

SDG&E waives deposit requirements for customersseeking to re-establish service at either the same location or a new location.

Extended Payment Plans

SDG&E extends payment arrangements with a 0-percent down payment and offers a repayment period of 12 months to all impacted customers, including customers whose employment was impacted by wildfires.

Suspension of Disconnection and Nonpayment Fees

For customers impacted by wildfires, including customers whose employment was affected by wildfires, SDG&E suspends disconnection for non-payment and associated fees, waives the deposit and late fee requirements for affected customers who pay their utility bills late, and does not report late payments by customers who are eligible for these protections to credit reporting agencies or to other such services.

SDG&E identifies the premises of customers impacted by wildfires that are not capable of receiving utility services and discontinues billing these premises. Currently there is no disconnect charge. Additionally, there is no reconnection charge for customers impacted by wildfires will not be charged a reconnection charge.

Repair Processing and Timing (Move In-Move Out)

SDG&E initiates best efforts to expedite move-ins and move-outs to support customers impacted by wildfires returning to their homes. If a customer advises SDG&E that they are relocating to another location as a result of damage to their home due to a wildfire, every attempt is made to have service available to the customer on the requested day. Additionally, SDG&E will track the time from when the service is requested to the time it is completed.

Access to Utility Representatives

Customers and stakeholders have a variety of representatives available to them to receive information and communicate concerns. These include representatives in SDG&E's Call Centers, Regional Public Affairs, Business Services, and Fire Coordination.

- Call Centers: Any customer or concerned person, can contact SDG&E's call center to obtain information before, during, or after a wildfire event. SDG&E's call center adjusts resource levels accordingly to support wildfire events.
- Regional Public Affairs: Personnel are assigned to develop and maintain relationships with local elected officials. As a wildfire event approaches, the SDG&E representative will establish and maintain contact with their key stakeholder. The SDG&E representative provides answers to questions and addresses concerns.
- Business Services: Key and critical accounts are identified and assigned a specific resource to establish and maintain contact during a wildfire event. The SDG&E representative reaches out to the customer as the wildfire event develops and maintains contact until the wildfire event is over.
- Fire Coordination: The Fire Coordinators are experienced in fire behavior, fire prevention, and firefighting techniques. They serve as the direct link between SDG&E and emergency-response agencies. They also serve as the single point of contact for the fire agency Incident Command System, provide periodic updates to fire emergency personnel and SDG&E personnel, establish

radio and communications assignments, assist in the coordination of activities related to de-energizing and reenergizing power lines, and update on-scene personnel, control centers, service dispatch, and the SDG&E regional operations centers as to the status of each incident.

Risk Reduction Estimation Methodology

This initiative does not have its own Risk Reduction Estimation because it is considered foundational to supporting wildfire mitigation efforts. Quantifying a Risk Reduction Estimation for such a mitigation would be difficult and not beneficial because it cannot be directly tied to reducing a risk driver and measuring the effectiveness of that reduction.

3. Region prioritization

These customer protections are available throughout the service territory for eligible customers. Descriptions of the customer protections offered to affected customers are provided on a special landing page, SDGE.com (with a contact telephone number for more details of eligibility and protections available). The page is promoted with social media campaigns. In addition, every possible effort is made to contact impacted customers to bring awareness regarding these protections. An Energy Service Specialist (ESS) or an account executive makes these calls.

4. Progress on initiative

Enhancements and progress made in 2021 include:

- Continuing to focus outreach on the most vulnerable customers, including MBL customers.
- Continuing efforts to update contact records for wildfire event communications.
- Adding ENS notifications with an accessible format and videos with American Sign Language translation and audio readout.

5. Future improvements to initiative

SDG&E will evaluate new partnerships, programs, and service offerings provided directly or through community partnerships. Central to SDG&E's planning will be collaboration with 211 San Diego and 211 Orange County on continued ways to support AFN customers in 2021. (See Section 8.4 Engaging Vulnerable Communities)

7.3.9.4 Disaster and emergency preparedness plan

1. Risk to be mitigated

If responders are not qualified and prepared to respond safely and successfully to likely threats and hazards through the application of leading emergency practices, maintaining 24/7 situational awareness, and strengthening readiness through training and exercising "real-life" scenarios, public safety could be at risk.

2. Initiative selection

SDG&E is guided by its mission to improve lives and communities by building the cleanest, safest, and most reliable energy company in America. In support of this mission, SDG&E engages in proactive planning and preparedness efforts to respond effectively to any hazard the Company may encounter.

To mitigate this risk, the Company Emergency Response Plan (CERP) was developed as a guide to achieving the following objectives:

- Implementing and adopting all-hazards response processes that are applicable regardless of incident type
- Using an ICS utility compatible emergency response structure and processes
- Providing roles, responsibilities, and key response processes to response team members
- Applying lessons learned from activations, exercises, and industry-leading practices to response practices

The CERP, along with related standards and other SDG&E documentation, governs emergency response efforts. This plan supports and is part of the overall emergency response plan framework.

The CERP supports an all-hazards approach to incident response. All-hazards emergency management considers all hazards and incidents that the entity may encounter. Emergency management must be able to respond to natural and artificial hazards, homeland security-related incidents, and other emergencies that may threaten the safety and well-being of citizens and communities. An all-hazards approach to emergency preparedness encourages effective and consistent response to any disaster or emergency, regardless of the cause.

Risk Reduction Estimation Methodology

This initiative does not have a Risk Reduction Estimation because it is considered foundational to supporting wildfire mitigation efforts. Quantifying a Risk Reduction Estimation would be difficult and not beneficial because it cannot be directly tied to reducing a risk driver and measuring the effectiveness of that reduction.

3. Region prioritization

CERP is applied throughout the service territory.

4. Progress on initiative

Enhancements and progress made in 2021 include

- Updating the CERP based on lessons learned and additional regulatory requirements. The CERP is currently in the process of final review by operational directors.
- Hiring a contract Emergency Planner to assist in the CERP update

No changes are expected to be made in 2022

5. Future improvements to initiative

SDG&E will continue to update its CERP based on lessons learned.

7.3.9.5 Preparedness and planning for service restoration

1. Risk to be mitigated

Restoring power after a major incident is a complex and difficult task. Without the appropriate resources and equipment, restoring power can be delayed.

2. Initiative selection

A speedy restoration requires significant logistical expertise, skilled line workers and assessors, and specialized equipment on a large scale. Mutual assistance is an essential part of the energy industry's contingency planning and restoration process. Utility companies impacted by a major outage event are able, under mutual assistance, to increase the size of their workforce by borrowing restoration workers from other companies. When called up, a company will send skilled restoration workers along with specialized equipment, oversight management, and support personnel to assist the restoration efforts of a fellow electric/gas service company. Crew members who deploy for mutual assistance are provided just-in-time training at the pre-deployment briefing, including review of all COVID-19 protocols.

The primary goal of the mutual assistance program is to restore service in a safe, effective, and efficient manner. The program also serves additional objectives that benefit the entire energy industry. These include:

- Promote the safety of employees and customers
- Strengthen relationships among utility companies
- Provide a means for utility companies to receive competent, trained employees and contractors from other experienced companies
- Provide a predefined mechanism to share industry resources expeditiously
- Mitigate the risks and costs of member companies related to major incidents
- Proactively improve resource-sharing during emergency conditions
- Share best practices and technologies that help the utility industry improve its ability to prepare for, and respond to, emergencies
- Promote and strengthen communication among Regional Mutual Assistance Groups (RMAGs)
- Enables a consistent, unified response to emergency events

Mutual assistance is both incoming and outgoing. There are situations where SDG&E's resources are taxed and require the assistance of other SMEs from visiting utilities. There are other situations where the service territory is not affected but other utilities require outside assistance. Planning efforts cover both scenarios. SDG&E is a member of multiple emergency associations to facilitate mutual assistance and maintains active mutual assistance agreements with the following organizations:

- California Utilities Emergency Association (CUEA)
- Western Regional Mutual Assistance Group
- Western Energy Institute
- Edison Electric Institute
- American Gas Association

<u>Risk Reduction Estimation Methodology</u>

This initiative does not have a Risk Reduction Estimation because it is foundational to supporting wildfire mitigation efforts. Quantifying a Risk Reduction Estimation would be difficult and not beneficial because it cannot be directly tied to reducing a risk driver and measuring the effectiveness of that reduction.

3. Region prioritization

The decision to deploy a response team or request mutual assistance is facilitated by Emergency Management and determined by the Utility Incident Commander in consultation with key operations directors and executives.

4. Progress on initiative

Enhancements and progress made in 2021 include

- Reviewing the Mutual Assistance Plan annually, in accordance with GO 166.[61]
- Transitioning from cash advances to a debit card system for per diem disbursements. Debit card systems are safer for COVID-19 purposes as handling cash is discouraged by the Centers for Disease Control.
- Utilizing the Mutual Assistance Program to assist the Imperial Irrigation District.

Enhancements in 2022 will include:

- Development of a formal mutual assistance training program

5. Future improvements to initiative

SDG&E plans to maintain the Mutual Assistance Plan and update it as needed. SDG&E will also maintain three mutual assistance agreements (one in California, one in the region, and the other nationwide).

7.3.9.6 Protocols in place to learn from wildfire events

1. Risk to be mitigated

Emergency response is critical and complex in nature. If processes and procedures remain stagnant, they may not provide the best response year after year.

2. Initiative selection

SDG&E's emergency response has significantly grown in scope over the last year. To mitigate the risk, a systematic, inclusive, and transparent process to review incidents was developed with continuous quality assurance and improvement as a core value.

By providing strategic, data-driven direction, the AAR Program facilitates solutions and vital conversations between stakeholders to effectively enhance emergency preparedness and mitigate any risks identified during incidents and events.

As an essential part of the AAR Program, Emergency Management conducts a facilitated de-brief of all major fire and PSPS-related incidents and activations where an opportunity for improved safety, scene management, communications, and/or training have been identified. Feedback is solicited from all responding and supporting departments, including external agencies such as San Diego Fire and Rescue, CAL FIRE, and additional public safety partners. The initial stages of the AAR process call for a thorough evaluation of emergency response related core capabilities and competencies from all key stakeholders.

[61] GO 166, Standard 2. SDG&E is in the process of developing a formal Mutual Assistance training. SDG&E currently does what can be considered "just in time" training during the pre-deployment briefing on policies and procedures, including COVID-19 protocols

Following this stage, corrective actions and emergency readiness capabilities are integrated into the annual Training and Exercise calendar to ensure operational and organizational effectiveness.

The Operational Field & Emergency Readiness Division (OFER Div.) manages the comprehensive continuous improvement process to continue building and improving SDG&E's emergency response capabilities in operational planning and response to wildfire and PSPS incidents. Following all EOC activations and major exercises, the AAR Program initiates a series of workshops to solicit feedback from the appropriate stakeholders to ensure best practices are further developed and areas of improvement are documented on an improvement plan to be tracked to completion.

<u>Risk Reduction Estimation Methodology</u>

This initiative does not have a Risk Reduction Estimation because it is foundational to supporting wildfire mitigation efforts. Quantifying a Risk Reduction Estimation would be difficult and not beneficial because it cannot be directly tied to reducing a risk driver and measuring the effectiveness of that reduction.

3. Region prioritization

The region prioritization for the AAR process is not based on a physical location. AAR activities and the resulting documentation of the event and related lessons learned are engaged based on the impacted and responding stakeholder groups.

4. Progress on initiative

Enhancements and progress made in 2021 include

- Maturing the AAR program to align and integrate processes with SDG&E's SMS. Where the AAR focuses on emergency incidents and events involving SDG&E's EOC, the SMS will provide an enterprise-wide approach to risk and safety and allow for cross-functional learning and information sharing on all events.
- Partnering with the Training and Exercise program to draft core capabilities for continuous quality improvement, performance management, and benchmarking of emergency response to wildfire incidents/events.
- Creating an AAR application for a systematic approach to managing corrective actions and the associated workflow and accountability tracking.

No changes are expected to be made in 2022.

5. Future improvements to initiative

The increase in demand for continuous quality improvement projects and post-incident evaluations coincides with three future initiatives:

- Setting aggressive training and exercise goals to address a broader range of hazards and risks. The Training & Exercise Division will heavily rely on the AAR program to provide a mechanism to benchmark, measure the maturity of programmatic elements, and determine progress towards strengthening emergency response practices in an all-risk, all-hazard environment.
- Providing an enterprise-wide approach to risk and safety. the AAR program will partner, align, and adopt Emergency Management's continuous improvement processes with the SMS.

- Implementing an ambitious, utility-wide ICS goal has widened the scope of stakeholder groups requesting post-incident evaluations.

7.3.10 Stakeholder Cooperation and Community Engagement

SDG&E remains dedicated to partnering with utility customers, elected officials, AFN partners, tribal nations, nonprofit support organizations, first responders, and all other public safety and community partners, understanding they all play a unique and significant role in achieving wildfire prevention and mitigation in the service territory. SDG&E takes its role within the communities it serves seriously. This is especially true during times of PSPS, when communities depend on complete, accurate, and timely information for their safety.

SDG&E strives to provide all stakeholders upfront awareness and information, educate the public on wildfire preparedness, and equip those it serves with information and resources to navigate the adversity of an emergency, wildfire, or PSPS event. Through research, planning and strategic partnerships, SDG&E has implemented a robust public education and outreach strategy, which is continuously analyzed to identify areas of improvement. Relationships with CBOs and stakeholders are also utilized to amplify and disseminate critical, sometimes life-saving information.

The Energy Solutions Partner network consists of nearly 200 CBOs. These year-round efforts and partnerships are further explained below. In 2021, SDG&E enhanced its partnerships with 40 of these CBOs who serve the HFTD to provide enhanced funding and training to enable further support of their constituents. In addition, key to SDG&E's stakeholder engagement is its relationships with emergency response agencies, locally and at the state-level. SDG&E is widely recognized as a world-class innovator with its FS&CA department. This team routinely provides best practices to other national utilities and international entities.

SDG&E remains committed to fostering productive collaboration and engaging the communities it serves. Endeavoring to collaboratively identify fresh ways to better serve our communities will remain a top priority in 2021 and beyond. SDG&E will continue to leverage its partner network, agency relationships to strive for clear, concise education and messaging.

7.3.10.1 Community engagement

1. Risk to be mitigated

Customers and the general public may not have knowledge of wildfire safety, resiliency, and emergency preparedness. In addition, they do not have a way to access information before an emergency, wildfire, or PSPS event occurs. Without this information, customers cannot take the necessary steps to prepare for and navigate the inherent difficulties these events may bring.

2. Initiative selection

To mitigate this risk, a comprehensive wildfire safety communications and outreach plan was developed with the intent of increasing proactive emergency preparedness efforts and community resiliency to wildfires. See Section 7.3.9.2 Community outreach, public awareness, and communication efforts for details.

In addition to online webinars, Drive-Thru Wildfire Safety Fairs, and the comprehensive year-round campaign described in Section 7.3.9.2, outreach advisors work with community organizations to provide education, programs, and services that focus on wildfire preparedness, PSPS notifications, and support services.

A key channel and support network utilized by outreach advisors is the Energy Solutions Partner Network (see Section 8.4 Engaging Vulnerable Communities for details). This network is comprised of nearly 200 Community Based Organizations (CBOs) who serve a critical role in connecting SDG&E with its constituencies. Through the Energy Solutions Partner Network, multicultural, multilingual, senior, special needs, disadvantaged, and AFN communities can be reached. In many cases, CBOs are trusted partners and experts by the communities they serve, providing valuable feedback on the needs of their constituents.

SDG&E works with CBOs year-round to help prepare customers for wildfires through presentations, meetings, and amplification of emergency preparedness information. Additionally, when a PSPS is possible, notifications and updates are provided to these organizations who then amplify wildfire preparedness and notification messaging to hard-to-reach customers who may not utilize traditional channels.

Wildfire Safety Community Advisory Council

The Wildfire Safety Community Advisory Council (WSCAC) is a forum allowing well-connected and trusted community leaders to provide feedback recommendations and support to SDG&E senior management and the Safety Committee of SDG&E's Board of Directors. This specialized group of diverse and independent leaders from public safety, tribal government, business, nonprofit, and academic organizations in the San Diego region possess extensive experience in public safety, wildfire management, community-based services, and applied technology, providing valuable insight to SDG&E's continuous improvement efforts.

WSCAC meetings are hosted quarterly, led by SDG&E's Chief Executive Officer, and are attended by members of the Safety Committee of the SDG&E Board and representatives from other key areas of the company. At WSCAC meetings, the WMP and subsequent updates are presented for discussion, suggestions, and recommendations. WSCAC members also provide input on relevant emerging community issues on wildfire safety and preparedness.

Risk Reduction Estimation Methodology

This initiative does not have a Risk Reduction Estimation because it is primarily around educating the community about wildfire safety, resiliency, and emergency preparedness. Quantifying a Risk Reduction Estimation for it would be difficult and not beneficial because it cannot be directly tied to reducing a risk driver and measuring effectiveness of that reduction.

3. Region prioritization

Public education and outreach efforts target the entire service territory with a particular focus on the areas that are most at risk of PSPS or wildfire.

4. Progress on initiative

Enhancements and progress made in 2021 include:

- Identified prevalent languages for SDGE's service territory based on most recent census data
- Increased support by CBOs who serve the HFTD during PSPS
- Expanded direct CBO partnerships to provide AFN support during PSPS
- Added America Sign Language accessible notifications, increased accessibility at CRCs, and enabled 24/7 conversion of emergency messages to accessible format

Enhancement in 2022 will include:

- Augment public education and outreach to AFN and tribal communities in a more customized manner
- Refine processes and procedures based on stakeholder and community feedback
- Enhance identification of AFN customers for the purposes of targeting outreach, communications, and solutions
- Enhance collaboration with community partners, including Fire Safe Councils, local Fire Departments, Community Emergency Response Teams (CERT), AFN partners, tribal nations, local town organizations, and other CBOs in order to educate on PSPS, emergency response, and programs available to all communities

Actual performance for 2021 and targets for 2022 for this initiative are provided in Attachment B, Table 12.

5. Future improvements to initiative

Beyond 2022, ongoing reviews and assessments of the prevalent languages identified will be conducted. The expanded CBO collaboration will help with this effort. Many of these organizations target in-language communities to help refine communications and further identify non-English-speaking populations. Partnerships with CBOs will continue and be expanded in the coming years as necessary.

7.3.10.1.1 PSPS communication practices

1. Risk to be mitigated

As the climate changes and the threat of wildfire increases across California, SDG&E utilizes PSPS events as a last resort mitigation tool to reduce the risk of infrastructure-related catastrophic wildfires. Customers and the general public do not have knowledge of when and where PSPS will occur, and without this knowledge they cannot prepare for these events.

2. Initiative selection

To mitigate this risk, a robust communications and outreach effort was developed to educate customers and the general public about PSPS events and how to prepare for potential outages. The goal of this effort is increased awareness, preparation, and community resiliency to wildfire and PSPS events.

PSPS-specific communications are conducted in three phases: prior to, during, and following a PSPS event. Efforts before a PSPS event focus on educating customers and the public about what a PSPS event is and tactics they can employ to remain safe, resilient, and updated during a PSPS event. During a PSPS event, real-time awareness and updates are provided along with information on how to remain safe. Following a PSPS event, communications are examined and customer feedback is solicited with the intent of refining and improving communication efforts for the following year. For example, customers communicated that wildfire safety notifications were not easy to understand, did not provide sufficient information regarding resources available during a PSPS event, and did not clearly associate a PSPS event as mitigation tool for wildfire prevention. Therefore, in 2021 all customer notifications were modified to realize customer recommendations, achieving a nearly 80 percent customer satisfaction rate with notification content. Additionally, notifications were made accessible in American Sign Language and in addition to the 21 prevalent languages in the service territory.

3. Region prioritization

Public education and outreach efforts target the entire service territory with a particular focus on the areas that are most at risk of PSPS events or wildfire, such as the HFTD.

4. Progress on initiative

<u>Before a Public Safety Power Shutoff</u>

In 2021, SDG&E expanded its public education and outreach efforts associated with its PSPS Communications Plan. PSPS safety and resiliency communications are part of a territory-wide public education campaign. These communications included promotions for Online Wildfire Safety Webinars, Drive-Thru Wildfire Safety Fairs, the enhanced PSPS Mobile App, and launch of an expanded AFN public-education campaign. In light of COVID-19 considerations, special emphasis was placed on reaching and educating customers and the public in new and novel manners.

Online Webinars and Drive-Thru Wildfire Safety Fairs

Online Webinars and Drive-Thru Wildfire Safety Fairs were offered this year to customers and the general public. A large portion of these events provided information about PSPS events and how to prepare for and remain resilient through the events. Record attendance was reached in 2021 and planning for future events will focus on expanding participation in future community events. Additionally, social media tool kits were provided to community partners to help raise awareness by trusted community partners with constituency allowing for far greater community reach.

PSPS Mobile App

The PSPS Mobile App (Alerts by SDG&E) was launched in September 2020 and its capabilities were expanded in 2021. This tool enables customers to receive information including notifications, CRC information with GPS directions, and other real-time updates and safety information related to PSPS activities. Awareness of the app is included in SDG&E's PSPS public education campaign that primarily enlists digital tactics to reach customers and the public with direct links to app stores on available mobile platforms. To date, promotional efforts have garnered more than 31,000 app downloads.

Access and Functional Needs Populations Dedicated Campaign

In 2021, SDG&E continued to build on the 2020 education efforts for customers with AFN and launched an enhanced dedicated campaign in April. This campaign promoted available solutions to customers via

SDG&E's partnerships with entities such as 211, FACT, and the Salvation Army. Additionally, the campaign promoted the collaboration between SDG&E and local community-based organizations across the service territory, helping connect customers with services and resources available to the public during PSPS events.

In 2021, SDG&E continued its partnerships with 211 San Diego and 211 Orange County to serve as resource hubs for customers with AFN. FACT was engaged to provide accessible transportation, while SDG&E partnered with Salvation Army to provide hotel stays. Additionally, SDG&E added the ability to dispatch warm food to severely impacted areas. Following the 2020 season, this support model was adopted statewide. 211 staff help direct constituents to resources such as food delivery, transportation, hotel stays, and an extensive list of other services. For more information see Section 8.4 Engaging Vulnerable Communities.

A co-branded public education campaign was launched and deploys mass-communications, similar to the wildfire and PSPS campaigns outlined in Section 7.3.9.2 Community outreach, public awareness, and communication efforts, and includes the same expansive set of tactics, all targeted towards vulnerable and hard to reach populations. In 2021, SDG&E created a dedicated AFN landing page with links to available solutions, and the AFN campaign provided additional awareness of this page.

Mass public education campaigns have achieved substantial reach through September 30, 2021. Digital banners have achieved nearly 103 million impressions (or touchpoints), with nearly 21 million impression in-language, and social media messaging has garnered over 3,000,0000 impressions with nearly 360,000 in-language. Print advertising, particularly in-language local community newspapers and magazine publications, helped reach affected communities more readily as well as AFN and 16 hard-to-reach audiences. Print provided over 21 million campaign impressions with over 6 million in-language. Traditional radio buy reached over 89 million and 28 million in-language, with streaming radio adding another 11 million and nearly 2 million in-language. Traditional television advertising achieved nearly 136 million impressions with 24 million in-language. The outdoor advertising campaign delivered over 77 million impressions with 37 million in-language. Event-specific community flyers were also developed and posted in community centers and high traffic areas in affected communities. These flyers were intended to reach audiences that may not have had readily available internet or cable access.

Along with the public education campaign, PSPS messaging and creative assets are provided for the 211 websites and social media platforms. Digital versions of SDG&E collateral, such as the High Fire Threat District Newsletter and the PSPS Resource Fact Sheet, were distributed to 211 San Diego and 211 Orange County for inclusion on their websites.

Media Collaboration

SDG&E continues to foster partnerships with local broadcast and print media to inform customers of proactive safety and preparedness outreach prior to a PSPS event. Local broadcast and print media, including the designated emergency broadcast radio, amplify SDG&E's messaging during a wildfire or PSPS event.

Prior to 2020, broadcast and print media were brought into the EOC before a potential wildfire-related event and provided situational awareness that could be shared with their audiences. Due to COVID-19, event briefings from Meteorology are now pre-recorded and shared via social media channels (YouTube, Twitter, Facebook and Nextdoor). The media is kept informed throughout the duration of an event by media representatives, real-time updates via the NewsCenter (sdgenews.com), and social media channels. These efforts will continue through 2022.

During a PSPS

During PSPS events in 2021, SDG&E continued to communicate through customer notifications, media updates, the sdge.com webpage and situational awareness postings across social media channels, in order to provide information about the latest developments during a PSPS.

One of the most effective platforms used is the PSPS Mobile App (Alerts by SDG&E). PSPS notifications for up to five customizable addresses are pushed directly to the app concurrently with other PSPS phone, text, and email alerts. The app also provides real-time updates about each PSPS and information for the user about what stage of the PSPS process they are currently in. Users can also get information about any CRCs and 211 resources. The app is closely aligned content to SDG&E's dedicated PSPS website landing page (sdge.com/ready), including the outage map and new list of affected communities displays.

As part of its expanded outreach to vulnerable communities during an event, roadside electronic message signs are placed in strategic, highly traveled locations throughout affected communities. During PSPS events, these signs are critically important to communicating with travelers going in and out of affected communities. A total of 31 signs (per PSPS event) were deployed in 2021.

SDG&E has also launched a dedicated AFN liaison role and support team in the EOC. This role collaborates closely with AFN partners such as 211 to provide real-time updates and assist any customers in need. Standard communication channels are also employed to promote 211 service resources including, but not limited to social media channels, broadcast and print media, and the SDG&E NewsCenter and website.

During 2021 PSPS events, a digital document listed communities affected by a PSPS event was produced, distributed, and shared with local municipalities and agencies. This effort was intended to give additional context about PSPS events and help communities prepare.

To expand on its digital outreach, radio-script templates were produced for DJs to read live on the airwaves. These scripts are intended for use on San Diego's designated regional Emergency Broadcast radio station. They allow for the addition of real-time awareness details and refer to the SDG&E website for additional safety information and updates.

Following a PSPS

SDG&E reaches out to customers through formal surveys to establish a baseline awareness of PSPS-related messaging and communications at the beginning of wildfire season. At the end of wildfire season, customers are surveyed again to measure the effectiveness of public education efforts and communications. Throughout the year, ongoing customer sentiment continues to be gauged through surveys, online chats, and focus groups. Feedback is used to evaluate, refine, and improve customer and public education efforts for 2022 and beyond. Customers affected by a PSPS event are surveyed following PSPS events and customer data is utilized to inform the customer outreach and public education strategy. Below is a representative sample of some customer feedback received and tactic implications:

- Data Conclusion: Perceptions of SDG&E and their performance of safety measures have greatly improved among HFTD residents. HFTD customers also continue to be much more aware of safety communications than Non-HFTD.
    - Tactic: Continue to supply HFTD customers with wildfire safety news, tips, resources for information, and efforts SDG&E is taking to ensure safety.
- Data Conclusion: SDG&E emails and direct mail are a prominent source for safety information, but other SDG&E channels are less often cited.
    - Tactic: Increase promotion of the SDG&E website, internet banner ads and social media accounts, especially as a means of communicating real-time information during emergencies.
- Data Conclusion: Recall of all wildfire ads shown has decreased, especially for the print ads (English). Appeal and attribute ratings of the print ads (English) are also somewhat low.
    - Tactic: Consider adding color to the print ads, and re-formatting/enlarging the font at the bottom. “AFN” is seen as the least relevant piece – consider elaborating on the assistance aspect (hearing/ visually impaired, or those that rely on electrical equipment for health reasons).

Based on feedback from customers, notification messaging was updated to make content more representative of the conditions being experienced. Updated notifications are translated and recorded in the 21 prevalent languages in the service territory. Additionally, in 2021 notifications were converted to an available video format with American Sign Language translation and audio read out.

In 2022 SDG&E will continue to collaborate with AFN councils and working groups as well as other stakeholders to identify and implement opportunities for enhancement.

New opportunities within established partnerships with local Tribal Councils and other resources that serve Native American communities will be explored. Currently, 2022 planning efforts are under way with organizations such as Indian Health Councils, the Inter-Tribal Long Term Recovery Foundation and third-party, and other tribal communication consultants that specialize in tribal communications. SDG&E is working to significantly expand 2022 wildfire safety and PSPS outreach communications to Native American communities. Along with the expanded communication efforts, SDG&E is working to develop new communications in a culturally appropriate and relevant manner.

Actual performance for 2021 and targets for 2022 for this initiative are provided in Attachment B, Table 12.

5. Future improvements to initiative

Future improvements will be available and utilized for both communications initiatives. As noted in Section 7.3.9.2 Community outreach, public awareness, and communication efforts, these efforts will include the expansion of the AFN and tribal nation campaigns to better communicate with hard-to-reach populations in customized and meaningful ways.

Additional communication efforts will be examined, including working with local school districts to enhance public education efforts. Considerations include school newsletters, communications to parents, and leveraging established school communication platforms (emails, text messages and collateral materials).

7.3.10.2 Cooperation and best practice sharing with agencies outside CA

7.3.10.2.1 Emergency Management and Fire Science & Climate Adaptation

1. Risk to be mitigated

Wildfire is the most pressing climate hazard for the San Diego region today. Cooperation and best practice sharing with agencies outside of California is necessary to build resilience to wildfire and minimize the effects of wildfire.

2. Initiative selection

The increasing occurrence of significant weather events across the globe has become more evident in recent years, which has led to national discussions about climate resiliency. Because of SDG&E's progressive wildfire risk mitigation strategies, it was asked to join the DOE Partnership for Energy Sector Climate Resilience Initiative. As a leading participant in the partnership, SDG&E collaborated with the DOE and 16 other utilities to improve the resilience of the nation's energy infrastructure against extreme weather and climate change impacts. The goal of the partnership is to identify the challenges national energy partners are facing today and work together to develop sustainable solutions. The value of this collaboration extends back into the San Diego region.

SDG&E hosted numerous knowledge sharing tours of the EOC and weather center for utility personnel from throughout the U.S., as well as for international utility partners. Cooperation and sharing of best practices are important components of fire mitigation activities and have contributed to the success of wildfire mitigation activities over the last decade. SDG&E maintains memberships in multiple international utility organizations designed to collaborate and share best wildfire practices from around the world. Prior to the upcoming wildfire season and before the next WMP Update, as well as over the next 3 to 10 years, SDG&E will continue its practice of cooperation and sharing of best practices outside of California.

Understanding the issues at hand and having the best information with which to address these issues is an integral aspect of building smart, long-term solutions to climate change issues. In order to develop and utilize the best climate science in California and the country, strategic partnerships have been developed with academic and research institutions, as well as with the DOE Partnership for Energy Sector Climate Resilience initiative.

3. Region prioritization

Cooperation and best practice sharing with agencies outside California benefit the entire service territory.

4. Progress on initiative

Enhancements and progress made in 2021 include:

- Progressed the development of the FSI Lab (see Section 7.3.2.4.1 Fire Potential Index for details). The lab will bring together leading thinkers and problem solvers in academia, government, and the community to create forward-looking solutions to help prevent ignitions, mitigate the impacts of fires, and ultimately help build a more resilient region. Lab construction was paused in late March 2020 due to the onset of the COVID-19 pandemic.
- Partnered with academia, government, and public safety professionals to innovate and implement more advanced technologies designed to further improve wildfire safety. Initial innovations include maximizing artificial intelligence and machine learning to improve situational awareness.
- Emergency Management established a relationship with PS&E, a local and experienced HFE and HMI scientific company. PS&E secured a $1.4 million grant through DOE's SBIR Grant program to partner with a utility, SDG&E, to identify how the science of HFE/HMI could apply to the utility industry. This led to significant improvements in situational awareness and decision-making processes with PSPS events and Aviation Services flight coordination and tracking. SDG&E entered into a multi-year contract with PS&E to integrate this science into operations company-wide.

5. Future improvements to initiative

To continue to build comprehensive resilience to wildfire and other climate hazards, SDG&E will expand its proven formula of cooperation and best practice sharing with agencies outside California. This will be achieved by combining the best available science (spearheading the development of that science where it is lacking), cutting-edge situational awareness technology, and subject matter expertise dedicated to solving complex climate change-related issues.

7.3.10.2.2 International Wildfire Risk Mitigation Consortium

1. Risk to be mitigated

Wildfire is the most pressing climate hazard for the San Diego region today. Cooperation and best practice sharing with agencies outside of California is necessary to build resilience to wildfire and minimize the effects of wildfire.

2. Initiative selection

To mitigate this risk, SDG&E is a member of a consortium of utilities brought together by UMS Group Inc., an international management consulting firm specializing in solutions for the global energy and utility industries. The IWRMC is comprised of multiple utilities from the United States, Australia, South America, and other areas.

The IWRMC was established to provide members of the global utility community who face wildfire risk a system of sharing of data, information, technology and safe practices. This will reduce the risk of siloed approaches, avoid repeating unsuccessful initiatives other utilities may already have pursued, and allow for more comprehensive development of new solutions.

Engaging with this international consortium provides an opportunity to leverage global experience along with local or regional wildfire risk mitigation experience. It also may accelerate development of new solutions, helping guide industry direction and innovative approaches to risk mitigation.

Risk Reduction Estimation Methodology

This initiative does not have a Risk Reduction Estimation because it is considered foundational to supporting wildfire mitigation efforts. Quantifying a Risk Reduction Estimation would be difficult and not beneficial because it cannot be directly tied to reducing a risk driver and measuring the effectiveness of that reduction.

3. Region prioritization

The IWRMC voted on the focus areas member utilities thought would most benefit wildfire risk advancements. These four areas are vegetation management, risk management, asset management, and operations and protocols.

4. Progress on initiative

The IWRMC established four areas of focus and four working groups. These areas of focus were formed after input from participating utilities. In 2021, specific topics and activities were explored and ideas were shared across the participating utilities. In 2022, the working groups will continue to conduct webinars and other sessions to develop ideas and share results.

5. Future improvements to initiative

The IWRMC plans to continue adding utilities interested in participating and contributing to the collaboration and learnings. Experiences with various mitigation approaches and implementations could be used to inform future SDG&E wildfire risk mitigation. In the future, more details regarding the progress of the various activities from this consortium may be shared.

7.3.10.3 Cooperation with suppression agencies

1. Risk to be mitigated

SDG&E's service territory spans multiple local, state, tribal, and federal fire jurisdictions. Cooperation with suppression agencies is necessary to build an efficient and safe response to emergency incidents and strengthen the overall resiliency of the region.

2. Initiative selection

Fire is a constant risk and utility equipment in or around a fire presents an added complexity to any incident. By ensuring good communication and regularly strengthening relationships before, during, and after incidents SDG&E can increase the likelihood of achieving positive outcomes during emergencies. A main goal of cooperating with suppression agencies is to prevent situations where a breakdown in communication could cause bodily injury.

SDG&E has successfully built relationships with suppression agencies and provides in-person trainings at a Chief and engine level throughout the year. SDG&E also sponsors and participates in the County Wildland Exercise that brings together a variety of suppression and law enforcement agencies.

3. Region prioritization

This work spans San Diego County, Orange County, and Imperial Valley. SDG&E also regularly attends and meets with suppression training officers from around the service territory.

4. Progress on initiative

Relationships with suppression agencies were maintained in 2021 and will continue to be fostered in 2022.

5. Future improvements to initiative

Beyond 2022, training will be refined as input is received from training officers. Topics that firefighters are interested in, as well as lessons learned on incidents, will be incorporated into future trainings.

7.3.10.4 Forest service and fuel reduction cooperation and joint roadmap

Refer to Section 7.3.5.2 Detailed inspections and management practices for vegetation clearances around distribution electrical lines and equipment.

8 Public Safety Power Shutoff (PSPS), including directional vision for PSPS

8.1 Directional Vision for Necessity of PSPS

Instructions: *Describe any lessons learned from PSPS since the last WMP submission and describe expectations for how the utility's PSPS program will evolve over the coming 1, 3, and 10 years. Be specific by including a description of the utility's protocols and thresholds for PSPS implementation. Include a quantitative description of the projected evolution over time of the circuits and numbers of customers that the utility expects will be impacted by any necessary PSPS events. The description of protocols must be sufficiently detailed and clear to enable a skilled operator to follow the same protocols.*

When calculating anticipated PSPS, consider recent weather extremes, including peak weather conditions over the past 10 years as well as recent weather years, and how the utility's current PSPS protocols would have been applied to those years.

Since SDG&E initially developed and implemented the first version of the PSPS Program over a decade ago, California has seen a drastic increase in catastrophic wildfire activity, including the deadliest and most destructive wildfires in state history. This increase in public safety risk over the last decade and especially the last few years, has prompted SDG&E to leverage additional technology and analytics to evolve its PSPS Program. In some cases, this had led to an increase in PSPS events due to climate change, the confluence of extreme high risk weather events, and the integration of additional analytics that assess wildfire risk. For example, lessons learned from the catastrophic wildfire outbreaks across the state in 2017 resulted in the implementation of a 99th percentile alert wind speed as a factor to be considered during a potential PSPS event. Following the wildfires of 2018, areas at higher risk were analyzed for tree strike potential and a VRI was created to identify the areas of the electric system that are most vulnerable to tree strikes during Santa Ana wind events. Additional analysis is also used to target the highest risk areas of the electric system with strategic hardening and will be leveraged to strategically mitigate the impacts of PSPS events while keeping communities safe. Key achievements include an enhanced ability to forecast fire danger; an expanded, rebuilt, and upgraded Weather Station Network; a developed PoF and PoI models; and strides towards the continuous hardening of the electrical system. For more information on the models and/or initiatives, see the following sections:

- VRI: Section 4.5.1.2 Vegetation Risk Index
- Strategic Hardening: Section 7.3.3.8.1 PSPS sectionalizing enhancements
- Weather Station Network: Section 7.3.2.1 Advanced weather monitoring and weather stations
- PoF/PoI: Section 7.3.1.1 A summarized risk map showing the overall ignition probability and estimated wildfire consequence along electric lines and equipment.

The implementation of PSPS is not a decision that is taken lightly, and SDG&E leverages a multitude of situational awareness data and input from its SMEs when deciding whether to de-energize. The first PSPS was implemented in 2013 and since then, the process continues to be refined and improved. Given the dynamic and constantly changing nature of wildfire conditions, there is no "one size fits all" approach to a PSPS and every situation is different. Therefore, in determining whether to employ a PSPS in a given area of the electric system, several factors are analyzed and weighed in preparation and in real-time, including weather conditions, grid conditions, vegetation conditions and VRI, field observations, information from first responders, flying and falling debris, expected duration of conditions, and location of existing fires or wildfire activity in the region or state that would affect resource availability. In 2021, wildfire risk modeling and the comparison of wildfire risk to the public safety risk associated with PSPS events was further integrated with the first version of the WiNGS-Ops model, described in Section 4.5.1 Additional Models for Ignition Probability, Wildfire, and PSPS Risk. PSPS protocols and thresholds for implementation are discussed in Section 8.2 Protocols on Public Safety Power Shut-off.

In 2021, several strategies focused on minimizing PSPS impacts were implemented across the highest fire risk areas in the service territory, including strategic undergrounding, covered conductor, grid reconfiguration, and continued accelerated overhead hardening. This work was developed by a team that evaluated every portion of the grid with the goal to reduce both wildfire risk and PSPS impacts. Over 100 miles of overhead lines were hardened in 2021. Advanced protection systems were deployed to mitigate or reduce the potential for a fire ignition. The falling conductor protection operates to detect and de-energize a falling conductor before it hits the ground. High-speed relays were also deployed that reduce the amount of energy into a fault, which reduces the likelihood of an ignition. Microgrids were built at four sites in 2020 and two additional sites are being converted to renewable resources including CAL FIRE's Ramona Air Attack Base, which help keep more customers energized during a PSPS event and improve community resilience.

Based on existing electrical system data, every mile of strategic undergrounding completed in the HFTD is anticipated to reduce PSPS impacts for approximately 13 customers and for every sectionalizing device installed in the HFTD is anticipated to reduce PSPS impacts for approximately 371 customers. Additionally, since 2019, 6,268 customers have utilized resiliency programs to provide backup generation to their homes. Understanding that there are a finite number of customers and that the rate at which customers are requesting backup support will eventually diminish, it is estimated that approximately 2,000 customers per year will take advantage of SDG&E's resiliency programs over the next three to five years.

All of these assumptions and predictions are dependent on the number of PSPS events per year, weather patterns, wind speeds, and fire potential.

2021 began with unseasonal dry conditions that lead to multiple RFWs, impacting portions of the service territory during the month of January. During these strong wind events, situational awareness tools and system protections such as reclosing and sensitive relay settings were leveraged, resulting in the avoidance of a PSPS event. In October, local high winds impacted portions of the service territory, however an analysis of recent rainfall determined that wildfire potential had been suppressed to a level that system protections would be sufficient to protect public safety.

Permanent renewable solutions for two microgrids sites (Cameron Corners and Ramona Air Attack Base) are estimated to be completed by the first quarter of 2022 (see Section 7.3.3.8.2 Microgrids for details). For the weather event of November 24-26, 2021, three 275 kW diesel generators were deployed to Shelter Valley, a desert community in the far eastern section of the service territory, providing power to 221 customers for over 36 hours, and a second deployment of three 275 kW diesel generators was sent to Butterfield Ranch, another desert community in the far eastern section of the service territory, providing power to 119 customers for over 32 hours. These two sites are planned to have renewable resources by the end of 2023. SDG&E will also explore temporary portable renewable generator options to deploy during PSPS events for critical loads or microgrid sites awaiting the final construction.

***Instructions for Table 8.1-1**: Rank order, from highest (1 – greatest anticipated change in reliability or impact on ignition probability or estimated wildfire consequence over the next 10 years) to lowest (9 - minimal change or impact, next 10 years), the characteristics of PSPS events (e.g., numbers of customers affected, frequency, scope, and duration), regardless of if the change is an increase or a decrease. To the right of the ranked magnitude of impact, indicate whether the impact would be a significant increase in reliability, a moderate increase in reliability, limited or no impact, a moderate decrease in reliability, or a significant decrease in reliability. For each characteristic, include comments describing the expected change and expected impact, using quantitative estimates wherever possible.*

In evaluating Table 8-1, it is important to note that the listed PSPS characteristics are not independent from each other. In many instances, when one characteristic is targeted for reduction, another will also be reduced. For example, if reducing the number of customers impacted by PSPS is ranked as number 1, it will also result in reducing the scope of PSPS events. As such, giving a lower ranking to any one of these characteristics does not imply a level of priority in mitigating the issues. The suite of initiatives that SDG&E deploys to mitigate PSPS impacts target all these characteristics simultaneously. Additionally, the effects of climate change can significantly influence the outlook of PSPS characteristics. The wildfire risk trend continues to point to an increasing level of risk year after year, which could limit or alter progress on decreasing PSPS and require adapting wildfire mitigation strategies for evolving or unforeseen risk in the future. However, due to all of its PSPS mitigation work, SDG&E forecasts a general decrease in PSPS event impacts compared to the impacts if there was not a focus on PSPS mitigation.

Table 8.1-1: Anticipated Characteristics of PSPS Use Over Next 10 Years

Rank Order 1-9	PSPS Characteristic	Significantly increase; increase; no change; decrease; significantly decrease	Comments
1	Number of customers affected by PSPS events (total)	Decrease	A key objective is to reduce the number of customers impacted by PSPS events through the various initiatives outlined in the WMP.
2	Number of customers affected by PSPS events (normalized by fire weather, e.g., Red Flag Warning line mile days)	Decrease	See #1.
5	Frequency of PSPS events in number of instances where utility operating protocol requires de-energization of a circuit or portion thereof to reduce ignition probability (total)	Decrease	Long-term strategies under consideration include enhanced grid hardening to reduce the need for PSPS events and reduce the risk of wildfires. However, it is important to note that the frequency of PSPS events is dependent on weather conditions which continue to evolve year after year.
6	Frequency of PSPS events in number of instances where utility operating protocol requires de-	Decrease	See #5

	energization of a circuit or portion thereof to reduce ignition probability (normalized by fire weather, e.g., Red Flag Warning line mile days)		
3	Scope of PSPS events in circuit-events, measured in number of events multiplied by number of circuits targeted for de-energization (total)	Decrease	The objective of reducing the number of customers impacted by PSPS events inherently includes a need to reduce the scope of PSPS events
4	Scope of PSPS events in circuit-events, measured in number of events multiplied by number of circuits targeted for de-energization (normalized by fire weather, e.g., Red Flag Warning line mile days)	Decrease	See #3.
7	Duration of PSPS events in customer hours (total)	Decrease	As the scope of PSPS events decreases over time, durations of PSPS events should be reduced. However, this characteristic is heavily dependent on weather. PSPS patrol initiations (such as helicopter flights) are dependent on weather conditions and if climate change affects the duration of RFWs or strong wind events, this would limit the ability to reduce the duration.
8	Duration of PSPS events in customer hours (normalized by fire weather, e.g., Red Flag Warning line mile days)	Decrease	See #7.
9	Other (Describe) – Rank as 9 and leave other columns blank if no other characteristics associated with PSPS		

8.2 Protocols on Public Safety Power Shut-off

Instructions: *Describe protocols on Public Safety Power Shut-off (PSPS or de-energization), highlighting changes since the previous WMP submission:*

1. *Method used to evaluate the potential consequences of PSPS and wildfires. Specifically, the utility is required to discuss how the relative consequences of PSPS and wildfires are compared and evaluated. In addition, the utility must report the wildfire risk thresholds and decision-making process that determine the need for a PSPS.*

SDG&E utilizes multiple factors outside of weather to assist in making the decision to de-energize. Some factors pertain to information in the field based on known compliance issues on the electrical system, active temporary construction/configuration of the electrical system, and a CRI to identify locations in the system with a potential of having higher failure rates. These factors are compiled and populated for each sectionalizing device to assist with developing alert speeds and increased awareness of risky assets on the electrical system.

In advance of an approaching Santa Ana Wind event, the WiNGS-Ops model is utilized to determine if there are areas in the service territory where the wildfire risk could outweigh the risk of PSPS. See Section 4.5.1.8 Wildfire Next Generation System-Operations for details on the WiNGS-Ops model.

2. *Strategy to minimize public safety risk during high wildfire risk conditions and details of the considerations, including but not limited to a list and description of community assistance locations and services provided during a de-energization event.*

SDG&E employs a number of mitigations and strategies designed to reduce public safety risk during high wildfire risk conditions and mitigate the impacts of PSPS on customers. SDG&E pioneered the GGP, which provides portable renewable generators to MBL customers in the HFTD to ensure access to electricity during a PSPS event. In 2021, the number of available units was increased from about 1,250 to about 2,000 and eligibility was expanded to include AFN customers. SDG&E also partnered with Indian Health Councils to identify and distribute generators to tribal communities in addition to reserving units for these communities. The GAP offers rebates of up to $450 to customers who reside in the HFTD for the purchase of portable generators and power stations. Customers most at risk of PSPS may be offered a standby generator solution through one of the Standby Power programs.

The Emergency Backup Battery Program was also expanded and will be available for all PSPS events. For medically vulnerable customers who have identified needs beyond hotel, transportation, and/or other available no-cost services, a fully-charged backup battery can be dispatched within 1-4 hours during PSPS events. See section 7.3.3.11 Mitigation of impact on customers and other residents affected during PSPS events for more information on these programs.

After the significant PSPS events across the region in December of 2017, SDG&E held meetings in impacted communities throughout its service territory. As a result of community feedback, a network of CRCs was established to help communities in real-time during PSPS events. Volunteers are employed to staff the CRCs and provide situational awareness, including updates and real-time information, directly to the impacted community. Each CRC also provides bottled water, light snacks, Wi-Fi access, medical device charging, ice, outage updates, water for animals, portable restrooms, cold weather blankets, and hand warmers.

In 2021, SDG&E had agreements with facility owners to establish 11 CRCs located at fixed facilities. Generally, CRCs are open from 8 a.m. to 10 p.m. when activated to support PSPS events. In response to the COVID-19 pandemic, the CRC program deployed health and safety precautions consistent with prevailing guidelines. For the 2021 wildfire season, CRCs were operated as drive-thrus. No entry to the CRC building was allowed except for building owners and SDG&E employees. All personnel (employees, volunteers, CRC partners) were instructed to use proper PPE such as face coverings and gloves. Resources and care kits were pre-assembled and handed to vehicles visiting the CRC in a drive-thru fashion, allowing essential supplies to be distributed while following social distancing protocols.

Table 8-2 lists the 2021 CRCs, including the addition of a new CRC located at the Fallbrook Branch Library. For 2022, SDG&E will continue discussions with communities who request adjustments to existing CRCs or new CRCs. After discussions with Southern Orange County stakeholders in 2021, it was determined that a mobile CRC would be adequate to support any future PSPS impacts.

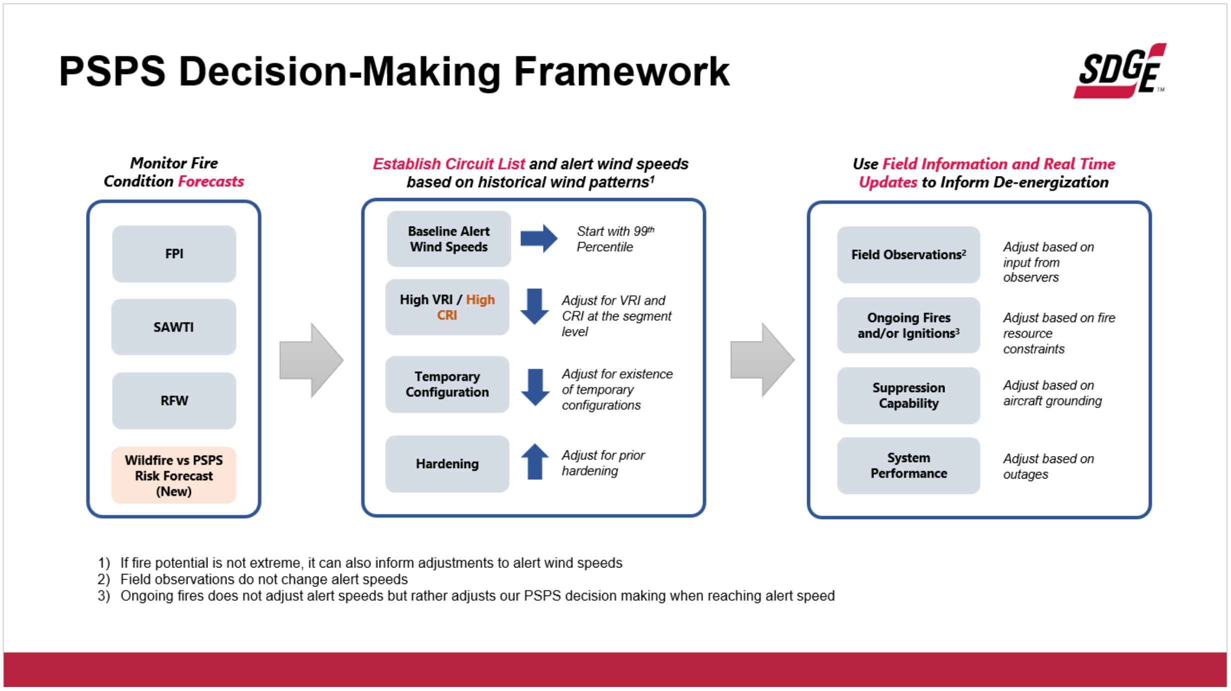
Table 8-2: SDG&E Community Resource Centers

Community Resource Center	Area Served	Facility Name	Location	Site Description
Descanso CRC	Descanso	Descanso County Library	9545 River Drive Descanso, 91916	Building + Trailer
Lake Morena CRC	Lake Morena	Lake Morena Community Church	29765 Oak Drive Campo, 91906	Building + Trailer
Pine Valley CRC	Pine Valley	Pine Valley Improvement Club	28890 Old Hwy 80 Pine Valley, 91962	Building + Trailer
Julian CRC	Julian	Whispering Winds Catholic Camp	17606 Harrison Park Road Julian, 92036	Building + Trailer
Jacumba CRC	Jacumba	Jacumba Highlands Community Center	44645 Old Highway 80 Jacumba, 91934	Building + Trailer
Dulzura CRC	Dulzura	Dulzura Community Development Center	1136 Community Building Road Dulzura, 91917	Building + Trailer
Warner Springs CRC	Warner Springs	Warner Springs Community Resource Center	30950 Highway 79 Warner Springs, 92086	Building + Trailer
Potrero CRC	Potrero	Potrero Community Center	24550 Highway 94 Potrero, 91963	Building + Trailer
Valley Center CRC	Valley Center	Valley Center Branch Library	29200 Cole Grade Rd Valley Center, CA 92082	Building + Trailer
Ramona CRC	Ramona	Ramona Branch Library	1275 Main Street Ramona, CA 92065	Building + Trailer
Fallbrook CRC	Fallbrook	Fallbrook Branch Library	124 S Mission Rd, Fallbrook, CA 92028	Building + Trailer

3. *Outline of tactical and strategic decision-making protocol for initiating a PSPS/de-energization (e.g., decision tree).*

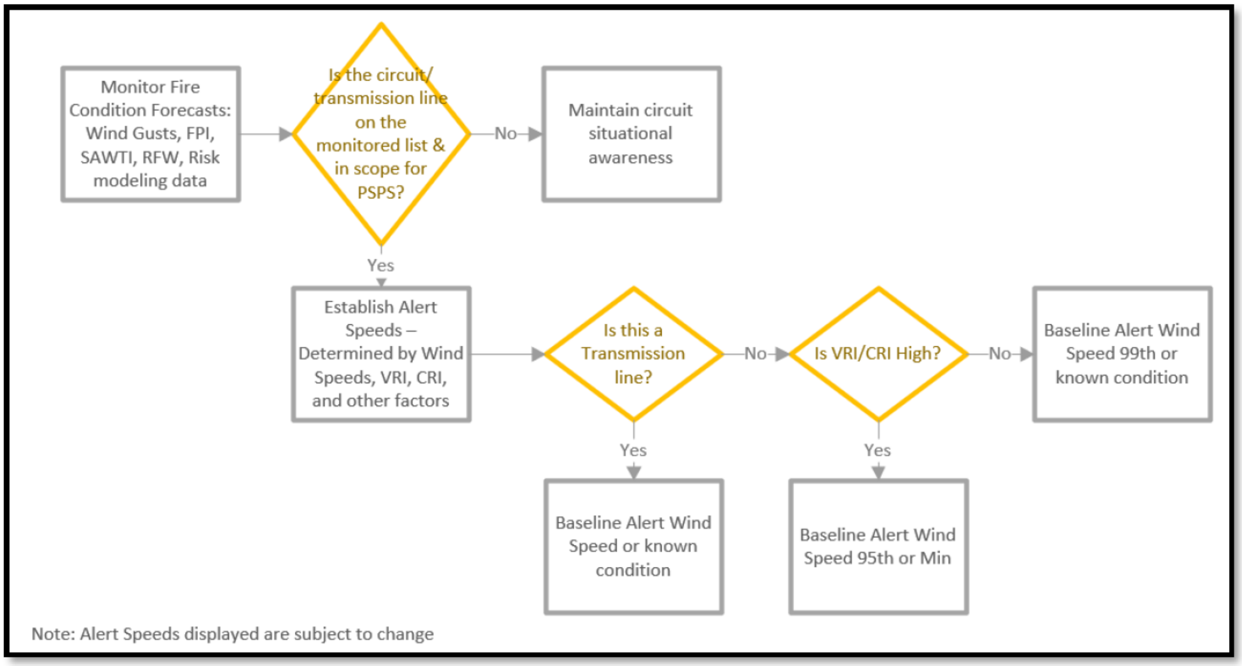
SDG&E utilizes multiple factors to assist in the decision to de-energize. Some factors pertain to information in the field based on known compliance issues on the electrical system, active temporary construction/configuration of the electrical system, and a CRI to identify locations in the system with a potential of having higher failure rates. These factors are compiled and populated for each sectionalizing device to assist with developing alert speeds and increased awareness of risky assets on the electrical system (see Figure 8-1).

Figure 8-1: PSPS Decision-Making Framework



Sectionalizing device alert speeds are determined separately for each device tied to a weather station and are based on a variety of factors such as wind speeds, the VRI, and the CRI. Alert speed thresholds are lowered if the VRI or the CRI is high (see Figure 8-2). Other factors such as maintenance issues, existing construction, other real time observations, ongoing fires and/or ignitions, suppression capabilities, and/or system protection could lower the thresholds for specific events.

Figure 8-2: Alert Speed Calculation



Due to the dynamic nature of wildfire conditions, it is appropriate to use a real–time situational awareness technique to determine when to initiate a PSPS event, considering a variety of factors such as:

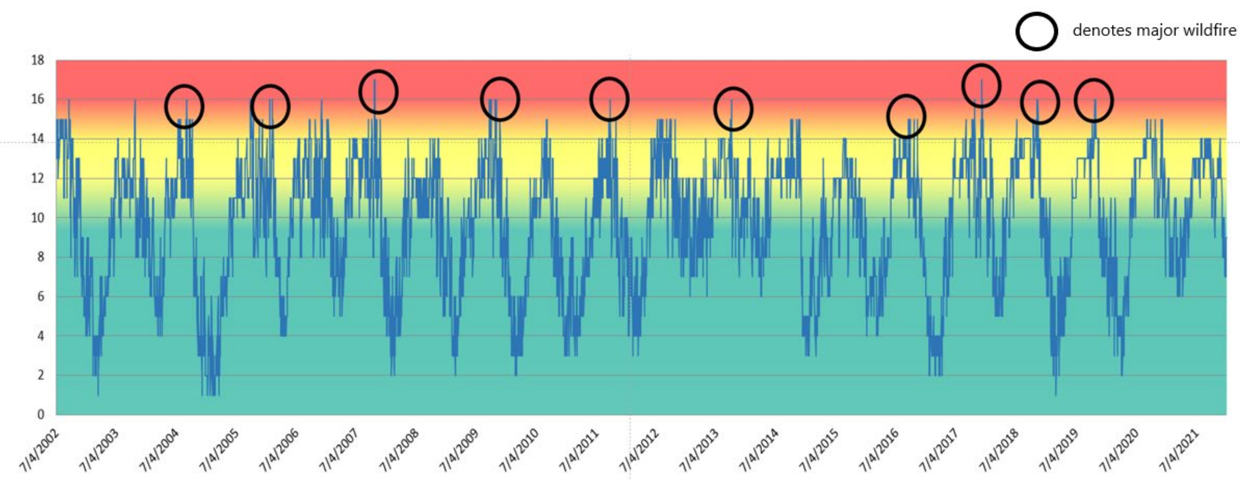
- Weather Condition-FPI
- Weather Condition-RFWs
- Weather Condition-SAWTI
- Weather Condition-72-hour circuit forecast
- Vegetation Conditions and VRI
- PoI
- Field observations and flying/falling debris
- Information from first responders
- Meteorology, including 10 years of history, 99^{th} and 95^{th} percentile winds
- Expected duration of conditions
- Location of any existing fires
- Wildfire activity in other parts of the state affecting resource availability
- Information on temporary construction

SDG&E is transparent in how it approaches PSPS decision-making. The following is a description of the factors listed above and how they are utilized to inform decisions on PSPS events.

Weather Condition-Fire Potential Index: The FPI has proven to be historically accurate in predicting the potential for large fires. The FPI is created through three separate components: green up, fuels, and weather (see Section 4.5.1.5 Fire Potential Index for details). The FPI is a forecasted value based on measured data looking 7 days in the future. Certain components such as green-up and live fuel moisture do not materially change significantly over a 7-day period, while other components such as specific wind speeds, atmospheric dryness and dead fuel moisture are more volatile and can change significantly. Consequently, PSPS events are not implemented on FPI alone, real time conditions are also considered.

Figure 8-3 shows the historical FPI from 2002 to 2021. Peaks depict Extreme FPI days and circles indicate that major wildfires ignited during those conditions. Catastrophic wildfires in these years also occurred during Extreme FPI days, demonstrating a close correlation between Extreme FPI and wildfires.

Figure 8-3: Historical FPI from 2002 to 2021



When studying reliability and ignition data from 2015-2019, ignition percentage for faults increases significantly with higher FPI. Table 8-3 shows that during days with an FPI rating of Extreme in the HFTD it is over 5 times more likely that a fault will result in an ignition, and during days with an FPI rating of Elevated the chance of a fault resulting in an ignition is over twice as likely. These results have been mitigated through the historical use of PSPS, therefore, ignition rates would likely be higher without the execution of PSPS during days with an FPI rating of Extreme from 2015-2019.

Table 8-3: 5-Year Ignition Rate Average 2015-2019

		Ignition Rate		
Location	**Normal**	**Elevated**	**Extreme**	**All**
Non-HFTD	1.17%	2.91%	0.00%	1.46%
Tier 2	2.20%	5.07%	10.34%	3.37%
Tier 3	1.62%	4.31%	10.00%	2.74%
HFTD (Tier 2+Tier 3)	1.92%	4.69%	10.20%	3.07%

		Ignition Rate		
Location	**Normal**	**Elevated**	**Extreme**	**All**
System	1.42%	3.91%	6.10%	2.09%

Weather Condition-Red Flag Warnings: RFWs, issued by the National Weather Service, use similar weather data as used to determine the FPI, including conditions such as low humidity and high winds. SDG&E has generally observed a correlation between high FPI days and RFW days. In 2019 for example, SDG&E forecasted an FPI rating of Extreme on 9 of 365 days; the National Weather Service issued a RFW on 8 of those days.

Weather Condition-SAWTI: Refer to Section 4.5.1.8 Wildfire Next Generation System-Operations.

Weather Condition-72-hour circuit forecast: Prior to an EOC activation, Meteorology issues a circuit forecast, which is a matrix of circuit-associated weather stations and numerous forecasted wind parameters. The 72-Hour circuit forecast is a high-level forecast which includes Tiers or Districts that could be impacted. The 48-hour and 24-hour forecasts include a 48-hour peak gust value and time of achieving that gust, a 24-hour peak gust value and time of achieving that gust, earliest date/time to reach the 95th percentile, and the forecasted max gusts for all weather stations. The circuit forecast becomes a reference point for SDG&E to assess which areas demand greater focus as the event unfolds.

Vegetation Conditions and VRI: The VRI was developed internally using information from the Vegetation Management database and the Reliability database. See Section 4.5.1.2 Vegetation Risk Index for details. The VRI is broken down into high, medium, and low. A circuit with a high VRI may require a more conservative wind speed shutoff decision in an extremely high-risk event. For example, on a day with an FPI rating of Extreme, where an RFW is declared and real-time wind speeds are exceeding their 95th percentile for a given circuit segment on the associated weather station, SMEs would be consulted to confirm that winds were increasing and forecast to persist at high levels and the VRI was considered high. This information, along with additional factors, would inform the decision to de-energize. If the VRI was low, the decision to de-energize may not be made until the 99th percentile wind was exceeded.

Probability of Ignition/Probability of Failure: See Section 4.5.1.1 POI Model

Field Observations and Flying/Falling Debris: When an FPI rating of Extreme is forecast and a RFW is declared, QEWs are sent to various locations across the service territory based on where weather is forecasted to be the most extreme. These QEWs serve as field observers who report real-time observations. While weather stations measure actual wind speeds, they are in fixed locations. Field observers can move around the area and observe the risk in the environment, regardless of the measured wind speed. Field observers look for tree branches and unsecured customer items (tarps, umbrellas) or whether conductors are holding still, swaying, or galloping in the wind. Depending on the situation, a field observer may report on an hourly basis or may be asked to report on a far more frequent basis. They also have the ability to radio in and declare if a situation is unsafe based on their observations. These field observer reports may inform decisions about the use of PSPS. These reports are not measurements, but they provide strong qualitative situational awareness that is combined with other quantitative information sources for improved overall decision making.

Information from First Responders: During days with an FPI rating of Extreme and in preparation for potential PSPS events, many first responder agencies, including police and fire, are in active communication with SDG&E. These agencies provide information such as wind speeds that are too high to utilize helicopters to combat fires. An understanding that if a fire were to occur, some of the more impactful fire suppression resources would be unavailable, thus increasing the chance that a fire could become catastrophic, helps to inform decisions regarding PSPS. Further while not a technical PSPS event, if a fire should occur, agencies such as CAL FIRE may request to de-energize a line for safety while suppressing a fire.

Meteorology including 10-year History, 95th and 99th Percentile Winds: Weather data plays a major role in PSPS decision making. There are currently 221 unique weather stations in various parts of the service territory that are tied to certain circuits or circuit segments.

The 95th and 99th percentile wind gusts are calculated values based on a statistical analysis of a 10-year history of 10-minute wind reads for each of the weather stations. The 99th percentile wind is the cutoff between the top 1 percent and the bottom 99 percent of wind speeds. The 95th percentile wind is the cutoff between the top 5 percent and the bottom 95 percent of wind speeds. Even though a given weather station may have a low 99th percentile wind speed that is within the design criteria of most electric lines, whether the area rarely sees that wind speed, the chances of foreign object or vegetation contact, and other environmental factors contacting lines may affect consideration of PSPS.

Wind forecasts are also evaluated along with the FPI rating. If winds are forecasted to exceed the 99th percentile but the FPI rating is Normal, indicating a lower potential for large and damaging fires, PSPS protocols are less likely to be initiated. If the FPI rating indicates that large and damaging wildfires are possible and winds are forecasted to exceed 95th and/or 99th percentile winds, PSPS protocols are more likely to be initiated. Once PSPS protocols are initiated, granular weather forecasts are developed to identify communities that may experience strong winds. Customers and community partners are then notified of the PSPS potential, and additional inspections of the circuit segments forecasted to be impacted are initiated to assess their condition before the event begins. Once the wind event develops, real-time, 10-minute, and in some cases 30-second weather observations are recorded for the duration. Ultimately, forecasts facilitate preparation for a possible PSPS event, however, decisions to de-energize are based off all the real time conditions described in this section.

Expected Duration of Conditions: The length of forecasted high-risk conditions, based on meteorological measurements and models, also has a role in the decision to de-energize. If an event is forecasted to be short in duration, there are no active fires, and wind speeds are not grounding CAL FIRE helicopters, a decision may be made to simply continue to monitor. However, if the event is expected to last multiple days, and the risk exposure is prolonged, a more conservative PSPS decision that is in alignment with the 99th percentile wind forecast tends to be made.

Location of Existing Fires: Locations of existing fires are communicated and tracked through relationships with CAL FIRE and other first responder agencies. Active fires can influence PSPS decisions in multiple ways. For instance, an existing fire may indicate potential resource constraints if additional ignitions occur, causing a more conservative approach to de-energization.

Wildfire Activity Across the State: This is also communicated through emergency response partners. Fires in other parts of the state could impact response resources in San Diego if they are being diverted elsewhere. If resources become limited in San Diego due to other response efforts, SDG&E may be more conservative with PSPS decisions.

Information on Temporary Construction: In order to continue hardening areas at the highest risk of wildfire, existing lines will be replaced with new construction, which requires temporary configurations to keep customers energized while new lines are built and old lines are removed. Temporary construction can include lines being left in rollers in preparation for pulling new conductor or temporary "shoe flies" that use temporary structures to reroute power around the construction area. These areas of temporary construction are documented and their wind speed thresholds are lowered. Sometimes this de-rated wind speed threshold is higher than the 99th percentile wind and would not be a deciding factor in PSPS, however, when the wind speed threshold drops below the 99th percentile that information is considered in the decision to de-energize.

4. *Strategy to provide for safe and effective re-energization of any area that is de-energized due to PSPS protocol.*

See Section 7.3.6.5 Protocols for PSPS re-energization.

5. *Company standards relative to customer communications, including consideration for the need to notify priority essential services – critical first responders, public safety partners, critical facilities and infrastructure, operators of telecommunications infrastructure, and water utilities/agencies. This section, or an appendix to this section, must include a complete listing of which entities the electrical corporation considers to be priority essential services. This section must also include a description of strategy and protocols to ensure timely notifications to customers, including access and functional needs populations, in the languages prevalent within the utility's service territory.*

Prior to a PSPS event and when potentially affected circuits are identified by Meteorology, notifications are sent to all affected customers that have contact information on file with SDG&E through the ENS. These notifications are sent to customers consistent with CPUC mandates.[62] Communications are sent by phone call, text, and email. The ENS system provides PSPS information in 22 languages.

Notifications are also made available in American Sign Language. Prior to impacted customers being notified, public safety partners and critical facilities are provided advance notification of a potential PSPS event as prescribed by the CPUC.

SDG&E is heavily focused on notifying AFN customers. SDG&E partners with CBOs, 211 San Diego, and Orange County to amplify PSPS notifications for AFN customers and has made significant accessibility improvements to target this audience. Notifications and updates are provided to organizations who serve as a critical channel to amplify and communicate to customers who may not utilize traditional channels. Through its Partner Network, SDG&E is able to reach diverse, multicultural, multilingual, senior, special needs, disadvantaged, and AFN communities as well as translate notifications into over 200 languages.

All impacted MBL customers are notified prior to a potential PSPS event interrupting electrical service. This process includes SDG&E Customer Care Center employees attempting to reach MBL customers for whom SDG&E did not receive confirmation of receipt of an ENS notification. If a live agent is unable to

[62] See D.19-05-042, D.20-05-051, and D.21-06-034. The languages used are: English, Spanish, Tagalog, Mandarin, Cantonese, Vietnamese, Arabic, Korean, Russian, French, German, Farsi, Japanese, Punjabi, Khmer, Somali, Mixtec, Zapotec, Armenian, Hindi, Portuguese and Thai.

speak to and inform the MBL customer of an imminent PSPS, a subsequent service order is issued a Customer Service Field employee to notify the customer by visiting their address. If contact is still not made, an informational door hanger is left at the residence. All Customer Service Field employees conducting these in-person visits are required to watch all videos in the County of San Diego's First Responder Access and Functional Needs Training Series.

Additionally, there is a dedicated AFN Liaison role in the Emergency Operating Center. Upon EOC activation, this role is responsible for partnering with 211 and other CBOs to provide real time updates, promote available services, and amplify notifications. They are also available to support any customer concerns that arise as a result of a PSPS event.

In 2020, the Alerts by SDG&E app was launched to provide communication to customers who are not identified as the customer of record (e.g., mobile home parks) as well as visitors. Through the Alerts by SDG&E app, customers and the general public can sign-up to receive real-time notifications leading up to and through a de-energization event. The app also contains links to additional resources, including 211 San Diego.

Other non-digital channels employed include:

- Changeable and moveable roadside signs – partnering with Caltrans to identify highly traveled HFTD intersections, roadside signage is deployed to inform communities of PSPS events and provide updates
- Tribal Nation casino and school marquees – leveraging existing marquees, SDG&E partnered with tribal nations and schools in the HFTD to display PSPS messaging before, during, and after PSPS events
- Enhanced AM radio spots – increased information disseminated on AM radio frequencies to include 30-second plays and scripts provided to disc jockeys

In 2021, SDG&E's public safety partner portal was released. This new tool allows for more effective communication with Public Safety Partners, including first responders, jurisdictions, tribal governments, water and telecommunications providers, CalOES, and County OES. This portal streamlines information sent to Public Safety Partners during a PSPS event so they can access the most up-to-date information. Outreach and education on the safety partner portal included four Public Safety Partner training sessions. A tutorial video is also available on the PSPS portal.

6. *Protocols for mitigating the public safety impacts of these protocols, including impacts on first responders, health care facilities, operators of telecommunications infrastructure, and water utilities/agencies.*

SDG&E has well established relationships with many of the partners that operate critical facilities such as first responder facilities, health care facilities, operators of telecommunication infrastructure and water utilities/agencies. Throughout the year, SDG&E maintains communication with these critical customers by collaborating and partnering through Wildfire Preparedness meetings, with a focus on continuous improvement and discussion of enhancements. One example of a mitigation targeted to aid critical facilities is the microgrid at the Ramona Air Attack Station and the microgrid at Cameron Corners serving the community of Campo and including an AT&T communication hub.

Preplanning and education efforts through webinars, Wildfire Safety Fairs, meetings, EOC tours, and After-Action Reviews have allowed both SDG&E and communication partners to better understand PSPS protocols. These meetings also provide an opportunity for our customers and partners to express concerns, which ultimately promote shared understandings.

Outreach to critical facilities is iterative and ongoing, and PSPS contact lists are regularly updated to ensure proper notifications for critical facilities and ensure the correct customer locations are flagged as critical facilities. Many critical facilities are assigned customers with a dedicated account executive. Account executives work with assigned critical facility customers to update their contact information for all accounts. Additionally, account executives survey customers' resiliency efforts. Backup generation is encouraged as a solution to promote continuous power operations during a PSPS event and SDG&E continues to provide tools and information to help critical facilities prepare for PSPS events. All unassigned critical facilities are contacted by U.S. mail and email if on file with SDG&E, providing a link[63] to update contact information and request information regarding back-up-power-generation.

In 2021, SDG&E launched the Critical Facilities landing page,[64] another mechanism for customers to update contact information for all emergencies. This landing page provides the definition of customers that qualify as a critical facility, a link to request status as a critical facility, a web form where customers can request validation of data that SDG&E has on record for emergency preparedness, and a web form for them to request a back-up power assessment. The landing page also has an Emergency Preparedness Checklist, created as a mechanism for customers to self-assess their emergency preparedness, and a Wildfire and PSPS Safety Tips and Recommendations flyer.

8.3 Projected Changes to PSPS Impact

Instructions: *Describe utility-wide plan to reduce scale, scope and frequency of PSPS for each of the following time periods, highlighting changes since the prior WMP report and including key program targets used to track progress over time,*

1. *By June 1 of current year*
2. *By September 1 of current year*
3. *By next WMP submission*

SDG&E has a number of programs that aid in mitigating customer impacts of a PSPS event (see Section 7.3.3.8 Grid topology improvements to mitigate or reduce PSPS events.). These include customer resiliency and microgrid programs, the PSPS sectionalizing enhancement program, and strategic undergrounding. Based on the goals and timeframes of these programs, an estimated additional 2,500 to 4,500 customers could benefit from reduced PSPS impacts by the next Wildfire Mitigation Plan. Actual reductions will depend largely on the scale and severity of events experienced in 2022, including weather conditions. The estimated savings are further broken out by program in Table 8-4.

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[63] https://www.sdge.com/tellus

[64] https://www.sdge.com/psps-critical-facilities

Table 8-4: Projected PSPS Reduced Impacts

Project	2021 Number of Locations	2021 Customer PSPS Impact Reduction	Q2 2022 Number of Locations	Q3 2022 Number of Locations	2022 Total Number of Locations	2022 Customer PSPS Impact Reduction
PSPS Sectionalizing	11	9719	5	8	10	4,607
Standby Power Programs	353	353	75	150	300	300
Generator Grant Program	2,310	2,310	150	2,400	3,000	3,000
Generator Assistance Program	735	735	~	375	1,250	1,250
Microgrids	0	0	0	2	2	5
Undergrounding	9	242	22	26	26	2,533

8.4 Engaging Vulnerable Communities

Report on the following:

1. *Describe protocols for PSPS that are intended to mitigate the public safety impacts of PSPS on vulnerable, marginalized and/or at-risk communities. Describe how the utility is identifying these communities.*

In 2021, SDG&E expanded the Access and Functional Needs Outreach & Education Team dedicated to supporting customers with AFN, with a focus on mitigating PSPS-event impacts for this group. This business unit advanced key initiatives that began in 2020, including:

- Continued enhancement to the AFN support model of supporting during PSPS events
- Identification of customers with AFN for improved outreach, preparedness, and solutions offerings
- Increased and strengthened partnership with CBOs
- Increased accessibility of communications
- Enhanced generator offerings

The Access and Functional Needs Outreach & Education Team expanded support available to customers with AFN during PSPS events through direct contracts with partners based on feedback from Statewide and Regional AFN Councils and stakeholders. Specific examples include:

- Partnered with FACT to provide accessible transportation across the service territory
- Partnered with Salvation Army to offer no-cost hotel stays

- Partnered with two catering companies to provide warm food at CRCs and other impacted communities as needed
- Partnered with the San Diego Food Bank to conduct additional food distributions in impacted areas following a PSPS event

Additionally, SDG&E continued to offer other services through its partnerships with 211 San Diego and 211 Orange County, who serve as a resource hub for customers with AFN during a PSPS event, including resiliency items and wellness checks.

The Access and Functional Needs Outreach & Education Team enhanced its identification of customers with AFN for the purposed of improving targeting of outreach, preparedness materials, and solutions. The team continues to utilize data from its system and created a new field for customers to self-identify as desired.

A key support mechanism for customers with AFN continues to be collaboration with SDG&E's network of CBOs. SDG&E has formal partnerships with over 200 Energy Solutions Partners who help to prepare AFN customers for a PSPS event and amplify notifications and solutions. In 2021, SDG&E enhanced its partnership with approximately 40 CBOs who serve the HFTD by providing additional training and resources. Through this network, there are more than 700 partners that serve customers with AFN who help to provide frequent updates and situational awareness as well as direction to support services. Some specific enhancements in 2021 include the addition of paratransit agencies and multi-family building managers to partner updates in order to address these key customer segments.

One significant focus for AFN support in 2021 centered around increasing accessibility of communications. SDG&E partnered with DeafLink to convert all PSPS and outage notifications to an accessible format including a video with an American Sign Language interpreter, an audio read-out, and a transcript. SDG&E is also in the process of adding a service to provide accessible versions of all emergency communications 24/7.

To promote PSPS awareness and preparedness in tribal communities, in 2021, SDG&E partnered with the La Jolla Band of Luiseno Indians to host a Wildfire Resiliency Fair to help prepare the surrounding communities in advance of wildfire season. SDG&E is also in discussions with several tribes to potentially install Tribal Resource Centers—resources that would be deployed during a PSPS event. Tribal Resource Centers would be similar to a CRC but run by a tribal government, and would include energy backup, training, and resources provided by SDG&E.

In addition to individual meetings with tribal governments throughout the year, in 2021 SDG&E briefed the Southern California Tribal Chairmen's Association on enhancements to support tribal communities during PSPS events. All tribes were provided information and offered training on the new Safety Partner portal to provide MBL information to tribal governments. In August 2021, a Tribal Relations Manager was added to SDG&E's Tribal Relations team. This role is focused on supporting tribes year-round with wildfire resiliency and PSPS.

2. List all languages which are "prevalent" in utility's territory. A language is prevalent if it is spoken by 1,000 or more persons in the utility's territory or if it is spoken by 5% or more of the population within a "public safety answering point" in the utility territory[65] (D.20-03-004).

To complement the public education channels across the service territory, SDG&E has developed access to in-language PSPS and Wildfire Safety preparedness and event information designed to reach disadvantaged communities and non-English-proficient audiences within the territory. Though the PSPS public education campaign and the Wildfire Safety public education campaign are available in multiple languages, the language requirements applicable to each campaign are distinct.

PSPS-related communications are accessible in the following prevalent languages identified for the service territory:

1. English
2. Spanish
3. Mandarin
4. Cantonese
5. Vietnamese
6. Korean
7. Tagalog
8. Russian
9. Arabic
10. French
11. German
12. Farsi
13. Japanese
14. Punjabi
15. Khmer
16. Somali
17. Mixtec
18. Zapotec
19. Armenian
20. Hindi
21. Portuguese
22. Thai

Wildfire safety related communications are provided in the same prevalent languages listed above.

3. List all languages for which public outreach material is available, in written or oral form.

1. English
2. Spanish
3. Mandarin

[65] See Cal. Government Code § 53112

4. Cantonese
5. Vietnamese
6. Korean
7. Tagalog
8. Russian
9. Arabic
10. French
11. German
12. Farsi
13. Japanese
14. Punjabi
15. Khmer
16. Somali
17. Mixtec
18. Zapotec
19. Armenian
20. Hindi
21. Portuguese
22. Thai

4. Detail the community outreach efforts for PSPS and wildfire-related outreach. Include efforts to reach all languages prevalent in utility territory.

See Section 7.3.9.2 Community outreach, public awareness, and communication efforts, which describes PSPS- and wildfire-related outreach.

8.5 PSPS-Specific Metrics

Instructions: *PSPS data reported quarterly. Placeholder tables below to be filled in based on quarterly data.*

In the attached spreadsheet document, report performance on the following PSPS metrics within the utility's service territory over the past seven years as needed to correct previously reported data. Where the utility does not collect its own data on a given metric, the utility is required to work with the relevant state agencies to collect the relevant information for its service territory, and clearly identify the owner and dataset used to provide the response in the "Comments" column.

See Attachment B, Table 11. The data provided in Table 11 is based on the most current information available and is subject to modification resulting from additional analyses, internal outage audits, and assessments completed following submission of this WMP Update.

8.6 Identification of Frequently De-Energized Circuits

Senate Bill 533 (2021) added an additional requirement to the WMPs. Pub. Util. Code Section 8386(c)(8) requires the "Identification of circuits that have frequently been de-energized[66] pursuant to a de-energization event to mitigate the risk of wildfire and the measures taken, or planned to be taken, by the electrical corporation to reduce the need for, and impact of, future de-energization of those circuits, including, but not limited to, the estimated annual decline in circuit de-energization and de-energization impact on customers, and replacing, hardening, or undergrounding any portion of the circuit or of upstream transmission or distribution lines." To comply with this statutory addition, utilities are required to populate Table 8.6-1 and provide a map showing the listed frequently de-energized circuits.

SDG&E has identified 17 circuits that have experienced three or more PSPS events in a calendar year since 2018. To date, 35.87 miles of undergrounding and 103.95 miles of overhead hardening have been completed, with 101.13 miles of undergrounding and 54.71 miles of overhead hardening in scope for 2022/2023. Additionally, 35 SCADA sectionalizing devices have been replaced, upgraded, or added to these circuits. Lastly, customers on these circuits have and will continue to benefit from backup resiliency programs (portable or fixed generators, batteries, and microgrids) when PSPS events are inevitable. See Table 8-5 below for the list of circuits and a breakdown of mitigation efforts.

Table 8.6-1: Identification of Frequently De-Energized Circuits

ID of Circuit	County	Dates of Outages	# of Customers Affected	Measures taken, or planned to be taken, to reduce the need for, and impact of, future PSPS of circuit
1030	San Diego	Oct 10-11, 2019	30	• 26.4 miles of undergrounding completed; 28 miles in scope for 2022 • 2.3 miles of overhead hardening completed • Added or replaced 3 SCADA sectionalizing devices • 185 customers have benefitted from backup resiliency programs
		Oct 24-25, 2019	185	
		Oct 30-31, 2019	1,341	
		Sept 9, 2020	30	
		Dec 2-4, 2020	1,182	
		Dec 7-9, 2020	1,363	
		Dec 23-24, 2020	30	
1166	San Diego	Dec 2-4, 2020	322	• 0.29 miles of overhead hardening completed • Added or replaced 1 SCADA sectionalizing device • 17 customers have benefitted from backup resiliency programs
		Dec 7-8, 2020	60	
		Dec 23-24, 2020	322	
1215	San Diego	Oct 27, 2020	133	• 0.78 miles of overhead hardening completed • 18 customers have benefitted from backup resiliency programs
		Dec 2-4, 2020	144	
		Dec 7-8, 2020	133	

[66] "Frequently de-energized circuit" has been defined in the glossary as "A circuit which has been de-energized pursuant to a de-energization event to mitigate the risk of wildfire three or more times in a calendar year."

ID of Circuit	County	Dates of Outages	# of Customers Affected	Measures taken, or planned to be taken, to reduce the need for, and impact of, future PSPS of circuit
				• Customers have been invited to participate in the Fixed Backup Program with a 36% adoption rate; additional customers will be invited in 2022
157	San Diego	Dec 2-4, 2020 Dec 7-9, 2020 Dec 23-24, 2020	1,028 614 660	• 34.26 miles of overhead hardening completed; 33 miles in scope for 2022/2023 • Added or replaced 8 SCADA sectionalizing devices • 97 customers have benefitted from backup resiliency programs
214	San Diego	Jan 28-29, 2018 Oct 15, 2018 Nov 12-14, 2018 Dec 2-4, 2020 Dec 7-9, 2020 Dec 23-24, 2020	359 360 360 682 682 682	• 1.36 miles of overhead hardening completed • Added or replaced 2 SCADA sectionalizing devices • 59 customers have benefitted from backup resiliency programs
215	San Diego	Dec 3-4, 2020 Dec 7-8, 2020 Dec 24, 2020	510 385 385	• 1.30 miles of overhead hardening completed • Added or replaced 4 SCADA sectionalizing devices • 83 customers have benefitted from backup resiliency programs
220	San Diego	Dec 2-4, 2020 Dec 7-9, 2020 Dec 24, 2020	324 324 324	• 3.42miles of undergrounding in scope for 2023 • 0.15 miles of overhead hardening completed • Santa Ysabel Microgrid in scope for 2022 • 22 customers have benefitted from backup resiliency programs
222	San Diego	Dec 2-4, 2020 Dec 7-10, 2020 Dec 23-24, 2020	1,355 1,302 402	• 2.52miles of undergrounding in scope for 2022; 7.7 miles in scope for 2023 • 21.17 miles of overhead hardening completed; 3.18 miles in scope for 2022/2023 • Added or replaced 3 SCADA sectionalizing devices • 115 customers have benefitted from backup resiliency programs • Customers have been invited to participate in the Fixed Backup Program with a 36% adoption rate; additional customers will be invited in 2022

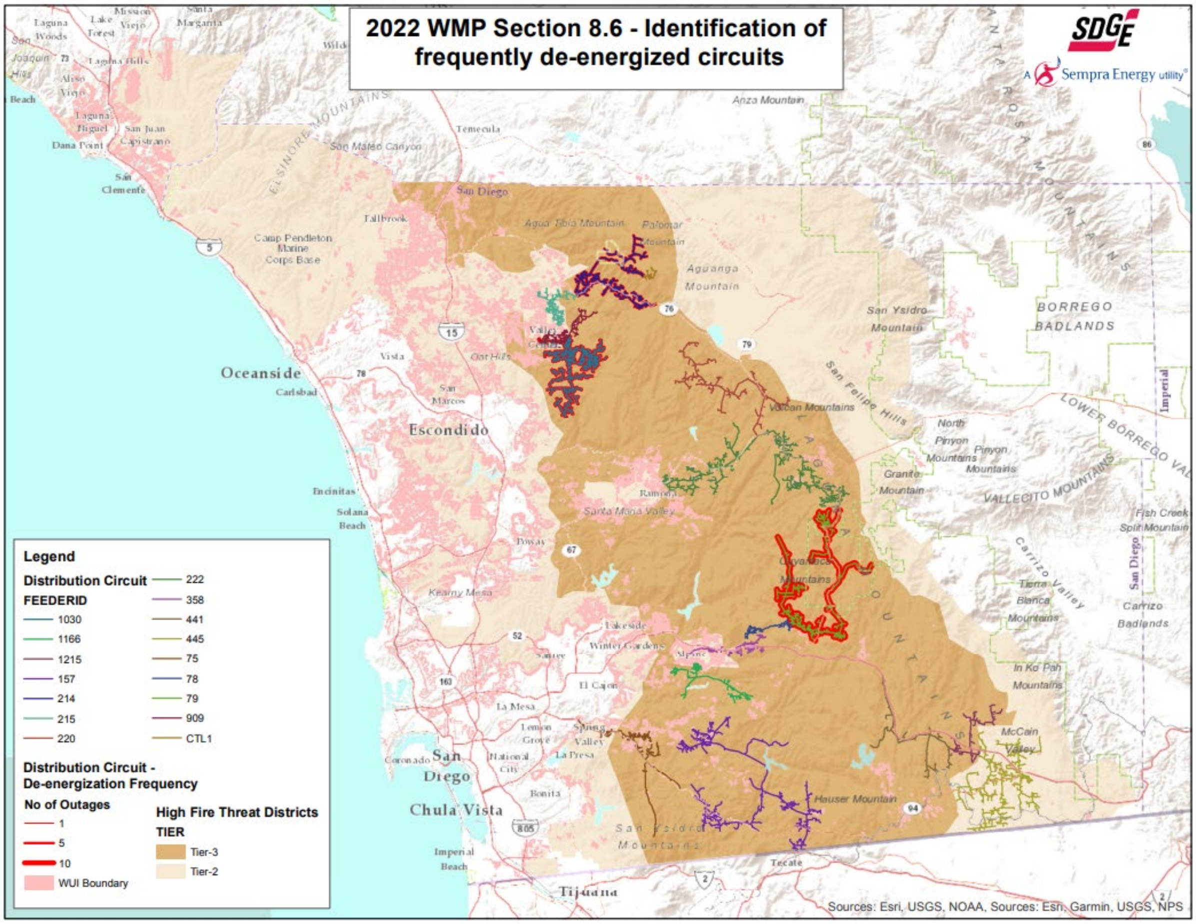
ID of Circuit	County	Dates of Outages	# of Customers Affected	Measures taken, or planned to be taken, to reduce the need for, and impact of, future PSPS of circuit
238	San Diego	Oct 10-11, 2019	2	• Two meters belonging to one customer on Cir 238 were cut over to Cir 222 in mid-2020
		Oct 24-26, 2019	2	
		Oct 29-Nov 1, 2019	2	
		Nov 17, 2019	2	
358	San Diego	Dec 2-4, 2020	359	• 1.62 miles of undergrounding in scope for 2022; 1.85 miles in scope for 2023 • 0.11 miles of overhead hardening completed to date • 48 customers have benefitted from backup resiliency programs
		Dec 7-8, 2020	247	
		Dec 23-24, 2020	359	
441	San Diego	Oct 27, 2020	104	• 4.9 miles of undergrounding in scope for 2023 • 0.19 miles of overhead hardening in scope for 2022 • Added or replaced 1 SCADA sectionalizing device • 10 customers have benefitted from backup resiliency programs • Customers have been invited to participate in the Fixed Backup Program with a 36% adoption rate; additional customers will be invited
		Dec 2-3, 2020	104	
		Dec 7-8, 2020	104	
445	San Diego	Oct 10-11, 2019	344	• 3.08 miles of undergrounding in scope for 2022; 43.21 miles in scope for 2023/2024 • 17.27 miles of overhead hardening completed; 16.68 miles in scope for 2022/2024 • Added or replaced 3 SCADA sectionalizing devices • 86 customers have benefitted from backup resiliency programs
		Oct 24-26, 2019	344	
		Oct 30-31, 2019	344	
		Oct 27, 2020	801	
		Dec 2-4, 2020	967	
		Dec 7-9, 2020	967	
75	San Diego	Dec 2-4, 2020	752	• 6.83 miles of undergrounding completed; 4.16 miles in scope for 2022 • 47 customers have benefitted from backup resiliency programs
		Dec 7-9, 2020	16	
		Dec 23-24, 2020	16	
78	San Diego	Dec 2-4, 2020	276	• 0.35 miles of overhead hardening completed; 1.51 miles in scope for 2022 • Added or replaced 3 SCADA sectionalizing devices • 23 customers have benefitted from backup resiliency programs
		Dec 7-8, 2020	121	
		Dec 24, 2020	276	

ID of Circuit	County	Dates of Outages	# of Customers Affected	Measures taken, or planned to be taken, to reduce the need for, and impact of, future PSPS of circuit
79	San Diego	Jan 27-29, 2018	838	• 3.38 miles of undergrounding completed • 22.23 miles of overhead hardening completed; 4.65 miles in scope for 2022/2023 • Added or replaced 6 SCADA sectionalizing devices • 110 customers have benefitted from backup resiliency programs • Customers have been invited to participate in the Fixed Backup Program with a 36% adoption rate; additional customers will be invited
		Oct 15-16, 2018	20	
		Oct 19-20, 2018	20	
		Nov 11-15, 2018	852	
		Oct 10-11, 2019	19	
		Oct 24-26, 2019	870	
		Oct 29-31, 2019	867	
		Nov 17-18, 2019	19	
		Sept 8-9, 2020	19	
		Dec 2-4, 2020	879	
		Dec 7-9, 2020	879	
		Dec 23-24, 2020	18	
909	San Diego	Dec 2-4, 2020	494	• Added or replaced 1 SCADA sectionalizing devices • 43 customers have benefitted from backup resiliency programs
		Dec 7-8, 2020	362	
		Dec 23-24, 2020	494	
CTL1	San Diego	Dec 2-4, 2020	201	• 26 customers have benefitted from backup resiliency programs
		Dec 7-9, 2020	201	
		Dec 24, 2020	200	

See Figure 8-4 for a map of frequently de-energized circuits.

Also refer to the geospatial map file titled: 2022_02_05_SDGE_2022_WMP Update_GIS Layer_86.zip

Figure 8-4: Map of Frequently De-energized Circuits



9 Appendix

9.1 Definitions of Initiative Activities by Category

Table 9-1: Definitions of Initiative Activities by Category

Category	Initiative Activity	Definition
A. Risk Mapping and simulation	A summarized risk map that shows the overall ignition probability and estimated wildfire consequence along the electric lines and equipment	Development and use of tools and processes to develop and update risk map and simulations and to estimate risk reduction potential of initiatives for a given portion of the grid (or more granularly, e.g., circuit, span, or asset). May include verification efforts, independent assessment by experts, and updates.
	Climate-driven risk map and modeling based on various relevant weather scenarios	Development and use of tools and processes demonstrating medium and long-term climate trends based on the best available climate models demonstrating the most wildfire-relevant impacts (e.g., warming trends, fuel moisture trends, soil moisture trends, vegetation distribution trends). Describe how these trends are being incorporated into risk modeling or other risk-informed analyses.
	Ignition probability mapping showing the probability of ignition along the electric lines and equipment	Development and use of tools and processes to assess the risk of ignition across regions of the grid (or more granularly, e.g., circuits, spans, or assets).
	Initiative mapping and estimation of wildfire and PSPS risk-reduction impact	Development of a tool to estimate the risk reduction efficacy (for both wildfire and PSPS risk) and risk-spend efficiency of various initiatives.
	Match drop simulations showing the potential wildfire consequence of ignitions that occur along the electric lines and equipment	Development and use of tools and processes to assess the impact of potential ignition and risk to communities (e.g., in terms of potential fatalities, structures burned, monetary damages, area burned, impact on air quality and greenhouse gas, or GHG, reduction goals, etc.).
B. Situational awareness and forecasting	Advanced weather monitoring and weather stations	Purchase, installation, maintenance, and operation of weather stations. Collection, recording, and analysis of weather data from weather stations and from external sources.
	Continuous monitoring sensors	Installation, maintenance, and monitoring of sensors and sensorized equipment used to monitor the condition of electric lines and equipment.
	Fault indicators for detecting faults on electric lines and equipment	Installation and maintenance of fault indicators.
	Forecast of a fire risk index, fire potential index, or similar	Index that uses a combination of weather parameters (such as wind speed, humidity, and temperature), vegetation and/or fuel conditions, and other factors to judge current fire risk and to create a forecast indicative of fire risk. A sufficiently granular index is required to inform operational decision-making.
	Personnel monitoring areas of electric lines and equipment in elevated fire risk conditions	Personnel position within utility service territory to monitor system conditions and weather on site. Field observations is required to inform operational decisions.

Category	Initiative Activity	Definition
	Weather forecasting and estimating impacts on electric lines and equipment	Development methodology for forecast of weather conditions relevant to utility operations, forecasting weather conditions and conducting analysis to incorporate into utility decision-making, learning and updates to reduce false positives and false negatives of forecast PSPS conditions.
C. Grid design and system hardening	Capacitor maintenance and replacement program	Remediation, adjustments, or installations of new equipment to improve or replace existing capacitor equipment.
	Circuit breaker maintenance and installation to deenergize lines upon detecting a fault	Remediation, adjustments, or installations of new equipment to improve or replace existing fast switching circuit breaker equipment to improve the ability to protect electrical circuits from damage caused by overload of electricity or short circuit.
	Covered conductor installation	Installation of covered or insulated conductors to replace standard bare or unprotected conductors (defined in accordance with GO 95 as supply conductors, including but not limited to lead wires, not enclosed in a grounded metal pole or not covered by: a "suitable protective covering" (in accordance with Rule 22.8), grounded metal conduit, or grounded metal sheath or shield). In accordance with GO 95, conductor is defined as a material suitable for: (1) carrying electric current, usually in the form of a wire, cable or bus bar, or (2) transmitting light in the case of fiber optics; insulated conductors as those which are surrounded by an insulating material (in accordance with Rule 21.6), the dielectric strength of which is sufficient to withstand the maximum difference of potential at normal operating voltages of the circuit without breakdown or puncture; and suitable protective covering as a covering of wood or other non-conductive material having the electrical insulating efficiency (12kV/in. dry) and impact strength (20ft.-lbs) of 1.5 inches of redwood or other material meeting the requirements of Rule 22.8-A, 22.8-B, 22.8-C or 22.8-D
	Covered conductor maintenance	Remediation and adjustments to installed covered or insulated conductors. In accordance with GO 95, conductor is defined as a material suitable for: (1) carrying electric current, usually in the form of a wire, cable or bus bar, or (2) transmitting light in the case of fiber optics; insulated conductors as those which are surrounded by an insulating material (in accordance with Rule 21.6), the dielectric strength of which is sufficient to withstand the maximum difference of potential at normal operating voltages of the circuit without breakdown or puncture; and suitable protective covering as a covering of wood or other nonconductive material having the electrical insulating efficiency (12kV/in. dry) and impact strength (20ft.-lbs) of 1.5 inches of redwood or other material meeting the requirements of Rule 22.8-A, 22.8-B, 22.8-C or 22.8-D.
	Crossarm maintenance, repair, and replacement	Remediation, adjustments, or installations of new equipment to improve or replace existing crossarms, defined as horizontal support attached to poles or

Category	Initiative Activity	Definition
		structures generally at right angles to the conductor supported in accordance with GO 95.
	Distribution pole replacement and reinforcement, including with composite poles	Remediation, adjustments, or installations of new equipment to improve or replace existing distribution poles (i.e., those supporting lines under 65kV), including with equipment such as composite poles manufactured with materials reduce ignition probability by increasing pole lifespan and resilience against failure from object contact and other events.
	Expulsion fuse replacement	Installations of new and CAL FIRE-approved power fuses to replace existing expulsion fuse equipment.
	Grid topology improvements to mitigate or reduce PSPS events	Plan to support and actions taken to mitigate or reduce PSPS events in terms of geographic scope and number of customers affected, such as installation and operation of electrical equipment to sectionalize or island portions of the grid, microgrids, or local generation.
	Installation of system automation equipment	Installation of electric equipment that increases the ability of the utility to automate system operation and monitoring, including equipment that can be adjusted remotely such as automatic reclosers (switching devices designed to detect and interrupt momentary faults that can reclose automatically and detect if a fault remains, remaining open if so).
	Maintenance, repair, and replacement of connectors, including HLCs	Remediation, adjustments, or installations of new equipment to improve or replace existing connector equipment, such as HLCs.
	Mitigation of impact on customers and other residents affected during PSPS event	Actions taken to improve access to electricity for customers and other residents during PSPS events, such as installation and operation of local generation equipment (at the community, household, or other level).
	Other corrective action	Other maintenance, repair, or replacement of utility equipment and structures so that they function properly and safely, including remediation activities (such as insulator washing) of other electric equipment deficiencies that may increase ignition probability due to potential equipment failure or other drivers.
	Pole loading infrastructure hardening and replacement program based on pole loading assessment program	Actions taken to remediate, adjust, or install replacement equipment for poles that the utility has identified as failing to meet safety factor requirements in accordance with GO 95 or additional utility standards in the utility's pole loading assessment program.
	Transformers maintenance and replacement	Remediation, adjustments, or installations of new equipment to improve or replace existing transformer equipment.
	Transmission tower maintenance and replacement	Remediation, adjustments, or installations of new equipment to improve or replace existing transmission towers (e.g., structures such as lattice steel towers or tubular steel poles that support lines at or above 65kV).

Category	Initiative Activity	Definition
	Undergrounding of electric lines and/or equipment	Actions taken to convert overhead electric lines and/or equipment to underground electric lines and/or equipment (i.e., located underground and in accordance with GO 128).
	Updates to grid topology to minimize risk of ignition in HFTDs	Changes in the plan, installation, construction, removal, and/or undergrounding to minimize the risk of ignition due to the design, location, or configuration of utility electric equipment in HFTDs.
D. Asset management and inspections	Detailed inspections of distribution electric lines and equipment	In accordance with GO 165, careful visual inspections of overhead electric distribution lines and equipment where individual pieces of equipment and structures are carefully examined, visually and through use of routine diagnostic test, as appropriate, and (if practical and if useful information can be so gathered) opened, and the condition of each rated and recorded.
	Detailed inspections of transmission electric lines and equipment	Careful visual inspections of overhead electric transmission lines and equipment where individual pieces of equipment and structures are carefully examined, visually and through use of routine diagnostic test, as appropriate, and (if practical and if useful information can be so gathered) opened, and the condition of each rated and recorded.
	Improvement of inspections	Identifying and addressing deficiencies in inspections protocols and implementation by improving training and the evaluation of inspectors.
	Infrared inspections of distribution electric lines and equipment	Inspections of overhead electric distribution lines, equipment, and right-of-way using infrared (heat-sensing) technology and cameras that can identify "hot spots", or conditions that indicate deterioration or potential equipment failures, of electrical equipment.
	Infrared inspections of transmission electric lines and equipment	Inspections of overhead electric transmission lines, equipment, and right-of-way using infrared (heat-sensing) technology and cameras that can identify "hot spots", or conditions that indicate deterioration or potential equipment failures, of electrical equipment.
	Intrusive pole inspections	In accordance with GO 165, intrusive inspections involve movement of soil, taking samples for analysis, and/or using more sophisticated diagnostic tools beyond visual inspections or instrument reading.
	LiDAR inspections of distribution electric lines and equipment	Inspections of overhead electric transmission lines, equipment, and right-of-way using LiDAR (Light Detection and Ranging, a remote sensing method that uses light in the form of a pulsed laser to measure variable distances).
	LiDAR inspections of transmission electric lines and equipment	Inspections of overhead electric distribution lines, equipment, and right-of-way using LiDAR (Light Detection and Ranging, a remote sensing method that uses light in the form of a pulsed laser to measure variable distances).
	Other discretionary inspection of distribution electric lines and equipment, beyond inspections mandated by rules and regulations	Inspections of overhead electric transmission lines, equipment, and right-of-way that exceed or otherwise go beyond those mandated by rules and regulations, including GO 165, in terms of frequency, inspection checklist requirements or detail, analysis of and response to

Category	Initiative Activity	Definition
		problems identified, or other aspects of inspection or records kept.
	Other discretionary inspection of transmission electric lines and equipment, beyond inspections mandated by rules and regulations	Inspections of overhead electric distribution lines, equipment, and right-of-way that exceed or otherwise go beyond those mandated by rules and regulations, including GO 165, in terms of frequency, inspection checklist requirements or detail, analysis of and response to problems identified, or other aspects of inspection or records kept.
	Patrol inspections of distribution electric lines and equipment	In accordance with GO 165, simple visual inspections of overhead electric distribution lines and equipment that is designed to identify obvious structural problems and hazards. Patrol inspections may be carried out in the course of other company business.
	Patrol inspections of transmission electric lines and equipment	Simple visual inspections of overhead electric transmission lines and equipment that is designed to identify obvious structural problems and hazards. Patrol inspections may be carried out in the course of other company business.
	Pole loading assessment program to determine safety factor	Calculations to determine whether a pole meets pole loading safety factor requirements of GO 95, including planning and information collection needed to support said calculations. Calculations must consider many factors including the size, location, and type of pole; types of attachments; length of conductors attached; and number and design of supporting guys, per D.15-11-021.
	Quality assurance / quality control of inspections	Establishment and function of audit process to manage and confirm work completed by employees or contractors, including packaging QA/QC information for input to decision-making and related integrated workforce management processes.
	Substation inspections	In accordance with GO 175, inspection of substations performed by qualified persons and according to the frequency established by the utility, including record-keeping.
E. Vegetation management and inspection	Additional efforts to manage community and environmental impacts	Plan and execution of strategy to mitigate negative impacts from utility vegetation management to local communities and the environment, such as coordination with communities, local governments, and agencies to plan and execute vegetation management work
	Detailed inspections and management practices for vegetation clearances around distribution electrical lines and equipment	Careful visual inspections and maintenance of vegetation around the distribution right-of-way, where individual trees are carefully examined, visually, and the condition of each rated and recorded. Describe the frequency of inspection and maintenance programs
	Detailed inspections and management practices for vegetation clearances around transmission electrical lines and equipment	Careful visual inspections and maintenance of vegetation around the transmission right-ofway, where individual trees are carefully examined, visually, and the condition of each rated and recorded. Describe the frequency of inspection and maintenance programs.

Category	Initiative Activity	Definition
	Emergency response vegetation management due to red flag warning or other urgent weather conditions	Plan and execution of vegetation management activities, such as trimming or removal, executed based upon and in advance of forecast weather conditions that indicate high fire threat in terms of ignition probability and wildfire consequence.
	Fuel management and, management of all wood and “slash” from vegetation management activities	Plan and execution of fuel management activities in proximity to potential sources of ignition. This includes pole clearing per PRC 4292 and reduction or adjustment of live fuel (based on species or otherwise) and of dead fuel, including all downed wood and “slash” generated from vegetation management activities.
	Improvement of inspections	Identifying and addressing deficiencies in inspections protocols and implementation by improving training and the evaluation of inspectors
	Remote sensing inspections of vegetation around distribution electric lines and equipment	Inspections of right-of-way using remote sensing methods such as LiDAR, satellite imagery, and UAV.
	Remote sensing inspections of vegetation around transmission electric lines and equipment	Inspections of right-of-way using remote sensing methods such as LiDAR, satellite imagery, and UAV.
	Other discretionary inspections of vegetation around distribution electric lines and equipment	Inspections of rights-of-way and adjacent vegetation that may be hazardous, which exceeds or otherwise go beyond those mandated by rules and regulations, in terms of frequency, inspection checklist requirements or detail, analysis of and response to problems identified, or other aspects of inspection or records kept.
	Other discretionary inspections of vegetation around transmission electric lines and equipment	Inspections of rights-of-way and adjacent vegetation that may be hazardous, which exceeds or otherwise go beyond those mandated by rules and regulations, in terms of frequency, inspection checklist requirements or detail, analysis of and response to problems identified, or other aspects of inspection or records kept.
	Patrol inspections of vegetation around distribution electric lines and equipment	Visual inspections of vegetation along rights-ofway that is designed to identify obvious hazards. Patrol inspections may be carried out in the course of other company business.
	Patrol inspections of vegetation around transmission electric lines and equipment	Visual inspections of vegetation along rights-ofway that is designed to identify obvious hazards. Patrol inspections may be carried out in the course of other company business.
	Quality assurance / quality control of vegetation management	Establishment and function of audit process to manage and oversee the work completed by employees or contractors, including packaging QA/QC information for input to decision-making and workforce management processes. This includes identification of the percentage of vegetation inspections that are audited annually, as a program target in Table 5.3-1.
	Recruiting and training of vegetation management personnel	Programs to ensure that the utility can identify and hire qualified vegetation management personnel and to ensure that both employees and contractors tasked with

Category	Initiative Activity	Definition
		vegetation management responsibilities are adequately trained to perform vegetation management work, according to the utility's wildfire mitigation plan, in addition to rules and regulations for safety. Include discussion of continuous improvement of training programs and personnel qualifications.
	Identification and remediation of "at-risk species"	Specific actions, not otherwise described in other WMP initiatives, taken to reduce the ignition probability and wildfire consequence attributable to "at-risk species", such as trimming, removal, and replacement.
	Removal and remediation of trees with strike potential to electric lines and equipment	Actions taken to identify, remove, or otherwise remediate trees that pose a high risk of failure or fracture that could potentially strike electrical equipment.
	Substation inspection	Inspection of vegetation surrounding substations, performed by qualified persons and according to the frequency established by the utility, including record-keeping.
	Substation vegetation management	Based on location and risk to substation equipment only, actions taken to reduce the ignition probability and wildfire consequence attributable to contact from vegetation to substation equipment.
	Vegetation management enterprise system	Inputs, operation, and support for a centralized vegetation management enterprise system updated based upon inspection results and management activities such as trimming and removal of vegetation.
	Vegetation management to achieve clearances around electric lines and equipment	Actions taken to ensure that vegetation does not encroach upon the minimum clearances set forth in Table 1 of GO 95, measured between line conductors and vegetation, such as trimming adjacent or overhanging tree limbs.
	Vegetation management activities post-fire	Vegetation management (VM) activities during post-fire service restoration including, but not limited to: activities or protocols that differentiate post-fire VM from programs described in other WMP initiatives; supporting documentation for the tool and/or standard the utility uses to assesses the risk presented by vegetation post-fire; and how the utility includes fire-specific damage attributes into its assessment tool/standard.
F. Grid operations and protocols	Automatic recloser operations	Designing and executing protocols to deactivate automatic reclosers based on local conditions for ignition probability and wildfire consequence.
	Protective equipment and device settings	The utility's procedures for adjusting the sensitivity of grid elements to reduce wildfire risk, other than automatic reclosers (such as circuit breakers, switches, etc.). For example, PG&E's Fast Trip Settings.
	Crew-accompanying ignition prevention and suppression resources and services	Those firefighting staff and equipment (such as fire suppression engines and trailers, firefighting hose, valves, and water) that are deployed with construction crews and other electric workers to provide site-specific fire prevention and ignition mitigation during on-site work.

Category	Initiative Activity	Definition
	Personnel work procedures and training in conditions of elevated fire risk	Work activity guidelines that designate what type of work can be performed during operating conditions of different levels of wildfire risk. Training for personnel on these guidelines and the procedures they prescribe, from normal operating procedures to increased mitigation measures to constraints on work performed.
	Protocols for PSPS reenergization	Designing and executing procedures that accelerate the restoration of electric service in areas that are de-energized, while maintaining safety and reliability standards.
	PSPS events and mitigation of PSPS impacts	Designing, executing, and improving upon protocols to conduct PSPS events, including development of advanced methodologies to determine when to use PSPS, and to mitigate the impact of PSPS events on affected customers and local residents.
	Stationed and on-call ignition prevention and suppression resources and services	Firefighting staff and equipment (such as fire suppression engines and trailers, firefighting hose, valves, firefighting foam, chemical extinguishing agent, and water) stationed at utility facilities and/or standing by to respond to calls for fire suppression assistance.
G. Data governance	Centralized repository for data	Designing, maintaining, hosting, and upgrading a platform that supports storage, processing, and utilization of all utility proprietary data and data compiled by the utility from other sources.
	Collaborative research on utility ignition and/or wildfire	Developing and executing research work on utility ignition and/or wildfire topics in collaboration with other non-utility partners, such as academic institutions and research groups, to include data-sharing and funding as applicable.
	Documentation and disclosure of wildfire-related data and algorithms	Design and execution of processes to document and disclose wildfire-related data and algorithms to accord with rules and regulations, including use of scenarios for forecasting and stress testing.
	Tracking and analysis of near miss data	Tools and procedures to monitor, record, and conduct analysis of data on near miss events.
H. Resource allocation methodology	Allocation methodology development and application	Development of prioritization methodology for human and financial resources, including application of said methodology to utility decision-making.
	Risk reduction scenario development and analysis	Development of modeling capabilities for different risk reduction scenarios based on wildfire mitigation initiative implementation; analysis and application to utility decision-making.
	Risk spend efficiency (RSE) analysis	Tools, procedures, and expertise to support analysis of wildfire mitigation initiative risk spend efficiency, in terms of MAVF and/ or MARS methodologies.
I. Emergency planning and preparedness	Adequate and trained workforce for service restoration	Actions taken to identify, hire, retain, and train qualified workforce to conduct service restoration in response to emergencies, including short-term contracting strategy and implementation.

Category	Initiative Activity	Definition
	Community outreach, public awareness, and communications efforts	Actions to identify and contact key community stakeholders; increase public awareness of emergency planning and preparedness information; and design, translate, distribute, and evaluate effectiveness of communications taken before, during, and after a wildfire, including Access and Functional Needs populations and Limited English Proficiency populations in particular.
	Customer support in emergencies	Resources dedicated to customer support during emergencies, such as website pages and other digital resources, dedicated phone lines, etc.
	Disaster and emergency preparedness plan	Development of plan to deploy resources according to prioritization methodology for disaster and emergency preparedness of utility and within utility service territory (such as considerations for critical facilities and infrastructure), including strategy for collaboration with Public Safety Partners and communities.
	Preparedness and planning for service restoration	Development of plans to prepare the utility to restore service after emergencies, such as developing employee and staff trainings, and to conduct inspections and remediation necessary to re-energize lines and restore service to customers
	Protocols in place to learn from wildfire events	Tools and procedures to monitor effectiveness of strategy and actions taken to prepare for emergencies and of strategy and actions taken during and after emergencies, including based on an accounting of the outcomes of wildfire events.
J. Stakeholder cooperation and community engagement	Community engagement	Strategy and actions taken to identify and contact key community stakeholders; increase public awareness and support of utility wildfire mitigation activity; and design, translate, distribute, and evaluate effectiveness of related communications. Includes specific strategies and actions taken to address concerns and serve needs of Access and Functional Needs populations and Limited English Proficiency populations in particular.
	Cooperation and best practice sharing with agencies outside CA	Strategy and actions taken to engage with agencies outside of California to exchange best practices both for utility wildfire mitigation and for stakeholder cooperation to mitigate and respond to wildfires.
	Cooperation with suppression agencies	Coordination with CAL FIRE, federal fire authorities, county fire authorities, and local fire authorities to support planning and operations, including support of aerial and ground firefighting in real-time, including informationsharing, dispatch of resources, and dedicated staff.
	Forest service and fuel reduction cooperation and joint roadmap	Strategy and actions taken to engage with local, state, and federal entities responsible for or participating in forest management and fuel reduction activities; and design utility cooperation strategy and joint stakeholder roadmap (plan for coordinating stakeholder efforts for forest management and fuel reduction activities).

9.2 Citations for Relevant Statutes, Commission Directives, Proceedings, and Orders

Instructions: *Throughout the WMP, cite relevant state and federal statutes, Commission directives, orders, and proceedings. Place the title or tracking number of the statute in parentheses next to comment, or in the appropriate column if noted in a table. Provide in this section a brief description or summary of the relevant portion of the statute. Track citations as end-notes and order (1, 2, 3…) across sections (e.g., if section 1 has 4 citations, section 2 begins numbering at 5).*

Citation	Description/Summary	WMP Sections
Public Utilities Code § 8386	Law that, among other things, requires electric corporations to submit wildfire mitigation plans	Section 5.2
Public Resources Code § 4292	CAL FIRE requires 10 feet of minimum clearance around the base of the pole cleared of all flammable vegetation down to bare soil and the removal of all dead tree branches within this cylinder up to the cross-arm (within the State Responsibility Area)	Section 7.3.4 Section 7.3.4.2 Section 7.3.5.5 Section 7.3.5.20
Public Resources Code § 4293	CAL FIRE requires 10 feet of minimum clearance around the base of the pole cleared of all flammable vegetation down to bare soil and the removal of all dead tree branches within this cylinder up to the cross-arm (within the State Responsibility Area)	Section 5.4 Section 7.3.4 Section 7.3.4.2 Section 7.3.5.20
Resolution WSD-002	Guidance Resolution on 2020 Wildfire Mitigation Plans Pursuant to Public Utilities Code Section 8386.	Section 4.5.1 Section 4.6
Resolution WSD-005	Resolution Ratifying Action of the Wildfire Safety Division on San Diego Gas & Electric Company's 2020 Wildfire Mitigation Plan Pursuant to Public Utilities Code Section 8386.	Section 4.6
Resolution WSD-011	Resolution implementing the requirements of Public Utilities Code Sections 8389(d)(1), (2) and (4), related to catastrophic wildfire caused by electrical corporations subject to the Commission's regulatory authority	Section 1
Resolution M-4835	Orders emergency residential and non-residential customer protections for wildfire victims	Section 7.3.9.3
R.18-10-007	Order Instituting Rulemaking to Implement Electric Utility Wildfire Mitigation Plans Pursuant to Senate Bill 901 (2018)	Section 7.3.9.2
R.20-07-013	Order Instituting Rulemaking to Further Develop a Risk-based Decision-making Framework for Electric and Gas Utilities	Section 4.2
D.14-02-015	CPUC Decision Adopting Regulations to Reduce the Fire Hazards Associated with Overhead Electric Utility Facilities and Aerial Communication Facilities; Requires annual reportable ignitions report	Section 4.2 Section 4.4.2.1 Section 4.4.2.7
D.15-11-021	CPUC Decision on Test Year 2015 General Rate Case for Southern California Edison Company	Section 9.1
D.16-08-018	CPUC Interim Decision Adopting the Multi-Attribute Approach (or Utility Equivalent Features) and Directing	Section 4.2

Citation	Description/Summary	WMP Sections
	Utilities to Take Steps Toward a More Uniform Risk Management Framework	
D.18-12-014	CPUC Phase 2 Decision Adopting Safety Model Assessment Proceeding Settlement Agreement with Modifications	Section 4.2
D.19-05-042	CPUC Decision Adopting De-Energization (Public Safety Power Shutoff) Guidelines (Phase 1 Guidelines)	Section 8.2
D.19-05-039	CPUC Decision on SDG&E's 2019 WMP Pursuant to Senate Bill 901	Section 7.3.9.3
D.19-07-015	CPUC Decision Adopting an Emergency Disaster Relief Program for Electric, Natural Gas, Water, and Sewer Utility Customers	Section 7.3.9.3
D.20-05-051	CPUC Decision Adopting Phase 2 Updated and Additional Guidelines for De-Energization of Electric Facilities to Mitigate Wildfire Risk	Section 8.2
D.20-03-004	CPUC Decision on Community Awareness and Public Outreach Before, During, and After a Wildfire, and Explaining Next Steps for Other Phase 2 Issues	Section 4.5.2
General Order 95	Overhead electric line design, construction, and maintenance requirements in order to ensure adequacy of service and safety; covers topics such as proper grounding, clearances, strength requirements, and tree trimming	Section 4.2 Section 4.4.2.6 Section 5.4 Section 7.1 Section 7.3.3.3 Section 7.3.3.9 Section 7.3.3.16 Section 7.3.3.17.1 Section 7.3.3.17.3 Section 7.3.4.2 Section 7.3.4.5 Section 7.3.9.1 Section 9.1
General Order 128	Underground electric line design, construction, and maintenance requirements in order to ensure adequacy of service and safety; covers clearance and depths	Section 7.1 Section 7.3.4.2 Section 7.3.9.1 Section 9.1
General Order 131-D	CPUC Rules relating to the planning and construction of electric operation, transmission/power/distribution line facilities and substations located in California	Section 7.3.3.17.2
General Order 165	Inspection requirements for transmission and distribution facilities in order to ensure safety and high-quality electrical service; sets maximum allowable inspection cycle lengths, scheduling and performance of corrective action, record-keeping, and reporting	Section 5.3 Section 5.4 Section 7.1 Section 7.3.3.6 Section 7.3.4.1 Section 7.3.4.6 Section 7.3.4.9.1 Section 7.3.4.10

Citation	Description/Summary	WMP Sections
		Section 9.1
General Order 174	Inspection requirements for substations to promote the safety of workers, the public, and enable adequacy of service	Section 5.3 Section 7.1 Section 7.3.4.14
NERC FAC-003-4	Federal reliability standard; establishes a minimum clearance that must be maintained at all times between trees and transmission line rights of way that include consideration for line sag and wind sway	Section 5.4 Section 7.3.4.8
WSD GIS Data Standards	Wildfire Safety Division Draft Geographic Information System Data Reporting Requirements and Schema for California Electrical Corporations (August 21, 2020); Sets forth requirements for WMP spatial data submissions	Section 4.1 Section 7.1 Section 7.3.7
WSD Evaluation of SDG&E RCP	Wildfire Safety Division Evaluation of San Diego Gas & Electric Company's Remedial Compliance Plan (December 30, 2020); Assessing SDG&E's 2020 WMP Class A Deficiencies	Section 4.6 Section 4.4.2.9 Section 7.3
WSD Quality Control Report on SDG&E GIS Data	Wildfire Safety Division Quality Control Report on GIS Data Submitted by San Diego Gas & Electric on September 9, 2020 (December 29, 2020); Assesses SDG&E spatial data submission	Section 4.6
WSD Evaluation of SDG&E Initial Quarterly Report	Wildfire Safety Division Evaluation of San Diego Gas & Electric Company's First Quarterly Report (January 8, 2021); Assessing SDG&E's 2020 WMP Class B Deficiencies	Section 4.6
OEIS Final Action Statements	Office of Energy Infrastructure Safety Final Revised Action Statement issued July 2021.	*Passim*
OEIS Final Guidelines	Office of Energy Infrastructure Safety Final Guidelines issued December 2021.	*Passim*

9.3 Covered Conductor Installation Reporting

In Section 7.3.2.3.3, Covered Conductor Installation, report on the following key information for covered conductor installation:

- *Methodology for installation and implementation*
- *Design and design considerations (such as selection of type of covered conductor, additional hardware needed for installation, pole strengthening or replacements, etc.)*
- *Implementation (including timeframes, prioritization, contractor and labor needs, etc.)*
- *Long-term operations and considerations (including maintenance, long-term effectiveness and feasibility, effectiveness monitoring, etc.)*
- *Key assumptions*
- *Cost effectiveness evaluations (including cost breakdown per circuit mile, comparison with alternatives, etc.)*
- *Any other activities relevant to the covered conductor installation*

This information must be derived from utility-specific programs and supplemented by the findings of the covered conductor working group.

Methodology for installation and implementation

The methodology for the installation and implementation of covered conductor is similar to installation and implementation of bare conductor. The same engineering and design practices apply, material is largely the same except for the conductor and related components that are unique to covered conductor, and other processes such as environmental, land rights (research, interpretations, and acquisitions), permitting, and methods of construction and equipment used for installation are essentially the same.

Design and design considerations (such as selection of type of covered conductor, additional hardware needed for installation, pole strengthening or replacements, etc.)

The design of covered conductor is similar to traditional hardening, installing in an open-crossarm configuration. In this configuration, the conductor is self-supported and attached to insulators on crossarms at the structure. Currently only two covered conductor sizes that have three-layer insulation are kept in stock. The smallest wire size is 1/0 ACSR, 6/1 (AL/Steel) stranding and is typically used in branch lines of the distribution circuit where the ampacity requirements do not exceed 234 amps. The largest wire size is 336 ACSR, 26/7 (AL/Steel) stranding and is used in applications where the ampacity does not exceed 490 amps. Two additional sizes, 636 ACSR and #2 AWAC, are under evaluation. Historically, much of the focus of Electric System Hardening jobs was on replacing small wire conductor, such as #4 CU and #6 CU. With implementation of the new WiNGS-Planning model and an updated focus on both failure risk mitigation and PSPS reductions, other wire sizes and types are being replaced, depending on the circuit-section.

One of the biggest impacts covered conductor has on the design of facilities is due to the size (larger diameter) and weight per foot of the conductor compared to a bare conductor equivalent. The larger diameter and weight per foot increase the sag and wind loading impacts on the insulators, crossarms, poles, guys, and anchors. To counteract these impacts, taller poles, higher strength poles (larger class), and sometimes new poles (e.g., inter-set poles) are introduced into the design. In cases above 3,000 feet, ice loading is introduced into the calculations (i.e., GO 95 Heavy Loading conditions), which can substantially increase the height and class of poles necessary or require the inter-setting of new poles. In some cases, the soil bearing strength needs to be increased with concrete backfill, deeper embedment depths, or additional guying.

In many cases other equipment is replaced during these reconductor projects if it is older, showing signs of failure, and/or needs to be brought up to current standards. For instance, replacing wood poles with steel may be performed for several reasons, including increased fire resistance, more consistent strength and dimensions with smaller tolerances, the use of man-made material, and the fact that many wood poles are decades old and near the end of useful life. In some cases, the pole line is relocated to an area where it is more accessible to build and maintain. However, relocation requires obtaining a new easement and is not always feasible. Wood crossarms are also replaced with fiberglass crossarms and insulators are replaced with polymer insulators, switches, and regulators. For transformers, specific criteria were developed for replacement. A transformer is replaced if it is internally fused (regardless of age), if it's greater than 7 years old, if it has visual defects or damage (leaks, burns, corrosion, etc.), if it is less than 25 Kilovolt-Amps (kVA), or the transformer does not pass volt-drop-flicker calculation. The secondary wire that is either open (non-insulated) or "grey wire" (covered secondary wire where the insulation is grey in color) is also replaced.

On many projects there may be additional, smaller underground work associated with overhead work. This occurs when the circuit transitions underground (e.g., Cable or Riser Pole) and the new pole location is too far from the existing position and the existing cable, conduit, and terminations may not reach the new pole position. In these cases, crews will intercept the run of underground conduit, install a new handhole, install a new run of conduit and cable to the new pole location, and splice the cable in the new handhole to make the connection to the existing underground system.

SDG&E is implementing covered conductor to avoid exposed electrical connections for equipment taps, over-the-arm jumpers, or dead-ends to name a few examples. For this reason, special hardware such as IPCs and Tensioning Clamps are also implemented. This hardware eliminates the need to remove the covering and avoids causing damage to the conductor. By using piercing connectors and tension clamps, incidental contacts by external objects and animals are reduced.

Other hardware that was implemented in order to mitigate failure include Composite Post Line Insulators with Helical Tie Wraps, Spiral Dampers, Pole Top Brackets, cold shrink end caps to protect cut end from moisture ingress, and increased usage of Lightning Arrestors.

Implementation (including timeframes, prioritization, contractor and labor needs, etc.)

Covered conductor uses the same schedule and process as traditional hardening. As SDG&E began incorporating more covered conductor in 2020 and 2021, many lessons were learned in the engineering and design processes. SDG&E anticipates incorporating many of these lessons learned to stabilize scheduling and processes in 2022 as more experience is gained with the new conductor. The prioritization of projects is identified through WiNGS-Planning by circuit and mitigation by circuit-section. WiNGS-Planning model outputs go through a detailed scoping process with various stakeholders and the results are shared with the Project Management team. Project schedules are then developed based on typical activities and durations for each step in the project lifecycle based on the history of traditional hardening projects. Other activities also drive the schedule, including land rights research/interpretation/acquisitions, environmental review/mitigations, and permitting. The land rights acquisitions, environmental process, and permitting often dictate the final schedule for construction and are not fully within SDG&E’s control. Some permitting processes can take from six months to a year. In some cases, obtaining land rights can take months or even years, especially if legal processes must be employed.

Four primary construction contractors currently perform electrical construction work associated with covered conductor. These primary contractors typically sub-contract civil work (pole hole and anchor digging), helicopter, traffic control and dedicated fire watch. Internal electric construction teams may also perform some covered conductor installation, but typically associated work, such as helicopter, traffic control, dedicated fire watch, and civil work (pole hole and anchor digging) is performed by contractors. Based on experience with bare conductor, 75 percent of work is typically performed by contractors and 25 percent by internal crews.

Long-term operations and considerations (including maintenance, long-term effectiveness and feasibility, effectiveness monitoring, etc.)

SDG&E will continue to maintain covered conductor lines in accordance with GO 95 and 165. As covered conductor becomes a larger part of the electric system, SDG&E will continue to monitor and measure all performance indicators that impact the efficiency of this mitigation, including the measured effectiveness (number of faults per operating year per mile relative to the unhardened system averages) and the cost per mile.

Key assumptions

In order to quantify the risk reduction that could be achieved by covered conductor, SDG&E evaluated 80 events over a 5-year period that resulted in ignitions. SMEs determined the likelihood that covered conductor installation would prevent an ignition for that particular type of outage depending on the severity of the incident. As seen in Table 9-2, the result is a reduction in ignitions from 80 to 28.4, and a resulting effectiveness estimate of 64.5 percent.

Table 9-2: SDG&E Covered Conductor Mitigation Effectiveness Estimate

Fault/Ignition Cause	Number of Ignitions	SME Effectiveness	Post-Mitigation Ignitions
Animal contact	5	90%	0.5
Balloon contact	8	90%	0.8
Vegetation contact	10	90%	1.0
Vehicle contact	14	20%	11.2
Other contact	4	10%	3.6
Other	2	10%	1.8
Equipment - All	34	80%	6.8
Unknown	3	10%	2.7
Total	**80**	**64.5%**	**28.4**

Cost effectiveness evaluations (including cost breakdown per circuit mile, comparison with alternatives, etc.)

WiNGS-Planning assists in the allocation of grid hardening initiatives across the HFTD based on assessment of both wildfire risk and PSPS impacts. WiNGS-Planning is built upon the MAVF framework in RAMP and evaluates both wildfire and PSPS impacts at the sub-circuit/segment level. Information is used to inform investment decisions by determining and prioritizing mitigation based on RSE, improving wildfire safety and limiting the impact of PSPS on customers.

SDG&E assumes approximately 20 poles per mile:

(5,280 feet per mile) ÷ (262 feet per span) = 20.15 poles per mile

Each project averages 15 to 45 poles in a single job package; however, the number of poles can be greater or less depending on the configuration of the circuit, design and construction, land rights restrictions, and/or environmental challenges. Regardless of project size each project goes through a 6-stage gate process defined as follows with typical durations:

- Stage 1 – Project Initiation (1-3 months),
- Stage 2 – Preliminary Engineering & Design (6-9 months)
- Stage 3 – Final Design (3-5 months)
- Stage 4 – Pre-Construction (1-2 months)
- Stage 5 – Construction (3-4 months)
- Stage 6 – Close Out (8-10 months)
- Total Duration of a single project - 22 – 33 months

The estimated direct capital costs of covered conductor per circuit mile are shown in

Table 9-3.

Table 9-3: Estimated Direct Capital Costs of Covered Conductor per Circuit Mile

Cost Category	Cost per Circuit Mile	%
Labor (Internal)	$182,000	15%
Materials	$130,000	11%
Construction Contractor	$481,000	40%
Overhead (engineering, design, project management, etc.)	$418,000	34%
Total	**$1,211,000**	**100%**

Table 9-3 includes the following assumptions:

- Costs are based on estimated values using average bare conductor construction costs with a 15 percent adder on contractor costs to account for uncertainty with the new conductor, not enough projects fully completed and all costs accumulated as of the date of this filing.
- Costs do not include indirect, O&M, costs or AFUDC costs.
- Costs were rounded to the nearest thousand.

Covered conductor direct capital costs per circuit mile are made up of 4 major categories:

1. Internal labor – directs costs associated with SDG&E FTE, including but not limited to individuals from project management, engineering, permitting, environmental, land management, and construction departments. This costs also assumes that approximately 25 percent of the electric work is completed by internal SDG&E construction crews.
2. Materials – estimated costs of material used for construction including steel poles, wire, transformers, capacitors, regulators, switches, fuses, crossarms, insulators, guy wire, anchors, hardware (nuts, bolts, and washers), signage, conduit, cable, secondary wire, ground rods, and connectors.
3. Construction Contractors – estimated costs for construction-related services, including civil construction contractors for pole hole digging, anchor digging and substructures, and

street/sidewalk repair; electrical construction for pole setting, wire stringing, electric equipment installation, and removals; vegetation management where required including tree trimming or removal, and vegetation removal for poles and access paths; environmental support services including biological and cultural monitoring; traffic control; and helicopter support for pole setting, wire stringing, and removals. This cost assumes approximately 75 percent of the electric work is performed by contractor crews.

4. Overheads – estimated costs associated with contracted services not related to construction including engineering, design, project management, scheduling, reporting, document management, GIS services, material management, constructability reviews by QEW, staging yard leases/setup/teardown/maintenance, and permitting support throughout the entire lifecycle of a project, as well as services related to program management including long term planning and risk assessment.

Costs can vary significantly from project to project for a variety of reasons, including engineering and design, land rights, environmental, permitting, materials, and construction. A comparison of estimated direct capital costs for three hardening programs is provided in Table 9-4.

Table 9-4: Comparison of Estimated Direct Capital Costs

Alternatives Cost Comparison	Cost Per Mile
Strategic Undergrounding (per mile)	$2,660,460
Covered Conductor (per circuit mile)	$1,211,000
Traditional Hardening (per mile)	$1,050,000

Any other activities relevant to the covered conductor installation

SDG&E requires every pole to be engineered using PLS-CADD software during the design and post construction phase of the project lifecycle. This software utilizes LiDAR survey data (pre- and post-construction) to ensure poles, wires, and anchors are designed to meet GO 95 Loading (Light and Heavy Loading) Clearance Requirements, and known local wind requirements (85 mph and in some cases 111 mph). SDG&E also requires engineering and design contractors who use PLS-CADD to have a California registered Professional Engineer oversee and stamp the final PLS-CADD design.

In 2021 SDG&E experienced significant material supply chain issues, especially for covered conductor materials, due to impacts from COVID-19. In the case of covered conductor, SDG&E currently sources wire from multiple suppliers; however, the associated material such as helical tie wires, piercing connectors and clamping dead-ends come from one supplier out of Europe and significant delays were experienced in 2021. SDG&E also experienced delays receiving other material due to COVID-19 supply chain disruptions. In some cases, there was competition with other utilities for the same material. Material delays can cause construction delays or cause construction to work less efficiently, thus impacting project schedules and costs. Due to the ongoing COVID-19 pandemic it is anticipated that during 2022 lead times will be longer than historically experienced. SDG&E will work diligently with its suppliers to provide long-term forecasting and prioritization as necessary.

9.4 Undergrounding Implementation Reporting

In Section 7.3.3.16 Undergrounding of electric lines and/or equipment, report on the following key information for undergrounding implementation:

- *Methodology for installation and implementation*
- *Design and design considerations (such as permitting requirements, additional hardware needed for installation, etc.)*
- *Implementation (including timeframes, prioritization, contractor and labor needs, etc.)*
- *Long-term operations and considerations (including maintenance, long-term effectiveness and feasibility, effectiveness monitoring, etc.) Key assumptions*
- *Cost effectiveness evaluations (including cost breakdown per circuit mile, comparison with alternatives, etc.)*
- *Any other activities relevant to the undergrounding implementation*

This information must be derived from utility-specific programs.

Methodology for installation and implementation

The installation and implementation of SDG&E's Strategic Undergrounding program largely follows existing standards for design and construction that exist throughout the service territory. In order to address the risk of ignition and mitigate PSPS impacts, SDG&E strives to underground both the primary voltage cable and the secondary service cable serving the customer. As part of the Strategic Undergrounding initiative several improvements or enhancements have been identified including:

- Decreasing trench depth from 30 inches to 24 inches of trench cover. This new design standard allows for a reduction in construction effort and cost, especially in difficult rocky terrain.
- Implementing breakaway technology when overhead service wire is required for a customer. This allows the service wire to disconnect from power when struck by debris and the span of overhead wire to break free and deenergize. This technology is a useful alternative when customer concerns raise about undergrounding or SDG&E encounters difficulties to physically underground some routes.
- Conducting thorough field surveys during the design phase to identify locations for equipment placement that will minimize easement requirements. The strategic placement of equipment significantly reduces the time it takes to acquire land, effectively shortening overall project execution.
- Utilizing trenchless technologies such as Horizontal Directional Drilling (HDD) and Auger Boring (also known as Jack and Bore) when environmentally sensitive areas or difficult easements are encountered. These technologies are also used at Caltrans crossings to reduce the permitting process time.
- Implementing reduced conduit diameters, instead of applying a one-size-fits-all-approach. By using the minimum conduit size for the specific cable and future system need, the decreased trench depth reduces the civil construction effort, utilities conflict, and overall cost.

Design and design considerations (such as permitting requirements, additional hardware needed for installation, etc.)

The design and design considerations of undergrounding as part of the Strategic Undergrounding initiative largely follow existing processes for design, permitting, and land acquisition. Several improvements or enhancements have been identified including:

- Permitting requirements are identified as early as possible to accurately scope and schedule the project. Agencies such as CNF, Caltrans, and the Bureau of Indian Affairs typically have a longer permitting lead time compared to San Diego County permits and those timelines need to be accurately reflected in the schedule. When working with these agencies the project managers should be involved early on to define a clear permitting approach and strategy.
- Strategic Undergrounding Projects are conducted in the areas of highest wildfire risk, typically in rural areas of the service territory. There are numerous narrow and remote roads and paths on these projects. The design team should consider egress and ingress as they progress through the design phase and should select the most appropriate design for the specific location. For example, if egress and ingress is an issue at a construction site, the designer may consider using native backfill instead of slurry fill, working space, traffic coordination, and the type of equipment used to minimize potential traffic issues.
- Geotechnical investigation is usually conducted at each job location to identify the soil condition in the area. Rocky subsurface is common in the back country and is a difficult subsurface for underground construction. A rocky subsurface should be identified early in the design process to minimize design changes.
- The environmental team is involved during the scoping phase to identify any environmental constraints that could negatively impact the project schedule. These issues include avoiding cultural resources, water resources, and biological resources by rerouting or going trenchless.
- The project management team works closely with the design team to identify any conflicts between the undergrounding route and the resurfacing plans of either the County or Caltrans. If a conflict is identified, the Strategic Undergrounding project is either expedited to construct before the road is repaved, or it is postponed until the moratorium expires. The project management team holds quarterly and monthly meetings with the County to coordinate this effort.
- At the 60 percent design submittal stage, every project team performs a constructability walk, where experienced underground construction experts walk the entire route with the design and environmental teams and other necessary stakeholders to identify and resolve any potential construction and environmental issues before final design to reduce instances of field change orders.

Implementation (including timeframes, prioritization, contractor and labor needs, etc.)

The Strategic Undergrounding initiative is constantly making planning and process improvements based on feedback from the parties involved. Many processes have been updated and streamlined to shorten the design duration while maintaining technical quality and integrity. Examples include:

- Completing field constructability reviews

- Resurfacing coordination to avoid repaving
- Implementing a permit strike team
- Collaboration and partnering with design firms
- Building relationship with San Diego County and their inspectors
- Re-evaluating program contracting strategy

The project management team works with supply management to bundle and bid projects strategically to expedite schedules while maintaining construction quality. Fixed pricing is sometimes a strategic option with contractors that have demonstrated outstanding performance. This allows SDG&E to leverage efficiencies and the contractor's direct knowledge of site conditions in exchange for a fixed price. Projects in the same area are often bundled to streamline supply management efforts and reduce overall cost. In addition, civil and electrical work are bid out separately to minimize cost and expedite schedule.

Strategic Undergrounding works with the Logistics business unit to provide material forecasting for long-lead time materials or low quantities of material in stock. Ordering material ahead of time reduces the chance of delays to construction and energization planned dates. Working closely with the logistics team allows the project management team to stay ahead of any foreseeable issues with material acquisition and find solutions before the schedule is impacted.

Continuous process improvements are also one of the major cost reduction initiatives that contributed to SDG&E's unit cost baseline for 2021. By improving current processes and/or creating new ones, the project team has been able to effectively support the Strategic Undergrounding initiative and show immediate benefits. Examples of these process improvements are:

- Removing unnecessary data in the design documents
- Going to the field with construction, design, and environmental personnel to review the design package at 60 percent completion
- Developing new design standards that make construction more efficient
- Planning and scoping for the next 3 years, which includes prioritization, and creating an execution plan and map

Long-term operations and considerations (including maintenance, long-term effectiveness and feasibility, effectiveness monitoring, etc.)

There are multiple wildfire mitigation and PSPS reduction benefits from the undergrounding of overhead facilities, including:

- Vegetation Management: elimination of the need to perform continued tree inspection, pole brushing, and auditing activities; cost savings associated with these activities; reduced risk of ignition caused by tree-line contacts; allowing trees to reach mature height and avoiding tree removals and trims; reduced visits to properties and reduced impacts to customers.
- Asset management and inspections: reduction in overhead inspections; longer asset life expectancy; easier-to-diagnose outage causes.
- PSPS risk is reduced or eliminated.

- Probability of faults leading to an ignition are reduced or eliminated.

Key assumptions

Undergrounding will reduce risk events associated with overhead faults, reducing wildfire risk. SDG&E will continue to study the recorded effectiveness of its strategic undergrounding projects. Reviews of previous ignitions show undergrounding has a greater than 98 percent effectiveness at reducing wildfire risk.

Cost effectiveness evaluations (including cost breakdown per circuit mile, comparison with alternatives, etc.)

The estimated direct capital costs of undergrounding per mile shown in Table 9-5.

Table 9-5: Estimated Direct Capital Costs of Undergrounding per Mile

Cost Category	Cost per Circuit Mile	%
Construction	$1,800,000	68%
Engineering & Design, Environmental, Land, Staging Yard, Project Support	$740,460	28%
Material	$120,000	4%
Total	**$2,660,460**	**100%**

Table 9-5 includes the following assumptions:

- Costs do not include indirect, O&M, or AFUDC costs.
- Costs were rounded to the nearest thousand

There can be additional cost benefits related to undergrounding such as a reduction of vegetation management activities associated with the removal of overhead infrastructure. Electric facilities that remain overhead will require continued vegetation management and inspection activities. In 2022, life-cycle cost savings will be analyzed based on the cost of vegetation management activities, including pre-inspection, tree trimming, pole brushing and auditing. To compare the effectiveness of cost savings, circuits were broken into segments and associated asset units to determine the location and related cost benefits for undergrounding. The preliminary results show that the annual cost savings related to the reduction in vegetation management is estimated to average $9,900 per circuit mile annually.

Table 9-6: Comparison of Estimated Direct Costs

Alternatives Cost Comparison	Cost Per Mile
Strategic Undergrounding (per mile)	$2,660,460
Covered Conductor (per circuit mile)	$1,211,000
Traditional Hardening (per mile)	$1,050,000

Attachment A: Long Term Vision

Wildfire Mitigation Plan

Long-Term Vision

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List of Abbreviations

Abbreviation	**Name**
AAR	After-Action Review
AFN	Access and Functional Needs
AI	Artificial Intelligence
AIM	Asset Integrity Management
AQI	Air Quality Index
BMP	best management practice
CAL FIRE	California Department of Forestry and Fire Protection
CBO	Community Based Organization
CMP	Corrective Maintenance Program
CPUC	California Public Utilities Commission
CR	central repository
CRI	Circuit Risk Index
DGF	data governance framework
DOP	Distribution Operating Procedure
EOC	Emergency Operations Center
FPI	Fire Potential Index
FROP	First Responder Outreach Program
FSI	Fire Science and Innovation
GIS	Geographic Information System
GO	General Order
HFTD	High Fire Threat District
HPCC	High Performance Computing Clusters
IBEW	International Brotherhood of Electrical Workers
ICS	Incident Command System
IMP	Ignition Management Program
IOU	Investor-Owned Utility
LE	Law Enforcement
LEP	Limited English Proficiency

LiDAR	Light detection and ranging
MAVF	Multi-Attribute Value Function
NDVI	Normalized Difference Vegetation Index
NIMS	National Incident Management System
NMS	Network Management System
NUTIF	National Utility Industry Training Fund
OEIS	Office of Energy Infrastructure Safety
PoI	Probability of Ignition
PSPS	Public Safety Power Shutoff
QFF	qualified firefighter
RSE	Risk Spend Efficiency
SAWTI	Santa Ana Wildfire Threat Index
SCADA	supervisory control and data acquisition
SDG&E	San Diego Gas & Electric
SDSC	San Diego Supercomputer Center
SMS	Safety Management System
UAS	Unmanned Aerial System
UICS	Utility Incident Command System
VRI	Vegetation Risk Index
WiNGS	Wildfire Next Generation System
WMP	Wildfire Mitigation Plan
WRRM	Wildfire Risk Reduction Model
WSD	Wildfire Safety Division
WUI	Wildland Urban Interface

Introduction

This document provides updated details regarding long-term wildfire mitigation plans and how the initiatives in the 2022 Wildfire Mitigation Plan (WMP) Update align with and support San Diego Gas & Electric's (SDG&E's) long-term strategies.[1]

As a recognized leader in wildfire mitigation, SDG&E's vision for wildfire mitigation continues to focus on reducing the risk of wildfires as well as reducing the impacts of Public Safety Power Shutoff (PSPS) events to customers. While SDG&E aspires to minimize the need for PSPS events over the next 10 years to the greatest extent practicable, California continues to experience increasing levels of wildfire risk, largely as a result of climate change. As such, SDG&E will continue to modernize its system to mitigate the risk of wildfires and build a more resilient grid for the future. But PSPS may continue to be a part of SDG&E's portfolio of mitigation options to be implemented as a measure of last resort to protect public safety.

To achieve its vision, SDG&E continues to focus on enhancing its data analytics capabilities across the organization, supporting a more granular view of risk across its system. This will include better integration of data captured from weather stations and situational awareness tools in addition to data from new technology applications. This enhanced data analytics capability will support a better understanding of risk across the system and support further optimization of resources through more refined targeting of mitigations, enhanced alternatives analysis, and prioritization of mitigations based on risk.

SDG&E continuously seeks input and guidance both internally and externally on its vision and long-term roadmap for maturing its wildfire mitigation capabilities. As demonstrated in the 2020 WMP and subsequent WMP Updates for 2021 and 2022, high-level objectives were provided for each of the 10 categories of capabilities, depicting a vision for enhancing the Wildfire Mitigation Program in the 2020 WMP cycle and by 2030. In 2021, an extensive effort was undertaken to build more refined objectives and annual timelines for maturing wildfire mitigation capabilities over the next 10 years. Due to the long timeframe, rapidly changing technologies, the evolution of regulatory and legislative priorities and efforts, and the constantly evolving climate, there are bound to be unforeseen refinements and improvements to SDG&E's wildfire mitigation strategies in the future. SDG&E views this roadmap as a guiding vision that it will continue to work towards and develop as time passes.

This Wildfire Mitigation Plan Long-Term Vision sets forth SDG&E's current plan to mature capabilities in each of the 10 categories outlined in the 2022 WMP Update. This is a living document, and the long-term vision will be continually updated to incorporate new technologies, methodologies, and best practices identified in consequent years and as the dynamic world of wildfire mitigation continues to evolve. As such, the response is structured in accordance with each of the 10 categories outlined in the 20222 WMP Update.

[1] SDG&E originally included a long-term assessment of wildfire mitigation measures in its 2021 WMP Update to address deficiencies noted by the Commission in Resolution WSD-002, specifically Guidance-12 (Lack of Long-Term Planning). For continuity, SDG&E has included a further update on its long-term strategies herein.

Risk Assessment & Mapping

Expected State of Wildfire Mitigation in 10 Years

Risk Assessment and Mapping capabilities are foundational elements of enhancing SDG&E's Wildfire Mitigation Program. Maturation of risk assessment and modeling capabilities will include increasing granularity and accuracy in assessments to better manage wildfire risk, as well as incorporating broader ranges of inputs in risk assessment. Pursuits in automation will enable more real-time updates to risk maps which will facilitate scenario planning and focus mitigation efforts.

The 2020 WMP Cycle forms the foundation for achieving SDG&E's 10-year plan for expanding risk assessment and mapping capabilities. Increasing the accuracy and usefulness of risk mapping is dependent upon a very strong foundational understanding of the risk. SDG&E will continue to integrate and analyze climate, fire, and weather-related data and incorporate the best possible data into the risk assessment and mapping tools for ongoing decision support.

In addition to the integration of the latest science, SDG&E is currently utilizing its enhanced understanding to develop the next generation of risk-based RSE models. These models will be continuously refined and improved, and particular focus will be given to increasing granularity, establishing new principal components as applicable, and the accuracy of the modeling and resultant mapping.

By 2030, SDG&E expects to expand its academic partnerships to aid in enhancing risk assessment capabilities by integrating the latest intelligence related to climate, fire, and weather into its models. Increasing automation and enabling real-time learning capabilities will continue to enhance model algorithms. Additionally, while SDG&E has already established asset-level risk assessments for key assets, it plans to further enhance granularity by 2030 to better understand risk at granularities ranging from asset level to system-wide, enabling a broader view of risk tailored to various applications. A year-by-year timeline of SDG&E's roadmap for maturing this category is provided in Table 1.

Year-by-Year Timeline for Maturing Risk Assessment & Mapping

Table 1: Year-by-Year Timeline for Maturing Risk Assessment & Mapping

2020	2021	2022
• Expand the Ignition Management Program (IMP) • Provide ongoing enhancements for Wildfire Risk Reduction Model (WRRM) • Create the Fire Science and Innovation (FSI) Lab • Modify python code driving weather data processing	• Continue expansion[2] of the IMP • Develop preliminary Probability of Ignition (PoI) models • Integrate (PoI) modeling for the development of Wildfire Next Generation System (WiNGS) Ops model • Enhance WRRM[3]	• Continue WRRM enhancements WRRM[3] • Expand and integrate academic partnerships. • Upgrade High-Performance Computing Infrastructure • Operationalize the WRRM-Ops platform into a single visual and configurable live map that can

[2] Refresh data with new observations, explore new methodologies, explore new datasets.
[3] Weather Station Network modernization and expansion

	• Increase data sharing across the modeling community to expedite modeling enhancements • Develop WiNGS-Ops Model • Develop initial Cloud risk models	be utilized to support operational decisions, including PSPS decisions. • Enhance PoI Models within the IMP • Migrate existing models to Amazon Web Services Cloud. • Execute risk models in Cloud environment • Initiate third-party model reviews Introduce egress in wildfire risk modeling • Develop visualization tools (proof of concept) for WiNGS-Ops • Develop user interface/ visualization tool for WiNGS-Planning • Evaluate updates on WiNGS-Planning model and finalize methodology • Evaluate updates on existing PoI models and finalize methodology • Integrate PoI models in WiNGS-Planning and WiNGS-Ops • Integrate and align with SDG&E Climate Vulnerability Assessment. • Incorporate WRRM-Ops enhancements into Multi-Attribute Value Function (MAVF) in the determination of risk consequences.
2023-2025		
• Enhance[4] PoI models within the IMP. • Integrate and align with SDG&E's Climate Vulnerability Assessment • Incorporate WRRM enhancements into MAVF in the determination of risk consequences • Iterate and improve[5] egress in wildfire risk modeling • Continue to leverage WiNGS-Planning to inform risk assessment and system hardening prioritization. • Enhance[5] WiNGS-Ops modeling • Increase WiNGS-Planning automation		

[4] Refresh data with new observations, explore new methodologies, explore new datasets.
[5] Integration of disparate dashboards of weather and camera data into Wildfire Analyst Software

• Continue working with academia to identify and incorporate latest science and analytics. • Improve material traceability within the IMP • Continue to coordinate and merge risk assessment and mapping technology with the California Department of Forestry and Fire Protection (CAL FIRE) through fire behavior modeling systems • Continue to seek third-party reviews of models to validate risk assessment approaches
2026-2030
• Enhance[5] Probability of PoI Models with IMP • Enhance[5] of WiNGS-Planning/WiNGS-Ops Modeling • Modification of software code driving weather data processing • Iterate and improve[5] egress into wildfire risk modeling • Continue to update model automation as applicable, including the incorporation of vegetation risk, circuit risk, wildfire risk and asset data. • Upgrading High-Performance Computing Infrastructure • Incorporate lessons learned from post project implementations • Continue to enhance[6] the temporal and spatial granularity of the modeling as applicable and beneficial. • Incorporation of broader range of inputs in risk assessment • Increased automation of risk modeling • More real-time updates of risk models • Enhanced risk understanding is driving the ongoing development of the next generation of risk assessments and mapping. • Granularity of risk assessment modeling is optimized • Modification of computing code driving weather data processing • Re-evaluate and expand academic partnerships to enhance and integrate the latest climate science, fire science and weather science into risk assessments and mapping

Situational Awareness and Forecasting

Expected State of Wildfire Mitigation in 10 Years

SDG&E's Situational Awareness and Forecasting capability is based on a solid technological and data-rich foundation on which the next generation of advanced prediction and analytics will be built. Data gathered from a Weather Station Network exceeding 220 stations in 4,100 square miles and collecting over 31,000 observations per day helps initialize 6 high-resolution models operating on 3 supercomputers that generate nearly 200 gigabytes of daily data. This data is archived for accessibility and searchability through a joint venture with the San Diego Super Computing Center and represents the first of its kind to advance wildfire science and research.

SDG&E's fire potential and fire weather indices are based on this foundation of fuels and weather data. Further automation of product generation coupled with increased resolution will continue to aid in refinement and innovation of early warning tools to evaluate impending fire risk. In addition to increased data collection and improved post processing for product refinement, in-situ sensor

[6] Refresh data with new observations, explore new methodologies, explore new datasets.

observations from fixed multi-spectral cameras and airborne drone assets will be a data multiplier demanding greater management and analysis.

As SDG&E continues to enhance its situational awareness capabilities, it will focus on increasing the scope of reliable weather data, improving the process for validating readings, and increasing the resolution of weather data across the grid with the overall objective of increasing accuracy of its forecasts. By 2030, SDG&E expects to advance its fire behavior modeling capabilities, automate its Fire Potential Index (FPI), and invest in additional technologies such as Normalized Difference Vegetation Index (NDVI) cameras, enhanced camera smoke detection capabilities, and real-time satellite monitoring of wildfire spread to aid with future mitigation and response measures. A year-by-year timeline of SDG&E's roadmap for maturing this category is provided in Table 2.

Year-by-Year Timeline for Maturing Situational Awareness and Forecasting

Table 2: Year-by-Year Timeline for Maturing Situational Awareness and Forecasting

2020	2021	2022

• Install over 200 weather stations with 30-sec observation capability[7]
• Advance Fire Behavior Modeling[8]
• Improve high resolution model forecasts using machine learning
• Automate FPI
• Establish state of the art data archiving for follow on analysis
	• Through established academic research partnerships, change to 1 km resolution for operational indices:
	  • FPI
	  • Santa Ana Wildfire Threat Index (SAWTI)
	  • Fire Behavior Modeling Risk Forecast
	• Re-write code for weather awareness site and mobile app
	• Add fuel moisture modeling to Weather Station Network
		• Acquire next generation High Performance Computing Clusters (HPCC)
		• Open fully operational FSI Lab
		• Install NDVI cameras and Air Quality Index (AQI) sensors at key locations
		• Operationalize Artificial Intelligence (AI) based smoked detection from cameras

2023-2025		
• Integrate weather data into Network Management System (NMS) for real-time operational decision-making • Integrate and increase automation of broader datasets such as the Vegetation Risk Index (VRI), Circuit Risk Index (CRI) and historical wind conditions into the PSPS Situational Awareness Dashboard • Integrate and align with SDG&E's Climate Vulnerability Assessment • Conduct model enhancements and improvements through academic partnerships • Establish a tuition reimbursement program for SDG&E employees to prepare a workforce trained to deal with the evolving needs associated with wildland fire management and climate change as it relates to power utilities. • Improve weather forecast products through all PSPS phases with AI applications • Advance and integrate satellite-based heat detection algorithms • Integrate real-time electric system monitoring to predict equipment failures and incorporate into CRI • Continue data integration into operational systems		

[7] Weather network modernization and expansion
[8] Integration of disparate dashboards of weather and camera data into Wildfire Analyst Software

• Improve fire potential indices based on lessons learned and new information and garner efficiencies through achievable consolidation • Modify and strengthen strategic partnerships
2026-2030
• Assess situational awareness synergies from various initiatives • Evaluate archived weather and fuels data with advanced analytics • Lead collaborative partnerships to address the greatest challenges • Leverage identified situational awareness synergies to improve procedural effectiveness and latency • Improve model output bias with machine learning and analytic results • Investigate advanced wildfire monitoring and reporting techniques • Utilize real time satellite video to monitor wildfire spread • Explore AI-controlled drone squadrons providing situational awareness and automated fire detection • Assess synergies of various initiatives • Increase scope of reliable weather data and improve processes for validating readings • Increase resolution of weather data to sub-1 km across the grid • Develop new AI models for weather forecasts • Develop full automation in fire detection capabilities

Grid Design and System Hardening

Expected state of wildfire mitigation in 10 years

The current WMP cycle includes significant milestones along the way to SDG&E's 10-year wildfire mitigation goals, including the recent completion of fire hardening programs within Cleveland National Forest. This geographic location has some of the highest wildfire consequence risk within the service territory, and SDG&E spent over 10 years in design, permitting, and construction to advance and complete this mitigation project. The project was completed in early 2022 and represents significant wildfire risk reduction, including the removal of a transmission line near Boulder Creek and Sill Hill, areas where there is an abundance of dry fuels and very poor access for suppression efforts, and consistently some of the highest-level winds in the service territory. This project also reduces PSPS impacts by hardening transmission lines into the Descanso Substation.

SDG&E has also launched the strategic undergrounding program and covered conductor program, which will become the preferred hardening strategies based on the WiNGS-Planning risk model to focus on both on wildfire risk reduction and mitigating PSPS impacts to customers. WiNGS-Planning tranches risk at the circuit segment level, which coincides with how the system is operated during high-risk events. Because whole circuit segments will be hardened as opposed to only high-risk assets, customers will see more tangible benefits of hardening in the form of reduced PSPS events.

In addition, SDG&E is making significant progress on its high-risk equipment replacement program, including the forecasted completion of its branch fuse replacement programs within the HFTD in 2022. SDG&E also initiated its capacitor and lighting arrestor replacement programs within the HFTD, and made continued progress on the hot line clamp replacement program, targeting risk reduction on the types of equipment that have led to ignitions in the past. Finally, during this WMP cycle, SDG&E will expand its advanced protection systems, working towards a goal of applying this protection to every circuit within Tier 3 of the HFTD by 2023.

Over the next 10 years, SDG&E will continue to identify the highest risk areas to apply targeted wildfire mitigation efforts, including strategies such as strategic undergrounding; overhead system hardening such as covered conductors, sectionalizing, or circuit reconfigurations; enhanced vegetation management and fuels management; and backup generators and microgrid solutions. These mitigation solutions will focus on improving public safety by reducing the risk of wildfire associated with utility infrastructure and reducing PSPS impacts to customers.

In the next 10 years, specific equipment programs such as capacitors, fuses, hot line clamps, and lightning arrestors will be 100 percent converted to CAL FIRE-approved equipment or other fire safe standards within the High Fire Thread District (HFTD). SDG&E also plans to complete the hardening of its transmission system, completing Tier 3 of the HFTD by 2022 followed by the completion of Tier 2 by 2027.

SDG&E will utilize its improved risk modeling to prioritize its core mitigation strategies (strategic undergrounding, covered conductor, and traditional hardening), focusing on reducing the greatest risk first. The WiNGS-Planning model now includes PSPS impacts to customers, improving the value of mitigation efforts such as undergrounding and covered conductor. These mitigations not only significantly reduce the risk of wildfire but also keep more lines energized during certain high-risk operational periods. The new models support a shift in hardening strategy, incorporating more covered conductor and undergrounding in the 10-year hardening plan with reduced emphasis on traditional hardening.

Model enhancements that incorporate risks associated with PSPS events also allow a more complete evaluation of additional mitigation strategies, such as microgrids and backup generation, against more traditional hardening methods to assess the most appropriate solution. In addition to core-hardening strategies, SDG&E will build out its advanced protection capabilities and communication network across the Tier 3 HFTD, and eventually the Tier 2, providing additional risk reduction. Hardening programs are aimed at reducing the risk of a fault occurring, but if one does occur, the advanced protection program reduces the chance that the fault leads to an ignition, allowing complementary mitigation strategies.

The 10-year plan also includes the deployment of new monitoring technology that looks at electrical property anomalies to try and predict system faults before they occur, providing yet another layer of fire hardening protection. As SDG&E completes these programs, data will be reviewed on at least an annual basis to measure the effectiveness of mitigations. Risk models will be updated with the latest effectiveness measures based on actual data, to continually assess the most efficient mitigations. A year-by-year timeline of SDG&E’s roadmap for maturing this category is provided in Table 3.

Year-by-Year Timeline for Maturing Grid Design and System Hardening

Table 3: Year-by-Year Timeline for Maturing Grid Design and System Hardening

<table>
<tr><th>2020</th><th>2021</th><th>2022</th></tr>
<tr>
<td>• Incorporate PSPS impacts in risk reduction modeling to determine the optimal hardening solution
• Complete the 11 miles of pilot undergrounding projects
• Initiate overhead and undergrounding program in communities across the HFTD</td>
<td>• Complete Cleveland National Forest (CNF) transmission and distribution hardening project, reducing the risk of ignition in one of the highest risk areas of the service territory
• Incorporate risk of PSPS impacts into model for selection of mitigation solutions to include in the 2021 WMP Update
• Continue overhead and undergrounding program in communities across the HFTD</td>
<td>• Upgrade all branch expulsion fuses within the HFTD to CAL FIRE-approved power fuses
• Continue replacing hot line clamp connectors within the HFTD
• Evaluate additional microgrid locations to support resiliency and reduce PSPS impacts to additional customers
• Continue overhead and undergrounding program in communities across the HFTD</td>
</tr>
<tr><th colspan="3">2023-2025</th></tr>
<tr><td colspan="3">• Upgrade all capacitors with fire ignition risk in the HFTD and Wildland Urban Interface (WUI) to reduce the risk of ignition
• Harden 100 percent of Transmission lines within the Tier 3 HFTD
• Continue overhead and undergrounding program in communities across the HFTD
• Deploy predictive equipment failure analytics utilizing high fidelity monitors
• Upgrade all lightning arrestors to CAL FIRE-approved arrestors within the HFTD</td></tr>
<tr><th colspan="3">2026-2030</th></tr>
<tr><td colspan="3">• Harden 100 percent of high-risk transmission lines within the HFTD
• Continue overhead and undergrounding program in communities across the HFTD
• Continue the use of switches, weather stations, microgrids, and generators to mitigate the impacts of PSPS events
• Complete advanced protection rollout in the HFTD
• Continue risk-based distribution hardening programs, hardening approximately 200 miles per year with covered conductors or underground cables
• Deploy falling conductor in all of Tier 2 HFTD
• Fully deploy the high-speed distribution communications reliability initiative (private LTE)</td></tr>
</table>

Asset Management and Inspections

Expected state of wildfire mitigation in 10 years

As SDG&E continues aligning its practices with ISO 55000, SDG&E's 10-year asset management vision focuses on enhancing data collection, integration, and analysis to better understand asset health, enable predictive modeling, and improve its inspection programs based on quantitative risk assessments. By 2030, SDG&E expects to continue its inspection programs while further integrating and expanding use of new technologies such as infrared, Light detection and ranging (LiDAR), drones, and intelligent image processing, along with lessons learned and procedural updates. In addition, SDG&E will continue to develop asset management plans with predictive analytics for each of its asset classes and types to inform its asset management and risk mitigation strategies. A year-by-year timeline of SDG&E's roadmap for maturing this category is provided in Table 4.

The 2022 WMP Update continues to reinforce SDG&E's priorities for safe management and reliable operations of electric assets. In alignment with the 10-year plan, SDG&E intends to continue the existing standard electric inspection program, including existing non-discretionary routine patrols and inspections, to aid in promoting wildfire mitigation. Supplementary discretionary assessments will also continue to further observe, collect more asset-related data, and augment the standard electric inspection program to allow for incremental validation of asset conditions or additional assessments of assets flagged for follow-up during the standard electric inspection program.

SDG&E leverages technological advancements to further expand the current enhanced electric assessment program, which includes supplementary discretionary assessments. SDG&E examines opportunities for innovative use of new technologies, streamlining processes, or adopting new industry best practices to make asset management and inspections more adaptable to ever-changing regulatory, compliance, and wildfire mitigation direction. For feedback and continuous improvement, SDG&E intends to continually perform monitoring and audits of the standard electric inspection program and utilize findings to develop training enhancements for field employees. To reinforce data-driven performance evaluation and sustainable and integrated risk-informed asset management, SDG&E is pursuing alignment with ISO 55000 standards through the implementation of the Asset Integrity Management (AIM) Program. As one of the several key workstreams of the AIM Program, the asset data foundation project is integrating key asset-related attributes to enable predictive asset health analyses and risk modeling with the goal of providing data and insight to optimize inspection/assessment strategies and prioritization.

The Skills Training Center has a robust plan to further enhance the overhead QC inspection program. In 2020 the Skills Training Center developed and incorporated the use of virtual reality and completed a physical build out of the skills training yard with 15 poles and infractions. In 2021 the Electric Troubleshooter Curriculum was enhanced to promote learning and information retention, using tools such e-learning and exploring the use 2.5D and virtual reality/augmented reality where applicable. Finally, in August 2020, an eight-week Climbing School and Advanced Secondary Apprentice class session was launched and for the first time, the Line school Instructors and Apprentices began using the newly structured curriculum obtained from the NUITF, a product of the Electrical Training Alliance and the IBEW that was modified by SDG&E's internal instructional design team and aimed at the development of best-in-class linemen.

Year-by-Year Timeline for Maturing Asset Management and Inspections

Table 4: Year-by-Year Timeline for Maturing Asset Management and Inspections

2020	2021	2022
• Continue standard electric inspection program and supplementary discretionary	• Begin wood pole intrusive inspections of transmission	• Expand distribution inspection program of expediting repairs of

assessments for transmission, substation, and distribution assets • Include new program to expedite distribution repairs of fire safety infractions in HFTD Tier 3. • Streamline process to collect more granular asset information from As-Builts for upload into GIS and other geospatial platform. • Develop PSPS patrol training for internal field personnel and contractors • Begin electric distribution drone inspections for Tier 3.	structures from 10-year to 8-year cycle • Leverage patrols, inspections, and assessments to begin collecting key asset-related attributes to support asset data analytics foundation and integration (pilot on select distribution asset types) • Build out PSPS training module for existing and new electric line crew field personnel. • Update electric first responder training modules and build PSPS module to include e-learning • Build out new International Brotherhood of Electrical Workers (IBEW)/National Utility Industry Training Fund (NUITF) apprentice training program into apprentice curriculum • Modernize overhead Corrective Maintenance Program (CMP) inspection and QC training with the use of virtual reality (test basis) • Build out hands on overhead infraction yard at Skills Training Center to compliment virtual and instructor-led training. • Finish electric distribution drone inspections for Tier 3. Begin electric distribution drone inspections for Tier 2.	fire safety infractions into HFTD Tier 2. • Identify the appropriate cycle, locations, and/or types of structures to utilize drones as part of routine inspection programs. • Assess wildfire reduction benefit cost effectiveness after drone pilot assessments completion. • Explore virtual reality/augmented reality opportunities to enhance electric first responder training program • Build electric first responder testing into Learning Management System • Finish electric distribution drone inspections for Tier 2. • Evaluate if drones provide good value and should continue to be used in regular inspection efforts (including auditing contractor activities). • Prepare for implementation of risk-based prioritized inspections by developing workflows, processes, and procedures, and update systems to convert current QC inspections (approx. 13,000 distribution pole inspections performed on a 3-year cycle in Tier 3 HFTD) to risk-based inspections across the entire HFTD. These inspections would be over and above the time-based 5-year inspections required by General Order (GO) 95.

2023-2025

- Evaluate transmission inspection frequencies for high-risk equipment and areas based on vegetation
- Enhance training for field personnel educating on findings and data gaps for feedback and continuous improvement through improvements
- Explore virtual reality/augmented reality around the proper operation of field and substation equipment
- Begin integrating digital asset imagery collected from drones, LiDAR, and other assessments
- Integrate asset management system for electric transmission, substation, and distribution in alignment to ISO 55000 standards

• Restart electric distribution drone inspections using the proposed cycle of approximately 22,000 inspections per year based on completing Tier 3 every 3 years and Tier 2 every 5 years • Utilize LiDAR to support post-construction survey (including auditing contractor activities), pre-construction design conditions, and vegetation analysis for all transmission projects inclusive of projects within the HFTD. • Develop predictive asset health analyses and risk modeling test case utilizing integrated asset data foundation (distribution). • Implement key virtual reality/augmented reality components into electric line personnel and first responder training program • Begin assessing accumulated data and utilization/adoption of geospatial platform • Begin asset data analytics foundation and integration for transmission (pilot on select transmission asset types) • Examine electric line crew field personnel and first responder training for possible improvements
2026-2030
• Continue intelligent image processing, utilizing artificial intelligence and innovation, to detect damage to high fire risk distributions assets and vegetation • Begin transmission intrusive inspection on new 8-year cycle • Evaluate geospatial technology evolution and capability to submit circuit vulnerabilities and automate prioritization to streamline follow-up process. • Develop test case on predictive asset health analyses and risk modeling utilizing integrated asset data (transmission) • End distribution intrusive inspection 10-year cycle • Explore more LiDAR use cases in advancing QA/QC processes and informing other asset management strategies. • Develop test case using asset health and risk modeling in prioritizing detailed inspections (in compliance with regulatory requirement)

Vegetation Management Plan

Expected state of wildfire mitigation in 10 years

SDG&E's Vegetation Management Program is aimed at reducing the risk of vegetation related outages and ignitions using mitigation strategies that meet or exceed regulatory requirements, including the continued use of data and collaboration to refine and apply enhanced clearances on high-risk trees. In 2021 SDG&E completed the design, development, and implementation of its new electronic work management system, EPOCH, which enhanced performance and efficiency, including improved mapping functionality, asset (trees/poles) geolocating, and data management. SDG&E continues to refine its application of expanded trim clearances at the tree asset level applying site-specific considerations for risk reduction and tree health. Expanded use of data will improve operational awareness and management options, including engagement of external supercomputing analyses, and further refinement of the VRI.

In 2021 SDG&E continued to build its use case of integrating LiDAR to augment its vegetation inspection and auditing activities. SDG&E will continue to determine the practical scalability of LiDAR, data capture and processing, and integrated scheduling. SDG&E has begun the expansion of its workforce for WMP implementation with the addition of internal staffing to perform inspection activities and support PSPS operations.

SDG&E will continue to maintain its Vegetation Management Program following an annual master schedule of activities including pre-inspection, tree trimming, pole brushing, and auditing to ensure compliance, system reliability, and ignition avoidance, while incorporating new and innovative initiatives as they arise. By 2030, SDG&E expects to further increase the granularity of its vegetation database, enhance modeling capabilities to better predict vegetation growth patterns and probability of failures, optimize its vegetation inspection cycles based on risk, enhance its vegetation inspection capabilities to better identify and target high risk areas, evolve its understanding of tree strike potential, and build more robust processes, training, and technologies to monitor and validate work performed by its crews. Additionally, SDG&E will continue to consider the environmental and sustainability impacts of its vegetation management program, and implement initiatives such as planting or distributing up to 10,000 trees that are compatible with safe utility practices, in part to offset the customer and community impacts of tree trimming or removal.

A year-by-year timeline of SDG&E's roadmap for maturing this category is provided in Table 5.

Year-by-Year Timeline for Maturing Vegetation Management

Table 5: Year-by-Year Timeline for Maturing Vegetation Management

<table>
<tr><th>2020</th><th>2021</th><th>2022</th></tr>
<tr><td>• Continue enhanced clearances of targeted tree species
• Develop LiDAR pilot for Vegetation Management activities
• Engage supercomputing technologies for vegetation analyses
• Finalize requirements for new work management system—EPOCH
• Improve tree outage data dashboarding and analytics
• Develop new sustainability initiative for green waste
• Increase collaborative tree planting initiatives with customer and external stakeholders.</td><td>• Train and deploy EPOCH
• Develop and integrate business process flow for additional WMP activities
• Add internal staffing resources for WMP strategy including pre-inspection, fuels management, and business controls
• Develop and implement fuel management activities
• Continue use case LiDAR technology and modeling
• Deploy collaborative training curriculum for utility arborist</td><td>• Expand fuel management activities in Vegetation Management operations
• Enhance[9] VRI modeling
• Further engage supercomputing for predictive analysis and prioritization activities
• Develop work management system for unplanned vegetation management activities
• Develop multiple reporting improvement associated with customer refusal process.
• Develop training curriculum to address audit deficiencies
• Review feasibility of integration of LiDAR technology into pre-inspection and auditing activities.
• Source native tree stock from nursery vendors
• Engage third-party analysis of clearance and outage data
• Promote ongoing sustainability through additional tree planting and distribution efforts.</td></tr>
<tr><th colspan="3">2023-2025</th></tr>
<tr><td colspan="3">• Integrate technological improvement to work management system
• Enhance[10] VRI modeling
• Engagement with IOUs to strategize best management practices (BMPs) for Vegetation Management
• Continue to develop improved reporting capabilities (HANA)
• Establish new sustainability initiative for green waste
• Integrate advanced equipment technology for tree operations
• Implement biofuel sustainability options (Bio-digestor)
• Engage with legislative initiatives on wildfire related efforts
• Develop partnerships with academia to advance the data analysis of outages and line clearances
• Increase interdepartmental data sharing for modeling enhancements
• Utilize methodology to inform 2026 WMP</td></tr>
<tr><th colspan="3">2026-2030</th></tr>
</table>

[9] Refresh data with new observations, explore new methodologies, explore new datasets.
[10] Portfolio optimization approach refers to the ability to evaluate risk mitigation benefits and optimize spend across various programs such as hardening vs vegetation management, etc. via a multi-dimensional value framework

- Continue technological improvements to work management system
- Engage with IOUs to strategize BMPs for Vegetation Management
- Continue to update model automation as applicable, including the incorporation of VRI, CRI, wildfire risk and asset data.
- Improve models based on lessons learned, new information, and improved technology
- Develop Inspections informed by predictive modeling of multiple vegetation conditions
- Increase automation of risk modeling
- Continue to work with utilities to better inform future plans
- Utilize methodology to inform 2029 WMP
- Continue engagement with legislative initiatives on wildfire related efforts
- Increase granularity in vegetation database
- Enhance modeling capabilities to better predict vegetation growth patterns and probability of failure
- Optimize inspection cycles based on risk mitigation efficacy
- Increase interdepartmental data sharing for modeling enhancements
- Develop more robust processes, training, and technologies to monitor and validate work

Grid Operations and Protocols

Expected state of wildfire mitigation in 10 years

As SDG&E continues to mature its grid operations capabilities, it will focus on increasing automation in grid operations based on risk, enhancing protocols to decrease PSPS events over time, and deploying advanced technologies to increase efficiency in post-PSPS-event restoration efforts. In addition, SDG&E will continue to enhance training, tools, and policies to prevent and/or reduce the consequence of ignitions related to grid activities and will expand its public education campaigns to better inform Access and Functional Needs (AFN) and Limited English Proficiency (LEP) populations during emergencies. A year-by-year timeline of SDG&E's roadmap for maturing this category is provided in Table 6.

The current WMP cycle initiatives are aimed at accomplishing milestones to meet the 10-year goal of maximizing capabilities with respect to operations technology, risk-based decision making, accurate event forecasting, and policies around preventing and suppressing fire ignitions. These milestones include the following:

- Significantly enhance recloser protocols through the development of more efficient automated processes in lieu of the current less efficient and maintenance-intensive manual processes. These enhancements include improved situational awareness dashboards to easily verify how reclosers are set from a systemwide viewpoint, real-time settings change management, and dynamic recloser sensitivity adjustment and will enable the operations teams to react faster to changing climate conditions.
- Improve protocols to reduce the impacts of PSPS events through the enhancement of operations technology. The as-switched model of NMS will be ported to the PSPS dashboard for more refined customer pre-notifications. Automating the as-switched model, which accounts for abnormal circuit conditions, into the PSPS dashboard will expedite the customer notification process and free internal resources to prep for extreme weather events. The as-switched model

will also be rolled out to the mobile NMS app to improve situational awareness for field personnel.

- Enhance protocols for PSPS re-energization to reduce restoration timeframes for customers once electric infrastructure is cleared for patrol. To expedite the operations center's capabilities for managing the re-energization process, enterprise NMS will be enhanced to include pre-requisite checklists to verify patrols are complete, contracted fire resources are on-scene, and that the appropriate approvals have been given to allow for re-energization. Helicopter and ground patrols will also be reorganized to follow known routes to flexibly and safely patrol lines as quickly as possible. Availability of Unmanned Aerial Systems (UAS) to patrol lines that are both difficult to reach from the ground and difficult to see from helicopters will be increased, and a focus on long-term investments in this technology will increase safety and efficiency.
- Utilize the Aviation Firefighting program to enhance stationed on-call ignition prevention and suppression resources and services. A key contributor to this enhancement will be the incorporation of a Sikorsky S-70M Firehawk into full operation to augment air resource capabilities.
- Complete Industrial Fire Brigade emergency pre-plans for critical electric substations and continue research, development, and implement training for local fire departments on emergency response procedures for energy storage resources located within the HFTD.
- Enhance coordination of contract fire resources for support during extreme weather events. These enhancements will include formalizing the process of documenting qualified firefighter (QFF) requirements, strengthening coordination with local, state, and federal fire agencies, and building up a yearly cadence in updating available contract resources during contractual periods and extreme weather events.
- Continue coordinating and forming partnerships with local, state, and federal agencies to support the development of effective strategies to reduce the impacts of extreme weather events to communities. This includes building on operations technology enhancements to provide advanced notification to critical customers and government agencies ahead of PSPS de-energizations, expanding public education on Medical Baseline enrollments, engaging customers on PSPS communication and notification practices, and conducting after-action event reviews to understand how we can improve in the future.

Year-by-Year Timeline for Maturing Grid Operations and Protocols

Table 6: Year-by-Year Timeline for Maturing Grid Operations and Protocols

2020	2021	2022
• Continue use of various inputs for operational decision-making such as the FPI and the SAWTI • Integrate live view of recloser settings into dashboards based on HFTD location	• Continue to generate and improve decision factors that are considered when initiating PSPS events • Automate FPI flags into NMS to better automate the functionality of our reclosers • Report profile 3 and SGF settings directly to EDO via	• Establish a qualified roster for the upcoming fire season for staffing Infrastructure Protection Team in Q2 of each year • Launch predictive and fault signature AI for development of real-time

• Train AI to identify predictive equipment failure analytics for underground connectors.	SCADA to manage device settings year-round more accurately • Train AI to identify overhead fault signature analytics • Enhance risk analytics that inform PSPS operations via new decision-support dashboard	operations predictive equipment failure analytics • Develop as-switched system model to mobile NMS app (OMA)
2023-2025		
• Enhance as-switched system model for PSPS pre-notifications, to more accurately contact impacted customers compared to nominal circuit configuration • Allow profile 3 to automatically turn on depending on HFTD tier and FPI. • Leverage academic partnerships to analyze risk factors and incorporate into PSPS protocols • Deploy operations-based platform that flags predicted equipment failures based on real-time system monitoring • Continuously incorporate latest information regarding system hardening and system protections into PSPS protocols • Expand operations-based platform that flags predicted equipment failures based on real-time system monitoring to include a notification integration and incorporate fault location analysis • Launch new dispatch and post event patrol damage capture software tools • Complete integration of operational decision-making and communication of tools such as the FPI and the SAWTI into Distribution Management System • Continue to refine new PSPS decision-support tool		
2026-2030		
• Enhance prediction, communication, and mitigation of PSPS consequences • Use advanced technologies to increase efficiency in post-PSPS inspections • Enhance training, tools, and policies to prevent and suppress ignitions related to grid activities • Add new failure signature types operations-based platform that flags predicted equipment failures based on real-time system monitoring. • Develop and strengthen partnerships with academia to advance the data analysis of ignition and near ignition data • Automate distribution relay profile changes in field devices based on risk pre-defined levels • Enhance protocols for grid operations and better understanding of associated wildfire risk • Develop and train first responders on emergency response procedures to energy storage technologies as they advance over the next decade • Eliminate use of PSPS event as a primary wildfire mitigation measure for localized wind events		

Data Governance Methodology

Expected state of wildfire mitigation in 10 years

The 2022 WMP Update includes the creation of a comprehensive data strategy and data governance plan to achieve SDG&E’s 10-year goal to combine and cross reference data sources and align processes across business units with associated programs that support wildfire mitigation efforts. Enhancing data analytics and model capabilities to process and share large amounts of data will support asset-related operational decision-making and strategy for enhanced reliability and safe operation of assets.

Over the next 10 years, SDG&E plans to build out its data and analytics capabilities by establishing a data governance framework (DGF) to guide all its wildfire-related analytics. By 2030, SDG&E expects to enhance its analytics capabilities by continuing to integrate various data sources into its wildfire mitigation central repository (CR), enable real-time reporting, establish advanced sharing capabilities, enhance tracking of near-misses, and increase its role in utility-ignited wildfire research. A year-by-year timeline of SDG&E's roadmap for maturing this category is provided in Table 7.

Year-by-Year Timeline for Maturing Data Governance Methodology

Table 7: Year-by-Year Timeline for Maturing Data Governance Methodology

<table>
<tr><th>2020</th><th>2021</th><th>2022</th></tr>
<tr>
<td>• Establish and align on vision and goals for Wildfire Safety Division (WSD) data strategy
• Design a CR for Appendix A of the WMP (Tables 1-12)
• Implement role-based access security for central repository</td>
<td>• Design and build digital data platform to deliver data use cases
• Create of Data Taxonomy and Data Dictionary
• Form dedicated Accountability team to maintain program oversight
• Develop risk event-based tracking process (e.g., WRRM)
• Use risk event data to change grid operations in real time (e.g., FPI)
• Collaborate with San Diego Supercomputer Center (SDSC) to create fire-weather data sharing platform with research community</td>
<td>• Implement data platform architecture capable of collecting disparate information sources into a centralized repository
• Deploy advanced analytics solutions and leverage robust reporting tools to drive utility wildfire mitigation decisions
• Document CR of data sources, assumptions, and algorithms into a single document
• Delivery of data governance education program
• Implement OEIS GeoDatabase schema
• Enhance publicly available tools to visualize fire-weather data, collected via sensors
• Enhance ability to Ingest and share weather data using real-time API protocols with a wide variety of stakeholders
• Utilize methodology to inform 2023 WMP</td>
</tr>
<tr><th colspan="3">2023-2025</th></tr>
<tr><td colspan="3">• Use advanced analytics to inform utility allocations of resources for proactive wildfire mitigation measures
• Enhance risk event data to change grid operations in real time (e.g., FPI and live fuel moisture)
• Enhance fire-weather data real-time sharing capability
• Integrate real-time electric system monitoring to predict equipment failures and incorporate into CRI
• Explain and document algorithms and analysis with risk sensitivities disclosed</td></tr>
</table>

• Implement data monitoring and data remediation processes • Utilize full extent of the data strategy, efficiently and effectively collecting, ingesting, validating, and storing data in a platform to support complex analyses • Provide initial access to wildfire asset data in near real time with external stakeholders • Identify new sources of data for increased visibility into data trends and enable benchmarking of metrics • Share best practices and research with other utilities • Enhance stronger partnership with academic community to sponsor ongoing wildfire mitigation-related data collaborative research through internship programs for graduate-level students • Utilize methodology to inform 2026 WMP
2026-2030
• Enhance data analytic and model capabilities to process large amounts of data and conduct real-time reporting • Establish more comprehensive databases, analyses, and algorithms with advanced sharing capabilities • Enhance tracking of near-misses and increase accuracy in estimating potential ignitions • Increase participation in utility-ignited-wildfire research by investing in platforms such as SDSC, and Cal Poly WUI Fire Institute research • Continue to work with utilities to review their allocations of resources towards proactive wildfire mitigation measures, using advanced analytics to better inform most efficient and effective plans • Enhance GeoDatabase with additional data layers to mitigate wildfire risk • Utilize methodology to inform 2029 WMP

Resource Allocation Methodology

Expected state of wildfire mitigation in 10 years

The 2022 WMP Update includes initiatives critical to achieving SDG&E’s 10-year plan for building a robust resource allocation methodology. Currently, Asset Management is developing a resource allocation tool for evaluating investments and risk mitigation benefits. This tool incorporates a multi-dimensional value framework to quantitatively compare projects, thereby enhancing the ability to cross-prioritize across SDG&E’s portfolio and optimize investment decisions, including wildfire mitigation investments, while effectively spending ratepayer funds. In addition, the Wildfire Mitigation and Vegetation Management business unit built on the efforts of Asset Management to develop a wildfire-mitigation-specific tool to align with the maturity model laid out by the Energy Safety. In addition to the specific initiatives discussed in this section, other initiatives such as the centralization of data, improvement of asset analytics, development of situational awareness tools, and PSPS mitigation engineering all support the improvement of resource allocation methodologies as they provide critical data points and key considerations to incorporate in the decision-making framework.

Over the next 10 years, SDG&E will continue to enhance its approach to resource allocation for risk-based decision-making. As data becomes available and integrated across systems, SDG&E plans to increase the use of risk to inform decision-making and increase granularity of risk assessments to enhance the ability to aggregate and disaggregate assets for various modeling applications. This visibility will enable real-time scenario and sensitivity analyses for mature risk-based decision-making. By 2030, SDG&E expects to enable real-time updates of risk spend efficiencies (RSEs) as new projects and programs are implemented and to enhance its ability to conduct risk-based portfolio-wide optimizations across its various wildfire mitigation programs. Knowledge-sharing will continue to be a cornerstone of our approach as SDG&E validates and reviews advances with peer utilities and external parties.

A year-by-year timeline of SDG&E's roadmap for maturing this category is provided in Table 8. It is divided into two timelines, one that pertains to methodologies used for allocating resources within programs and one that pertains to methodologies used for allocating resources across programs. Methodologies used for allocating resources within programs include tools such as WiNGS which provides a more granular assessment of risk and mitigation alternatives to guide prioritization and scoping of strategic underground and covered conductor.

Year-by-Year Timeline for Maturing Resource Allocation Methodology

Table 8: Year-by-Year Timeline for Maturing Resource Allocation Methodology

2020	2021	2022
WiNGS-Planning	**WiNGS-Planning**	**WiNGS-Planning**
• Develop tool that incorporates wildfire and PSPS risk into evaluation of mitigation alternatives at the segment level • Continue to leverage existing risk tools such as WRRM to prioritize grid hardening in the near-term	• Refresh and Update WiNGS to improve risk assessment • Leverage WiNGS in future scoping and prioritization of undergrounding and covered conductor programs • Begin automation of WiNGS-Planning tool • Develop proof-of-concept for WiNGS visualization and scenario analysis • Initiate lifecycle cost analysis with preliminary approaches to incorporate into RSE calculations	• Complete WiNGS-Planning automation • Develop user interface/ visualization tool for WiNGS to enhance grid hardening planning process • Improve WiNGS with new data and models such as PoI models • Migrate WiNGS to the cloud for advanced analysis • Initiate third-party model review • Initiate egress analysis and explore ways to incorporate into WiNGS • Incorporate life cycle cost analysis into WiNGS
Investment Prioritization	**Investment Prioritization**	**Investment Prioritization**
• Develop data-driven, risk-informed investment prioritization value framework prototype for evaluating capital projects using transmission and substation projects as initial sample	• Draft associated business processes to implement the tool with transmission and substation business units • Begin developing the investment prioritization prototype as a software solution for the CPUC electric distribution value framework and risk calculations.	• Continue investment prioritization prototype development for application to electric distribution projects, including wildfire-driven projects • Review associated business processes drafts with relevant business units to finalize for T&S implementation. • Commence developing associated business processes to implement the tool with electric distribution business units.

2023-2025
WiNGS
• Leverage WiNGS to inform 2023-2025 WMP grid hardening scope • Evaluate the need and use cases for creating additional tools to inform other large programs in the WMP • Leverage new risk tools such as PoI models to inform various programs as applicable • Continue to improve modeling capabilities through integration of additional datasets and further development of predictive risk models where applicable • Incorporate egress risk into WiNGS • Incorporate climate vulnerability assessment into WiNGS • Enhance granularity of assessments to achieve span-level granularity as applicable • Continue third-party validation and knowledge-sharing
Investment Prioritization
• Expand the investment prioritization prototype development to other lines of business (i.e., Gas, IT, Fleet, Facilities) to adopt a consistent, common value framework • Develop proof of concept for portfolio optimization approach across lines of business • Develop associated business processes to implement the tool across lines of business
2026-2030
WiNGS
• Improve existing models for resource allocation within programs • Develop new tools to support resource allocation within programs • Enhance granularity of assessments to achieve asset-level granularity as applicable • Implement more dynamic and real-time model update capabilities
Investment Prioritization
• Implement investment prioritization across all lines of business

Emergency Planning and Preparedness

Expected state of wildfire mitigation in 10 years

Emergency Planning and Preparedness involves an extensive amount of coordination, both internally and externally. SDG&E is focused on public protecting lives, property, and assets, while encouraging proper use of resources. The Company plans on focusing and engaging the best industry practices to successfully fulfill this objective. The Wildfire Emergency Response Plan is designed to mitigate the occurrence of wildfires, and one should occur, to protect lives and reduce the amount of property/asset loss and increase response times in restoring power to customers.

SDG&E continues to build a coordinated National Incident Management System (NIMS) ICS framework, accessing resources and knowledge across the region in our planning and response efforts. This framework focuses on engagement with stockholders, as well as building a knowledge-structure foundation with our customers, utility companies, CAL FIRE, and other local, state, and federal resources. Through these efforts, experiences shared by both community and regulatory partners aid in the implementation of improvements to the Wildfire Emergency Response Plan.

SDG&E seeks to increase stakeholder engagement and plans to use simulations to stress-test the Wildfire Emergency Response Plan, while increasing granularity and customization from lessons-learned. Enhancing customer communication will focus on reaching vulnerable populations before and during emergencies to promote awareness and preparedness for emergencies and to disseminate critical safety information. SDG&E leverages its existing partnerships with local and regional governments to promote wildfire preparation, and continues to build those relationships. If local communities are well educated and knowledgeable of the hazards and risks of wildfires, public confidence will increase.

The 2022 WMP Update builds upon SDG&E's existing collaboration with key internal and external stakeholders, as well as lessons learned from past incidents, trainings, and exercises. Collaboration with external stakeholders is essential, as County and other local government agencies and CBOs are primarily responsible for emergency planning across the region. While SDG&E has strong existing relationships with many of these agencies, continuing to improve education, outreach, and coordination today can result in expanded information and resource sharing in the future.

A year-by-year timeline of SDG&E's roadmap for maturing this category is provided in Table 9, which includes engaging our stakeholders and employees towards mutual capabilities.

Year-by-Year Timeline for Maturing Emergency Planning and Preparedness

Table 9: Year-by-Year Timeline for Maturing Emergency Planning and Preparedness

2020	2021	2022
• Implement new apprentice lineman training program and virtual reality patrol and inspection program • Develop and implement Virtual Emergency Operations Center (EOC) response plans • Mature EOC Utility Incident Command System (UICS) with second and third simultaneous event management • Provide bi-annual First Responder UICS/PSPS emergency response training • Complete annual After-Action Review (AAR) metrics report	• In-Service two new state of the art Tactical Command Vehicles • Review and train bi-annual evacuation plan in partnership with CALFIRE and the Sheriff's Department • Review/revise AAR Review program with Executive report on position and progress with internal and external stakeholders • Provide UICS/PSPS training for Fire Department Chief Officer and Dispatch Services	• Complete planning of new EOC and place in-service • Complete bi-annual internal/ external stakeholder plan review and audit • Build depth in Utility Incident Commander position • Implement night fly firefighting program with CAL FIRE approval • Further refine the K2 system to identify jurisdictions/ adjacencies to support public safety partner notifications • Complete Event Emergency Plan and Enterprise Resource Planning integration process with Fire and Law Enforcement (LE) Chief Officer and Dispatch Services UICS/PSPS workshops and meetings • Complete AAR program alignment/integration with Safety Management System (SMS)

		• Develop AAR content management system • Conduct ICS functional field exercise with Eastern Zone fire agencies • Complete bi-annual evacuation plan review and training in partnership with CAL FIRE and Sheriff’s Department • Initiate EOC Credential Program • Implement a 24/7 Watch Desk • Purchase 1 Incident Support Vehicle for field support • Conduct Incident Support Team Position training • Integrate the science of Human Factors Engineering company-wide
2023-2025		
• Complete Event Emergency Plan and Company ERP integration process Fire and LE Chief Officer and Dispatch Services UICS/PSPS workshops/meetings • Complete bi-annual AAR review/revision • Conduct ICS functional field exercise Eastern Zone fire agencies • Conduct IST Position training • Develop a multi-year training and exercise plan • Automate EOC responder data and response tracking • Provide field leadership in Wildland County fire drills • Support evacuation planning committee representation and training delivery • Expand First Responder Outreach Program (FROP) partnership with local law enforcement agencies to include training videos • Conduct Emergency Plan Stakeholder workshop • Conduct bi-annual First Responder UICS/PSPS emergency response training with field exercise • Conduct mutual Assistance exercise • Conduct functional field exercise for SDG&E and external stakeholders • Complete review/audit bi-annual internal/external stakeholder Plan • Complete annual AAR metrics report • Expand exercises into multi-Deputy Operations Chief functional, field functional, or full-scale • Conduct emergency risk mapping through AAR • Support evacuation planning committee representation and training delivery • Conduct ICS functional field exercise for Central Zone fire agencies • Review and train annual evacuation plan in partnership with CAL FIRE and Sheriff's Department • Standardize Emergency Management training curricula via Learning Management System		
2026-2030		
• Complete bi-annual internal/external stakeholder Plan review/audit		

- Complete bi-annual First Responder UICS/PSPS emergency response training with field exercise
- Complete annual AAR metrics report
- Initiate development of training sandboxes for dashboards and online systems
- Develop emergency risk mapping through AAR program
- Expand ICS field mentoring
- Provide field leadership in Wildland County fire drills
- Support evacuation planning committee representation and training delivery
- Conduct Fire & LE Department Chief Officer and Dispatch Services UICS/PSPS workshops/mtgs
- Conduct ICS functional field exercise for Metro Zone fire agencies
- Complete bi-annual AAR review/revision
- Review and train bi-annual evacuation plan in partnership with CAL FIRE and Sheriff's Department

Stakeholder Cooperation & Community Engagement

Expected state of wildfire mitigation in 10 years

Stakeholder cooperation and community engagement are at the core of SDG&E's WMP. For more than a decade, SDG&E has continuously invested in building partnerships with community organizations in order to strengthen overall community preparedness, response, and resiliency. The goal is to create an environment where internal and external stakeholders can network, share necessary knowledge and expertise, engage each other, especially when wildfires strike the territory, region, or state. United with our community members and leaders, other service providers, and first responders, SDG&E aims to create and implement best in class wildfire resiliency training.

Communication with stakeholders and customers is an important element in helping them prepare for a PSPS event. Building upon existing relationships with regional stakeholders and the community, SDG&E was able to quickly adapt in the face of a global pandemic and continue education and outreach with stakeholders and customers, transitioning from in-person events to virtual and drive-thru events. Education and outreach will remain pivotal in the next decade as improvements and enhancements are made to infrastructure, communications and technology.

SDG&E has actively solicited feedback from customers, local public agencies, and other stakeholders through town hall community meetings, open houses, community fairs and one-on-one meetings, surveys, focus groups, and social media engagement in order to refine and improve its wildfire and PSPS operational protocols, public education and outreach, communications, and overall coordination. Those efforts will continue over the next 10 years. SDG&E has existing collaborative partnerships with local governments, regional partners, and CBOs, and will continue to develop these relationships over the next decade to further strengthen resilience and preparedness in the region.

SDG&E's commitment to the safety of the communities it serves is unwavering. Over the next 10 years, SDG&E will continue to strive for ongoing improvement and will continue to work with customers, community leaders, and community partners to help identify and implement the right solutions to adequately address wildfire risk and minimize PSPS events. SDG&E engages in regional and statewide working groups and advisory councils to identify and understand the needs of customers during PSPS events. This information will assist AFN support models and enable organizations such as 211 to serve as resource hubs for vulnerable customers who may need support or services like transportation, food security, or health and welfare checks during PSPS events. These organizations are well known and have relationships with hundreds of CBOs that can meet the needs of vulnerable customers. SDG&E intends to build upon its established agreements with these organizations over the next 10 years to maximize outreach to vulnerable populations.

As SDG&E looks to its 10-year vision on stakeholder cooperation and community engagement, its primary goal will be to reach 95-100 percent of the HFTD territory population with a focus on AFN and LEP customers. It is essential to utilize a breadth and depth of communications and outreach, and engage a diverse set of measures to reach audiences in a meaningful way. Equally important is purposefully soliciting continuous feedback to refine, adapt, and enhance the measures being utilized, especially with more vulnerable AFN and LEP customers. SDG&E continues to actively engage on AFN policy issues through a variety of forums, providing leadership at statewide and regional levels. This area of focus will continue to be developed and matured over the course of the next 10 years, including through SDG&E's Wildfire Safety Community Advisory Council, which includes a group of diverse local leaders from public safety, tribal government, business, nonprofit, telecommunications, public health and academia, and the PSPS Working Group, which is a new sub-committee of the existing County AFN Working Group. The PSPS Working Group will share lessons-learned to help refine wildfire and PSPS protocols. Participants include, but are not limited to, critical customers such as water agencies and telecommunications providers, tribal nations, local governments, public safety partners, municipal utilities and community choice providers, and others.

Additionally, efforts will focus on formalizing processes to learn from peers in and outside of California and continue to expand community relationships and enhance partnerships. This will broaden engagement and planning efforts with emergency and non-emergency planning agencies as well as manage and direct comprehensive communication campaigns to communities. SDG&E will also continue to focus on the strategic enhancement of utilizing CBOs, either located in or serving customers in the HFTD, to provide PSPS notification support and amplify messaging to potentially affected customers. It also remains critical to continue ongoing efforts to disseminate emergency preparedness messaging via social media messaging, presentations, community events, and meetings.

A year-by-year timeline of SDG&E's roadmap for maturing this category is provided in Table 10.

Year-by-Year Timeline for Maturing Stakeholder Cooperation & Community Engagement

Table 10: Year-by-Year Timeline for Maturing Stakeholder Cooperation & Community Engagement

2020	2021	2022
• Develop initial Customer Support Models • Establish year-round public education campaign • Continue customer engagement with "Right Tree, Right Place" initiative • Release PSPS Mobile App	• Augment Customer Support Models with broader reach • Solicit large-scale customer/ stakeholder feedback (campaign/notifications) for public education campaign • Expand outreach to Tribal communities	• Refine and Augment public education campaign and notifications; expand reach based on customer /stakeholder feedback. • Expand public education to AFN, LEP, and Tribal communities.

		• Enhance PSPS Mobile App notifications to include 21 prevalent languages, and American Sign Language • Develop Public Safety Partner Mobile App
2023-2025		
• Refine and augment campaign and notifications for Annual Public education; expand reach based on customer/stakeholder feedback. Expand public education to AFN, LEP populations and Tribal communities. • Enhance multiple mobile Apps and communication platforms including school communication platforms		
2026-2030		
• Refine and augment campaign and notifications for Annual Public education campaign and expand reach based on customer/stakeholder feedback • Enhance multiple mobile Apps and communication platforms • Expand exercise program via exercises of increasing complexity to include external stakeholders		

Attachment B: WMP Tables 1-12

Office of Energy Infrastructure Safety Attachment 3
Wildfire Mitigation Plan Quarterly Data Report - non-spatial data template

Instructions for use

1. Fill out the tan cells (color represented here) starting with the cell below (D17: Utility). The Utility name will populate the Table tabs to follow. Date modified will vary by table.
2. Cells will only accept valid entries. For most cells, this is positive numbers
3. For each Table tab, after a modification is made, denote the date of the change in cell C4 for each Table tab.
4. Some columns have an additional header in row 5 to serve as clarification for several columns. With the exception of projected data, row 5 will be highlighted in blue (color represented here)
5. Some required metrics are future projections. For these, row 5, above the projections will be highlighted light green (color represented here)
   In future submissions, report updated projected numbers if / when projections have changed, and report actuals once the quarter / year has passed.
6. For data required annually rather than quarterly (see Tables 7.2 - 10, 12), report for entire year even if part of the year is projected. Once year has passed, update cell with actuals
7. Some tables will have additional instructions provided in a **Notes** box located in cells D2 - D4
   Notes will explain terms, signal where projections are required, and provide other useful information.
8. For the initial quarterly submission, utilities are required to submit data on annual metrics for 2015 - 2020, which should represent the most updated data from the 2020 WMP for years 2015-2019

* Do not add or manipulate the template for any of the tabs

Update the below table to establish which year, quarter of the WMP cycle this submission this represents.

Utility	SDG&E
First year of 3-year WMP cycle	2020
Submission year	2022
Submission quarter	Q4
Date Modified	#REF!

Utility	SDG&E
Table No.	1
Date Modified	2022 02 09

Notes:
Transmission lines refer to all lines at or above 65kV, and distribution lines refer to all lines below 65kV.

Note: These columns are placeholders for future QR submissions.

Table 1: Recent performance on progress metrics

Metric type	#	Progress metric name	2015	2016	2017	2018	2019	Q1 2020	Q2 2020	Q3 2020	Q4 2020	Q1 2021	Q2 2021	Q3 2021	Q4 2021	Q1 2022	Q2 2022	Q3 2022	Q4 2022	Unit(s)	Comments
1. Grid condition findings from inspection - Distribution lines in HFTD	1.a.	Number of circuit miles inspected from patrol inspections in HFTD - Distribution lines	3448.9	3448.9	3448.9	3448.9	3448.9	1297.5	1247.9	800.8	102.5	1245.0	1272.1	920.1	34.2					# circuit miles	
	1.b.	Number of circuit miles inspected from detailed inspections in HFTD - Distribution lines	1524.6	1425.6	1337.4	1458.4	942.1	852.6	289.1	90.2	19.8	873.7	294.0	138.2	61.2					# circuit miles	1. In earlier submissions, the HFTD Tier 3 inspections was placed in the "other" category; these inspections are now grouped in the "Detailed" inspections. 2. The gaps in the "other" category with regards to HFTD miles is primarily driven by
	1.c.	Number of circuit miles inspected from other inspections (list types of "other" inspections in comments) in HFTD - Distribution lines	39.8	78.5	256.9	712.4	733.9	832.7	1056.8	707.0	247.9	228.4	186.9	508.9	997.8					# circuit miles	Sum of all other distribution inspections in HFTD- intrusive poles, infrared and drone inspections.
	1.d.	Level 1 findings in HFTD for patrol inspections - Distribution lines	15.0	3.0	4.0	8.0	8.0	1.0	4.0	1.0	0.0	1.0	0.0	0.0	0.0					# findings	
	1.e.	Level 1 findings in HFTD for detailed inspections - Distribution lines	235.0	192.0	11.0	67.0	8.0	9.0	9.0	2.0	0.0	3.0	3.0	1.0	0.0					# findings	
	1.f.	Level 1 findings in HFTD for other inspections (list types of "other" inspections in comments) - Distribution lines	0.0	3.0	25.0	5.0	36.0	63.0	32.0	11.0	1.0	0.0	8.0	19.0	72.0					# findings	Sum of all level 1 findings for intrusive poles, infrared and drone inspections in HFTD.
	1.g.	Level 2 findings in HFTD for patrol inspections - Distribution lines	175.0	212.0	234.0	171.0	240.0	71.0	66.0	51.0	16.0	22.0	152.0	199.0	85.0					# findings	
	1.h.	Level 2 findings in HFTD for detailed inspections - Distribution lines	1066.0	952.0	638.0	737.0	666.0	919.0	303.0	81.0	6.0	284.0	730.0	394.0	392.0					# findings	
	1.i.	Level 2 findings in HFTD for other inspections (list types of "other" inspections in comments) - Distribution lines	35.0	52.0	327.0	261.0	1350.0	4356.0	2660.0	906.0	228.0	44.0	41.0	2087.0	6128.0					# findings	Sum of all level 2 findings for intrusive poles, infrared and drone inspections in HFTD.
	1.j.	Level 3 findings in HFTD for patrol inspections - Distribution lines	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A					# findings	All inspections are followed up based on level 2 requirement, level 3 does not apply to distribution inspection
	1.k.	Level 3 findings in HFTD for detailed inspections - Distribution lines	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A					# findings	
	1.l.	Level 3 findings in HFTD for other inspections (list types of "other" inspections in comments) - Distribution lines	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A					# findings	
1. Grid condition findings from inspection - Distribution lines total	1.a.ii.	Number of total circuit miles inspected from patrol inspections - Distribution lines	6445.4	6445.4	6445.4	6445.4	6445.4	2242.0	2188.4	1564.4	450.6	2186.5	2266.3	1809.4	208.5					# circuit miles	
	1.b.ii.	Number of total circuit miles inspected from detailed inspections - Distribution lines	2129.1	1877.5	1898.3	2159.7	1637.3	992.9	492.8	261.8	105.7	993.1	423.5	288.5	110.3					# circuit miles	
	1.c.ii.	Number of total circuit miles inspected from other inspections (list types of "other" inspections in comments) - Distribution lines	440.8	550.2	578.2	820.5	849.3	934.4	1133.9	738.5	282.8	242.4	260.4	581.9	1107.5					# circuit miles	Sum of infrared and drone inspections in HFTD and intrusive pole inspection in all territory.
	1.d.ii.	Level 1 findings for patrol inspections - Distribution lines	49.0	19.0	26.0	24.0	21.0	9.0	16.0	2.0	3.0	5.0	2.0	3.0	1.0					# findings	
	1.e.ii.	Level 1 findings for detailed inspections - Distribution lines	261.0	218.0	57.0	101.0	28.0	22.0	18.0	9.0	2.0	11.0	8.0	5.0	1.0					# findings	
	1.f.ii.	Level 1 findings for other inspections (list types of "other" inspections in comments) - Distribution lines	59.0	39.0	52.0	6.0	37.0	67.0	33.0	11.0	2.0	0.0	9.0	19.0	72.0					# findings	Sum of infrared and drone inspections in HFTD and intrusive pole inspection in all territory.
	1.g.ii.	Level 2 findings for patrol inspections - Distribution lines	704.0	1130.0	1005.0	969.0	933.0	387.0	345.0	213.0	129.0	102.0	365.0	526.0	336.0					# findings	
	1.h.ii.	Level 2 findings for detailed inspections - Distribution lines	2553.0	2314.0	1966.0	1746.0	1760.0	1271.0	670.0	349.0	77.0	528.0	1320.0	1286.0	1114.0					# findings	
	1.i.ii.	Level 2 findings for other inspections (list types of "other" inspections in comments) - Distribution lines	1747.0	1027.0	1127.0	380.0	1433.0	4394.0	2694.0	934.0	267.0	45.0	84.0	2129.0	6183.0					# findings	Sum of infrared and drone inspections in HFTD and intrusive pole inspection in all territory.
	1.j.ii.	Level 3 findings for patrol inspections - Distribution lines	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A					# findings	All inspections are followed up based on level 2 requirement, level 3 does not apply to distribution inspection
	1.k.ii.	Level 3 findings for detailed inspections - Distribution lines	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A					# findings	
	1.l.ii.	Level 3 findings for other inspections (list types of "other" inspections in comments) - Distribution lines	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A					# findings	
1. Grid condition findings from inspection - Transmission lines in HFTD	1.a.iii.	Number of circuit miles inspected from patrol inspections in HFTD - Transmission lines	940.9	971.4	972.0	987.0	1000.0	716.6	183.6	101.0	0.0	510.4	370.3	101.0	0.0					# circuit miles	SDG&E has implemeted centrolized data repository and automated solution for computing transmission asset-inspection metrics (patrol and details). Historical values are updated based on the automted output in Feb 2022. Due to the new requirement of HFTD breakdown, SDG&E continues to validate the output and improve the data process accordingly.
	1.b.iii.	Number of circuit miles inspected from detailed inspections in HFTD - Transmission lines	349.9	278.6	343.5	328.9	298.9	46.8	112.8	79.5	133.1	90.5	69.5	133.9	30.5					# circuit miles	
	1.c.iii.	Number of circuit miles inspected from other inspections (list types of "other" inspections in comments) in HFTD - Transmission lines	981.0	956.0	955.0	984.0	985.7	16.7	0.0	478.3	649.1	26.2	4.0	898.4	136.7					# circuit miles	Sum of all other transmission inspections-infrared and drone inspections in HFTD. SDG&E drone inspection program only inspects the structures, not the conductors; in order to calcualate the circuit miles, GIS span length assciated with the
	1.d.iii.	Level 1 findings in HFTD for patrol inspections - Transmission lines	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0					# findings	
	1.e.iii.	Level 1 findings in HFTD for detailed inspections - Transmission lines	0.0	0.0	0.0	2.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0					# findings	
	1.f.iii.	Level 1 findings in HFTD for other inspections (list types of "other" inspections in comments) - Transmission lines	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1.0	0.0	0.0	0.0	0.0					# findings	Sum of all other transmission inspections-infrared and drone inspections in HFTD.
	1.g.iii.	Level 2 findings in HFTD for patrol inspections - Transmission lines	19.0	18.0	7.0	10.0	4.0	0.0	3.0	0.0	0.0	1.0	1.0	0.0	0.0					# findings	
	1.h.iii.	Level 2 findings in HFTD for detailed inspections - Transmission lines	323.0	100.0	161.0	385.0	365.0	170.0	126.0	49.0	44.0	80.0	62.0	53.0	40.0					# findings	
	1.i.iii.	Level 2 findings in HFTD for other inspections (list types of "other" inspections in comments) - Transmission lines	5.0	1.0	35.0	0.0	1.0	0.0	0.0	0.0	16.0	2.0	3.0	27.0	18.0					# findings	Sum of all other transmission inspections-infrared and drone inspections in HFTD.
	1.j.iii.	Level 3 findings in HFTD for patrol inspections - Transmission lines	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0					# findings	
	1.k.iii.	Level 3 findings in HFTD for detailed inspections - Transmission lines	26.0	36.0	41.0	31.0	27.0	0.0	8.0	0.0	3.0	1.0	8.0	2.0	0.0					# findings	
	1.l.iii.	Level 3 findings in HFTD for other inspections (list types of "other" inspections in comments) - Distribution lines	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0					# findings	
1. Grid condition findings from inspection - Transmission lines	1.a.iv.	Number of total circuit miles inspected from patrol inspections - Transmission lines	1810.4	1868.4	1876.8	1898.0	1914.0	1228.6	564.3	133.9	0.0	979.0	794.4	133.9	0.0					# circuit miles	SDG&E has implemeted centrolized data repository and automated solution for computing transmission asset-inspection metrics (patrol and details). Historical values are updated based on the automted output in Feb 2022. Due to the new
	1.b.iv.	Number of total circuit miles inspected from detailed inspections - Transmission lines	658.5	593.3	654.4	605.9	586.4	150.3	230.0	156.0	177.6	213.0	140.2	200.2	66.5					# circuit miles	
	1.c.iv.	Number of total circuit miles inspected from other inspections (list types of "other" inspections in comments) - Transmission lines	1860.5	1828.4	1829.2	1861.5	1874.6	16.7	30.0	1032.5	956.2	26.2	35.0	1645.3	250.1					# circuit miles	Sum of all other transmission inspections-infrared (all territory) and drone inspections in HFTD.
	1.d.iv.	Level 1 findings for patrol inspections - Transmission lines	1.0	0.0	2.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0					# findings	
	1.e.iv.	Level 1 findings for detailed inspections - Transmission lines	3.0	1.0	1.0	8.0	2.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0					# findings	
	1.f.iv.	Level 1 findings for other inspections (list types of "other" inspections in comments) - Transmission lines	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1.0	0.0	0.0	0.0	0.0					# findings	
	1.g.iv.	Level 2 findings for patrol inspections - Transmission lines	70.0	42.0	11.0	11.0	8.0	1.0	4.0	0.0	0.0	1.0	2.0	0.0	0.0					# findings	
	1.h.iv.	Level 2 findings for detailed inspections - Transmission lines	1060.0	353.0	470.0	934.0	799.0	398.0	254.0	117.0	89.0	168.0	253.0	180.0	180.0					# findings	
	1.i.iv.	Level 2 findings for other inspections (list types of "other" inspections in comments) - Transmission lines	9.0	4.0	37.0	1.0	2.0	0.0	0.0	1.0	16.0	2.0	4.0	30.0	18.0					# findings	
	1.j.iv.	Level 3 findings for patrol inspections - Transmission lines	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0					# findings	
	1.k.iv.	Level 3 findings for detailed inspections - Transmission lines	60.0	69.0	66.0	66.0	55.0	10.0	9.0	1.0	19.0	4.0	30.0	3.0	4.0					# findings	
	1.l.iv.	Level 3 findings for other inspections (list types of "other" inspections in comments) - Transmission lines	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0					# findings	
2. Vegetation clearance findings from inspection - total	2.a.i	Number of spans insepcted where at least some vegetation was found in non-compliant condition - total	2559.0	2815.0	3085.0	3404.0	3044.0	548.0	605.0	995.0	1317.0	558.0	699.0	852.0	940.0					# of spans inspected with	
	2.a.ii	Number of spans insepcted for vegetation compliance - total	173677.0	173421.0	173151.0	172832.0	173192.0	43511.0	43454.0	43064.0	42742.0	43501.0	43360.0	43207.0	43119.0					# of spans	
2. Vegetation clearance findings from inspection - in HFTD	2.b.i	Number of spans insepcted where at least some vegetation was found in non-compliant condition in HFTD	999.0	1092.0	1407.0	1624.0	1250.0	297.0	359.0	428.0	383.0	312.0	446.0	280.0	219.0					# of spans inspected with	
	2.b.ii	Number of spans insepcted for vegetation compliance in HFTD	76949.0	76856.0	76541.0	76324.0	76698.0	19190.0	19128.0	19059.0	19104.0	19175.0	19041.0	19207.0	19268.0					# of spans	
3. Community outreach metrics	3.a.	# Customers in an evacuation zone for utility-ignited wildfire	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA					# customers (if customer was	
	3.b.	# Customers notified of evacuation orders	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA					# customers	
	3.c.	% of customers notified of evacuation in evacuation zone of a utility-ignited wildfire	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA					Percentage of	
4. Grid condition findings from other inspections - Distribution	4.a.	Number of circuit miles inspected from other inspections (Intrusive Pole) in HFTD - Distribution lines	39.8	78.5	256.9	712.4	619.6	163.3	151.6	164.8	162.2	175.0	72.0	31.0	15.0					# circuit miles	
	4.b.	Number of circuit miles inspected from other inspections (Infrared) in HFTD - Distribution lines	0.0	0.0	0.0	0.0	0.0	0.0	267.4	370.6	49.2	53.4	114.9	166.2	428.8					# circuit miles	
	4.c.	Number of circuit miles inspected from other inspections (Drone) in HFTD - Distribution lines	0.0	0.0	0.0	0.0	114.3	669.4	637.8	171.6	36.6	0.0	0.0	311.8	554.0					# circuit miles	
	4.d.	Level 1 findings in HFTD for other inspections (Intrusive Pole) - Distribution lines	0.0	3.0	25.0	5.0	13.0	1.0	0.0	0.0	0.0	0.0	2.0	0.0	0.0					# findings	
	4.e.	Level 1 findings in HFTD for other inspections (Infrared) - Distribution lines	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0					# findings	
	4.f.	Level 1 findings in HFTD for other inspections (Drone) - Distribution lines	0.0	0.0	0.0	0.0	23.0	62.0	32.0	11.0	1.0	0.0	6.0	19.0	72.0					# findings	
	4.g.	Level 2 findings in HFTD for other inspections (Intrusive Pole) - Distribution line	35.0	52.0	327.0	261.0	228.0	18.0	26.0	26.0	54.0	44.0	32.0	6.0	13.0					# findings	
	4.h.	Level 2 findings in HFTD for other inspections (Infrared) - Distribution lines	0.0	0.0	0.0	0.0	0.0	0.0	1.0	0.0	0.0	0.0	9.0	7.0	0.0					# findings	
	4.i	Level 2 findings in HFTD for other inspections (Drone) - Distribution lines	0.0	0.0	0.0	0.0	1122.0	4338.0	2633.0	880.0	174.0	0.0	0.0	2074.0	6115.0					# findings	
	4.j.	Level 3 findings in HFTD for other inspections (Intrusive Pole) - Distribution line	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A					# findings	
	4.k.	Level 3 findings in HFTD for other inspections (Infrared) - Distribution lines	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A					# findings	
	4.l.	Level 3 findings in HFTD for other inspections (Drone) - Distribution lines	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A					# findings	
4. Grid condition findings from other inspections -	4.m	Number of circuit miles inspected from other inspections (Infrared) in HFTD - Transmission lines	981.0	956.0	955.0	984.0	985.7	0.0	0.0	478.3	488.0	0.0	0.0	882.7	85.7					# circuit miles	
	4.n	Number of circuit miles inspected from other inspections (Drone) in HFTD - Transmission lines	N/A	N/A	N/A	N/A	N/A	16.7	0.0	0.0	161.2	26.2	4.0	15.7	51.0					# circuit miles	
	4.o	Level 1 findings in HFTD for other inspections (Infrared) - Transmission lines	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0					# findings	
	4.p	Level 1 findings in HFTD for other inspections (Drone) - Transmission lines	N/A	N/A	N/A	N/A	N/A	0.0	0.0	0.0	1.0	0.0	0.0	0.0	0.0					# findings	
	4.q.	Level 2 findings in HFTD for other inspections (Infrared) - Transmission lines	5.0	1.0	35.0	0.0	1.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0					# findings	
	4.r	Level 2 findings in HFTD for other inspections (Drone) - Transmission lines	N/A	N/A	N/A	N/A	N/A	0.0	0.0	0.0	16.0	2.0	3.0	27.0	18.0					# findings	
	4.s.	Level 3 findings in HFTD for other inspections (Infrared) - Transmission lines	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0					# findings	
	4.t.	Level 3 findings in HFTD for other inspections (Drone) - Transmission lines	N/A	N/A	N/A	N/A	N/A	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0					# findings	

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Table 2: Recent performance on outcome metrics

Metric type	#	Outcome metric name	Wind Warning Stat	HFTD Tier	2015	2016	2017	2018	2019	Q1 2020	Q2 2020	Q3 2020	Q4 2020	Q1 2021	Q2 2021	Q3 2021	Q4 2021	Q1 2022	Q2 2022	Q3 2022	Q4 2022	Unit(s)	Comments
1. Risk Events	1.a.	Number of all events with probability of ignition, including	All	1																		Number per year	
		Number of all events with probability of ignition, including	RFW	1																			
		Number of all events with probability of ignition, including	HWW	1																			
		Number of all events with probability of ignition, including	HWW & RFW	1																			
		Number of all events with probability of ignition, including	HWW & not RFW	1																			
		Number of all events with probability of ignition, including	All	2	231	261	258	209	257	61	64	68	53	81	54	80	67						
		Number of all events with probability of ignition, including	RFW	2	1	3	17	17	4	0	0	18	9	0	0	0	4						
		Number of all events with probability of ignition, including	HWW	2	17	10	42	11	4	2	0	0	5	13	0	0	2						
		Number of all events with probability of ignition, including	HWW & RFW	2	0	0	8	9	3	0	0	0	5	0	0	0	2						
		Number of all events with probability of ignition, including	HWW & not RFW	2	17	10	34	2	1	2	0	0	0	13	0	0	0						
		Number of all events with probability of ignition, including	All	3	188	209	203	203	257	32	51	68	48	64	45	65	52						
		Number of all events with probability of ignition, including	RFW	3	2	2	10	9	10	0	0	12	8	0	0	0	4						
		Number of all events with probability of ignition, including	HWW	3	7	0	37	7	5	5	0	0	3	11	0	0	1						
		Number of all events with probability of ignition, including	HWW & RFW	3	0	0	6	7	5	0	0	0	3	0	0	0	1						
		Number of all events with probability of ignition, including	HWW & not RFW	3	7	0	31	0	0	5	0	0	0	11	0	0	0						
		Number of all events with probability of ignition, including	All	Non- HFTD	595	775	664	616	602	136	142	202	152	184	182	195	197						
		Number of all events with probability of ignition, including	RFW	Non- HFTD	2	10	17	15	5	0	0	27	7	0	0	0	4						
		Number of all events with probability of ignition, including	HWW	Non- HFTD	9	109	128	8	4	3	0	0	6	36	0	0	3						
		Number of all events with probability of ignition, including	HWW & RFW	Non- HFTD	0	1	7	6	3	0	0	0	6	0	0	0	3						
		Number of all events with probability of ignition, including	HWW & not RFW	Non- HFTD	9	108	121	2	1	3	0	0	0	36	0	0	0						
1. Risk Events	1.b.	Number of wires down	All	1																		Number of wires down per year	
		Number of wires down	RFW	1																			
		Number of wires down	HWW	1																			
		Number of wires down	HWW & RFW	1																			
		Number of wires down	HWW & not RFW	1																			
		Number of wires down	All	2	14	30	30	21	20	10	5	5	5	10	4	4	10						
		Number of wires down	RFW	2	0	1	0	1	0	0	0	0	2	0	0	0	0						
		Number of wires down	HWW	2	1	1	5	0	0	0	0	0	1	1	0	0	0						
		Number of wires down	HWW & RFW	2	0	0	0	0	0	0	0	0	1	0	0	0	0						
		Number of wires down	HWW & not RFW	2	0	0	0	0	0	0	0	0	0	0	0	0	0						
		Number of wires down	All	3	12	19	19	10	27	3	2	6	3	4	5	1	6						
		Number of wires down	RFW	3	0	0	0	0	1	0	0	2	0	0	0	0	0						
		Number of wires down	HWW	3	1	0	8	0	0	1	0	0	0	0	0	0	0						
		Number of wires down	HWW & RFW	3	0	0	0	0	0	0	0	0	0	0	0	0	0						
		Number of wires down	HWW & not RFW	3	0	0	0	0	0	0	0	0	0	0	0	0	0						
		Number of wires down	All	Non- HFTD	35	94	88	65	68	15	12	10	18	12	14	9	19						
		Number of wires down	RFW	Non- HFTD	1	1	2	1	1	0	0	1	0	0	0	0	0						
		Number of wires down	HWW	Non- HFTD	0	21	30	1	1	0	0	0	0	2	0	0	0						
		Number of wires down	HWW & RFW	Non- HFTD	0	0	1	0	1	0	0	0	0	0	0	0	0						
		Number of wires down	HWW & not RFW	Non- HFTD	0	0	0	0	0	0	0	0	0	0	0	0	0						
1. Risk Events	1.c.	Number of outage events not caused by contact with vegetation	All	1																		Number of outage events per year	
		Number of outage events not caused by contact with vegetation	RFW	1																			
		Number of outage events not caused by contact with vegetation	HWW	1																			
		Number of outage events not caused by contact with vegetation	HWW & RFW	1																			
		Number of outage events not caused by contact with vegetation	HWW & not RFW	1																			
		Number of outage events not caused by contact with vegetation	All	2	223	245	245	200	255	59	63	68	52	78	53	79	67						
		Number of outage events not caused by contact with vegetation	RFW	2	1	3	16	13	4	0	0	18	9	0	0	0	4						
		Number of outage events not caused by contact with vegetation	HWW	2	16	8	38	8	4	2	0	0	5	12	0	0	2						
		Number of outage events not caused by contact with vegetation	HWW & RFW	2	0	0	7	6	3	0	0	0	5	0	0	0	2						
		Number of outage events not caused by contact with vegetation	HWW & not RFW	2	16	8	31	2	1	2	0	0	0	12	0	0	0						
		Number of outage events not caused by contact with vegetation	All	3	188	208	194	200	253	31	51	67	48	63	45	63	51						
		Number of outage events not caused by contact with vegetation	RFW	3	2	2	9	9	10	0	0	11	8	0	0	0	4						
		Number of outage events not caused by contact with vegetation	HWW	3	7	0	32	7	5	4	0	0	3	11	0	0	1						
		Number of outage events not caused by contact with vegetation	HWW & RFW	3	0	0	5	7	5	0	0	0	3	0	0	0	1						
		Number of outage events not caused by contact with vegetation	HWW & not RFW	3	7	0	27	0	0	4	0	0	0	11	0	0	0						
		Number of outage events not caused by contact with vegetation	All	Non- HFTD	576	731	616	594	581	128	136	198	145	171	179	190	186						
		Number of outage events not caused by contact with vegetation	RFW	Non- HFTD	2	10	15	11	4	0	0	26	7	0	0	0	4						
		Number of outage events not caused by contact with vegetation	HWW	Non- HFTD	8	98	99	5	3	3	0	0	6	30	0	0	3						
		Number of outage events not caused by contact with vegetation	HWW & RFW	Non- HFTD	0	1	6	5	2	0	0	0	6	0	0	0	3						
		Number of outage events not caused by contact with vegetation	HWW & not RFW	Non- HFTD	8	97	93	0	1	3	0	0	0	30	0	0	0						
1. Risk Events	1.d.	Number of outage events caused by contact with vegetation	All	1																		Number of outage events per year	
		Number of outage events caused by contact with vegetation	RFW	1																			
		Number of outage events caused by contact with vegetation	HWW	1																			
		Number of outage events caused by contact with vegetation	HWW & RFW	1																			
		Number of outage events caused by contact with vegetation	HWW & not RFW	1																			
		Number of outage events caused by contact with vegetation	All	2	8	16	13	9	2	2	1	0	1	3	1	1	0						
		Number of outage events caused by contact with vegetation	RFW	2	0	0	1	4	0	0	0	0	0	0	0	0	0						
		Number of outage events caused by contact with vegetation	HWW	2	1	2	4	3	0	0	0	0	0	1	0	0	0						
		Number of outage events caused by contact with vegetation	HWW & RFW	2	0	0	1	3	0	0	0	0	0	0	0	0	0						
		Number of outage events caused by contact with vegetation	HWW & not RFW	2	1	2	3	0	0	0	0	0	0	1	0	0	0						

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Metric type	#	Outcome metric name	Wind Warning Stat	HFTD Tier	2015	2016	2017	2018	2019	Q1 2020	Q2 2020	Q3 2020	Q4 2020	Q1 2021	Q2 2021	Q3 2021	Q4 2021	Q1 2022	Q2 2022	Q3 2022	Q4 2022	Unit(s)	Comments
		Number of outage events caused by contact with vegetation	All	3	0	1	9	3	4	1	0	1	0	1	0	2	1						
		Number of outage events caused by contact with vegetation	RFW	3	0	0	1	0	0	0	0	1	0	0	0	0	0						
		Number of outage events caused by contact with vegetation	HWW	3	0	0	5	0	0	1	0	0	0	0	0	0	0						
		Number of outage events caused by contact with vegetation	HWW & RFW	3	0	0	1	0	0	0	0	0	0	0	0	0	0						
		Number of outage events caused by contact with vegetation	HWW & not RFW	3	0	0	4	0	0	1	0	0	0	0	0	0	0						
		Number of outage events caused by contact with vegetation	All	Non- HFTD	19	44	48	22	21	8	6	4	7	13	3	5	11						
		Number of outage events caused by contact with vegetation	RFW	Non- HFTD	0	0	2	4	1	0	0	1	0	0	0	0	0						
		Number of outage events caused by contact with vegetation	HWW	Non- HFTD	1	11	29	3	1	0	0	0	0	6	0	0	0						
		Number of outage events caused by contact with vegetation	HWW & RFW	Non- HFTD	0	0	1	1	1	0	0	0	0	0	0	0	0						
		Number of outage events caused by contact with vegetation	HWW & not RFW	Non- HFTD	1	11	28	2	0	0	0	0	0	6	0	0	0						
2. Utility inspection findings - Distribution	2.a.	Number of Level 1 findings (distribution)	N/A	1																			
		Number of Level 1 findings (distribution)	N/A	2	161	102	30	21	17	7	9	3	0	3	10	20	62						
		Number of Level 1 findings (distribution)	N/A	3	89	96	10	59	35	66	36	11	1	1	1	0	10						
		Number of Level 1 findings (distribution)	N/A	Non- HFTD	119	78	95	51	34	25	22	8	6	12	8	7	2						
	2.b.	Number of Level 2 findings (distribution)	N/A	1																			
		Number of Level 2 findings (distribution)	N/A	2	606	696	756	594	557	619	236	101	20	168	652	2299	6339						
		Number of Level 2 findings (distribution)	N/A	3	670	520	443	575	1699	4727	2793	937	230	182	271	381	266						
		Number of Level 2 findings (distribution)	N/A	Non- HFTD	3728	3255	2899	1926	1870	706	680	458	223	325	846	1261	1028						
	2.c.	Number of Level 3 findings (distribution)	N/A	1																			
		Number of Level 3 findings (distribution)	N/A	2	na	na	na	na	na	na	na	na	na	na	na	na	na						
		Number of Level 3 findings (distribution)	N/A	3	na	na	na	na	na	na	na	na	na	na	na	na	na						
		Number of Level 3 findings (distribution)	N/A	Non- HFTD	na	na	na	na	na	na	na	na	na	na	na	na	na						
	2.d.	Number of distribution circuit miles inspected	N/A	1																			
		Number of distribution circuit miles inspected	N/A	2	2338.1	2580.4	2626.2	2617.5	2429.0	1008.8	884.3	625.8	150.0	993.0	875.3	1066.5	872.7						
		Number of distribution circuit miles inspected	N/A	3	2675.2	2372.5	2416.9	3002.2	2695.9	1974.0	1709.5	972.2	220.4	1353.9	878.1	501.0	220.8						
		Number of distribution circuit miles inspected	N/A	Non- HFTD	4002.1	3920.2	3878.8	3806.0	3807.2	1186.4	1221.2	966.7	468.8	1075.1	1196.7	1112.3	332.8						
2. Utility inspection findings - Transmission	2.a.ii	Number of Level 1 findings (transmission)	N/A	1																			
		Number of Level 1 findings (transmission)	N/A	2	0	0	0	2	0	0	0	0	0	0	0	0	0						
		Number of Level 1 findings (transmission)	N/A	3	0	0	0	0	0	0	0	0	1	0	0	0	0						
		Number of Level 1 findings (transmission)	N/A	Non- HFTD	4	1	3	6	2	0	0	0	0	0	0	0	0						
	2.b.ii	Number of Level 2 findings (transmission)	N/A	1																			
		Number of Level 2 findings (transmission)	N/A	2	194	81	127	342	304	170	117	40	36	65	65	80	58						
		Number of Level 2 findings (transmission)	N/A	3	153	38	76	53	66	0	12	9	24	18	1	0	0						
		Number of Level 2 findings (transmission)	N/A	Non- HFTD	792	280	315	551	439	229	129	69	45	88	193	130	140						
	2.c.ii	Number of Level 3 findings (transmission)	N/A	1																			
		Number of Level 3 findings (transmission)	N/A	2	23	34	25	31	22	0	8	0	3	1	8	2	0						
		Number of Level 3 findings (transmission)	N/A	3	3	2	16	0	5	0	0	0	0	0	0	0	0						
		Number of Level 3 findings (transmission)	N/A	Non- HFTD	34	33	25	35	28	10	1	1	16	3	22	1	4						
	2.d.ii	Number of transmission circuit miles inspected	N/A	1																			
		Number of transmission circuit miles inspected	N/A	2	1,666.8	1,606.3	1,631.8	1,668.7	1,606.1	605.2	225.0	353.3	470.9	475.1	337.6	805.1	151.5						
		Number of transmission circuit miles inspected	N/A	3	592.1	586.9	627.5	618.3	665.5	172.1	70.2	298.7	309.2	148.8	103.8	320.7	15.5						
		Number of transmission circuit miles inspected	N/A	Non- HFTD	2,070.5	2,096.9	2,101.2	2,078.5	2,103.4	618.3	529.0	670.4	353.8	594.3	528.2	853.6	149.6						Detailed, potral and infrared inspections
	3.a.	Fatalities due to utility-related ignitions (total)	N/A	N/A	0	0	0	0	0	0	0	0	0	0	0	0	0						
	3.b.	Injuries due to utility-related igntions (total)	N/A	N/A	0	0	0	0	0	0	0	0	0	0	0	0	0						
4. Value of assets destroyed by utility-related ignitions, listed by asset type	4.a.	Value of assets destroyed by utility-related ignitions (total)	N/A	N/A	0	0	0	2900	0	0	0	0	0	0	0	0	0						
5. Structures damaged or destroyed by utility-related ignitions	5.a.	Number of structures destroyed by utility-related ignitions (total)	N/A	N/A	0	0	0	1	0	0	0	0	0	0	0	0	0						
	5.b.	Critical infrastructure damaged/destroyed by utility-rleated ignitions (total)	N/A	N/A										0	0	0	0						Critical infrustructure was defined in 2021.
6. Acreage burned by utility-related ignitions	6.a.	Acreage burned by utility-rleated ignitions	N/A	N/A	211.60	18.79	29.60	38.50	14.80	0.25	0.26	7.69	4.37	0.01	0.35	1.01	0.65						SDG&E has centrolized and automated ignition metrics, acerage for historical years are updated based on automated output in Feb 2022.
7. Number of utility-related ignitions	7.a.	Number of ignitions (total) according to existing ignition data reporting requirement	N/A	N/A	32	30	23	26	21	3	5	16	5	3	9	9	4						
	7.b.	Number of ignitions	All	1																			
		Number of ignitions	RFW	1																			
		Number of ignitions	HWW	1																			
		Number of ignitions	HWW & RFW	1																			
		Number of ignitions	HWW & not RFW	1																			
		Number of ignitions	All	2	13	11	7	7	8	1	2	5	3	2	2	3	2						
		Number of ignitions	RFW	2	0	0	2	1	1	0	0	1	1	0	0	0	0						
		Number of ignitions	HWW	2	2	0	0	0	1	0	0	0	1	1	0	0	0						
		Number of ignitions	HWW & RFW	2	0	0	0	0	1	0	0	0	1	0	0	0	0						
		Number of ignitions	HWW & not RFW	2	2	0	0	0	0	0	0	0	0	1	0	0	0						
		Number of ignitions	All	3	6	7	8	6	3	1	2	7	2	0	3	3	2						
		Number of ignitions	RFW	3	0	0	2	0	1	0	0	0	0	0	0	0	0						
		Number of ignitions	HWW	3	0	0	2	0	1	1	0	0	0	0	0	0	0						
		Number of ignitions	HWW & RFW	3	0	0	2	0	1	0	0	0	0	0	0	0	0						
		Number of ignitions	HWW & not RFW	3	0	0	0	0	0	1	0	0	0	0	0	0	0						
		Number of ignitions	All	Non- HFTD	13	12	8	13	10	1	1	4	0	1	4	3	0						
		Number of ignitions	RFW	Non- HFTD	0	0	0	0	0	0	0	1	0	0	0	0	0						
		Number of ignitions	HWW	Non- HFTD	0	0	1	0	0	0	0	0	0	0	0	0	0						
		Number of ignitions	HWW & RFW	Non- HFTD	0	0	0	0	0	0	0	0	0	0	0	0	0						
		Number of ignitions	HWW & not RFW	Non- HFTD	0	0	1	0	0	0	0	0	0	0	0	0	0						
8. Fatalities resulting from utility wildfire mitigation initiatives	8.a.	Fatalities due to utility wildfire mitigation activities (total) - "activities" defined as all activities accounted for in the 2020	N/A	N/A	1	0	0	0	0	0	0	0	0	0	0	0	0						
9. OSHA-reportable injuries from utility wildfire mitigation initiatives	9.a.	OSHA-reportable injuries due to utility wildfire mitigation activities (total) - "activities" defined as all activities accounted	N/A	N/A	0	1	0	0	0	0	0	0	0	0	0	0	0						

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Note: These columns are placeholders for future QR submissions.

Table 3: List and description of additional metrics

Metric	#	Definition	Purpose	Assumptions made to connect me	Third-party validation (if any)	2015	2016	2017	2018	2019	Q1 2020	Q2 2020	Q3 2020	Q4 2020	Q1 2021	Q2 2021	Q3 2021	Q4 2021	Q1 2022	Q2 2022	Q3 2022	Q4 2022	Unit(s)	Comments
1. Elevated FPI and Red Flag Warning	1.a.	Number of elevated or extreme FPI		Elevated or extreme FPI is associated with greater wildfire	No	108	138	169	182	137	0	13	92	59	7	27	91	44					Days	
	1.b.	Number of RFW days		RFW is associated with greater wildfire risk.	No	4	19	22	12	10	0	0	6	13	5	0	0	4					Days	Time is not considered when calculating the number of RFW days.
2. Ignition Events	2.a.	Vegetation caused ignitons in HFTD with elevated or higher FPI			No	3	1	2	0	0	0	0	1	0	0	0	0	0					Incidents	
	2.b.	Vegetation caused ignitons in HFTD with RFW			No	0	0	1	0	0	0	0	1	0	0	0	0	0					Incidents	
	2.c.	Equipment caused ignitions in HFTD with elevated or higher FPI			No	2	6	4	2	4	0	0	9	3	0	2	2	1					Incidents	
	2.d.	Equipment caused ignitions in HFTD with RFW			No	0	0	2	1	2	0	0	1	1	0	0	0	0					Incidents	
	2.e.	Balloons caused ignitions in HFTD with elevated or higher FPI			No	1	0	3	3	0	0	0	0	0	0	1	0	1					Incidents	
	2.f.	Balloons caused ignitions in HFTD with RFW			No	0	0	0	0	0	0	0	0	0	0	0	0	0					Incidents	
	2.g.	Vehicles caused ignitions in HFTD with elevated or higher FPI			No	0	0	1	2	0	0	0	2	0	0	0	0	0					Incidents	
	2.h.	Vehicles caused ignitions in HFTD with RFW			No	0	0	0	0	0	0	0	0	0	0	0	0	0					Incidents	
3. Distribution Outages	3.a.	Vegetation caused outages in HFTD with Elevated FPI			No	3	5	8	5	2	0	0	1	2	0	1	3	0					Outages	
	3.b.	Vegetation caused outages in HFTD with RFW			No	0	0	2	4	0	0	0	1	0	0	0	0	0					Outages	
	3.c.	Overhead faults on circuits in HFTD with Elevated FPI			No	114	104	133	134	132	0	7	111	51	23	17	88	32					Outages	SDG&E has developed a more precise methodology for identifying the HFTD location of outages by utilizing the pole/asset location instead of the overall circuit location in 2021 Q4
	3.d.	Overhead faults on circuits in HFTD with RFW			No	1	2	20	25	13	0	0	28	17	0	0	0	5					Outages	
	3.e.	Energized wire down events in HFTD with Elevated FPI			No	3	7	9	6	8	0	0	5	2	2	4	5	4					Outages	
	3.f.	Energized wire down events in HFTD with RFW			No	0	0	0	1	1	0	0	0	0	0	0	0	0					Outages	
	3.g.	Number of non-CALFIRE rated fuse operations in HFTD with Elevated FPI			No	64	61	69	67	52	0	4	27	23	4	3	14	6					Outages	
	3.h.	Number of non-CALFIRE rated fuse operations in HFTD with RFW			No	0	3	9	10	2	0	0	1	7	0	0	0	0					Outages	

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Table 4: Fatalities due to utility wildfire mitigation initiatives

Metric type	#	Outcome metric name	2015	2016	2017	2018	2019	Q1 2020	Q2 2020	Q3 2020	Q4 2020	Q1 2021	Q2 2021	Q3 2021	Q4 2021	Q1 2022	Q2 2022	Q3 2022	Q4 2022	Unit(s)	Comments
1. Fatalities - Full-time Employee	1.a.	Fatalities due to utility inspection - Full-time employee	0	0	0	0	0	0	0	0	0	0	0	0	0					# fatalities	
	1.b.	Fatalities due to vegetation management - Full-time employee	0	0	0	0	0	0	0	0	0	0	0	0	0					# fatalities	
	1.c.	Fatalities due to utility fuel management - Full-time employee	0	0	0	0	0	0	0	0	0	0	0	0	0					# fatalities	
	1.d.	Fatalities due to grid hardening - Full-time employee	0	0	0	0	0	0	0	0	0	0	0	0	0					# fatalities	
	1.e.	Fatalities due to other - Full-time employee	0	0	0	0	0	0	0	0	0	0	0	0	0					# fatalities	
2. Fatalities - Contractor	2.a.	Fatalities due to utility inspection - Contractor	0	0	0	0	0	0	0	0	0	0	0	0	0					# fatalities	
	2.b.	Fatalities due to vegetation management - Contractor	1	0	0	0	0	0	0	0	0	0	0	0	0					# fatalities	
	2.c.	Fatalities due to utility fuel management - Contractor	0	0	0	0	0	0	0	0	0	0	0	0	0					# fatalities	
	2.d.	Fatalities due to grid hardening - Contractor	0	0	0	0	0	0	0	0	0	0	0	0	0					# fatalities	
	2.e.	Fatalities due to other - Contractor	0	0	0	0	0	0	0	0	0	0	0	0	0					# fatalities	
3. Fatalities - Member of public	3.a.	Fatalities due to utility inspection - Public	0	0	0	0	0	0	0	0	0	0	0	0	0					# fatalities	
	3.b.	Fatalities due to vegetation management - Public	0	0	0	0	0	0	0	0	0	0	0	0	0					# fatalities	
	3.c.	Fatalities due to utility fuel management - Public	0	0	0	0	0	0	0	0	0	0	0	0	0					# fatalities	
	3.d.	Fatalities due to grid hardening - Public	0	0	0	0	0	0	0	0	0	0	0	0	0					# fatalities	
	3.e.	Fatalities due to other - Public	0	0	0	0	0	0	0	0	0	0	0	0	0					# fatalities	

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Note: These columns are placeholders for future QR submissions.

Table 5: OSHA-reportable injuries due to utility wildfire mitigation initiatives

Metric type	#	Outcome metric name	2015	2016	2017	2018	2019	Q1 2020	Q2 2020	Q3 2020	Q4 2020	Q1 2021	Q2 2021	Q3 2021	Q4 2021	Q1 2022	Q2 2022	Q3 2022	Q4 2022	Unit(s)	Comments
1. OSHA injuries - Full-time Employee	1.a.	OSHA injuries due to utility inspection - Full-time employee	0	0	0	0	0	0	0	0	0	0	0	0	0					# OSHA-reportable injuries	
	1.b.	OSHA injuries due to vegetation management - Full-time employee	0	0	0	0	0	0	0	0	0	0	0	0	0					# OSHA-reportable injuries	
	1.c.	OSHA injuries due to utility fuel management - Full-time employee	0	0	0	0	0	0	0	0	0	0	0	0	0					# OSHA-reportable injuries	
	1.d.	OSHA injuries due to grid hardening - Full-time employee	0	0	0	0	0	0	0	0	0	0	0	0	0					# OSHA-reportable injuries	
	1.e.	OSHA injuries due to other - Full-time employee	0	0	0	0	0	0	0	0	0	0	0	0	0					# OSHA-reportable injuries	
2. OSHA injuries - Contractor	2.a.	OSHA injuries due to utility inspection - Contractor	0	0	0	0	0	0	0	0	0	0	0	0	0					# OSHA-reportable injuries	
	2.b.	OSHA injuries due to vegetation management - Contractor	0	1	0	0	0	0	0	0	0	0	0	0	0					# OSHA-reportable injuries	
	2.c.	OSHA injuries due to utility fuel management - Contractor	0	0	0	0	0	0	0	0	0	0	0	0	0					# OSHA-reportable injuries	
	2.d.	OSHA injuries due to grid hardening - Contractor	0	0	0	0	0	0	0	0	0	0	0	0	0					# OSHA-reportable injuries	
	2.e.	OSHA injuries due to other - Contractor	0	0	0	0	0	0	0	0	0	0	0	0	0					# OSHA-reportable injuries	
3. OSHA injuries - Member of public	3.a.	OSHA injuries due to utility inspection - Public	0	0	0	0	0	0	0	0	0	0	0	0	0					# OSHA-reportable injuries	
	3.b.	OSHA injuries due to vegetation management - Public	0	0	0	0	0	0	0	0	0	0	0	0	0					# OSHA-reportable injuries	
	3.c.	OSHA injuries due to utility fuel management - Public	0	0	0	0	0	0	0	0	0	0	0	0	0					# OSHA-reportable injuries	
	3.d.	OSHA injuries due to grid hardening - Public	0	0	0	0	0	0	0	0	0	0	0	0	0					# OSHA-reportable injuries	
	3.e.	OSHA injuries due to other - Public	0	0	0	0	0	0	0	0	0	0	0	0	0					# OSHA-reportable injuries	

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Note: These columns are placeholders for future QR submissions.

Table 6: Weather patterns

Metric type	#	Outcome metric name	2015	2016	2017	2018	2019	Q1 2020	Q2 2020	Q3 2020	Q4 2020	Q1 2021	Q2 2021	Q3 2021	Q4 2021	Q1 2022	Q2 2022	Q3 2022	Q4 2022	Unit(s)	Comments
1. Red Flag Warning Overhead circuit mile Days	1.a.	Red Flag Warning Overhead circuit mile days - entire utility territory	16,938.55	53,147.86	190,407.17	125,739.06	53,502.25	-	-	34,879.05	62,127.92	3,185.62	-	-	19,756.14					Sum of overhead circuit miles of utility grid subject to Red Flag Warning each day within a given time period, calculated as the number of overhead circuit miles	
	1.b.	Red Flag Warning Overhead circuit mile days - HFTD Zone 1	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA					Red Flag Warning Overhead circuit mile days, see above for definition	
	1.c.	Red Flag Warning Overhead circuit mile days - HFTD Tier 2	6,485.11	20,011.16	55,256.33	38,664.98	20,055.18	-	-	12,875.28	23,534.83	1,455.47	-	-	7,406.52					Red Flag Warning Overhead circuit mile days, see above for definition	
	1.d.	Red Flag Warning Overhead circuit mile days - HFTD Tier 3	3,730.77	14,904.54	30,735.98	22,286.47	12,370.46	-	-	9,106.04	14,432.21	-	-	-	4,432.54					Red Flag Warning Overhead circuit mile days, see above for definition	circuit/tieline spans that cross tier 2 and tier 3 are grouped in tier 3
	1.e.	Red Flag Warning Overhead circuit mile days - Non-HFTD	6,722.67	18,232.16	104,414.85	64,787.61	21,076.61	-	-	12,897.74	24,160.88	1,730.15	-	-	7,917.07					Red Flag Warning Overhead circuit mile days, see above for definition	
2. Wind conditions	2.a.	High wind warning overhead circuit mile days	51,231.92	13,751.87	107,921.70	53,297.72	26,851.75	8,646.89	-	-	17,019.78	38,371.81	-	-	6,137.61					Sum of overhead circuit miles of utility grid subject to High Wind Warnings (HWW, as defined by the National Weather Service) each day within a given time	
3. Other	3.a.	Other relevant weather pattern metrics tracked (add additional rows as needed)																			

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Notes:
Transmission lines refer to all lines at or above 65kV, and distribution lines refer to all lines below 65kV.
Data from 2015 - 2021 Q4 should be actual numbers. 2022 Q1 - 2024 should be projected. In future submissions update projected numbers with actuals

Table 7.1: Key recent and projected drivers of risk events

						Number of risk events													Projected risk events									
	Risk Event category	Cause category	#	Sub-cause category	Are risk e	2015	2016	2017	2018	2019	Q1 2020	Q2 2020	Q3 2020	Q4 2020	Q1 2021	Q2 2021	Q3 2021	Q4 2021	Q1 2022	Q2 2022	Q3 2022	Q4 2022	Q1 2023	Q2 2023	Q3 2023	Q4 2023	Unit(s)	Comments
x	Wire down event - Distr	1. Contact from object - Distribution	1.a.	Veg. contact- Distribution	Yes	10	22	31	13	12	3	4	2	4	4	2	3	2	3.869745	3.869745	3.869745	3.869745	3.68949	3.68949	3.68949	3.68949	# risk events	
			1.b.	Animal contact- Distribution	Yes	0	8	2	2	0	1	1	1	0	0	2	0	2	0.544376	0.544376	0.544376	0.544376	0.538752	0.538752	0.538752	0.538752	# risk events	
			1.c.	Balloon contact- Distribution	Yes	1	5	8	3	5	1	2	1	1	0	3	0	0	1.195143	1.195143	1.195143	1.195143	1.190287	1.190287	1.190287	1.190287	# risk events	
			1.d.	Vehicle contact- Distribution	Yes	6	13	17	23	28	11	6	7	9	6	5	3	8	6.132285	6.132285	6.132285	6.132285	6.114569	6.114569	6.114569	6.114569	# risk events	
			1.e.	Other contact from object - Distr	Yes	8	15	18	6	13	2	0	1	0	0	1	0	1	2.09095	2.09095	2.09095	2.09095	2.081901	2.081901	2.081901	2.081901	# risk events	
		2. Equipment / facility failure - Distribution	2.a.	Connector damage or failure- Dis	Yes	7	2	0	7	6	4	2	2	3	6	4	3	2	1.920313	1.920313	1.920313	1.920313	1.890626	1.890626	1.890626	1.890626	# risk events	
			2.b.	Splice damage or failure — Distri	No	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1	2	3	# risk events	
			2.c.	Crossarm damage or failure - Distribution	Yes	0	0	0	1	3	0	0	1	0	0	1	0	0	0.297852	0.297852	0.297852	0.297852	0.295703	0.295703	0.295703	0.295703	# risk events	
			2.d.	Insulator damage or failure- Distribution	Yes	0	0	0	0	0	1	0	0	0	0	0	0	0	0.049543	0.049543	0.049543	0.049543	0.047878	0.047878	0.047878	0.047878	# risk events	
			2.e.	Lightning arrestor damage or failure- Distribution	Yes	0	1	0	0	1	0	0	0	0	0	0	0	0	0.049494	0.049494	0.049494	0.049494	0.048989	0.048989	0.048989	0.048989	# risk events	
			2.f.	Tap damage or failure - Distribution	No	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	# risk events	
			2.g.	Tie wire damage or failure - Distribution	No	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	# risk events	
			2.h.	Other - Distribution	Yes	27	71	60	35	40	4	4	3	7	8	4	2	19	9.227681	9.227681	9.227681	9.227681	9.020624	9.020624	9.020624	9.020624	# risk events	
		3. Wire-to-wire contact - Distribution	3.a.	Wire-to-wire contact / contamin	Yes	0	0	0	0	1	0	0	0	0	0	0	0	0	0.049219	0.049219	0.049219	0.049219	0.048438	0.048438	0.048438	0.048438	# risk events	
		4. Contamination - Distribution	4.a.	Contamination - Distribution	Yes	0	0	0	2	2	1	0	1	2	0	0	0	0	0.399143	0.399143	0.399143	0.399143	0.398286	0.398286	0.398286	0.398286	# risk events	
		5. Utility work / Operation	5.a.	Utility work / Operation	Yes	1	1	1	2	1	0	0	0	0	0	1	0	0	0.25	0.25	0.25	0.25	0.23913	0.23913	0.23913	0.23913	# risk events	
		6. Vandalism / Theft - Distribution	6.a.	Vandalism / Theft - Distribution	Yes	0	0	0	1	1	0	0	2	0	2	0	1	1	0.399818	0.399818	0.399818	0.399818	0.399636	0.399636	0.399636	0.399636	# risk events	
		7. Other- Distribution	7.a.	All Other- Distribution	No	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	# risk events	
		8. Unknown- Distribution	8.a.	Unknown - Distribution	Yes	0	2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	# risk events	
x	Wire down event - Transmission	9. Contact from object - Transmission	9.a.	Veg. contact- Transmission	Yes	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	# risk events	
			9.b.	Animal contact- Transmission	Yes	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	# risk events	
			9.c.	Balloon contact- Transmission	Yes	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	# risk events	
			9.d.	Vehicle contact- Transmission	Yes	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	# risk events	
			9.e.	Other contact from object - Tran	Yes	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	# risk events	
		10. Equipment / facility failure - Transmission	10.a.	Connector damage or failure- Tra	Yes	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	# risk events	
			10.b.	Splice damage or failure — Trans	No	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	# risk events	
			10.c.	Crossarm damage or failure - Transmission	Yes	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	# risk events	
			10.d.	Insulator damage or failure- Transmission	Yes	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	# risk events	
			10.e.	Lightning arrestor damage or failure- Transmission	No	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	# risk events	
			10.f.	Tap damage or failure - Transmission	No	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	# risk events	
			10.g.	Tie wire damage or failure - Transmission	No	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	# risk events	
			10.h.	Other - Transmission	Yes	0	0	1	0	0	1	0	0	0	0	0	0	0	0.0995	0.0995	0.0995	0.0995	0.099	0.099	0.099	0.099	# risk events	
		11. Wire-to-wire contact - Transmission	11.a.	Wire-to-wire contact / contamin	Yes	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	# risk events	
		12. Contamination - Transmission	12.a.	Contamination - Transmission	Yes	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	# risk events	
		13. Utility work / Operation	13.a.	Utility work / Operation	Yes	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	# risk events	
		14. Vandalism / Theft - Transmission	14.a.	Vandalism / Theft - Transmission	Yes	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	# risk events	
		15. Other- Transmission	15.a.	All Other- Transmission	Yes	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	# risk events	
		16. Unknown- Transmission	16.a.	Unknown - Transmission	Yes	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	# risk events	
x	Outage - Distribution	17. Contact from object - Distribution	17.a.	Veg. contact- Distribution	Yes	27	61	70	34	27	11	7	5	8	17	4	8	12	9.69825	9.69825	9.69825	9.69825	9.2465	9.2465	9.2465	9.2465	# risk events	
			17.b.	Animal contact- Distribution	Yes	70	80	77	74	89	16	31	32	16	12	33	24	17	20.83475	20.83475	20.83475	20.83475	20.6195	20.6195	20.6195	20.6195	# risk events	
			17.c.	Balloon contact- Distribution	Yes	70	84	120	112	93	19	40	27	25	33	53	33	17	28.48425	28.48425	28.48425	28.48425	28.3685	28.3685	28.3685	28.3685	# risk events	
			17.d.	Vehicle contact- Distribution	Yes	94	96	93	99	100	30	25	25	27	28	37	25	30	25.87525	25.87525	25.87525	25.87525	25.8005	25.8005	25.8005	25.8005	# risk events	
			17.e.	Other contact from object - Distr	Yes	34	58	40	39	59	9	1	6	5	3	5	7	7	9.011	9.011	9.011	9.011	8.972	8.972	8.972	8.972	# risk events	
		18. Equipment / facility failure - Distribution	18.a.	Capacitor bank damage or failure	Yes	13	5	3	11	12	4	2	3	2	7	3	4	1	2.57625	2.57625	2.57625	2.57625	2.5525	2.5525	2.5525	2.5525	# risk events	
			18.b.	Conductor damage or failure — I	Yes	35	87	71	49	56	7	6	6	13	30	8	3	20	13.3345	13.3345	13.3345	13.3345	13.219	13.219	13.219	13.219	# risk events	
			18.c.	Fuse damage or failure - Distribution	Yes	67	109	57	55	66	10	22	30	20	11	7	19	25	15.904	15.904	15.904	15.904	15.708	15.708	15.708	15.708	# risk events	
			18.d.	Lightning arrestor damage or failure- Distribution	Yes	22	28	26	20	28	2	4	6	11	11	5	10	12	6.68175	6.68175	6.68175	6.68175	6.6135	6.6135	6.6135	6.6135	# risk events	
			18.e.	Switch damage or failure- Distribution	Yes	8	15	10	19	15	5	4	3	5	5	2	1	4	3.613	3.613	3.613	3.613	3.576	3.576	3.576	3.576	# risk events	
			18.f.	Pole damage or failure - Distribution	Yes	20	32	62	23	67	9	9	5	8	17	7	12	10	11.34875	11.34875	11.34875	11.34875	10.97875	10.97875	10.97875	10.97875	# risk events	
			18.g.	Insulator and brushing damage or failure - Distribution	Yes	2	7	7	9	10	2	2	0	0	1	4	5	1	2.03125	2.03125	2.03125	2.03125	1.963	1.963	1.963	1.963	# risk events	
			18.h.	Crossarm damage or failure - Distribution	Yes	4	14	20	30	33	10	3	5	11	9	12	8	14	7.6945	7.6945	7.6945	7.6945	7.639	7.639	7.639	7.639	# risk events	
			18.i.	Voltage regulator / booster damage or failure - Distribution	Yes	0	0	1	1	0	0	0	0	1	1	2	0	0	0.299	0.299	0.299	0.299	0.298	0.298	0.298	0.298	# risk events	
			18.j.	Recloser damage or failure - Distribution	Yes	4	0	0	1	2	0	0	5	0	0	0	1	0	0.448	0.448	0.448	0.448	0.446	0.446	0.446	0.446	# risk events	
			18.k.	Anchor / guy damage or failure - Distribution	Yes	2	3	1	2	1	0	0	1	0	1	0	0	1	0.345	0.345	0.345	0.345	0.34	0.34	0.34	0.34	# risk events	
			18.l.	Sectionalizer damage or failure - Distribution	No	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	# risk events	
			18.m.	Connection device damage or failure - Distribution	Yes	54	57	40	50	64	24	9	17	15	24	17	15	15	14.27925	14.27925	14.27925	14.27925	14.0585	14.0585	14.0585	14.0585	# risk events	

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Notes:
Transmission lines refer to all lines at or above 65kV, and distribution lines refer to all lines below 65kV.
Data from 2015 - 2021 Q4 should be actual numbers. 2022 Q1 - 2024 should be projected. In future submissions update projected numbers with actuals

Table 7.1: Key recent and projected drivers of risk events

Risk Event category	Cause category	#	Sub-cause category	Are risk e	2015	2016	2017	2018	2019	Q1 2020	Q2 2020	Q3 2020	Q4 2020	Q1 2021	Q2 2021	Q3 2021	Q4 2021	Q1 2022	Q2 2022	Q3 2022	Q4 2022	Q1 2023	Q2 2023	Q3 2023	Q4 2023	Unit(s)	Comments
					Number of risk events													Projected risk events									
		18.n.	Transformer damage or failure - Distribution	Yes	72	52	38	63	46	14	11	23	7	15	3	28	27	13.602	13.602	13.602	13.602	13.454	13.454	13.454	13.454	# risk events	
		18.o.	Other - Distribution	Yes	2	12	13	19	25	4	0	0	0	1	0	44	29	6.712	6.712	6.712	6.712	6.674	6.674	6.674	6.674	# risk events	Includes weather caused equipment failure
	19. Wire-to-wire contact - Distribution	19.a.	Wire-to-wire contact / contamin	Yes	3	6	8	2	4	1	0	0	1	0	0	0	0	0.7875	0.7875	0.7875	0.7875	0.775	0.775	0.775	0.775	# risk events	
	20. Contamination - Distribution	20.a.	Contamination - Distribution	Yes	1	0	0	0	2	0	0	0	0	2	0	2	1	0.34925	0.34925	0.34925	0.34925	0.3485	0.3485	0.3485	0.3485	# risk events	
	21. Utility work / Operation	21.a.	Utility work / Operation	Yes	6	9	5	9	9	2	8	9	11	4	5	5	2	3.45	3.45	3.45	3.45	3.3	3.3	3.3	3.3	# risk events	
	22. Vandalism / Theft - Distribution	22.a.	Vandalism / Theft - Distribution	Yes	2	4	1	3	2	1	4	1	0	2	5	1	2	1.0995	1.0995	1.0995	1.0995	1.099	1.099	1.099	1.099	# risk events	
	23. Other- Distribution	23.a.	All Other- Distribution	No	1	0	0	1	0	0	0	2	0	0	0	0	0	0.1495	0.1495	0.1495	0.1495	0.149	0.149	0.149	0.149	# risk events	
	24. Unknown- Distribution	24.a.	Unknown - Distribution	Yes	325	361	310	249	264	35	52	121	58	86	52	66	54	66.41525	66.41525	66.41525	66.41525	65.4805	65.4805	65.4805	65.4805	# risk events	
Outage - Transmission	25. Contact from object - Transmission	25.a.	Veg. contact- Transmission	Yes	1	1	0	1	0	0	0	0	0	0	0	0	0	0.04925	0.04925	0.04925	0.04925	0.0485	0.0485	0.0485	0.0485	# risk events	
		25.b.	Animal contact- Transmission	Yes	9	5	4	2	5	2	2	0	1	1	2	0	0	0.943	0.943	0.943	0.943	0.936	0.936	0.936	0.936	# risk events	
		25.c.	Balloon contact- Transmission	Yes	17	24	22	25	16	6	8	2	7	7	8	2	4	5.32	5.32	5.32	5.32	5.29	5.29	5.29	5.29	# risk events	
		25.d.	Vehicle contact- Transmission	Yes	1	2	0	3	1	1	0	0	0	0	3	0	2	0.5	0.5	0.5	0.5	0.125	0.125	0.125	0.125	# risk events	
		25.e.	Other contact from object - Tran	Yes	1	0	2	1	3	0	0	0	0	0	0	0	0	0.298	0.298	0.298	0.298	0.296	0.296	0.296	0.296	# risk events	
	26. Equipment / facility failure - Transmission	26.a.	Capacitor bank damage or failure	No	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	# risk events	
		26.b.	Conductor damage or failure — T	Yes	2	6	6	2	0	4	0	2	0	0	0	1	0	0.7455	0.7455	0.7455	0.7455	0.741	0.741	0.741	0.741	# risk events	
		26.c.	Fuse damage or failure - Transmission	No	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	# risk events	
		26.d.	Lightning arrestor damage or failure- Transmission	No	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	# risk events	
		26.e.	Switch damage or failure- Transmission	Yes	3	0	1	0	0	0	1	1	0	0	1	0	0	0.19875	0.19875	0.19875	0.19875	0.1975	0.1975	0.1975	0.1975	# risk events	
		26.f.	Pole damage or failure - Transmission	Yes	1	0	0	4	3	0	0	0	0	0	0	0	0	0.34775	0.34775	0.34775	0.34775	0.3455	0.3455	0.3455	0.3455	# risk events	
		26.g.	Insulator and brushing damage or failure - Transmission	Yes	29	13	6	3	8	0	0	0	0	0	0	11	11	1.95	1.95	1.95	1.95	1.95	1.95	1.95	1.95	# risk events	
		26.h.	Crossarm damage or failure - Transmission	Yes	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	# risk events	
		26.i.	Voltage regulator / booster damage or failure - Transmission	No	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	# risk events	
		26.j.	Recloser damage or failure - Transmission	No	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	# risk events	
		26.k.	Anchor / guy damage or failure - Transmission	Yes	0	0	1	0	0	0	0	0	0	0	0	0	0	0.04975	0.04975	0.04975	0.04975	0.0495	0.0495	0.0495	0.0495	# risk events	
		26.l.	Sectionalizer damage or failure - Transmission	No	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	# risk events	
		26.m.	Connection device damage or failure - Transmission	Yes	0	0	0	1	1	0	0	0	0	0	0	0	0	0.0995	0.0995	0.0995	0.0995	0.099	0.099	0.099	0.099	# risk events	
		26.n.	Transformer damage or failure - Transmission	No	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	# risk events	
		26.o.	Other - Transmission	Yes	1	0	0	0	0	0	2	0	0	0	0	0	0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	# risk events	
	27. Wire-to-wire contact - Transmission	27.a.	Wire-to-wire contact / contamin	Yes	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	# risk events	
	28. Contamination - Transmission	28.a.	Contamination - Transmission	Yes	3	8	0	3	1	0	1	0	0	0	0	1	0	0.29575	0.29575	0.29575	0.29575	0.2915	0.2915	0.2915	0.2915	# risk events	
	29. Utility work / Operation	29.a.	Utility work / Operation	Yes	0	0	2	0	0	1	0	0	1	1	0	0	0	0.25	0.25	0.25	0.25	0.0625	0.0625	0.0625	0.0625	# risk events	
	30. Vandalism / Theft - Transmission	30.a.	Vandalism / Theft - Transmission	Yes	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	# risk events	
	31. Other- Transmission	31.a.	All Other- Transmission	Yes	1	0	0	0	0	0	0	0	0	0	2	2	0	0.2	0.2	0.2	0.2	0.05	0.05	0.05	0.05	# risk events	
	32. Unknown- Transmission	32.a.	Unknown - Transmission	Yes	10	10	8	10	4	1	3	1	1	1	1	2	2	1.686	1.686	1.686	1.686	1.672	1.672	1.672	1.672	# risk events	

x

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Notes:
Transmission lines refer to all lines at or above 65kV, and distribution lines refer to all lines below 65kV.
Data from 2015 - 2021 should be actual numbers. 2022 and 2023 should be projected. In future submissions update projected numbers with actuals

Table 7.2: Key recent and projected drivers of ignitions

							Number of ignitions							Projected ignitions			
	Metric type	**#**	**Ignition driver**	**Line Type**	**HFTD tier**	**Are ignit**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**Unit(s)**	**Comments**
x	1. Contact from object	1.a.i	Veg. contact	Distribution	Non-HFTD	Yes	0	2	1	3	0	0	0	1.000	0.999	# ignitions	
		1.a.ii	Veg. contact	Distribution	HFTD Zone 1	Yes	[redacted]									# ignitions	
		1.a.iii	Veg. contact	Distribution	HFTD Tier 2	Yes	2	2	0	0	1	0	0	0.162	0.124	# ignitions	
		1.a.iv	Veg. contact	Distribution	HFTD Tier 3	Yes	3	0	2	0	0	0	0	0.347	0.294	# ignitions	
		1.a.v	Veg. contact	Distribution	System	Yes	5	4	3	3	1	0	0	1.509	1.417	# ignitions	
		1.a.vi	Veg. contact	Transmission	Non-HFTD	Yes	0	0	0	0	0	0	0	0.000	0.000	# ignitions	
		1.a.vii	Veg. contact	Transmission	HFTD Zone 1	Yes	[redacted]									# ignitions	
		1.a.viii	Veg. contact	Transmission	HFTD Tier 2	Yes	0	0	0	0	0	0	0	0.000	0.000	# ignitions	
		1.a.ix	Veg. contact	Transmission	HFTD Tier 3	Yes	0	0	0	0	0	0	0	0.000	0.000	# ignitions	
		1.a.x	Veg. contact	Transmission	System	Yes	0	0	0	0	0	0	0	0.000	0.000	# ignitions	
		1.b.i	Animal contact	Distribution	Non-HFTD	Yes	0	1	1	0	0	0	0	0.200	0.200	# ignitions	
		1.b.ii	Animal contact	Distribution	HFTD Zone 1	Yes	[redacted]									# ignitions	
		1.b.iii	Animal contact	Distribution	HFTD Tier 2	Yes	0	1	0	0	1	0	2	0.593	0.587	# ignitions	
		1.b.iv	Animal contact	Distribution	HFTD Tier 3	Yes	0	0	0	1	0	2	1	0.793	0.785	# ignitions	
		1.b.v	Animal contact	Distribution	System	Yes	0	2	1	1	1	2	3	1.586	1.572	# ignitions	
		1.b.vi	Animal contact	Transmission	Non-HFTD	Yes	2	0	0	0	0	0	0	0.000	0.000	# ignitions	
		1.b.vii	Animal contact	Transmission	HFTD Zone 1	Yes	[redacted]									# ignitions	
		1.b.viii	Animal contact	Transmission	HFTD Tier 2	Yes	1	0	0	1	0	0	0	0.192	0.184	# ignitions	
		1.b.ix	Animal contact	Transmission	HFTD Tier 3	Yes	0	0	0	0	0	1	1	0.392	0.384	# ignitions	
		1.b.x	Animal contact	Transmission	System	Yes	3	0	0	1	0	1	1	0.584	0.569	# ignitions	
		1.c.i	Balloon contact	Distribution	Non-HFTD	Yes	2	3	3	3	0	1	2	1.8	1.8	# ignitions	
		1.c.ii	Balloon contact	Distribution	HFTD Zone 1	Yes	[redacted]									# ignitions	
		1.c.iii	Balloon contact	Distribution	HFTD Tier 2	Yes	0	0	1	2	0	1	1	0.997	0.993	# ignitions	
		1.c.iv	Balloon contact	Distribution	HFTD Tier 3	Yes	0	0	1	3	0	0	0	0.785	0.77	# ignitions	
		1.c.v	Balloon contact	Distribution	System	Yes	2	3	5	8	0	2	3	3.581	3.563	# ignitions	
		1.c.vi	Balloon contact	Transmission	Non-HFTD	Yes	0	0	0	0	1	0	0	0.2	0.2	# ignitions	
		1.c.vii	Balloon contact	Transmission	HFTD Zone 1	Yes	[redacted]									# ignitions	
		1.c.viii	Balloon contact	Transmission	HFTD Tier 2	Yes	1	0	1	0	0	0	2	0.592	0.584	# ignitions	
		1.c.ix	Balloon contact	Transmission	HFTD Tier 3	Yes	0	0	0	0	0	0	0	0	0	# ignitions	
		1.c.x	Balloon contact	Transmission	System	Yes	1	0	1	0	1	0	2	0.792	0.784	# ignitions	
		1.d.i	Vehicle contact	Distribution	Non-HFTD	Yes	2	2	1	0	1	0	0	0.4	0.4	# ignitions	
		1.d.ii	Vehicle contact	Distribution	HFTD Zone 1	Yes	[redacted]									# ignitions	
		1.d.iii	Vehicle contact	Distribution	HFTD Tier 2	Yes	3	1	2	1	2	1	0	1.191	1.182	# ignitions	
		1.d.iv	Vehicle contact	Distribution	HFTD Tier 3	Yes	1	1	1	0	0	1	0	0.394	0.387	# ignitions	
		1.d.v	Vehicle contact	Distribution	System	Yes	6	4	4	1	3	2	0	1.985	1.969	# ignitions	
		1.d.vi	Vehicle contact	Transmission	Non-HFTD	Yes	0	0	0	2	0	0	0	0.4	0.4	# ignitions	
		1.d.vii	Vehicle contact	Transmission	HFTD Zone 1	Yes	[redacted]									# ignitions	
		1.d.viii	Vehicle contact	Transmission	HFTD Tier 2	Yes	0	0	0	0	0	0	0	0	0	# ignitions	
		1.d.ix	Vehicle contact	Transmission	HFTD Tier 3	Yes	0	0	0	1	0	0	0	0.2	0.2	# ignitions	
		1.d.x	Vehicle contact	Transmission	System	Yes	0	0	0	3	0	0	0	0.6	0.6	# ignitions	
		1.e.i	Other contact from object	Distribution	Non-HFTD	Yes	2	1	0	1	0	0	0	0.2	0.2	# ignitions	
		1.e.ii	Other contact from object	Distribution	HFTD Zone 1	Yes	[redacted]									# ignitions	
		1.e.iii	Other contact from object	Distribution	HFTD Tier 2	Yes	1	1	1	0	0	0	1	0.396	0.391	# ignitions	
		1.e.iv	Other contact from object	Distribution	HFTD Tier 3	Yes	0	0	1	0	0	0	1	0.396	0.392	# ignitions	
		1.e.v	Other contact from object	Distribution	System	Yes	3	2	2	1	0	0	2	0.992	0.983	# ignitions	
		1.e.vi	Other contact from object	Transmission	Non-HFTD	Yes	0	0	0	0	0	0	0	0	0	# ignitions	
		1.e.vii	Other contact from object	Transmission	HFTD Zone 1	Yes	[redacted]									# ignitions	
		1.e.viii	Other contact from object	Transmission	HFTD Tier 2	Yes	0	1	0	1	0	0	0	0.192	0.184	# ignitions	
		1.e.ix	Other contact from object	Transmission	HFTD Tier 3	Yes	0	0	0	0	0	0	0	0	0	# ignitions	
		1.e.x	Other contact from object	Transmission	System	Yes	0	1	0	1	0	0	0	0.192	0.184	# ignitions	
	2. Equipment / facility failure	2.a.i	Capacitor bank damage or failure	Distribution	Non-HFTD	Yes	0	0	0	0	0	0	1	0.2	0.2	# ignitions	
		2.a.ii	Capacitor bank damage or failure	Distribution	HFTD Zone 1	Yes	[redacted]									# ignitions	
		2.a.iii	Capacitor bank damage or failure	Distribution	HFTD Tier 2	Yes	0	1	0	0	0	0	0	0	0	# ignitions	
		2.a.iv	Capacitor bank damage or failure	Distribution	HFTD Tier 3	Yes	0	0	0	0	0	1	0	0.173	0.146	# ignitions	
		2.a.v	Capacitor bank damage or failure	Distribution	System	Yes	0	1	0	0	0	1	1	0.373	0.346	# ignitions	
		2.a.vi	Capacitor bank damage or failure	Transmission	Non-HFTD		0	0	0	0	0	0	0	0	0	# ignitions	
		2.a.vii	Capacitor bank damage or failure	Transmission	HFTD Zone 1		[redacted]									# ignitions	
		2.a.viii	Capacitor bank damage or failure	Transmission	HFTD Tier 2		0	0	0	0	0	0	0	0	0	# ignitions	
		2.a.ix	Capacitor bank damage or failure	Transmission	HFTD Tier 3		0	0	0	0	0	0	0	0	0	# ignitions	
		2.a.x	Capacitor bank damage or failure	Transmission	System		0	0	0	0	0	0	0	0	0	# ignitions	
		2.b.i	Conductor damage or failure	Distribution	Non-HFTD	Yes	1	1	0	0	0	0	1	0.2	0.2	# ignitions	
		2.b.ii	Conductor damage or failure	Distribution	HFTD Zone 1	Yes	[redacted]									# ignitions	
		2.b.iii	Conductor damage or failure	Distribution	HFTD Tier 2	Yes	1	1	0	1	0	0	0	0.193	0.187	# ignitions	
		2.b.iv	Conductor damage or failure	Distribution	HFTD Tier 3	Yes	0	1	1	0	0	1	1	0.586	0.571	# ignitions	
		2.b.v	Conductor damage or failure	Distribution	System	Yes	2	3	1	1	0	1	2	0.979	0.957	# ignitions	
		2.b.vi	Conductor damage or failure	Transmission	Non-HFTD		0	0	0	0	0	0	0	0	0	# ignitions	
		2.b.vii	Conductor damage or failure	Transmission	HFTD Zone 1		[redacted]									# ignitions	
		2.b.viii	Conductor damage or failure	Transmission	HFTD Tier 2		0	0	0	0	0	0	0	0	0	# ignitions	
		2.b.ix	Conductor damage or failure	Transmission	HFTD Tier 3		0	0	0	0	0	0	0	0	0	# ignitions	
		2.b.x	Conductor damage or failure	Transmission	System		0	0	0	0	0	0	0	0	0	# ignitions	
		2.c.i	Fuse damage or failure	Distribution	Non-HFTD	Yes	0	0	1	0	0	1	0	0.4	0.4	# ignitions	
		2.c.ii	Fuse damage or failure	Distribution	HFTD Zone 1	Yes	[redacted]									# ignitions	
		2.c.iii	Fuse damage or failure	Distribution	HFTD Tier 2	Yes	0	0	0	0	0	0	0	0	0	# ignitions	
		2.c.iv	Fuse damage or failure	Distribution	HFTD Tier 3	Yes	0	0	0	0	1	0	0	0.134	0.068	# ignitions	

Utility	SDG&E	**Notes:**
Table No.	7.2	Transmission lines refer to all lines at or above 65kV, and distribution lines refer to all lines below 65kV.
Date Modified	2022 02 09	Data from 2015 - 2021 should be actual numbers. 2022 and 2023 should be projected. In future submissions update projected numbers with actuals

Table 7.2: Key recent and projected drivers of ignitions

						Number of ignitions							Projected ignitions			
Metric type	**#**	**Ignition driver**	**Line Type**	**HFTD tier**	**Are ignit**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**Unit(s)**	**Comments**
	2.c.v	Fuse damage or failure	Distribution	System	Yes	0	0	1	0	1	1	0	0.534	0.468	# ignitions	
	2.c.vi	Fuse damage or failure	Transmission	Non-HFTD		0	0	0	0	0	0	0	0	0	# ignitions	
	2.c.vii	Fuse damage or failure	Transmission	HFTD Zone 1		[redacted]									# ignitions	
	2.c.viii	Fuse damage or failure	Transmission	HFTD Tier 2		0	0	0	0	0	0	0	0	0	# ignitions	
	2.c.ix	Fuse damage or failure	Transmission	HFTD Tier 3		0	0	0	0	0	0	0	0	0	# ignitions	
	2.c.x	Fuse damage or failure	Transmission	System		0	0	0	0	0	0	0	0	0	# ignitions	
	2.d.i	Lightning arrestor damage or failure	Distribution	Non-HFTD	Yes	0	0	0	0	0	0	0	0	0	# ignitions	
	2.d.ii	Lightning arrestor damage or failure	Distribution	HFTD Zone 1	Yes	[redacted]									# ignitions	
	2.d.iii	Lightning arrestor damage or failure	Distribution	HFTD Tier 2	Yes	0	1	0	0	0	2	0	0.4	0.4	# ignitions	
	2.d.iv	Lightning arrestor damage or failure	Distribution	HFTD Tier 3	Yes	0	1	1	0	0	3	0	0.39	0.39	# ignitions	
	2.d.v	Lightning arrestor damage or failure	Distribution	System	Yes	0	2	1	0	0	5	0	0.79	0.79	# ignitions	
	2.d.vi	Lightning arrestor damage or failure	Transmission	Non-HFTD		0	0	0	0	0	0	0	0	0	# ignitions	
	2.d.vii	Lightning arrestor damage or failure	Transmission	HFTD Zone 1		[redacted]									# ignitions	
	2.d.viii	Lightning arrestor damage or failure	Transmission	HFTD Tier 2		0	0	0	0	0	0	0	0	0	# ignitions	
	2.d.ix	Lightning arrestor damage or failure	Transmission	HFTD Tier 3		0	0	0	0	0	0	0	0	0	# ignitions	
	2.d.x	Lightning arrestor damage or failure	Transmission	System		0	0	0	0	0	0	0	0	0	# ignitions	
	2.e.i	Switch damage or failure	Distribution	Non-HFTD	Yes	0	0	0	0	0	1	0	0.2	0.2	# ignitions	
	2.e.ii	Switch damage or failure	Distribution	HFTD Zone 1	Yes	[redacted]									# ignitions	
	2.e.iii	Switch damage or failure	Distribution	HFTD Tier 2	Yes	0	0	0	1	1	0	0	0.393	0.387	# ignitions	
	2.e.iv	Switch damage or failure	Distribution	HFTD Tier 3	Yes	1	0	0	0	0	0	1	0	0	# ignitions	
	2.e.v	Switch damage or failure	Distribution	System	Yes	1	0	0	1	1	1	1	0.593	0.587	# ignitions	
	2.e.vi	Switch damage or failure	Transmission	Non-HFTD	Yes	0	0	0	0	0	0	0	0	0	# ignitions	
	2.e.vii	Switch damage or failure	Transmission	HFTD Zone 1	Yes	[redacted]									# ignitions	
	2.e.viii	Switch damage or failure	Transmission	HFTD Tier 2	Yes	0	0	0	0	0	0	0	0	0	# ignitions	
	2.e.ix	Switch damage or failure	Transmission	HFTD Tier 3	Yes	0	0	0	0	0	0	0	1	1	# ignitions	
	2.e.x	Switch damage or failure	Transmission	System	Yes	0	0	0	0	0	0	0	1	1	# ignitions	
	2.f.i	Pole damage or failure	Distribution	Non-HFTD	Yes	0	0	0	0	0	0	0	0	0	# ignitions	
	2.f.ii	Pole damage or failure	Distribution	HFTD Zone 1	Yes	[redacted]									# ignitions	
	2.f.iii	Pole damage or failure	Distribution	HFTD Tier 2	Yes	0	0	0	0	0	1	0	0.2	0.2	# ignitions	
	2.f.iv	Pole damage or failure	Distribution	HFTD Tier 3	Yes	0	0	0	0	0	0	0	0	0	# ignitions	
	2.f.v	Pole damage or failure	Distribution	System	Yes	0	0	0	0	0	1	0	0.2	0.2	# ignitions	
	2.f.vi	Pole damage or failure	Transmission	Non-HFTD		0	0	0	0	0	0	0	0	0	# ignitions	
	2.f.vii	Pole damage or failure	Transmission	HFTD Zone 1		[redacted]									# ignitions	
	2.f.viii	Pole damage or failure	Transmission	HFTD Tier 2		0	0	0	0	0	0	0	0	0	# ignitions	
	2.f.ix	Pole damage or failure	Transmission	HFTD Tier 3		0	0	0	0	0	0	0	0	0	# ignitions	
	2.f.x	Pole damage or failure	Transmission	System		0	0	0	0	0	0	0	0	0	# ignitions	
	2.g.i	Insulator and brushing damage or failure	Distribution	Non-HFTD		0	0	0	0	0	0	0	0	0	# ignitions	
	2.g.ii	Insulator and brushing damage or failure	Distribution	HFTD Zone 1		[redacted]									# ignitions	
	2.g.iii	Insulator and brushing damage or failure	Distribution	HFTD Tier 2		0	0	0	0	0	0	0	0	0	# ignitions	
	2.g.iv	Insulator and brushing damage or failure	Distribution	HFTD Tier 3		0	0	0	0	0	0	0	0	0	# ignitions	
	2.g.v	Insulator and brushing damage or failure	Distribution	System		0	0	0	0	0	0	0	0	0	# ignitions	
	2.g.vi	Insulator and brushing damage or failure	Transmission	Non-HFTD		0	0	0	0	0	0	0	0	0	# ignitions	
	2.g.vii	Insulator and brushing damage or failure	Transmission	HFTD Zone 1		[redacted]									# ignitions	
	2.g.viii	Insulator and brushing damage or failure	Transmission	HFTD Tier 2		0	0	0	0	0	0	0	0	0	# ignitions	
	2.g.ix	Insulator and brushing damage or failure	Transmission	HFTD Tier 3		0	0	0	0	0	0	0	0	0	# ignitions	
	2.g.x	Insulator and brushing damage or failure	Transmission	System		0	0	0	0	0	0	0	0	0	# ignitions	
	2.h.i	Crossarm damage or failure	Distribution	Non-HFTD	Yes	0	0	0	1	1	0	0	0.4	0.4	# ignitions	
	2.h.ii	Crossarm damage or failure	Distribution	HFTD Zone 1	Yes	[redacted]									# ignitions	
	2.h.iii	Crossarm damage or failure	Distribution	HFTD Tier 2	Yes	0	0	0	0	0	0	0	0	0	# ignitions	
	2.h.iv	Crossarm damage or failure	Distribution	HFTD Tier 3	Yes	0	0	0	0	0	0	0	0	0	# ignitions	
	2.h.v	Crossarm damage or failure	Distribution	System	Yes	0	0	0	1	1	0	0	0.4	0.4	# ignitions	
	2.h.vi	Crossarm damage or failure	Transmission	Non-HFTD		0	0	0	0	0	0	0	0	0	# ignitions	
	2.h.vii	Crossarm damage or failure	Transmission	HFTD Zone 1		[redacted]									# ignitions	
	2.h.viii	Crossarm damage or failure	Transmission	HFTD Tier 2		0	0	0	0	0	0	0	0	0	# ignitions	
	2.h.ix	Crossarm damage or failure	Transmission	HFTD Tier 3		0	0	0	0	0	0	0	0	0	# ignitions	
	2.h.x	Crossarm damage or failure	Transmission	System		0	0	0	0	0	0	0	0	0	# ignitions	
	2.i.i	Voltage regulator / booster damage or failure	Distribution	Non-HFTD		0	0	0	0	0	0	0	0	0	# ignitions	
	2.i.ii	Voltage regulator / booster damage or failure	Distribution	HFTD Zone 1		[redacted]									# ignitions	
	2.i.iii	Voltage regulator / booster damage or failure	Distribution	HFTD Tier 2		0	0	0	0	0	0	0	0	0	# ignitions	
	2.i.iv	Voltage regulator / booster damage or failure	Distribution	HFTD Tier 3		0	0	0	0	0	0	0	0	0	# ignitions	
	2.i.v	Voltage regulator / booster damage or failure	Distribution	System		0	0	0	0	0	0	0	0	0	# ignitions	
	2.i.vi	Voltage regulator / booster damage or failure	Transmission	Non-HFTD		0	0	0	0	0	0	0	0	0	# ignitions	
	2.i.vii	Voltage regulator / booster damage or failure	Transmission	HFTD Zone 1		[redacted]									# ignitions	
	2.i.viii	Voltage regulator / booster damage or failure	Transmission	HFTD Tier 2		0	0	0	0	0	0	0	0	0	# ignitions	
	2.i.ix	Voltage regulator / booster damage or failure	Transmission	HFTD Tier 3		0	0	0	0	0	0	0	0	0	# ignitions	
	2.i.x	Voltage regulator / booster damage or failure	Transmission	System		0	0	0	0	0	0	0	0	0	# ignitions	

Utility	SDG&E	**Notes:**
Table No.	7.2	Transmission lines refer to all lines at or above 65kV, and distribution lines refer to all lines below 65kV.
Date Modified	2022 02 09	Data from 2015 - 2021 should be actual numbers. 2022 and 2023 should be projected. In future submissions update projected numbers with actuals

Table 7.2: Key recent and projected drivers of ignitions

Metric type	#	Ignition driver	Line Type	HFTD tier	Are ignit	Number of ignitions 2015	2016	2017	2018	2019	2020	2021	Projected ignitions 2022	2023	Unit(s)	Comments
	2.j.i	Recloser damage or failure	Distribution	Non-HFTD		0	0	0	0	0	0	0	0	0	# ignitions	
	2.j.ii	Recloser damage or failure	Distribution	HFTD Zone 1											# ignitions	
	2.j.iii	Recloser damage or failure	Distribution	HFTD Tier 2		0	0	0	0	0	0	0	0	0	# ignitions	
	2.j.iv	Recloser damage or failure	Distribution	HFTD Tier 3		0	0	0	0	0	0	0	0	0	# ignitions	
	2.j.v	Recloser damage or failure	Distribution	System		0	0	0	0	0	0	0	0	0	# ignitions	
	2.j.vi	Recloser damage or failure	Transmission	Non-HFTD		0	0	0	0	0	0	0	0	0	# ignitions	
	2.j.vii	Recloser damage or failure	Transmission	HFTD Zone 1											# ignitions	
	2.j.viii	Recloser damage or failure	Transmission	HFTD Tier 2		0	0	0	0	0	0	0	0	0	# ignitions	
	2.j.ix	Recloser damage or failure	Transmission	HFTD Tier 3		0	0	0	0	0	0	0	0	0	# ignitions	
	2.j.x	Recloser damage or failure	Transmission	System		0	0	0	0	0	0	0	0	0	# ignitions	
	2.k.i	Anchor / guy damage or failure	Distribution	Non-HFTD		0	0	0	1	1	0	0	0.4	0.4	# ignitions	
	2.k.ii	Anchor / guy damage or failure	Distribution	HFTD Zone 1											# ignitions	
	2.k.iii	Anchor / guy damage or failure	Distribution	HFTD Tier 2		0	0	0	0	0	0	0	0	0	# ignitions	
	2.k.iv	Anchor / guy damage or failure	Distribution	HFTD Tier 3		0	0	0	0	0	1	0	0.2	0.2	# ignitions	
	2.k.v	Anchor / guy damage or failure	Distribution	System		0	0	0	1	1	1	0	0.6	0.6	# ignitions	
	2.k.vi	Anchor / guy damage or failure	Transmission	Non-HFTD		0	0	0	0	0	0	0	0	0	# ignitions	
	2.k.vii	Anchor / guy damage or failure	Transmission	HFTD Zone 1											# ignitions	
	2.k.viii	Anchor / guy damage or failure	Transmission	HFTD Tier 2		0	0	0	0	0	0	0	0	0	# ignitions	
	2.k.ix	Anchor / guy damage or failure	Transmission	HFTD Tier 3		0	0	0	0	0	0	0	0	0	# ignitions	
	2.k.x	Anchor / guy damage or failure	Transmission	System		0	0	0	0	0	0	0	0	0	# ignitions	
	2.l.i	Sectionalizer damage or failure	Distribution	Non-HFTD		0	0	0	0	0	0	0	0	0	# ignitions	
	2.l.ii	Sectionalizer damage or failure	Distribution	HFTD Zone 1											# ignitions	
	2.l.iii	Sectionalizer damage or failure	Distribution	HFTD Tier 2		0	0	0	0	0	0	0	0	0	# ignitions	
	2.l.iv	Sectionalizer damage or failure	Distribution	HFTD Tier 3		0	0	0	0	0	0	0	0	0	# ignitions	
	2.l.v	Sectionalizer damage or failure	Distribution	System		0	0	0	0	0	0	0	0	0	# ignitions	
	2.l.vi	Sectionalizer damage or failure	Transmission	Non-HFTD		0	0	0	0	0	0	0	0	0	# ignitions	
	2.l.vii	Sectionalizer damage or failure	Transmission	HFTD Zone 1											# ignitions	
	2.l.viii	Sectionalizer damage or failure	Transmission	HFTD Tier 2		0	0	0	0	0	0	0	0	0	# ignitions	
	2.l.ix	Sectionalizer damage or failure	Transmission	HFTD Tier 3		0	0	0	0	0	0	0	0	0	# ignitions	
	2.l.x	Sectionalizer damage or failure	Transmission	System		0	0	0	0	0	0	0	0	0	# ignitions	
	2.m.i	Connection device damage or failure	Distribution	Non-HFTD	Yes	2	1	0	0	1	1	0	0.4	0.399	# ignitions	
	2.m.ii	Connection device damage or failure	Distribution	HFTD Zone 1	Yes										# ignitions	
	2.m.iii	Connection device damage or failure	Distribution	HFTD Tier 2	Yes	0	1	0	0	0	0	0	0	0	# ignitions	
	2.m.iv	Connection device damage or failure	Distribution	HFTD Tier 3	Yes	0	1	0	0	0	2	2	0.792	0.784	# ignitions	
	2.m.v	Connection device damage or failure	Distribution	System	Yes	2	3	0	0	1	3	2	1.192	1.184	# ignitions	
	2.m.vi	Connection device damage or failure	Transmission	Non-HFTD	Yes	0	0	0	0	0	0	0	0	0	# ignitions	
	2.m.vii	Connection device damage or failure	Transmission	HFTD Zone 1	Yes										# ignitions	
	2.m.viii	Connection device damage or failure	Transmission	HFTD Tier 2	Yes	1	0	0	0	0	0	0	0	0	# ignitions	
	2.m.ix	Connection device damage or failure	Transmission	HFTD Tier 3	Yes	0	0	0	0	0	0	0	0	0	# ignitions	
	2.m.x	Connection device damage or failure	Transmission	System	Yes	1	0	0	0	0	0	0	0	0	# ignitions	
	2.n.i	Transformer damage or failure	Distribution	Non-HFTD	Yes	1	0	0	0	0	0	1	0.2	0.2	# ignitions	
	2.n.ii	Transformer damage or failure	Distribution	HFTD Zone 1	Yes										# ignitions	
	2.n.iii	Transformer damage or failure	Distribution	HFTD Tier 2	Yes	0	1	0	0	0	0	0	0	0	# ignitions	
	2.n.iv	Transformer damage or failure	Distribution	HFTD Tier 3	Yes	0	1	0	1	0	0	0	0.186	0.171	# ignitions	
	2.n.v	Transformer damage or failure	Distribution	System	Yes	1	2	0	1	0	0	1	0.386	0.371	# ignitions	
	2.n.vi	Transformer damage or failure	Transmission	Non-HFTD		0	0	0	0	0	0	0	0	0	# ignitions	
	2.n.vii	Transformer damage or failure	Transmission	HFTD Zone 1											# ignitions	
	2.n.viii	Transformer damage or failure	Transmission	HFTD Tier 2		0	0	0	0	0	0	0	0	0	# ignitions	
	2.n.ix	Transformer damage or failure	Transmission	HFTD Tier 3		0	0	0	0	0	0	0	0	0	# ignitions	
	2.n.x	Transformer damage or failure	Transmission	System		0	0	0	0	0	0	0	0	0	# ignitions	
	2.o.i	Other	Distribution	Non-HFTD	Yes	0	0	0	1	1	1	0	0.6	0.6	# ignitions	
	2.o.ii	Other	Distribution	HFTD Zone 1	Yes										# ignitions	
	2.o.iii	Other	Distribution	HFTD Tier 2	Yes	0	0	1	0	1	1	0	0.59	0.58	# ignitions	
	2.o.iv	Other	Distribution	HFTD Tier 3	Yes	0	1	0	0	1	0	0	0.186	0.171	# ignitions	
	2.o.v	Other	Distribution	System	Yes	0	1	1	1	3	2	0	1.375	1.351	# ignitions	
	2.o.vi	Other	Transmission	Non-HFTD	Yes	0	0	0	0	0	0	0	0	0	# ignitions	
	2.o.vii	Other	Transmission	HFTD Zone 1	Yes										# ignitions	
	2.o.viii	Other	Transmission	HFTD Tier 2	Yes	0	0	0	0	0	1	0	0.2	0.2	# ignitions	
	2.o.ix	Other	Transmission	HFTD Tier 3	Yes	0	0	0	0	0	0	0	0	0	# ignitions	
	2.o.x	Other	Transmission	System	Yes	0	0	0	0	0	1	0	0.2	0.2	# ignitions	
3. Wire-to-wire contact	3.a.i	Wire-to-wire contact / contamination	Distribution	Non-HFTD	Yes	0	0	0	1	1	0	0	0.4	0.4	# ignitions	
	3.a.ii	Wire-to-wire contact / contamination	Distribution	HFTD Zone 1	Yes										# ignitions	
	3.a.iii	Wire-to-wire contact / contamination	Distribution	HFTD Tier 2	Yes	0	0	0	0	1	0	0	0.197	0.193	# ignitions	
	3.a.iv	Wire-to-wire contact / contamination	Distribution	HFTD Tier 3	Yes	0	0	0	0	0	0	0	0	0	# ignitions	
	3.a.v	Wire-to-wire contact / contamination	Distribution	System	Yes	0	0	0	1	2	0	0	0.597	0.593	# ignitions	
	3.a.vi	Wire-to-wire contact / contamination	Transmission	Non-HFTD	Yes	0	0	0	0	0	0	1	0.2	0.2	# ignitions	
	3.a.vii	Wire-to-wire contact / contamination	Transmission	HFTD Zone 1	Yes										# ignitions	
	3.a.viii	Wire-to-wire contact / contamination	Transmission	HFTD Tier 2	Yes	0	0	0	0	0	0	0	0	0	# ignitions	
	3.a.ix	Wire-to-wire contact / contamination	Transmission	HFTD Tier 3	Yes	0	0	0	0	0	0	0	0	0	# ignitions	
	3.a.x	Wire-to-wire contact / contamination	Transmission	System	Yes	0	0	0	0	0	0	1	0.2	0.2	# ignitions	
4. Contamination	4.a.i	Contamination	Distribution	Non-HFTD		0	0	0	0	0	0	0	0	0	# ignitions	
	4.a.ii	Contamination	Distribution	HFTD Zone 1											# ignitions	
	4.a.iii	Contamination	Distribution	HFTD Tier 2		0	0	0	0	0	0	0	0	0	# ignitions	
	4.a.iv	Contamination	Distribution	HFTD Tier 3		0	0	0	0	0	0	0	0	0	# ignitions	

Utility	SDG&E
Table No.	7.2
Date Modified	2022 02 09

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Table 7.2: Key recent and projected drivers of ignitions

						Number of ignitions							Projected ignitions			
Metric type	**#**	**Ignition driver**	**Line Type**	**HFTD tier**	**Are ignit**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**Unit(s)**	**Comments**
	4.a.v	Contamination	Distribution	System		0	0	0	0	0	0	0	0	0	# ignitions	
	4.a.vi	Contamination	Transmission	Non-HFTD		0	0	0	0	0	0	0	0	0	# ignitions	
	4.a.vii	Contamination	Transmission	HFTD Zone 1											# ignitions	
	4.a.viii	Contamination	Transmission	HFTD Tier 2		0	0	0	0	0	0	0	0	0	# ignitions	
	4.a.ix	Contamination	Transmission	HFTD Tier 3		0	0	0	0	0	0	0	0	0	# ignitions	
	4.a.x	Contamination	Transmission	System		0	0	0	0	0	0	0	0	0	# ignitions	
5. Utility work / Operation	5.a.i	Utility work / Operation	Distribution	Non-HFTD		0	0	0	0	0	0	0	0	0	# ignitions	
	5.a.ii	Utility work / Operation	Distribution	HFTD Zone 1											# ignitions	
	5.a.iii	Utility work / Operation	Distribution	HFTD Tier 2		0	0	0	0	0	0	0	0	0	# ignitions	
	5.a.iv	Utility work / Operation	Distribution	HFTD Tier 3		0	0	0	0	0	0	0	0	0	# ignitions	
	5.a.v	Utility work / Operation	Distribution	System		0	0	0	0	0	0	0	0	0	# ignitions	
	5.a.vi	Utility work / Operation	Transmission	Non-HFTD		0	0	0	0	0	0	0	0	0	# ignitions	
	5.a.vii	Utility work / Operation	Transmission	HFTD Zone 1											# ignitions	
	5.a.viii	Utility work / Operation	Transmission	HFTD Tier 2		0	0	0	0	0	0	0	0	0	# ignitions	
	5.a.ix	Utility work / Operation	Transmission	HFTD Tier 3		0	0	0	0	0	0	0	0	0	# ignitions	
	5.a.x	Utility work / Operation	Transmission	System		0	0	0	0	0	0	0	0	0	# ignitions	
6. Vandalism / Theft	6.a.i	Vandalism / Theft	Distribution	Non-HFTD	Yes	0	0	1	0	0	0	0	0.2	0.2	# ignitions	
	6.a.ii	Vandalism / Theft	Distribution	HFTD Zone 1	Yes										# ignitions	
	6.a.iii	Vandalism / Theft	Distribution	HFTD Tier 2	Yes	0	0	0	0	0	0	1	0.2	0.2	# ignitions	
	6.a.iv	Vandalism / Theft	Distribution	HFTD Tier 3	Yes	0	1	0	0	0	0	0	0	0	# ignitions	
	6.a.v	Vandalism / Theft	Distribution	System	Yes	0	1	1	0	0	0	1	0.4	0.4	# ignitions	
	6.a.vi	Vandalism / Theft	Transmission	Non-HFTD		0	0	0	0	0	0	0	0	0	# ignitions	
	6.a.vii	Vandalism / Theft	Transmission	HFTD Zone 1											# ignitions	
	6.a.viii	Vandalism / Theft	Transmission	HFTD Tier 2		0	0	0	0	0	0	0	0	0	# ignitions	
	6.a.ix	Vandalism / Theft	Transmission	HFTD Tier 3		0	0	0	0	0	0	0	0	0	# ignitions	
	6.a.x	Vandalism / Theft	Transmission	System		0	0	0	0	0	0	0	0	0	# ignitions	
7. Other	7.a.i	All Other	Distribution	Non-HFTD		0	0	0	0	0	0	0	0	0	# ignitions	
	7.a.ii	All Other	Distribution	HFTD Zone 1											# ignitions	
	7.a.iii	All Other	Distribution	HFTD Tier 2		0	0	0	0	0	0	0	0	0	# ignitions	
	7.a.iv	All Other	Distribution	HFTD Tier 3		0	0	0	0	0	0	0	0	0	# ignitions	
	7.a.v	All Other	Distribution	System		0	0	0	0	0	0	0	0	0	# ignitions	
	7.a.vi	All Other	Transmission	Non-HFTD		0	0	0	0	0	0	0	0	0	# ignitions	
	7.a.vii	All Other	Transmission	HFTD Zone 1											# ignitions	
	7.a.viii	All Other	Transmission	HFTD Tier 2		0	0	0	0	0	0	0	0	0	# ignitions	
	7.a.ix	All Other	Transmission	HFTD Tier 3		0	0	0	0	0	0	0	0	0	# ignitions	
	7.a.x	All Other	Transmission	System		0	0	0	0	0	0	0	0	0	# ignitions	
8. Unknown	8.a.i	Unknown	Distribution	Non-HFTD	Yes	0	0	0	0	0	0	0	0	0	# ignitions	
	8.a.ii	Unknown	Distribution	HFTD Zone 1	Yes										# ignitions	
	8.a.iii	Unknown	Distribution	HFTD Tier 2	Yes	1	0	1	0	0	0	0	0.193	0.187	# ignitions	
	8.a.iv	Unknown	Distribution	HFTD Tier 3	Yes	1	0	0	0	0	0	0	0	0	# ignitions	
	8.a.v	Unknown	Distribution	System	Yes	2	0	1	0	0	0	0	0.193	0.187	# ignitions	
	8.a.vi	Unknown	Transmission	Non-HFTD	Yes	0	1	0	0	0	0	0	0	0	# ignitions	
	8.a.vii	Unknown	Transmission	HFTD Zone 1	Yes										# ignitions	
	8.a.viii	Unknown	Transmission	HFTD Tier 2	Yes	0	0	0	0	1	1	0	0.396	0.392	# ignitions	
	8.a.ix	Unknown	Transmission	HFTD Tier 3	Yes	0	0	0	0	0	0	0	0	0	# ignitions	
	8.a.x	Unknown	Transmission	System	Yes	0	1	0	0	1	1	0	0.396	0.392	# ignitions	
9. Secondary		All Secondary		Non-HFTD	Yes	1	0	0	0	3	0	2	1	1	# ignitions	

Utility	SDG&E		
Table No.	8		
Date Modified	2022 02 09		

Table 8: State of service territory and utility equipment

	Metric type	#	Outcome metric name	Non-HI 2015	HFTD Z 2015	HFTD T 2015	HFTD T 2015	Non-HI 2016	HFTD Z 2016	HFTD T 2016	HFTD T 2016	Non-HI 2017	HFTD Z 2017	HFTD T 2017	HFTD T 2017	Non-HI 2018	HFTD Z 2018	HFTD T 2018	HFTD Ti 2018	Non-HF 2019	HFTD Zc 2019	HFTD Ti 2019	HFTD Ti 2019	Non-HFTD 2020	HFTD Zone 1 2020	HFTD Tier 2 2020	HFTD Tier 3 2020	Non-HFTD 2021	HFTD Zone 1 2021	HFTD Tier 2 2021	HFTD Tier 3 2021	Non-HFTD 2022	HFTD Zone 1 2022	HFTD Tier 2 2022	HFTD Tier 3 2022	Unit(s)	Comments
x	1. State of service territory and equipment	1.a.	Circuit miles (including WUI and non-WUI)																					9276.9	0.1	1113.7	5.7	9821.1		1237.9	8.1					Circuit miles	For 2/5/21 submission, SDG&E approximated column AC by summing tier 2 and tier 3 data for 2020. For 2021 Q1
		1.b.	Circuit miles in WUI																					105.6	0.0	2.3	0.0	2493.4		932.3	8.0					Circuit miles in WUI	For 11/1/21 submission, SDG&E redefined and updated its WUI
		1.c.	Number of critical facilities (including WUI and non-WUI)																					13115.0	0.0	959.0	2.0	13431.0		926.0	5.0					Number of critical facilities	
		1.d.	Number of critical facilities in WUI																					109.0	0.0	0.0	0.0	2175.0		683.0	5.0					Number of critical facilities in WUI	
		1.e.	Number of customers (including WUI and non WUI)																					1037581.0	2.0	83589.0	115.0	1181644.0		89430.0	121.0					Number of customers	
		1.f.	Number of customers in WUI																					5445.0	2.0	0.0	0.0	215834.0		70821.0	118.0					Number of customers in WUI	
		1.g.	Number of customers belonging to access and functional needs populations (including WUI and non-WUI)																					40564.0	0.0	3678.0	14.0	52622.0		4501.0	12.0					Number of customers belonging to access and functional needs populations	
		1.h.	Number of customers belonging to access and functional needs populations in WUI																					171.0	0.0	0.0	0.0	10852.0		3481.0	12.0					Number of customers belonging to access and functional needs populations in WUI	
		1.i.	Circuit miles of overhead transmission lines (including WUI and non-WUI)																					429.2	0.0	110.7	0.0	437.2		108.3	0.0					Circuit miles of overhead transmission lines	
		1.j.	Circuit miles of overhead transmission lines in WUI																					33.9	0.0	1.7	0.0	143.8		42.2	0.0					Circuit miles of overhead transmission lines in WUI	
		1.k.	Circuit miles of overhead distribution lines (including WUI and non-WUI)																					2499.0	0.1	181.4	5.2	2488.4		180.9	5.4					Circuit miles of overhead distribution lines	
		1.l.	Circuit miles of overhead distribution lines in WUI																					41.6	0.0	0.1	0.0	402.8		95.5	5.3					Circuit miles of overhead distribution lines in WUI	
		1.m.	Number of substations (including WUI and non-WUI)																					79.0	0.0	6.0	0.0	78.0		6.0	0.0					Number of substations	
		1.n	Number of substations in WUI																					1.0	0.0	0.0	0.0	12.0		1.0	0.0					Number of substations in WUI	
		1.o.	Number of weather stations (including WUI and non-WUI)																					15.0	0.0	6.0	0.0	15.0		6.0	0.0					Number of weather stations	
		1.p.	Number of weather stations in WUI																					3.0	0.0	0.0	0.0	3.0		2.0	0.0					Number of weather stations in WUI	
x	2. State of service territory and equipment in rural areas	2.a.	Circuit miles (including WUI and non-WUI)																					1854.0	49.3	2789.1	1845.2	2078.7		3385.1	2129.6					Circuit miles	
		2.b.	Circuit miles in WUI																					182.0	0.0	6.5	0.0	869.1		1999.9	976.0					Circuit miles in WUI	
		2.c.	Number of critical facilities (including WUI and non-WUI)																					2427.0	4.0	1467.0	896.0	2525.0		1366.0	1009.0					Number of critical facilities	
		2.d.	Number of critical facilities in WUI																					66.0	0.0	0.0	0.0	508.0		776.0	396.0					Number of critical facilities in WUI	
		2.e.	Number of customers (including WUI and non WUI)																					87487.0	79.0	77782.0	21139.0	103826.0		86224.0	29508.0					Number of customers	
		2.f.	Number of customers in WUI																					3984.0	0.0	0.0	0.0	41415.0		62646.0	20177.0					Number of customers in WUI	
		2.g.	Number of customers belonging to access and functional needs populations (including WUI and non-WUI)																					3102.0	7.0	4630.0	1811.0	4336.0		5868.0	2676.0					Number of customers belonging to access and functional needs populations	
		2.h.	Number of customers belonging to access and functional needs populations in WUI																					137.0	0.0	0.0	0.0	2292.0		4634.0	2102.0					Number of customers belonging to access and functional needs populations in WUI	
		2.i.	Circuit miles of overhead transmission lines (including WUI and non-WUI)																					152.3	6.4	551.7	248.2	176.4		573.8	250.1					Circuit miles of overhead transmission lines	
		2.j.	Circuit miles of overhead transmission lines in WUI																					19.7	0.0	1.0	0.0	61.5		127.6	21.9					Circuit miles of overhead transmission lines in WUI	
		2.k.	Circuit miles of overhead distribution lines (including WUI and non-WUI)																					363.7	42.4	1470.3	1449.9	363.1		1459.4	1445.5					Circuit miles of overhead distribution lines	
		2.l.	Circuit miles of overhead distribution lines in WUI																					63.7	0.0	0.6	0.0	181.3		854.1	660.6					Circuit miles of overhead distribution lines in WUI	
		2.m.	Number of substations (including WUI and non-WUI)																					31.0	1.0	28.0	11.0	30.0		28.0	11.0					Number of substations	
		2.n	Number of substations in WUI																					1.0	0.0	0.0	0.0	4.0		5.0	0.0					Number of substations in WUI	
		2.o.	Number of weather stations (including WUI and non-WUI)																					4.0	2.0	51.0	82.0	4.0		54.0	85.0					Number of weather stations	
		2.p.	Number of weather stations in WUI																					1.0	0.0	0.0	0.0	1.0		12.0	12.0					Number of weather stations in WUI	
x	3. State of service territory and equipment in highly rural areas	3.a.	Circuit miles (including WUI and non-WUI)																					216.5	35.3	184.9	213.6	247.6		206.8	241.3					Circuit miles	
		3.b.	Circuit miles in WUI																					0.0	0.0	0.0	0.0	52.5		21.9	36.5					Circuit miles in WUI	
		3.c.	Number of critical facilities (including WUI and non-WUI)																					129.0	8.0	85.0	87.0	118.0		76.0	83.0					Number of critical facilities	
		3.d.	Number of critical facilities in WUI																					0.0	0.0	0.0	0.0	3.0		18.0	27.0					Number of critical facilities in WUI	
		3.e.	Number of customers (including WUI and non WUI)																					296.0	79.0	203.0	569.0	3291.0		999.0	2264.0					Number of customers	
		3.f.	Number of customers in WUI																					0.0	0.0	0.0	0.0	1093.0		319.0	1050.0					Number of customers in WUI	
		3.g.	Number of customers belonging to access and functional needs populations (including WUI and non-WUI)																					4.0	4.0	5.0	20.0	151.0		54.0	139.0					Number of customers belonging to access and functional needs populations	
		3.h.	Number of customers belonging to access and functional needs populations in WUI																					0.0	0.0	0.0	0.0	59.0		23.0	95.0					Number of customers belonging to access and functional needs populations in WUI	
		3.i.	Circuit miles of overhead transmission lines (including WUI and non-WUI)																					24.8	1.5	23.4	23.7	22.8		23.4	18.6					Circuit miles of overhead transmission lines	
		3.j.	Circuit miles of overhead transmission lines in WUI																					0.0	0.0	0.0	0.0	0.0		0.0	2.9					Circuit miles of overhead transmission lines in WUI	
		3.k.	Circuit miles of overhead distribution lines (including WUI and non-WUI)																					144.1	30.5	174.3	187.2	145.7		172.9	190.8					Circuit miles of overhead distribution lines	
		3.l.	Circuit miles of overhead distribution lines in WUI																					0.0	0.0	0.0	0.0	34.7		20.3	27.1					Circuit miles of overhead distribution lines in WUI	
		3.m.	Number of substations (including WUI and non-WUI)																					3.0	2.0	1.0	2.0	3.0		1.0	2.0					Number of substations	
		3.n	Number of substations in WUI																					0.0	0.0	0.0	0.0	0.0		0.0	0.0					Number of substations in WUI	
		3.o.	Number of weather stations (including WUI and non-WUI)																					2.0	2.0	8.0	18.0	2.0		8.0	18.0					Number of weather stations	
		3.p.	Number of weather stations in WUI																					0.0	0.0	0.0	0.0	0.0		1.0	2.0					Number of weather stations in WUI	

Utility	SDG&E	Notes:
Table No.	9	Transmission lines refer to all lines at or above 65kV, and distribution lines refer to all lines below 65kV. Report net additions using positive numbers and net removals and undergrounding using negative numbers for circuit miles and numbers of substations. Only report changes expected within the target year.
Date Modified	2022 02 09	For example, if 20 net overhead circuit miles are planned for addition by 2023, with 15 being added by 2022 and 5 more added by 2023, then report “15” for 2022 and “5” for 2023. Do not report cumulative change across years. In this case, do not report “20” for 2023, but instead the number planned to be added for just that year, which is “5”.

Table 9: Location of actual and planned utility equipment additions or removal year over year

				Actual								Projected					
				Non-HFTD	HFTD Zone 1	HFTD Tier 2	HFTD Tier 3	Non-HFTD	HFTD Zone 1	HFTD Tier 2	HFTD Tier 3	Non-HFTD	HFTD Zone 1	HFTD Tier 2	HFTD Tier 3		
	Metric type	**#**	**Outcome metric name**	**2020**	**2020**	**2020**	**2020**	**2021**	**2021**	**2021**	**2021**	**2022**	**2022**	**2022**	**2022**	**Unit(s)**	**Comments**
x	1. Planned utility equipment net addition (or removal) year over year - in urban areas	1.a.	Circuit miles of overhead transmission lines (including WUI and non-WUI)					-0.4		0.0	0.0	0.0		-0.3	0.0	Circuit miles	SDG&E started tracking historical outputs in table 8 from Q1 2021. The actuals reflect the differences (additions/removal)
		1.b.	Circuit miles of overhead distribution lines (including WUI and non-WUI)					-4.6		-0.3	0.0	0.0		0.0	0.0	Circuit miles	For 11/1/21 submission, SDG&E redefined and updated its WUI area and the polygon query for all WUI metrics in table 8. Metric values for "only WUI" have changed due to this update.
		1.c.	Circuit miles of overhead transmission lines in WUI					-0.2		0.0	0.0	0.0		0.0	0.0	Circuit miles in WUI	
		1.d.	Circuit miles of overhead distribution lines in WUI					-0.6		-0.2	0.0	0.0		0.0	0.0	Circuit miles in WUI	
		1.e.	Number of substations (including WUI and non-WUI)					-1.0		0.0	0.0	0.0		0.0	0.0	Number of substations	
		1.f.	Number of substations in WUI					1.0		0.0	0.0	0.0		0.0	0.0	Number of substations in WUI	
		1.g.	Number of weather stations (including WUI and non-WUI)					0.0		0.0	0.0	1.0		0.0	0.0	Number of weather stations	
		1.h.	Number of weather stations in WUI					0.0		0.0	0.0	0.0		0.0	0.0	Number of weather stations in WUI	
x	2. Planned utility equipment net addition (or removal) year over year - in rural areas	2.a.	Circuit miles of overhead transmission lines (including WUI and non-WUI)					-0.2		-0.1	0.0	0.1		-0.1	0.0	Circuit miles	
		2.b.	Circuit miles of overhead distribution lines (including WUI and non-WUI)					-0.6		-8.7	-8.4			0.0	0.0	Circuit miles	
		2.c.	Circuit miles of overhead transmission lines in WUI					0.0		0.0	0.1	0.1		-0.1	0.0	Circuit miles in WUI	
		2.d.	Circuit miles of overhead distribution lines in WUI					1.2		-3.1	-3.9	0.0		0.0	0.0	Circuit miles in WUI	
		2.e.	Number of substations (including WUI and non-WUI)					0.0		0.0	0.0	0.0		0.0	0.0	Number of substations	
		2.f.	Number of substations in WUI					0.0		0.0	0.0	0.0		0.0	0.0	Number of substations in WUI	
		2.g.	Number of weather stations (including WUI and non-WUI)					0.0		1.0	1.0	0.0		0.0	0.0	Number of weather stations	
		2.h.	Number of weather stations in WUI					0.0		-2.0	-1.0	0.0		0.0	0.0	Number of weather stations in WUI	
x	3. Planned utility equipment net addition (or removal) year over year - in highly rural areas	3.a.	Circuit miles of overhead transmission lines (including WUI and non-WUI)					0.0		0.0	-0.1	0.0		-0.2	0.0	Circuit miles	
		3.b.	Circuit miles of overhead distribution lines (including WUI and non-WUI)					1.6		-1.5	-4.3	0.0		0.0	0.0	Circuit miles	
		3.c.	Circuit miles of overhead transmission lines in WUI					0.0		0.0	0.0	0.0		0.0	0.0	Circuit miles in WUI	
		3.d.	Circuit miles of overhead distribution lines in WUI					0.0		0.1	-0.2	0.0		0.0	0.0	Circuit miles in WUI	
		3.e.	Number of substations (including WUI and non-WUI)					0.0		0.0	0.0	0.0		1.0	0.0	Number of substations	
		3.f.	Number of substations in WUI					0.0		0.0	0.0	0.0		0.0	0.0	Number of substations in WUI	
		3.g.	Number of weather stations (including WUI and non-WUI)					0.0		0.0	0.0	0.0		0.0	0.0	Number of weather stations	
		3.h.	Number of weather stations in WUI					0.0		0.0	0.0	0.0		0.0	0.0	Number of weather stations in WUI	

Utility	SDG&E
Table No.	10
Date Modified	2022 02 09

Notes:
Transmission lines refer to all lines at or above 65kV, and distribution lines refer to all lines below 65kV.
In future submissions update planned upgrade numbers with actuals

In the comments column on the far-right, enter the relevant program target(s) associated

Table 10: Location of actual and planned utility infrastructure upgrades year over year

				Actual								Projected					
				Non-HFTD	HFTD Zone 1	HFTD Tier 2	HFTD Tier 3	Non-HFTD	HFTD Zone 1	HFTD Tier 2	HFTD Tier 3	Non-HFTD	HFTD Zone 1	HFTD Tier 2	HFTD Tier 3		
	Metric type	**#**	**Outcome metric name**	**2020**	**2020**	**2020**	**2020**	**2021**	**2021**	**2021**	**2021**	**2022**	**2022**	**2022**	**2022**	**Unit(s)**	**Comments**
x	1. Planned utility infrastructure upgrades year over year - in urban areas	1.a.	Circuit miles of overhead transmission lines planned for upgrades (including WUI and non-WUI)	0.2		9.6	0	0.0		0.2	0.0	0.5		0.2	0.0	Circuit miles	
		1.b.	Circuit miles of overhead distribution lines planned for upgrades (including WUI and non-WUI)	1.9		0.3	0	0.0		0.0	0.0	0.0		0.0	0.0	Circuit miles	
		1.c.	Circuit miles of overhead transmission lines planned for upgrades in WUI	0		0	0	0.0		0.2	0.0	0.5		0.2	0.0	Circuit miles in WUI	
		1.d.	Circuit miles of overhead distribution lines planned for upgrades in WUI	0.7		0	0	0.0		0.0	0.0	0.0		0.0	0.0	Circuit miles in WUI	
		1.e.	Number of substations planned for upgrades (including WUI and non-WUI)	0		0	0	0.0		0.0	0.0	2.0		0.0	0.0	Number of substations	
		1.f.	Number of substations planned for upgrades in WUI	0		0	0	0.0		0.0	0.0	2.0		0.0	0.0	Number of substations in WUI	
		1.g.	Number of weather stations planned for upgrades (including WUI and non-WUI)	0		0	0	6.0		2.0	0.0	0.0		0.0	0.0	Number of weather stations	
		1.h.	Number of weather stations planned for upgrades in WUI	0		0	0	1.0		0.0	0.0	0.0		0.0	0.0	Number of weather stations in WUI	
x	2. Planned utility infrastructure upgrades year over year - in rural areas	2.a.	Circuit miles of overhead transmission lines planned for upgrades (including WUI and non-WUI)	0.4		10.8	29	0.0		0.1	0.0	0.1		7.9	0.0	Circuit miles	
		2.b.	Circuit miles of overhead distribution lines planned for upgrades (including WUI and non-WUI)	1.6		21.5	50.8	4.0		20.6	62.4	0.0		10.8	54.2	Circuit miles	
		2.c.	Circuit miles of overhead transmission lines planned for upgrades in WUI	0		0	0	0.0		0.0	0.0	0.1		5.6	0.0	Circuit miles in WUI	
		2.d.	Circuit miles of overhead distribution lines planned for upgrades in WUI	0		0	0	0.0		0.0	0.0	0.0		0.0	0.0	Circuit miles in WUI	
		2.e.	Number of substations planned for upgrades (including WUI and non-WUI)	0		0	0	0.0		0.0	0.0	0.0		0.0	1.0	Number of substations	
		2.f.	Number of substations planned for upgrades in WUI	0		0	0	0.0		0.0	0.0	0.0		0.0	0.0	Number of substations in WUI	
		2.g.	Number of weather stations planned for upgrades (including WUI and non-WUI)	0		15	13	2.0		8.0	15.0	0.0		3.0	4.0	Number of weather stations	
		2.h.	Number of weather stations planned for upgrades in WUI	0				0.0		1.0	1.0	0.0		0.0	0.0	Number of weather stations in WUI	
x	3. Planned utility infrastructure upgrades year over year - in highly rural areas	3.a.	Circuit miles of overhead transmission lines planned for upgrades (including WUI and non-WUI)	0		0	0	0.0		9.6	0.0	0.0		15.8	0.0	Circuit miles	
		3.b.	Circuit miles of overhead distribution lines planned for upgrades (including WUI and non-WUI)	0		22.8	21.3	0.0		20.0	19.9	0.0		0.0	0.0	Circuit miles	
		3.c.	Circuit miles of overhead transmission lines planned for upgrades in WUI	0		0	0	0.0		0.0	0.0	0.0		15.4	0.0	Circuit miles in WUI	
		3.d.	Circuit miles of overhead distribution lines planned for upgrades in WUI	0		0	0	0.0		0.0	0.0	0.0		0.0	0.0	Circuit miles in WUI	
		3.e.	Number of substations planned for upgrades (including WUI and non-WUI)	0		0	0	0.0		0.0	0.0	0.0		2.0	1.0	Number of substations	
		3.f.	Number of substations planned for upgrades in WUI	0		0	0	0.0		0.0	0.0	0.0		2.0	0.0	Number of substations in WUI	
		3.g.	Number of weather stations planned for upgrades (including WUI and non-WUI)	0		0	2	1.0		3.0	9.0	0.0		1.0	0.0	Number of weather stations	
		3.h.	Number of weather stations planned for upgrades in WUI	0		0	0	0.0		1.0	2.0	0.0		0.0	0.0	Number of weather stations in WUI	

Utility	SDG&E
Table No.	11
Date Modified	2022 02 09

Notes:
"PSPS" = Public Safety Power Shutoff
numbers with actuals

Table 11: Recent use of PSPS and other PSPS metrics

			Actual													Projected									
Metric type	**#**	**Outcome metric name**	**2015**	**2016**	**2017**	**2018**	**2019**	Q1 **2020**	Q2 **2020**	Q3 **2020**	Q4 **2020**	Q1 **2021**	Q2 **2021**	Q3 **2021**	Q4 **2021**	Q1 **2022**	Q2 **2022**	Q3 **2022**	Q4 **2022**	Q1 **2023**	Q2 **2023**	Q3 **2023**	Q4 **2023**	**Unit(s)**	**Comments**
1. Recent use of PSPS	1.a.	Frequency of PSPS events (total)	0	0	5	4	4	0	0	1	4	0	0	0	1	0	0	0	3.2	0	0	0	3.2	Number of instances where utility operating protocol requires de-	
	1.b.	Scope of PSPS events (total)	0	0	200	265	324	0	0	2	512	0	0	0	13	0	0	0	116.5	0	0	0	116.5	Circuit-events, measured in number of events multiplied by number of	
	1.c.	Duration of PSPS events (total)	0	0	658,397	1,044,423	1,304,723	0	0	358	2,631,426	0	0	0	147,767	0	0	0	617,794	0	0	0	617,794	Customer hours per year	Metric definition 1.c. was updated based on the correction
2. Customer hours of PSPS and other outages	2.a.	Customer hours of planned outages including PSPS (total)	1,010,005	859,290	1,771,855	2,062,326	2,333,445	246,957	98,578	428,184	2,805,055	384,390	445,526	549,162	493,707	256,240	289,673	328,685	867,872	256,240	289,673	328,685	997,294	Total customer hours of planned outages per year	In 2021 QDR-Q4 filing, data point for 2015 is updated using archieved data file. The reporting system of record stores data
	2.b.	Customer hours of unplanned outages, not including PSPS (total)	1,504,042	2,058,237	2,090,995	1,887,418	1,705,636	346,753	385,697	1,113,938	470,886	407,865	388,531	391,676	515,343	484,040	322,394	573,414	515,440	484,040	322,394	573,414	515,440	Total customer hours of unplanned outages per year	
	2.c.	System Average Interruption Duration Index (SAIDI) (including PSPS)	63.26	86.01	117.49	121.02	122.96	13.95	15.52	44.83	126.10	16.44	15.66	15.79	26.73	19.91	13.22	23.51	46.03	19.91	13.22	23.51	46.03	SAIDI index value = sum of all interruptions in time period where each interruption is defined as sum(duration of interruption * # of customer	
	2.d.	System Average Interruption Duration Index (SAIDI) (excluding PSPS)	63.26	86.01	86.64	77.45	69.21	13.95	15.52	44.81	18.94	16.44	15.66	15.79	20.77	19.91	13.22	23.51	21.13	19.91	13.22	23.51	21.13	SAIDI index value = sum of all interruptions in time period where each interruption is defined as sum(duration of interruption * # of customer	
	2.e.	System Average Interruption Frequency Index (SAIFI) (including PSPS)	0.62	0.68	0.58	0.66	0.64	0.13	0.17	0.27	0.22	0.16	0.14	0.15	0.18	0.16	0.13	0.19	0.17	0.16	0.13	0.19	0.17	SAIFI index value = sum of all interruptions in time period where each interruption is defined as (total # of customer interruptions) / (total # of	
	2.f.	System Average Interruption Frequency Index (SAIFI) (excluding PSPS)	0.62	0.68	0.57	0.64	0.61	0.13	0.17	0.27	0.16	0.16	0.14	0.15	0.18	0.16	0.13	0.19	0.16	0.16	0.13	0.19	0.16	SAIFI index value = sum of all interruptions in time period where each interruption is defined as (total # of customer interruptions) / (total # of	
3. Critical infrastructure impacted by PSPS	3.a.	Critical infrastructure impacted by PSPS	0	0	633	832	968	0	0	0	2359	0	0	0	241	0	0	0	1007	0	0	0	1007	Number of critical infrastructure (in accordance with D.19-05-042)	
4. Community outreach of PSPS metrics	4.a.	# of customers impacted by PSPS	0	0	17,619	30,069	49,880	0	0	49	100,488	0	0	0	5,858	0	0	0	14,858	0	0	0	14,858	same customer, count each event as a separate customer)	During PSPS events in 2020 December, customers who were
	4.b.	# of medical baseline customers impacted by PSPS	0	0	937	1,812	2,853	0	0	6	6,427	0	0	0	47	0	0	0	1,499	0	0	0	1,499	# of customers impacted by PSPS (if multiple PSPS events impact the same customer, count each event as a separate customer)	
	4.c.	# of customers notified prior to initiation of PSPS event	0	0	17,619	30,069	47,969	0	0	49	91,760	0	0	0	5,811	0	0	0	12,438	0	0	0	12438	# of customers notified of PSPS event prior to initiation (if multiple PSPS events impact the same customer, count each event in which customer	
	4.d.	# of medical baseline customers notified prior to initiation of PSPS event	0	0	937	1,812	2,756	0	0	6	6,262	0	0	0	47	0	0	0	1,272	0	0	0	1,272	# of customers notified of PSPS event prior to initiation (if multiple PSPS events impact the same customer, count each event in which customer	
	4.e.	% of customers notified prior to a PSPS event impacting them	0	0	100%	100%	96%	0	0	100%	91%	0	0	0	99%	0	0	0	97.8%	0	0	0	97.8%	=4.a. / 4.c.	
	4.f.	% of medical baseline customers notified prior to a PSPS event impacting them	0	0	100%	100%	97%	0	0	100%	97%	0	0	0	100%	0	0	0	99.0%	0	0	0	99.0%	=4.a. / 4.c.	
5. Other PSPS metrics	5.a.	Number of PSPS de-energizations	0	0	0	0	1	0	0	1	1	1	0	0	0	0.5	0.0	0.5	0.5	0.5	0	0.5	0.5	Number of de-energizations	Number of instances where utility notified the public of a potential PSPS event but no de-energization followed
	5.b.	Number of customers located on de-energized circuit	0	0	67,266	79,587	112,582	0	0	4,214	154,413	0	0	0	14,832	0	0	0	81,153	0	0	0	81,153	Number of customers	
	5.c.	Customer hours of PSPS per RFW OH circuit mile day	0	0	3.46	8.31	24.40	0.00	0.00	0.01	42.40	0	0	0	7.48	0	0	0	6.3	0	0	0	6.3	=1.c. / RFW OH circuit mile days in time period	=1.c./table 6 1.a.
	5.d.	Frequency of PSPS events (total) - High Wind Warning wind conditions	0	0	1	3	2	0	0	0	3	0	0	0	1	0	0	0	1.6	0	0	0	1.6	Events over time period that overlapped with a High Wind Warning as defined by the National Weather Service	
	5.e.	Scope of PSPS events (total) - High Wind Warning wind conditions	0	0	16,848	30,048	49,462	0	0	0	90,748	0	0	0	5,858	0	0	0	13,868	0	0	0	13,868	Estimated customers impacted over time period that overlapped with a High Wind Warning as defined by the National Weather Service	
	5.f.	Duration of PSPS events (total) - High Wind Warning wind conditions	0	0	703,117	1,037,164	1,226,192	0	0	0	2,341,161	0	0	0	147,767	0	0	0	597,055	0	0	0	597,055	Customer hours over time period that overlapped with a High Wind Warning as defined by the National Weather Service	In 2021 WMP update, 5.f. was based on the definition- "outage duration". To align with 1.c. definition correction requested in

Utility	SDG&E	**Notes:** Risk-Spend-Efficiency (RSE) is defined as "An estimate of the cost-effectiveness of initiative, calculated by dividing the mitigation risk reduction benefit by the mitigation cost estimate based on the full set of risk reduction benefits estimated from the incurred costs."
Table No.	12	
Date Modified	2022 02 0	CAPEX = Capital expenditure; OPEX = Operating expenditure. In future submissions update planned spend, line miles

Table 12: Mitigation initiative financials

Metric type	WMP Table # / Category	WMP Initiative #	Initative activity	Primary driver targeted	Secondary driver targeted	Year initiated	Estimated RSE territory-wide	Estimated RSE in non-HFTD region	Estimated RSE in HFTD Zone 1	Estimated RSE in HFTD Tier 2	Estimated RSE in HFTD Tier 3	If existing: most recent proceeding that has reviewed program	If new: memorandum account	Current compliance status - In / exceeding compliance with regulations	Associated rule(s) - if multiple, separate by semi-colon - ":"	If spend not disaggregated by category, note spend category or mark general operations	Comments
Other	Risk Assessment &	7.3.1.1	A summarized risk map that shows the overall ignition probability and estimated wildfire consequence along the electric lines			2012	NA	NA	NA	NA	NA	2019 GRC	NA	Exceeds	P.U. Code § 451		initiative is foundatio
Other	Risk Assessment &	7.3.1.2	Climate-driven risk map and modelling based on various relevant weather scenarios			2012	NA	NA	NA	NA	NA	NA	NA	NA	NA	A summarized risk	
Other	Risk Assessment &	7.3.1.3	Ignition probability mapping showing the probability of ignition along the electric lines and equipment			2012	NA	NA	NA	NA	NA	NA	NA	NA	NA	A summarized risk	
Other	Risk Assessment &	7.3.1.4	Initiative mapping and estimation of wildfire and PSPS risk-reduction impact			2012	NA	NA	NA	NA	NA	NA	NA	NA	NA	A summarized risk	
Other	Risk Assessment &	7.3.1.5	Match drop simulations showing the potential wildfire consequence of ignitions that occur along the electric lines and			2012	NA	NA	NA	NA	NA	NA	NA	NA	NA	A summarized risk	
Other	Situational Awarenes	7.3.2.1	Advanced weather monitoring and weather stations			2010	NA	NA	NA	NA	NA	2019 GRC	NA	Exceeds	P.U. Code § 451		
Other	Situational Awarenes	7.3.2.2	Continuous monitoring sensors			NA	NA	NA	NA	NA	NA	NA	NA	NA	NA		
Other	Situational Awarenes	7.3.2.2.1	Air Quality Index			2022	NA	NA	NA	NA	NA	NA	NA	NA	NA		
Other	Situational Awarenes	7.3.2.2.2	Satellite-based remote sensing			2022	NA	NA	NA	NA	NA	NA	NA	NA	NA		
Other	Situational Awarenes	7.3.2.3.	Fault indicators for detecting faults on electric lines and equipment	PSPS - for sectionalization,		2011	NA	371.78	NA	263.75	247.08	2019 GRC	NA	Exceeds	P.U. Code § 451		
Other	Situational Awarenes	7.3.2.4.1	Fire Potential Index			2012	NA	NA	NA	NA	NA	NA	NA	NA	NA	Fire Potential Index	
Other	Situational Awarenes	7.3.2.4.2	Santa Ana Wind Threat Index (SAWTI)			2014	NA	NA	NA	NA	NA	NA	NA	NA	NA	Forecast of a fire risk	
Other	Situational Awarenes	7.3.2.4.3	High-Performace Computing Infrastructure			2012	NA	NA	NA	NA	NA	2020 WMP	NA	Exceeds	P.U. Code § 451		
Other	Situational Awarenes	7.3.2.6.	Weather forecasting and estimating impacts on electric lines and equipment			2009	NA	NA	NA	NA	NA	NA	NA	NA	NA		
Grid hardening	Grid Design & System	7.3.3.1.	Capacitor maintenance and replacement program (SCADA)	Equipment failure		2016	NA	409.37	NA	165.61	31.62	2019 GRC	NA	Exceeds	G.O. 95		
Grid hardening	Grid Design & System	7.3.3.2.	Circuit breaker maintenance and installation to de-energize lines upon detecting a fault			1997	NA	NA	NA	NA	NA	NA	NA	NA	NA		
Grid hardening	Grid Design & System	7.3.3.3.	Covered conductor installation	Other contact with	Equipment failure	2020	NA	NA	NA	10.66	17.92	2020 WMP	NA	Exceeds	G.O. 95		
Grid hardening	Grid Design & System	7.3.3.4.	Covered conductor maintenance			1997	NA	NA	NA	NA	NA	NA	NA	NA	NA	Detailed inspections of	
Grid hardening	Grid Design & System	7.3.3.5.	Crossarm maintenance, repair, and replacement			1997	NA	NA	NA	NA	NA	NA	NA	NA	NA	Detailed inspections of	
Grid hardening	Grid Design & System	7.3.3.6.	Distribution pole replacement and reinforcement, including with composite poles			1997	NA	NA	NA	NA	NA	NA	NA	NA	NA		
Grid hardening	Grid Design & System	7.3.3.7.	Expulsion fuse replacement	Equipment failure		2019	NA	NA	NA	117.44	411.11	2020 WMP	NA	Exceeds	G.O. 95		
Grid hardening	Grid Design & System	7.3.3.8.1	PSPS Sectionalizing	PSPS - for sectionalization,		2019	NA	1067.23	NA	1106.66	2166.36	2020 WMP	NA	Exceeds	G.O. 95		
Grid hardening	Grid Design & System	7.3.3.8.2	Microgrids	PSPS - for sectionalization,		2019	NA	18.07	NA	1.02	203.25	2020 WMP	NA	Exceeds	P.U. Code § 451		
Grid hardening	Grid Design & System	7.3.3.9.	Installation of system automation equipment (advanced protection)	PSPS - for sectionalization,		2011	NA	NA	NA	NA	178.31	2020 WMP	NA	Exceeds	P.U. Code § 451		
Grid hardening	Grid Design & System	7.3.3.10.	Maintenance, repair, and replacement of connectors, including hotline clamps	PSPS - for sectionalization,		2019	NA	NA	NA	50.44	149.57	2020 WMP	NA	Exceeds	G.O. 95		
Grid hardening	Grid Design & System	7.3.3.11.1	Generator Grant Program	PSPS - for sectionalization,		2020	NA	2.81	NA	164.05	211.3	2020 WMP	NA	Exceeds	P.U. Code § 451		
Grid hardening	Grid Design & System	7.3.3.11.2	Standby Power Programs	PSPS - for sectionalization,		2020	NA	NA	NA	25.04	58.09	2020 WMP	NA	Exceeds	P.U. Code § 451		
Grid hardening	Grid Design & System	7.3.3.11.3	Generator Assistance Program	PSPS - for sectionalization,		2020	NA	388.94	NA	251.42	601.79	2020 WMP	NA	Exceeds	P.U. Code § 451		
Grid hardening	Grid Design & System	7.3.3.12.	Other corrective action			1997	NA	NA	NA	NA	NA	NA	NA	NA	NA	Detailed inspections of	
Grid hardening	Grid Design & System	7.3.3.13.	Pole loading infrastructure hardening and replacement program based on pole loading assessment program			2011	NA	NA	NA	NA	NA	NA	NA	NA	NA	Traditional Hardenin	
Grid hardening	Grid Design & System	7.3.3.14.	Transformers maintenance and replacement			1997	NA	NA	NA	NA	NA	NA	NA	NA	NA		
Grid hardening	Grid Design & System	7.3.3.15.	Transmission tower maintenance and replacement			1997	NA	NA	NA	NA	NA	NA	NA	NA	NA		
Grid hardening	Grid Design & System	7.3.3.16.	Undergrounding of electric lines and/or equipment	Other contact with	Equipment failure	2019	NA	NA	NA	113.77	57.66	2020 WMP	NA	Exceeds	G.O. 95		
Grid hardening	Grid Design & System	7.3.3.17.1	Traditional Hardening - Distribution overhead system hardening	Equipment failure	Other contact with	2009	NA	8.11	NA	13.14	18.14	2019 GRC	NA	Exceeds	G.O. 95		
Grid hardening	Grid Design & System	7.3.3.17.2.1	Overhead transmission fire hardening (Transmission)	Equipment failure	Other contact with	2009	NA	NA	NA	30.01	NA	FERC	NA	Exceeds	G.O. 95		

Actual

WMP Initiative #	2019 CAPEX ($ thousands) Territory	2019 CAPEX HFTD	2019 OPEX ($ thousands) Territory	2019 OPEX HFTD	2019 Line miles treated Territory	2019 Line miles treated HFTD	2019 Alternative units (if used)	2020 CAPEX ($ thousands) Territory	2020 CAPEX HFTD	2020 OPEX ($ thousands) Territory	2020 OPEX HFTD	2020 Line miles treated Territory	2020 Line miles treated HFTD	2020 Alternative units (if used)
7.3.1.1	270	270	-	-	-	-	-	1,191	1,191	-	-	-	-	-
7.3.1.2	-	-	-	-	-	-	-	-	-	-	-	-	-	-
7.3.1.3	-	-	-	-	-	-	-	-	-	-	-	-	-	-
7.3.1.4	-	-	-	-	-	-	-	-	-	-	-	-	-	-
7.3.1.5	-	-	-	-	-	-	-	-	-	-	-	-	-	-
7.3.2.1	564	564	-	-	-	-	13	1,087	1,087	-	-	-	-	30
7.3.2.2	-	-	-	-	-	-	-	-	-	-	-	-	-	-
7.3.2.2.1	-	-	-	-	-	-	-	-	-	-	-	-	-	-
7.3.2.2.2	-	-	-	-	-	-	-	-	-	-	-	-	-	-
7.3.2.3.	797	797	-	-	-	-	594	835	835	-	-	-	-	-
7.3.2.4.1	3	3	1,728	1,728	-	-	-	343	343	3,363	3,363	-	-	-
7.3.2.4.2	-	-	-	-	-	-	-	-	-	-	-	-	-	-
7.3.2.4.3	-	-	-	-	-	-	-	-	-	-	-	-	-	-
7.3.2.6.	-	-	-	-	-	-	-	-	-	-	-	-	-	-
7.3.3.1.	200	200	-	-	-	-	NA	1,038	1,038	-	-	-	-	30
7.3.3.2.	-	-	-	-	-	-	-	-	-	-	-	-	-	-
7.3.3.3.	1,463	1,463	-	-	-	-	-	2,594	2,594	-	-	-	###	-
7.3.3.4.	-	-	-	-	-	-	-	-	-	-	-	-	-	-
7.3.3.5.	-	-	-	-	-	-	-	-	-	-	-	-	-	-
7.3.3.6.	-	-	-	-	-	-	-	-	-	-	-	-	-	-
7.3.3.7.	3,716	3,716	-	-	-	-	2,490	6,521	6,521	-	-	-	-	3,179
7.3.3.8.1	1,321	1,106	-	-	-	-	7	4,854	4,062	-	-	-	-	23
7.3.3.8.2	188	169	-	-	-	-	-	3,542	2,964	371	108	-	-	4
7.3.3.9.	3,480	3,480	-	-	-	-	NA	9,117	9,117	-	-	-	-	6
7.3.3.10.	-	-	922	922	-	-	660	-	-	3,299	3,299	-	-	2,061
7.3.3.11.1	-	-	-	-	-	-	NA	-	-	5,076	4,813	-	-	1,420
7.3.3.11.2	-	-	592	592	-	-	NA	-	-	1,754	1,754	-	-	75
7.3.3.11.3	-	-	-	-	-	-	65	-	-	761	761	-	-	1,274
7.3.3.12.	-	-	-	-	-	-	-	-	-	-	-	-	-	-
7.3.3.13.	-	-	-	-	-	-	-	-	-	-	-	-	-	-
7.3.3.14.	-	-	-	-	-	-	-	-	-	-	-	-	-	-
7.3.3.15.	-	-	-	-	-	-	-	-	-	-	-	-	-	-
7.3.3.16.	192	192	-	-	-	3	-	38,790	38,790	-	-	-	###	-
7.3.3.17.1	113,424	113,415	2,162	2,162	-	123	-	136,811	136,800	3,446	3,446	-	###	-
7.3.3.17.2.1	-	-	-	-	-	7	-	-	-	-	-	-	###	-

Actual / Projected

WMP Initiative #	2021 CAPEX ($ thousands) Territory	2021 CAPEX HFTD	2021 OPEX ($ thousands) Territory	2021 OPEX HFTD	2021 Line miles treated Territory	2021 Line miles treated HFTD	2021 Alternative units (if used)	2022 CAPEX ($ thousands) Territory	2022 CAPEX HFTD	2022 OPEX ($ thousands) Territory	2022 OPEX HFTD	2022 Line miles to be treated Territory	2022 Line miles to be treated HFTD	2022 Alternative units (if used)	2023 CAPEX ($ thousands) Territory	2023 CAPEX HFTD	2023 OPEX ($ thousands) Territory	2023 OPEX HFTD	2023 Line miles to be treated Territory	2023 Line miles to be treated HFTD	2023 Alternative units (if used)
7.3.1.1	1,446	1,446	-	-	-	-	-	2,200	2,200	2,354	2,354	-	-	-	2,420	2,420	2,979	2,979	-	-	-
7.3.1.2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
7.3.1.3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
7.3.1.4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
7.3.1.5	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
7.3.2.1	391	391	-	-	-	-	46	525	525	-	-	-	-	20	383	383	-	-			18
7.3.2.2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
7.3.2.2.1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	6
7.3.2.2.2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
7.3.2.3.	1,104	1,104	-	-	-	-	544	687	687	-	-	-	-	500	-	-	-	-	-	-	-
7.3.2.4.1	38	38	2,812	2,812	-	-	-	243	243	3,697	3,697	-	-	-	323	323	4,066	4,066	-	-	-
7.3.2.4.2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
7.3.2.4.3	-	-	-	-	-	-	-	5,500	5,500	-	-	-	-	-	-	-	-	-	-	-	-
7.3.2.6.	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
7.3.3.1.	2,806	2,806	-	-	-	-	35	3,231	2,132	-	-	-	-	40	1,815	1,198	-	-	-	-	33
7.3.3.2.	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
7.3.3.3.	39,389	39,389	519	517		20	-	124,643	124,643	594	594	-	60	-	150,872	150,872	754	754	-	-	100
7.3.3.4.	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
7.3.3.5.	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
7.3.3.6.	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
7.3.3.7.	6,489	6,489	-	-	-	-	3,976	734	734	-	-		-	227	-	-	-	-	-	-	-
7.3.3.8.1	1,911	1,574	-	-	-	-	13	1,910	1,527	-	-	-	-	10	1,526	1,220	-	-	-	-	10
7.3.3.8.2	12,997	12,550	1,378	412	-	-	-	13,309	2,124	1,607	482		-	4	2,584	-	1,607	482	-	-	2
7.3.3.9.	10,825	10,825	-	-	-	-	4	12,938	12,938	-	-		-	8	11,669	11,669	-	-	-	-	8
7.3.3.10.	-	-	3,714	3,714	-	-	2,743	-	-	4,321	4,321		-	1,650	-	-	4,321	4,321	-	-	1,200
7.3.3.11.1	-	-	7,893	7,875	-	-	2,310	-	-	10,400	10,400		-	2,000	-	-	10,400	10,400	-	-	2,000
7.3.3.11.2	-	-	8,934	8,934	-	-	355	-	-	10,350	10,350		-	412	-	-	10,350	10,350	-	-	300
7.3.3.11.3	-	-	744	740	-	-	735	-	-	1,828	1,828		-	1,250	-	-	1,828	1,828	-	-	1,250
7.3.3.12.	-	-	-	-	-	-	-	-	-	-	-		-	-	-	-	-	-	-	-	-
7.3.3.13.	-	-	-	-	-	-	-	-	-	-	-		-	-	-	-	-	-	-	-	-
7.3.3.14.	-	-	-	-	-	-	-	-	-	-	-		-	-	-	-	-	-	-	-	-
7.3.3.15.	-	-	-	-	-	-	-	-	-	-	-		-	-	-	-	-	-	-	-	-
7.3.3.16.	69,410	69,410	-	-	-	26	-	188,845	188,845	1,049	1,049	-	65	-	310,038	310,038	1,726	1,726	-	-	125
7.3.3.17.1	94,372	94,350	2,596	2,595	-	21	-	16,312	15,810	178	173	-	60	-	5,479	5,311	55	53	-	-	1
7.3.3.17.2.1	-	-	-	-	-	7	-	-	-	-	-	-	29	-	-	-	-	-	-	-	-

Utility	SDG&E	**Notes:** Risk-Spend-Efficiency (RSE) is defined as "An estimate of the cost-effectiveness of initiative, calculated by dividing the mitigation risk reduction benefit by the mitigation cost estimate based on the full set of risk reduction benefits estimated from the incurred costs."
Table No.	12	
Date Modified	2022 02 0	CAPEX = Capital expenditure; OPEX = Operating expenditure. In future submissions update planned spend, line miles

Table 12: Mitigation initiative financials

Metric type	WMP Table # / Category	WMP Initiative #	Initative activity	Primary driver targeted	Secondary driver targeted	Year initiated	Estimated RSE territory-wide	Estimated RSE in non-HFTD region	Estimated RSE in HFTD Zone 1	Estimated RSE in HFTD Tier 2	Estimated RSE in HFTD Tier 3	If existing: most recent proceeding that has reviewed program	If new: memorandum account	Current compliance status - In / exceeding compliance with regulations	Associated rule(s) - if multiple, separate by semi-colon - ";"	If spend not disaggregated by category, note spend category or mark general operations	Comments
Grid hardening	Grid Design & System	7.3.3.17.2.2	Underground transmission fire hardening (Transmission)	Other contact with	Equipment failure	2009	NA	NA	NA	10.43	NA	FERC	NA	Exceeds	G.O. 95		
Grid hardening	Grid Design & System	7.3.3.17.2.3	Overhead transmission fire hardening (Distribution Underbuilt)	Equipment failure	Other contact with	2009	NA	NA	NA	14.44	NA	2019 GRC	NA	Exceeds	G.O. 95		
Grid hardening	Grid Design & System	7.3.3.17.3	CNF MSUP Powerline Replacement Program (Transmission)	Equipment failure	Other contact with	2009	NA	NA	NA	NA	72.93	FERC	NA	Exceeds	G.O. 95		
Grid hardening	Grid Design & System	7.3.3.17.3	CNF (Distributon Underground)	Other contact with	Equipment failure	2009	NA	NA	NA	NA	21.63	2019 GRC	NA	Exceeds	G.O. 95		
Grid hardening	Grid Design & System	7.3.3.17.3	CNF(Distribution Overhead)	Equipment failure	Other contact with	2009	NA	NA	NA	NA	22.73	2019 GRC	NA	Exceeds	G.O. 95		
Grid hardening	Grid Design & System	7.3.3.18.1	Distribution Communications reliability improvements (LTE)			2010	NA	NA	NA	NA	NA	2019 GRC	NA	NA	P.U. Code § 451		
Grid hardening	Grid Design & System	7.3.3.18.2	Lightning Arrestors Removal & Replacement	Equipment failure		2020	NA	NA	NA	35.44	176.05	2020 WMP	NA	Exceeds	G.O. 95		
Grid hardening	Grid Design & System	7.3.3.18.3	Avian Mitigation	Other contact with		2022	NA	0.68	NA	38.64	55.77	NA	NA	NA	NA		
Asset inspection	Asset Management &	7.3.4.1	Detailed inspections of distribution electric lines and equipment	Equipment failure		1997	NA	8.56	NA	87.59	68.39	2019 GRC	NA	Meets	G.O. 95		
Asset inspection	Asset Management &	7.3.4.2	Detailed inspections of transmission electric lines and equipment	Equipment failure		1997	NA	NA	NA	13.3	28.4	FERC	NA	Meets	G.O. 95		
Asset inspection	Asset Management &	7.3.4.3	Improvement of inspections			2019	NA	NA	NA	NA	NA	NA	NA	NA	NA		Drone assessments of
Asset inspection	Asset Management &	7.3.4.4	Infrared inspections of distribution electric lines and equipment	Equipment failure		2020	NA	NA	NA	9.49	17.17	2020 WMP	NA	Exceeds	P.U. Code § 451		
Asset inspection	Asset Management &	7.3.4.5	Infrared inspections of transmission electric lines and equipment	Equipment failure		2010	NA	NA	NA	106.13	239.22	FERC	NA	Meets	P.U. Code § 451		
Asset inspection	Asset Management &	7.3.4.6	Intrusive pole inspections	Equipment failure		1997	NA	3	NA	37.88	121.13	2019 GRC	NA	Meets	G.O. 95		
Asset inspection	Asset Management &	7.3.4.7	LiDAR inspections of distribution electric lines and equipment			2011	NA	NA	NA	NA	NA	2019 GRC	NA	Exceeds	G.O. 95		LiDAR inspections on
Asset inspection	Asset Management &	7.3.4.8	LiDAR inspections of transmission electric lines and equipment			2009	NA	NA	NA	NA	NA	FERC	NA	Exceeds	P.U. Code § 451		
Asset inspection	Asset Management &	7.3.4.9.1	HFTD Tier 3 Distribution Pole Inspections	Equipment failure		2009	NA	NA	NA	NA	NA	2019 GRC	NA	Exceeds	G.O. 95		
Asset inspection	Asset Management &	7.3.4.9.2	Drone assessments of distribution infrastructure	Equipment failure		2019	NA	NA	NA	39.07	52.13	2020 WMP	NA	Exceeds	G.O. 95		
Asset inspection	Asset Management &	7.3.4.9.3	Circuit ownership	Equipment failure		2019	NA	NA	NA	NA	NA	2020 WMP	NA	Exceeds	G.O. 95		Program ended. Costs
Asset inspection	Asset Management &	7.3.4.10.1	Drone assessments of transmission infrastructure	Equipment failure		2020	NA	NA	NA	12.14	153.32	FERC	NA	Exceeds	G.O. 95		
Asset inspection	Asset Management &	7.3.4.10.2	Additional Transmission Aerial 69kV Tier 3 Visual Inspection	Equipment failure		2010	NA	NA	NA	NA	50.54	FERC	NA	Exceeds	G.O. 95		
Asset inspection	Asset Management &	7.3.4.11.	Patrol inspections of distribution electric lines and equipment	Equipment failure		1997	NA	NA	NA	173.9	255.2	2019 GRC	NA	Meets	G.O. 95		
Asset inspection	Asset Management &	7.3.4.12.	Patrol inspections of transmission electric lines and equipment	Equipment failure		1997	NA	NA	NA	31.2	110.65	FERC	NA	Meets	G.O. 95		
Asset inspection	Asset Management &	7.3.4.13.	Pole loading assessment program to determine safety factor			2011	NA	NA	NA	NA	NA	NA	NA	NA	NA		
Asset inspection	Asset Management &	7.3.4.14.	Quality assurance / quality control of inspections			1997	NA	0.04	NA	55.68	81	NA	NA	NA	NA		
Asset inspection	Asset Management &	7.3.4.15.	Substation inspections			1997	NA	NA	NA	NA	NA	NA	NA	NA	NA		
Vegetation manage	Vegetation Manage	7.3.5.1.	Additional efforts to manage community and environmental impacts			1998	NA	NA	NA	NA	NA	NA	NA	NA	NA		
Vegetation inspection	Vegetation Manage	7.3.5.2.	Detailed inspections and management practices for vegetation clearances around distribution electrical lines and equipment	Contact with vegetatio		1998	NA	4.34	NA	100.57	126.95	2019 GRC	NA	Meets	P.U. Code § 451		
Vegetation inspection	Vegetation Manage	7.3.5.3.	Detailed inspections and management practices for vegetation clearances around transmission electrical lines and equipment			1998	NA	NA	NA	NA	NA	NA	NA	NA	NA		
Vegetation manage	Vegetation Manage	7.3.5.4.	Emergency response vegetation management due to red flag warning or other urgent weather conditions			1998	NA	NA	NA	NA	NA	NA	NA	NA	NA		
Vegetation manage	Vegetation Manage	7.3.5.5.	Fuel management (including all wood management) and management of "slash" from vegetation management activities	Contact with vegetatio		2019	NA	NA	NA	9.09	15.04	2020 WMP	NA	Exceeds	P.U. Code § 451		
Vegetation inspection	Vegetation Manage	7.3.5.6.	Improvement of inspections			1998	NA	NA	NA	NA	NA	NA	NA	NA	NA		
Vegetation inspection	Vegetation Manage	7.3.5.7.	Remote sensing inspections of vegetation around distribution electric lines and equipment (LiDAR)			2019	NA	NA	NA	NA	NA	NA	NA	NA	NA		
Vegetation inspection	Vegetation Manage	7.3.5.8.	Remote sensing inspections of vegetation around transmission electric lines and equipment (LiDAR)			2019	NA	NA	NA	NA	NA	NA	NA	NA	NA		
Vegetation inspection	Vegetation Manage	7.3.5.9.	Other discretionary inspections of vegetation around distribution electric lines and equipment	Contact with vegetatio		2019	NA	NA	NA	87.78	139.1	2019 GRC	NA	Exceeds	P.U. Code § 451		

Actual

WMP Initiative #	2019 CAPEX ($ thousands)		2019 OPEX ($ thousands)		2019 Line miles treated		2019 Alternative units (if used)	2020 CAPEX ($ thousands)		2020 OPEX ($ thousands)		2020 Line miles treated		2020 Alternative units (if used)	2021 CAPEX ($ thousands)		2021 OPEX ($ thousands)		2021 Line miles treated		2021 Alternative units (if used)
	Territory	HFTD	Territory	HFTD	Territory	HFTD		Territory	HFTD	Territory	HFTD	Territory	HFTD		Territory	HFTD	Territory	HFTD	Territory	HFTD	
7.3.3.17.2.2	-	-	-	-	-	3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
7.3.3.17.2.3	2,982	2,982	-	-	-	10	-	5,033	5,033	-	-	-	###	-	5,469	5,469	-	-	-	3	-
7.3.3.17.3	-	-	-	-		25		-	-	-	-	-	###	-	-	-	-	-	-	-	-
7.3.3.17.3	30,559	30,559	-	-		8.7		37,982	37,982	-	-	-	###	-	5,653	5,653	-	-	-	-	-
7.3.3.17.3	37,237	37,237	-	-		26.4		46,282	46,282	-	-	-	###	-	6,888	6,888	-	-	-	7	-
7.3.3.18.1	8,099	8,099	-	-	-	-	NA	35,476	35,476	-	-	-	-	15	49,458	49,458	-	-	-	-	-
7.3.3.18.2	-	-	-	-	-	-	NA	19	19	-	-	-	-	-	2,030	2,030	-	-	-	-	1,789
7.3.3.18.3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
7.3.4.1	9,028	3,421	567	364	-	-	16,329	8,536	3,235	179	115	-	-	17,977	9,378	4,576	1,464	714	-	-	22,354
7.3.4.2	437	437	-	-	-	-	37	860	860	-	-	-	-	2,679	337	337	-	-	-	-	1,957
7.3.4.3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
7.3.4.4	-	-	98	98	-	-	NA	-	-	175	175	-	-	13,077	-	-	146	146	-	-	17,068
7.3.4.5	-	-	-	-	-	-	112	-	-	-	-	-	-	110	-	-	-	-	-	-	6,239
7.3.4.6	615	529	1,249	1,201	-	-	19,729	581	500	884	387	-	-	14,450	1,906	782	803	330	-	-	8,271
7.3.4.7	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1,151	1,151	-	-	-
7.3.4.8	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
7.3.4.9.1	1,355	1,355	-	-	-	-	15,176	1,281	1,281	400	400	-	-	11,864	3,082	3,063	49	49	-	-	11,535
7.3.4.9.2	271	271	13,551	13,551	-	-	10,400	15,795	15,795	51,953	51,953	-	-	37,310	12,636	12,636	33,108	33,108	-	-	21,420
7.3.4.9.3	672	672	-	-	-	-	-	41	41	-	-	-	-	-	-	-	-	-	-	-	-
7.3.4.10.1	-	-	-	-	-	-	NA	-	-	-	-	-	-	2,679	-	-	-	-	-	-	1,440
7.3.4.10.2	-	-	-	-	-	-	27	-	-	-	-	-	-	21	-	-	-	-	-	-	1,652
7.3.4.11.	857	857	-	-	-	-	86,401	810	810	295	295	-	-	86,075	1,140	1,140	286	286	-	-	86,490
7.3.4.12.	-	-	-	-	-	-	116	-	-	-	-	-	-	114	-	-	-	-	-	-	6,423
7.3.4.13.	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
7.3.4.14.	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
7.3.4.15.	-	-	-	-	-	-	301	-	-	-	-	-	-	405	-	-	-	-	-	-	405
7.3.5.1.	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
7.3.5.2.	-	-	34,449	18,198	-	-	453,330	-	-	57,791	30,528	-	-	451,207	-	-	42,016	21,610	-	-	502,132
7.3.5.3.	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
7.3.5.4.	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
7.3.5.5.	-	-	5,093	5,093	-	-	511	-	-	5,805	5,805	-	-	324	-	-	4,350	4,350	-	-	463
7.3.5.6.	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
7.3.5.7.	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
7.3.5.8.	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
7.3.5.9.	-	-	-	-	-	-	-	-	-	10,235	10,235	-	-	17,075	-	-	9,955	9,955	-	-	12,578

Projected

WMP Initiative #	2022 CAPEX ($ thousands)		2022 OPEX ($ thousands)		2022 Line miles to be treated		2022 Alternative units (if used)	2023 CAPEX ($ thousands)		2023 OPEX ($ thousands)		2023 Line miles to be treated		2023 Alternative units (if used)
	Territory	HFTD	Territory	HFTD	Territory	HFTD		Territory	HFTD	Territory	HFTD	Territory	HFTD	
7.3.3.17.2.2	-	-	-	-	-	5.5	-	-	-	-	-	-	-	-
7.3.3.17.2.3	4,273	4,273	-	-	-	2.7	-	11,767	11,767	-	-	-	-	12
7.3.3.17.3	-	-	-	-	-	-	-	-	-	-	-	-	-	-
7.3.3.17.3	618	618	-	-	-	-	-	237	237	-	-	-	-	-
7.3.3.17.3	753	753	1,900	1,900	-	-	-	289	289	2,807	2,807	-	-	-
7.3.3.18.1	70,642	70,642	-	-	-	-	25	58,629	58,629	-	-	-	-	45
7.3.3.18.2	2,877	2,877	-	-	-	-	1,848	2,426	2,426	-	-	-	-	1,848
7.3.3.18.3	3,081	2,925	-	-	-	-	-	890	845	-	-	-	-	570
7.3.4.1	6,899	3,093	1,155	518	-	-	18,177	6,244	2,799	236	106	-	-	11,769
7.3.4.2	576	576	-	-	-	-	2,087	1,496	1,496	-	-	-	-	2,715
7.3.4.3	-	-	-	-	-	-	-	-	-	-	-	-	-	-
7.3.4.4	-	-	175	175	-	-	12,000	-	-	175	175	-	-	12,000
7.3.4.5	-	-	-	-	-	-	6,154	-	-	-	-	-	-	6,565
7.3.4.6	1,402	26	24	0	-	-	350	1,269	23	4	0	-	-	68
7.3.4.7	-	-	3,000	3,000	-	-	-	-	-	1,500	1,500	-	-	-
7.3.4.8	-	-	-	-	-	-	-	-	-	-	-	-	-	-
7.3.4.9.1	2,267	2,258	384	382	-	-	12,268	2,052	2,044	320	319	-	-	68
7.3.4.9.2	26,402	26,402	52,000	52,000	-	-	22,000	23,432	23,432	70,650	70,650	-	-	13,000
7.3.4.9.3	-	-	-	-	-	-	-	-	-	-	-	-	-	-
7.3.4.10.1	-	-	-	-	-	-	500	-	-	-	-	-	-	500
7.3.4.10.2	-	-	-	-	-	-	1,625	-	-	-	-	-	-	1,792
7.3.4.11.	839	839	279	279	-	-	86,490	759	759	279	279	-	-	86,122
7.3.4.12.	-	-	-	-	-	-	6,312	-	-	-	-	-	-	7,024
7.3.4.13.	-	-	-	-	-	-	-	-	-	-	-	-	-	-
7.3.4.14.	-	-	-	-	-	-	-	-	-	-	-	-	-	11,822
7.3.4.15.	-	-	-	-	-	-	330	-	-	-	-	-	-	330
7.3.5.1.	-	-	1,000	1,000	-	-	-	-	-	1,000	1,000	-	-	-
7.3.5.2.	-	-	45,443	23,774	-	-	491,822	-	-	43,730	22,878	-	-	491,822
7.3.5.3.	-	-	-	-	-	-	-	-	-	-	-	-	-	-
7.3.5.4.	-	-	-	-	-	-	-	-	-	-	-	-	-	-
7.3.5.5.	-	-	6,377	6,377	-	-	500	-	-	6,777	6,777	-	-	500
7.3.5.6.	-	-	-	-	-	-	-	-	-	-	-	-	-	-
7.3.5.7.	-	-	-	-	730	730	-	-	-	-	-	-	-	-
7.3.5.8.	-	-	-	-	-	-	-	-	-	-	-	-	-	-
7.3.5.9.	-	-	10,257	10,257	-	-	12,500	-	-	10,235	10,235	-	-	12,824

Utility	SDG&E
Table No.	12
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Notes:

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CAPEX = Capital expenditure; OPEX = Operating expenditure.

In future submissions update planned spend, line miles

Table 12: Mitigation initiative financials

Metric type	WMP Table # / Category	WMP Initiative #	Initative activity	Primary driver targeted	Secondary driver targeted	Year initiated	Estimated RSE territory-wide	Estimated RSE in non-HFTD region	Estimated RSE in HFTD Zone 1	Estimated RSE in HFTD Tier 2	Estimated RSE in HFTD Tier 3	If existing: most recent proceeding that has reviewed program	If new: memorandum account	Current compLiance status - In / exceeding compliance with regulations	Associated rule(s) - if multiple, separate by semi-colon - ";"	If spend not disaggregated by category, note spend category or mark general operations	Comments
Vegetation inspectio	Vegetation Manage	7.3.5.10.	Other discretionary inspections of vegetation around transmission electric lines and equipment			2019	NA	NA	NA	NA	NA	NA	NA	NA	NA		
Vegetation inspectio	Vegetation Manage	7.3.5.11.	Patrol inspections of vegetation around distribution electric lines and equipment			1998	NA	NA	NA	NA	NA	NA	NA	NA	NA		
Vegetation inspectio	Vegetation Manage	7.3.5.12.	Patrol inspections of vegetation around transmission electric lines and equipment			1998	NA	NA	NA	NA	NA	NA	NA	NA	NA		
Vegetation inspectio	Vegetation Manage	7.3.5.13	Quality assurance / quality control of vegetation management			1998	NA	NA	NA	NA	NA	NA	NA	NA	NA		
Vegetation manage	Vegetation Manage	7.3.5.14	Recruiting and training of vegetation management personnel			1998	NA	NA	NA	NA	NA	NA	NA	NA	NA		
Vegetation manage	Vegetation Manage	7.3.5.15	Identification and remediation of "at-risk species"			2019	NA	NA	NA	NA	NA	NA	NA	NA	NA		
Vegetation manage	Vegetation Manage	7.3.5.16	Removal and remediation of trees with strike potential to electric lines and equipment			1998	NA	NA	NA	NA	NA	NA	NA	NA	NA		
Vegetation inspectio	Vegetation Manage	7.3.5.17	Substation inspection			1998	NA	NA	NA	NA	NA	NA	NA	NA	NA		
Vegetation manage	Vegetation Manage	7.3.5.18	Substation vegetation management			1998	NA	NA	NA	NA	NA	NA	NA	NA	NA		
Vegetation manage	Vegetation Manage	7.3.5.19	Vegetation management system			2002	NA	NA	NA	NA	NA	NA	NA	NA	NA		
Vegetation manage	Vegetation Manage	7.3.5.20	Vegetation management to achieve clearances around electric lines and equipment	Other contact with		1998	NA	6.89	NA	57.76	78.18	2019 GRC	NA	Meets	P.U. Code § 451		
Vegetation manage	Vegetation Manage	7.3.5.21	Vegetation management activities post-fire			2022	NA	NA	NA	NA	NA	NA	NA	NA	NA		
Other	Grid Operations &	7.3.6.1	Automatic recloser operations	Other contact with	Equipment failure	2008	NA	NA	NA	1093803	2002522	2019 GRC	NA	Exceeds	P.U. Code § 451		
Other	Grid Operations &	7.3.6.1.2	Sensitive/Fast Protection settings	Other contact with	Equipment failure	2015	NA	NA	NA	75399.5	155234	2019 GRC	NA	Exceeds	P.U. Code § 451		
Other	Grid Operations &	7.3.6.2	Protective equipment and device settings			2008	NA	NA	NA	NA	NA	NA	NA	NA	NA		
Other	Grid Oper	7.3.6.3.	Crew-accompanying ignition prevention and suppression resources and services	Equipment failure	Other contact with	2009	NA	0.3	NA	32.03	123.4	2019 GRC	NA	Exceeds	P.U. Code § 451		
Other	Grid Oper	7.3.6.4.	Personnel work procedures and training in conditions of elevated fire risk	Equipment failure	Other contact with	2008	NA	NA	NA	118.3	135.33	2019 GRC	NA	Exceeds	P.U. Code § 451		
Other	Grid Oper	7.3.6.5.	Protocols for PSPS re-energization	Other contact with	Equipment failure	2013	NA	NA	NA	NA	NA	2020 WMP	NA	Exceeds	P.U. Code § 451		
Other	Grid Oper	7.3.6.6.	PSPS events and mitigation of PSPS impacts	Other contact with	Equipment failure	2013	NA	NA	NA	77.49	82.86	NA	NA	NA	NA		
Other	Grid Oper	7.3.6.7	Stationed and on-call ignition prevention and suppression resources and services			2013	NA	NA	NA	NA	NA	NA	NA	NA	NA		
Other	Grid Oper	7.3.6.7.1	Aviation firefighting program	Equipment failure	Other contact with	2008	NA	NA	NA	54.11	61.21	2019 GRC	NA	Exceeds	P.U. Code § 451		
Other	Data Gove	7.3.7.1.	Centralized repository for data			2019	NA	NA	NA	NA	NA	2020 WMP	NA	Exceeds	P.U. Code § 451		
Other	Data Gove	7.3.7.2.	Collaborative research on utility ignition and/or wildfire			2012	NA	NA	NA	NA	NA	NA	NA	NA	NA		
Other	Data Gove	7.3.7.3.	Documentation and disclosure of wildfire-related data and algorithms			2020	NA	NA	NA	NA	NA	2020 WMP	NA	Exceeds	P.U. Code § 451		
Other	Data Gove	7.3.7.4.	Tracking and analysis of risk event data			2019	NA	NA	NA	NA	NA	NA	NA	NA	NA		
Other	Data Gove	7.3.7.4.1	Ignition Management Program			2019	NA	NA	NA	NA	NA	NA	NA	NA	NA		
Other	Data Gove	7.3.7.4.2	Reliability Database			2020	NA	NA	NA	NA	NA	NA	NA	NA	NA		
Other	Resource A	7.3.8.1.	Allocation methodology development and application			2019	NA	NA	NA	NA	NA	2019 GRC		Exceeds	P.U. Code § 451		
Other	Resource A	7.3.8.2.	Risk reduction scenario development and analysis			2019	NA	NA	NA	NA	NA	NA	NA	NA	NA		
Other	Resource A	7.3.8.3.	Risk spend efficiency analysis not include PSPS			2019	NA	NA	NA	NA	NA	NA	NA	NA	NA		
Other	Emergenc	7.3.9.1.	Adequate and trained workforce for service restoration			2013	NA	NA	NA	NA	NA	NA	NA	NA	NA		
Other	Emergenc	7.3.9.2.	Community outreach, public awareness, and communications efforts			2013	NA	NA	NA	NA	NA	NA	NA	NA	NA		
Other	Emergenc	7.3.9.3	Customer support in emergencies			2013	NA	NA	NA	NA	NA	NA	NA	NA	NA		
Other	Emergenc	7.3.9.4.	Disaster and emergency preparedness plan			2013	NA	NA	NA	NA	NA	NA	NA	NA	NA		
Other	Emergenc	7.3.9.5.	Preparedness and planning for service restoration			2013	NA	NA	NA	NA	NA	NA	NA	NA	NA		

Actual

WMP Initiative #	2019 CAPEX ($ thousands) Territory	2019 CAPEX HFTD	2019 OPEX ($ thousands) Territory	2019 OPEX HFTD	2019 Line miles treated Territory	2019 Line miles treated HFTD	2019 Alternative units (if used)	2020 CAPEX ($ thousands) Territory	2020 CAPEX HFTD	2020 OPEX ($ thousands) Territory	2020 OPEX HFTD	2020 Line miles treated Territory	2020 Line miles treated HFTD	2020 Alternative units (if used)	2021 CAPEX ($ thousands) Territory	2021 CAPEX HFTD	2021 OPEX ($ thousands) Territory	2021 OPEX HFTD	2021 Line miles treated Territory	2021 Line miles treated HFTD	2021 Alternative units (if used)
7.3.5.10.	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
7.3.5.11.	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
7.3.5.12.	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
7.3.5.13	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
7.3.5.14	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
7.3.5.15	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
7.3.5.16	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
7.3.5.17	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
7.3.5.18	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
7.3.5.19	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
7.3.5.20	-	-	3,884	3,391	-	-	34,000	-	-	5,433	4,743	-	-	36,563	-	-	5,556	4,991	-	-	35,102
7.3.5.21	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
7.3.6.1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
7.3.6.1.2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
7.3.6.2	-	-	1,790	1,790	-	-	-	-	-	2,588	2,588	-	-	-	-	-	3,071	3,071	-	-	-
7.3.6.3.	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
7.3.6.4.	11	11	-	-	-	-	-	663	663	-	-	-	-	-	175	175	-	-	-	-	-
7.3.6.5.	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
7.3.6.6.	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
7.3.6.7	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
7.3.6.7.1	-	-	5,166	5,166	-	-	-	7,092	7,092	6,766	6,766	-	-	-	13,461	13,461	6,850	6,850	-	-	-
7.3.7.1.	19	19	-	-	-	-	-	6,895	6,895	-	-	-	-	-	7,814	7,814	-	-	-	-	-
7.3.7.2.	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
7.3.7.3.	-	-	-	-	-	-	-	2,208	2,208	-	-	-	-	-	2,800	2,800	-	-	-	-	-
7.3.7.4.	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
7.3.7.4.1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
7.3.7.4.2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
7.3.8.1.	-	-	369	369	-	-	-	-	-	3,718	3,718	-	-	-	-	-	5,299	5,299	-	-	-
7.3.8.2.	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
7.3.8.3.	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
7.3.9.1.	-	-	-	-	-	-	-	-	-	-	-	-	-	-	5,950	5,950	-	-	-	-	-
7.3.9.2.	217	217	4,727	4,727	-	-	-	2,405	2,405	12,214	12,214	-	-	-	2,981	2,981	12,907	12,907	-	-	-
7.3.9.3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
7.3.9.4.	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
7.3.9.5.	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

Projected

WMP Initiative #	2022 CAPEX ($ thousands) Territory	2022 CAPEX HFTD	2022 OPEX ($ thousands) Territory	2022 OPEX HFTD	2022 Line miles to be treated Territory	2022 Line miles to be treated HFTD	2022 Alternative units (if used)	2023 CAPEX ($ thousands) Territory	2023 CAPEX HFTD	2023 OPEX ($ thousands) Territory	2023 OPEX HFTD	2023 Line miles to be treated Territory	2023 Line miles to be treated HFTD	2023 Alternative units (if used)
7.3.5.10.	-	-	-	-	-	-	-	-	-	-	-	-	-	-
7.3.5.11.	-	-	-	-	-	-	-	-	-	-	-	-	-	-
7.3.5.12.	-	-	-	-	-	-	-	-	-	-	-	-	-	-
7.3.5.13	-	-	-	-	-	-	15%	-	-	-	-	-	-	15%
7.3.5.14	-	-	-	-	-	-	-	-	-	-	-	-	-	-
7.3.5.15	-	-	-	-	-	-	-	-	-	-	-	-	-	-
7.3.5.16	-	-	-	-	-	-	106	-	-	-	-	-	-	106
7.3.5.17	-	-	-	-	-	-	-	-	-	-	-	-	-	-
7.3.5.18	-	-	-	-	-	-	-	-	-	-	-	-	-	-
7.3.5.19	-	-	-	-	-	-	-	-	-	-	-	-	-	-
7.3.5.20	-	-	5,800	5,209	-	-	34,000	-	-	6,032	5,417	-	-	30,540
7.3.5.21	-	-	-	-	-	-	-	-	-	-	-	-	-	-
7.3.6.1	-	-	-	-	-	-	-	-	-	-	-	-	-	-
7.3.6.1.2	-	-	-	-	-	-	-	-	-	-	-	-	-	-
7.3.6.2	-	-	3,230	3,230	-	-	-	-	-	3,230	3,230	-	-	-
7.3.6.3.	-	-	-	-	-	-	-	-	-	-	-	-	-	-
7.3.6.4.	-	-	-	-	-	-	-	-	-	-	-	-	-	-
7.3.6.5.	-	-	-	-	-	-	-	-	-	-	-	-	-	-
7.3.6.6.	-	-	-	-	-	-	-	-	-	-	-	-	-	-
7.3.6.7	-	-	-	-	-	-	-	-	-	-	-	-	-	-
7.3.6.7.1	23,672	23,672	9,325	9,325	-	-	-	4,803	4,803	10,563	10,563	-	-	-
7.3.7.1.	16,776	16,776	1,490	1,490	-	-	-	16,611	16,611	1,665	1,665	-	-	-
7.3.7.2.	-	-	-	-	-	-	-	-	-	-	-	-	-	-
7.3.7.3.	3,993	3,993	-	-	-	-	-	3,372	3,372	-	-	-	-	-
7.3.7.4.	-	-	-	-	-	-	-	-	-	-	-	-	-	-
7.3.7.4.1	-	-	-	-	-	-	-	-	-	-	-	-	-	-
7.3.7.4.2	-	-	-	-	-	-	-	-	-	-	-	-	-	-
7.3.8.1.	-	-	4,786	4,786	-	-	-	-	-	6,092	6,092	-	-	-
7.3.8.2.	-	-	-	-	-	-	-	-	-	-	-	-	-	-
7.3.8.3.	-	-	-	-	-	-	-	-	-	-	-	-	-	-
7.3.9.1.	10,202	10,202	-	-	-	-	-	4,215	4,215	-	-	-	-	-
7.3.9.2.	8,848	8,848	15,170	15,170	-	-	-	21,157	21,157	15,843	15,843	-	-	-
7.3.9.3	-	-	-	-	-	-	-	-	-	-	-	-	-	-
7.3.9.4.	-	-	-	-	-	-	-	-	-	-	-	-	-	-
7.3.9.5.	-	-	-	-	-	-	-	-	-	-	-	-	-	-

Utility	SDG&E	**Notes:** Risk-Spend-Efficiency (RSE) is defined as "An estimate of the cost-effectiveness of initiative, calculated by dividing the mitigation risk reduction benefit by the mitigation cost estimate based on the full set of risk reduction benefits estimated from the incurred costs."
Table No.	12	
Date Modified	2022 02 0	CAPEX = Capital expenditure; OPEX = Operating expenditure. In future submissions update planned spend, line miles

Table 12: Mitigation initiative financials

Metric type	WMP Table # / Category	WMP Initiative #	Initative activity	Primary driver targeted	Secondary driver targeted	Year initiated	Estimated RSE territory-wide	Estimated RSE in non-HFTD region	Estimated RSE in HFTD Zone 1	Estimated RSE in HFTD Tier 2	Estimated RSE in HFTD Tier 3	If existing: most recent proceeding that has reviewed program	If new: memorandum account	Current compLiance status - In / exceeding compliance with regulations	Associated rule(s) - if multiple, separate by semi-colon - ";"	If spend not disaggregated by category, note spend category or mark general operations	Comments
Other	Emergenc	7.3.9.6.	Protocols in place to learn from wildfire events			2013	NA	NA	NA	NA	NA	NA	NA	NA	NA		
Other	Stakehold	7.3.10.1	Community engagement			2013	NA	NA	NA	NA	NA	2020 WMP	NA	Exceeds	P.U. Code § 451		
Other	Stakehold	7.3.10.1.1	PSPS Communicaiton Practices			2013	NA	NA	NA	NA	NA	2019 GRC	NA	Exceeds	P.U. Code § 451		
Other	Stakehold	7.3.10.2	Cooperation and best practice sharing with agencies outside CA			2013	NA	NA	NA	NA	NA	NA	NA	NA	NA		
Other	Stakehold	7.3.10.3	Cooperation with suppression agencies			2019	NA	NA	NA	NA	NA	NA	NA	NA	NA		
Other	Stakehold	7.3.10.4	Forest service and fuel reduction cooperation and joint roadmap			2022	NA	NA	NA	NA	NA	NA	NA	NA	NA		

Actual

WMP Initiative #	2019 CAPEX ($ thousands)		2019 OPEX ($ thousands)		2019 Line miles treated		2019 Alternative units (if used)	2020 CAPEX ($ thousands)		2020 OPEX ($ thousands)		2020 Line miles treated		2020 Alternative units (if used)
	Territory	HFTD	Territory	HFTD	Territory	HFTD		Territory	HFTD	Territory	HFTD	Territory	HFTD	
7.3.9.6.	-	-	-	-	-	-	-	-	-	-	-	-	-	-
7.3.10.1	-	-	5	5	-	-	-	-	-	448	448	-	-	-
7.3.10.1.1	743	743	3,840	3,840	-	-	-	4,474	4,474	8,313	8,313	-	-	-
7.3.10.2	-	-	-	-	-	-	-	-	-	-	-	-	-	-
7.3.10.3	-	-	-	-	-	-	-	-	-	-	-	-	-	-
7.3.10.4	-	-	-	-	-	-	-	-	-	-	-	-	-	-

WMP Initiative #	2021 CAPEX ($ thousands)		2021 OPEX ($ thousands)		2021 Line miles treated		2021 Alternative units (if used)
	Territory	HFTD	Territory	HFTD	Territory	HFTD	
7.3.9.6.	-	-	-	-	-	-	-
7.3.10.1	-	-	579	579	-	-	-
7.3.10.1.1	5,186	5,186	10,208	10,208	-	-	-
7.3.10.2	-	-	-	-	-	-	-
7.3.10.3	-	-	-	-	-	-	-
7.3.10.4	-	-	-	-	-	-	-

Projected

WMP Initiative #	2022 CAPEX ($ thousands)		2022 OPEX ($ thousands)		2022 Line miles to be treated		2022 Alternative units (if used)	2023 CAPEX ($ thousands)		2023 OPEX ($ thousands)		2023 Line miles to be treated		2023 Alternative units (if used)
	Territory	HFTD	Territory	HFTD	Territory	HFTD		Territory	HFTD	Territory	HFTD	Territory	HFTD	
7.3.9.6.	-	-	-	-	-	-	-	-	-	-	-	-	-	-
7.3.10.1	-	-	600	600	-	-	-	-	-	650	650	-	-	-
7.3.10.1.1	5,364	5,364	11,062	11,062	-	-	-	-	-	11,062	11,062	-	-	-
7.3.10.2	-	-	-	-	-	-	-	-	-	-	-	-	-	-
7.3.10.3	-	-	-	-	-	-	-	-	-	-	-	-	-	-
7.3.10.4	-	-	-	-	-	-	-	-	-	-	-	-	-	-

Attachment C: Priority Essential Services SDG&E Customer List

Priority Essential Services SDG&E Customer List

(As of February 2022 – Subject to Change)

CRITICAL_FAC_CODE	CUSTOMER_NAME
BLOOD BANK	AMERICAN RED CROSS
BLOOD BANK	SAN DIEGO BLOOD BANK
CHEMICAL	8141 CENTER ST, LLC
CHEMICAL	ABOVCHEM LLC
CHEMICAL	AIRGAS WEST INC
CHEMICAL	ALICHEM
CHEMICAL	ALLERMED LABS INC
CHEMICAL	AMERICAN PHARMA CORP
CHEMICAL	AMERICAN POWDER COAT LLC
CHEMICAL	ARENA PHARMACEUTICALS INC
CHEMICAL	ARGONAUT MANUFACTURING SRV
CHEMICAL	ARMOR CONTRACT GLAZING
CHEMICAL	ARTIFICIAL TURF SUPPLY LLC
CHEMICAL	AT SCIENTIFIC
CHEMICAL	ATLAS CHEMICAL CO
CHEMICAL	AVISTA TECHNOLOGIES INC
CHEMICAL	BACHEM AMERICAS INC
CHEMICAL	BELOTECA INC
CHEMICAL	BEN REDLICH
CHEMICAL	BIO D PRODUCTS
CHEMICAL	BIOFILM INCORPORATED
CHEMICAL	BIOFUELS ENERGY LLC
CHEMICAL	BIOMAX HEALTH PRODUCTS INC
CHEMICAL	BIOMED REALTY LP
CHEMICAL	BIOSETTIA INC
CHEMICAL	BIOTICS RESEARCH CORP
CHEMICAL	BRE IMAGINATION OFF HLDNG CO
CHEMICAL	BRENNTAG PACIFIC INC
CHEMICAL	CA BOTANA INT'L INC
CHEMICAL	CALASIA PHARMACEUTICALS
CHEMICAL	CALIFIA PHARMA INC
CHEMICAL	CARLSBAD MANUFACTURING CORP
CHEMICAL	CARLSBAD TECHNOLOGY INC
CHEMICAL	CHONTECH INC
CHEMICAL	CHRISTINE CORNISH
CHEMICAL	CLINIQA CORP
CHEMICAL	COLORESCIENCE INC
CHEMICAL	COMBI BLOCKS INCORPORATION

CRITICAL_FAC_CODE	CUSTOMER_NAME
CHEMICAL	CP KELCO
CHEMICAL	CW SAN DIEGO LLC
CHEMICAL	DIVERSIFIED NANO SOLUTIONS
CHEMICAL	DUN EDWARDS CORP
CHEMICAL	EBERT COMPOSITES CORP
CHEMICAL	ELEMENTARY DESIGN
CHEMICAL	EMERGING PHARMACIES LLC
CHEMICAL	ENERGY SUSPENSION
CHEMICAL	ENERGY SUSPENSIONS
CHEMICAL	EPIGEN BIOSCIENCES INC
CHEMICAL	FOODAROM USA INC
CHEMICAL	FX LABS
CHEMICAL	GABRIEL COSTILLA
CHEMICAL	GINOLIS INC
CHEMICAL	GREEN-GO RECYCLING INC
CHEMICAL	H AND M DIST INC
CHEMICAL	HARRELLS LLC
CHEMICAL	HEMPEL USA INC
CHEMICAL	HOCKING INTERNATIONAL LABS
CHEMICAL	HYDRO AGRI
CHEMICAL	INK SYSTEMS INC
CHEMICAL	INNOMINATA
CHEMICAL	INNOVATIVE BIOSCIENCES INC
CHEMICAL	INOVA DIAGNOSTICS
CHEMICAL	INVIVOSCRIBE TECH
CHEMICAL	IRISYS LLC
CHEMICAL	JACOB RUBENSTEIN
CHEMICAL	JAMES PYER
CHEMICAL	JESSICA SAUCEDO
CHEMICAL	JESSUP SERVICES
CHEMICAL	KUNHUA CHEN
CHEMICAL	LATITUDE PHARM INC
CHEMICAL	LEEMARC INDUSTRIES
CHEMICAL	LIFE TECHNOLOGIES
CHEMICAL	MC BRADFORD INC
CHEMICAL	METACRINE INC
CHEMICAL	METAROM USA LLC
CHEMICAL	NATURAL ALTERNATIVES INTNL
CHEMICAL	NATURAL THOUGHTS INC
CHEMICAL	NEURMEDIX
CHEMICAL	NEUVOGEN INC
CHEMICAL	NEW LEAF BIOFUEL LLC

CRITICAL_FAC_CODE	CUSTOMER_NAME
CHEMICAL	NICOPHARM PHARMACEUTICAL SOL
CHEMICAL	NINOS I BURKE LANE LLC
CHEMICAL	NITTO BIO PHARMA
CHEMICAL	O A L ASSOC INC
CHEMICAL	OTONOMY
CHEMICAL	PACK LAB INC
CHEMICAL	PFENEX INC
CHEMICAL	PHASEBIO PHARMACEUTICALS INC
CHEMICAL	PLANT DEVAS INC
CHEMICAL	PLASTIFAB INC
CHEMICAL	POLYPEPTIDE LABORATORIES SD
CHEMICAL	PROCHEM SPECIALTY PROD
CHEMICAL	PROMETHEUS LABS INC
CHEMICAL	PURETY COSMETICS
CHEMICAL	QPEX BIOPHARMA
CHEMICAL	QUIDEL CORP
CHEMICAL	R&G PRECISION MACHINING INC
CHEMICAL	RECYCLED AGGREGATE MATERIALS
CHEMICAL	RECYCLING TECH KNOWLEDGE
CHEMICAL	REJUVENATION THERAPEUTICS
CHEMICAL	RENEO PHARMACEUTICALS INC
CHEMICAL	RHINO LININGS USA INC
CHEMICAL	SALIS INTERNATIONAL INC
CHEMICAL	SAN DIEGO INSPIRE 1 LLC
CHEMICAL	SCANTIBODIES LAB INC
CHEMICAL	SCRIPPS LABORATORIES INC
CHEMICAL	SHELBY STANFILL
CHEMICAL	SHIRE PHARMACEUTICAL COMPANY
CHEMICAL	SPECIALTY MANUFACTURING INC
CHEMICAL	SPOERRI INC
CHEMICAL	STA PHARMACETICAL US LLC
CHEMICAL	STEGO INDUSTRIES LLC
CHEMICAL	STEROGENE BIO SEPR INC
CHEMICAL	STRATUM MEDICAL INC
CHEMICAL	SUN BUM LLC
CHEMICAL	SUNREZ CORP
CHEMICAL	SUNSET PHARMECUTICALS INC
CHEMICAL	SYNTHETIC PROTEOMICS INC
CHEMICAL	TAO OF MAN LLC
CHEMICAL	TARSAL PHARMACEUTICALS
CHEMICAL	TENOVA PHARMACEUTICALS
CHEMICAL	TOTAL POWER INC

CRITICAL_FAC_CODE	CUSTOMER_NAME
CHEMICAL	TRICITY PAINT
CHEMICAL	U-STOR-IT TORREY PINES LLC
CHEMICAL	VERSUM MATERIALS US LLC
CHEMICAL	VERTEX PHARMACEUTICALS LLC
CHEMICAL	VET-STEM INC
CHEMICAL	WESTAIR GASES & EQUIPMENT
CHEMICAL	WESTBRIDGE AGRICULTURAL
CHEMICAL	WONDFO USA CORPORATION LTD
CHEMICAL	XCOVERY BETTA PHARMA INC
CHEMICAL	XTRACTA PHARMA
COMMUNITY CENTERS	ABC YOUTH FOUNDATION
COMMUNITY CENTERS	ALPINE YOUTH CENTER
COMMUNITY CENTERS	ANGELS FOSTER FAMILY AGENCY
COMMUNITY CENTERS	ARMS WIDE OPEN
COMMUNITY CENTERS	BISCAYNE FURNITURE INC
COMMUNITY CENTERS	BOYS & GIRLS CLUB OF SD
COMMUNITY CENTERS	BROTHER BENNO FOUNDATION INC
COMMUNITY CENTERS	CHILD GUIDANCE CENTER INC
COMMUNITY CENTERS	CITY OF OCEANSIDE
COMMUNITY CENTERS	CITY OF SAN DIEGO
COMMUNITY CENTERS	CO OF SAN DIEGO
COMMUNITY CENTERS	COMMUNITY YOUTH ATHLETIC
COMMUNITY CENTERS	DANAWOODS COMM ASSC
COMMUNITY CENTERS	EPISCOPAL COMM SERVICES
COMMUNITY CENTERS	ESC COM CHILD DEV CTR
COMMUNITY CENTERS	ESCONDIDO EDUCATION COMPACT
COMMUNITY CENTERS	FALLBROOK YOUTH
COMMUNITY CENTERS	HARMONIUM INC
COMMUNITY CENTERS	LJ YOUTH SOCCER LEAGUE
COMMUNITY CENTERS	MAAC PROJECT HEAD START
COMMUNITY CENTERS	MY YARD LIVE LLC
COMMUNITY CENTERS	NATIONAL CROSSROADS INC
COMMUNITY CENTERS	NEW ALTERNATIVES INC
COMMUNITY CENTERS	NEW HAVEN
COMMUNITY CENTERS	NHA HEAD START PROG OF
COMMUNITY CENTERS	PATHFINDERS OF SD INC
COMMUNITY CENTERS	QUALITY CHILDRENS SERVICES
COMMUNITY CENTERS	SCRIPPS BRB LLC
COMMUNITY CENTERS	SD YOUTH & COMM SERV
COMMUNITY CENTERS	SD YOUTH & COMM SERVICE
COMMUNITY CENTERS	SD YOUTH SERVICES
COMMUNITY CENTERS	SDLGBT COMMUNITY CENTER

CRITICAL_FAC_CODE	CUSTOMER_NAME
COMMUNITY CENTERS	SO CALIF TEEN CHALLENGE
COMMUNITY CENTERS	SOCIAL ADVOCATES FOR YOUTH
COMMUNITY CENTERS	STAR PAL
COMMUNITY CENTERS	TERI INC
COMMUNITY CENTERS	ULTRA FUN RUN INC
COMMUNITY CENTERS	UNIVERSITY HTS COMM DEV
COMMUNITY CENTERS	YMCA OF SAN DIEGO COUNTY
COMMUNICATIONS	A WIRELESS
COMMUNICATIONS	AFKHAMI ENTERPRISES LP
COMMUNICATIONS	AMERICAN TOWER CORPORATION
COMMUNICATIONS	AOPS INC
COMMUNICATIONS	ARCADIA HUB HOLDINGS
COMMUNICATIONS	AT&T
COMMUNICATIONS	AT&T MOBILITY
COMMUNICATIONS	AT&T MOBILITY LLC
COMMUNICATIONS	AT&T SERVICES INC
COMMUNICATIONS	ATC TOWER CORP
COMMUNICATIONS	BLUE LINK WIRELESS LLC
COMMUNICATIONS	CALIFORNIA COX PCS
COMMUNICATIONS	CALVARY CHAPEL
COMMUNICATIONS	CHARTER COMMUNICATIONS HLDG
COMMUNICATIONS	CITY OF CARLSBAD
COMMUNICATIONS	CLEAR CHANNEL RADIO DIP
COMMUNICATIONS	CO OF SAN DIEGO
COMMUNICATIONS	COX COMMUNICATIONS CALIF LLC
COMMUNICATIONS	COX COMMUNICATIONS INC
COMMUNICATIONS	CW SAN DIEGO
COMMUNICATIONS	DEAN THACKREY
COMMUNICATIONS	EDCO DISPOSAL
COMMUNICATIONS	ELEMENT BIOSCIENCES INC
COMMUNICATIONS	ENTERCOM COMMUNICATIONS CORP
COMMUNICATIONS	FAMILY STATIONS INC
COMMUNICATIONS	FRONTIER CALIFORNIA INC DIP
COMMUNICATIONS	HERRING BROADCASTING INC
COMMUNICATIONS	HPI NCT
COMMUNICATIONS	INVENTORY MANAGEMENT SOLUTIONS
COMMUNICATIONS	JOSE TUINONEZ
COMMUNICATIONS	K N S D
COMMUNICATIONS	K29DX DIP
COMMUNICATIONS	KABUL GREEN MARKET
COMMUNICATIONS	KBNT CHANNEL 17
COMMUNICATIONS	KSYY RADIO

CRITICAL_FAC_CODE	CUSTOMER_NAME
COMMUNICATIONS	LA MAESTRA FAMILY CLINIC INC
COMMUNICATIONS	LEVEL 3 COMMUNICATIONS
COMMUNICATIONS	MARCUS EVANS CO
COMMUNICATIONS	MCKINNON BROADCASTING
COMMUNICATIONS	MCKINNON ENTERPRISES
COMMUNICATIONS	MEDIACOM CALIFORNIA LLC
COMMUNICATIONS	MIDWEST TV INC
COMMUNICATIONS	MILTON BLACK
COMMUNICATIONS	MOSTAFA ALANI
COMMUNICATIONS	OPTIMAL WIRELESS LLC
COMMUNICATIONS	PRIME COMMS RETAIL LLC
COMMUNICATIONS	R V S RETAIL LP
COMMUNICATIONS	RADIO 1210 INC
COMMUNICATIONS	RAMONA TOWN RADIO INC
COMMUNICATIONS	RELAXSPA 2
COMMUNICATIONS	RF EXPOSURE LAB LLC
COMMUNICATIONS	ROBERT MARTINENGO
COMMUNICATIONS	ROBEY & ASSOCIATES INC
COMMUNICATIONS	SCRIPPS MEDIA INC
COMMUNICATIONS	SPRINT NEXTEL CORPORATION
COMMUNICATIONS	STAR WEST PARKWAY MALL LP
COMMUNICATIONS	T W TELECOM
COMMUNICATIONS	TALK 4 LESS WIRELESS
COMMUNICATIONS	TELEPORT COMMUNICATIONS
COMMUNICATIONS	T-MOBILE USA INC
COMMUNICATIONS	T-MOBILE WEST LLC
COMMUNICATIONS	TRIBUNE
COMMUNICATIONS	U S SPRINT CO
COMMUNICATIONS	UNITED SITE SERVICES INC
COMMUNICATIONS	VERGE MOBILE CA LP
COMMUNICATIONS	VERIZON WIRELESS
COMMUNICATIONS	VLY CTR CABLE SYSTEMS
COMMUNICATIONS	VOICE STREAM WIRELESS
COMMUNICATIONS	WILLIAMS COMMUNICATIONS
COMMUNICATIONS	XO COMMUNICATIONS
DIALYSIS CENTER	DAVITA INC
DIALYSIS CENTER	DIALYSIS NEWCO INC
DIALYSIS CENTER	FMC SAN JUAN CAPISTRANO LLC
DIALYSIS CENTER	HOME DIALYSIS THERAPIES SD
DIALYSIS CENTER	INNOVATIVE DIALYSIS OF LJ
DIALYSIS CENTER	LP SCRIPPS LOT I LLC
DIALYSIS CENTER	MISSION CAMINO INVESTORS LP

CRITICAL_FAC_CODE	CUSTOMER_NAME
DIALYSIS CENTER	RENAL ADVANTAGE INC
DIALYSIS CENTER	SAN DIEGO DIALYSIS SRV
DIALYSIS CENTER	SATELLITE HEALTH CARE
FEEDING ORGANIZATION	BARRIO STATION
FEEDING ORGANIZATION	BELLISSIMO DISTRIBUTION LLC
FEEDING ORGANIZATION	CHOICES IN RECOVERY
FEEDING ORGANIZATION	FAMILY ASSISTANCE MINISTRIES
FEEDING ORGANIZATION	GRAIN AND GRIT FOOD HALL
FEEDING ORGANIZATION	HELPING HAND MISSION
FEEDING ORGANIZATION	JEWISH FAMILY SERVICE
FEEDING ORGANIZATION	LA MESA COMM
FEEDING ORGANIZATION	LIVE & LET LIVE ALANO
FEEDING ORGANIZATION	MARKET CREEK PARTNERS LLC
FEEDING ORGANIZATION	MEALS ON WHEELS GRTR SD INC
FEEDING ORGANIZATION	NATL CTY NUTRITION CTR
FEEDING ORGANIZATION	OAKS NORTH COMM CTR
FEEDING ORGANIZATION	PARK COMMONS SORRENTO VALLEY
FEEDING ORGANIZATION	RANCHO STA FE COMMUNITY CTR
FEEDING ORGANIZATION	SAN DIEGO FOOD BANK
FEEDING ORGANIZATION	SESAJAL LLC
FEEDING ORGANIZATION	SHELBY CURRIE
FEEDING ORGANIZATION	THE 12TH STEP HOUSE INC
FEEDING ORGANIZATION	UNITED WAY
FEEDING ORGANIZATION	URBAN CORPS OF SAN DIEGO
EMERGENCY OPERATIONS CENTERS	CITY OF CARLSBAD
EMERGENCY OPERATIONS CENTERS	CITY OF CHULA VISTA
EMERGENCY OPERATIONS CENTERS	CITY OF CORONADO
EMERGENCY OPERATIONS CENTERS	CITY OF DEL MAR
EMERGENCY OPERATIONS CENTERS	CITY OF EL CAJON
EMERGENCY OPERATIONS CENTERS	CITY OF ENCINITAS
EMERGENCY OPERATIONS CENTERS	CITY OF LEMON GROVE
EMERGENCY OPERATIONS CENTERS	CITY OF NATIONAL CITY
EMERGENCY OPERATIONS CENTERS	CITY OF OCEANSIDE
EMERGENCY OPERATIONS CENTERS	CITY OF POWAY
EMERGENCY OPERATIONS CENTERS	CITY OF SAN DIEGO
EMERGENCY OPERATIONS CENTERS	CITY OF SAN MARCOS
EMERGENCY OPERATIONS CENTERS	CITY OF SANTEE
EMERGENCY OPERATIONS CENTERS	CITY OF SOLANA BEACH
EMERGENCY OPERATIONS CENTERS	CITY OF VISTA
EMERGENCY OPERATIONS CENTERS	CO OF SAN DIEGO
EMERGENCY OPERATIONS CENTERS	SD UNIFIED PORT DIST
EMERGENCY OPERATIONS CENTERS	SDCWA

CRITICAL_FAC_CODE	CUSTOMER_NAME
COVID RELATED TEMP SITES*	1ST UNITED METHODIST CH
COVID RELATED TEMP SITES*	22ND DIST AGRI ASSN
COVID RELATED TEMP SITES*	833 ASH ST LLC
COVID RELATED TEMP SITES*	ACE PARKING
COVID RELATED TEMP SITES*	ALERE SAN DIEGO
COVID RELATED TEMP SITES*	ALLIANCE FOR QUALITY ED
COVID RELATED TEMP SITES*	ALVARADO HOSPITAL LLC
COVID RELATED TEMP SITES*	AMERICAN CAMPUS MANAGEMENT
COVID RELATED TEMP SITES*	APOSTOLIC ASSEMBLY
COVID RELATED TEMP SITES*	BAYVIEW BAPTIST CHURCH
COVID RELATED TEMP SITES*	BEYLER FEECE DEVELOPMENT
COVID RELATED TEMP SITES*	BONSALL PETROLEUM
COVID RELATED TEMP SITES*	BPO ELKS LODGE 1812
COVID RELATED TEMP SITES*	C C A E
COVID RELATED TEMP SITES*	C PATRICK COWAN TRUSTEE
COVID RELATED TEMP SITES*	C R ASSOCIATES
COVID RELATED TEMP SITES*	CALIFORNIA BANK & TRUST
COVID RELATED TEMP SITES*	CARLTON HILLS LUTHERAN
COVID RELATED TEMP SITES*	CASA FAMILIAR INC
COVID RELATED TEMP SITES*	CATH CHARITIES DIOCESE OF SD
COVID RELATED TEMP SITES*	CENTRO DE SALUD DE SY
COVID RELATED TEMP SITES*	CHICANO FEDERATION OF SD
COVID RELATED TEMP SITES*	CITY OF CARLSBAD
COVID RELATED TEMP SITES*	CITY OF CHULA VISTA
COVID RELATED TEMP SITES*	CITY OF CORONADO
COVID RELATED TEMP SITES*	CITY OF IMPERIAL BEACH
COVID RELATED TEMP SITES*	CITY OF LEMON GROVE
COVID RELATED TEMP SITES*	CITY OF NATIONAL CITY
COVID RELATED TEMP SITES*	CITY OF OCEANSIDE
COVID RELATED TEMP SITES*	CITY OF POWAY
COVID RELATED TEMP SITES*	CITY OF SAN DIEGO
COVID RELATED TEMP SITES*	CLINICAL MICRO SENSORS INC
COVID RELATED TEMP SITES*	CO OF SAN DIEGO
COVID RELATED TEMP SITES*	CSU SAN MARCOS
COVID RELATED TEMP SITES*	DOVE PROFESSIONAL GRP 2 LLC
COVID RELATED TEMP SITES*	DREAMS FOR CHANGE LLC
COVID RELATED TEMP SITES*	EAST COUNTY TRANSITIONAL
COVID RELATED TEMP SITES*	EL CAJON MAGNOLIA ASSOC LLC
COVID RELATED TEMP SITES*	ENCANTO BAPTIST CHURCH
COVID RELATED TEMP SITES*	ENSTROM MOLD & ENG
COVID RELATED TEMP SITES*	FAITH CHAPEL
COVID RELATED TEMP SITES*	FALLBROOK REG HEALTH DIST

CRITICAL_FAC_CODE	CUSTOMER_NAME
COVID RELATED TEMP SITES*	FAMILY HEALTH CENTERS OF SD
COVID RELATED TEMP SITES*	FIRST GROSSMONT PROPERTIES
COVID RELATED TEMP SITES*	GENENTECH INC
COVID RELATED TEMP SITES*	GENETRONICS INC
COVID RELATED TEMP SITES*	GON-REY LLC
COVID RELATED TEMP SITES*	GOODWILL INDUSTRIES SD CNTY
COVID RELATED TEMP SITES*	GREATER SD MUSLIM COMM CTR
COVID RELATED TEMP SITES*	GROSSMONT HEALTHCARE DIST
COVID RELATED TEMP SITES*	GROSSMONT HOSPITAL CORP
COVID RELATED TEMP SITES*	HOLOGIC INC
COVID RELATED TEMP SITES*	INTERFAITH COMMUNITY SVCS
COVID RELATED TEMP SITES*	ISHVERBHAI PATEL
COVID RELATED TEMP SITES*	JACOBS CENTR NONPROFIT INNOV
COVID RELATED TEMP SITES*	JEWISH FAMILY SERVICE
COVID RELATED TEMP SITES*	JIF PAK MFG INC
COVID RELATED TEMP SITES*	KAISER PERMANENTE
COVID RELATED TEMP SITES*	LABORATORY CORP OF AMERICA
COVID RELATED TEMP SITES*	MAAC PROJECT
COVID RELATED TEMP SITES*	MEADOW LAKE COUNTRY CLUB LLC
COVID RELATED TEMP SITES*	MENTAL HEALTH SYSTEMS INC
COVID RELATED TEMP SITES*	MEXICAN CONSULATE
COVID RELATED TEMP SITES*	MONICA PERLMAN MD INC
COVID RELATED TEMP SITES*	MV CHRISTIAN FELLOWSHIP
COVID RELATED TEMP SITES*	NAVAL HOSPITAL CAMP PENDLTN
COVID RELATED TEMP SITES*	NEIGHBORHOOD HEALTH CARE
COVID RELATED TEMP SITES*	NORTH COUNTY LIFELINE INC
COVID RELATED TEMP SITES*	NORTHGATE GONZALEZ LLC
COVID RELATED TEMP SITES*	OAK VALLEY HOTEL LLC
COVID RELATED TEMP SITES*	OCEAN RANCH BLVD 3605 CORP
COVID RELATED TEMP SITES*	OPERATION HOPE N COUNTY INC
COVID RELATED TEMP SITES*	PALM IV LLC
COVID RELATED TEMP SITES*	PALOMAR HEALTH
COVID RELATED TEMP SITES*	PATH
COVID RELATED TEMP SITES*	PAUMA VLY COMM ASSOC
COVID RELATED TEMP SITES*	PHARMINGEN
COVID RELATED TEMP SITES*	PT LOMA NAZARENE UNIVERSITY
COVID RELATED TEMP SITES*	QUEST DIAGNOSTICS
COVID RELATED TEMP SITES*	RACHAS INC
COVID RELATED TEMP SITES*	RADY CHILDREN'S HOSPITAL-SD
COVID RELATED TEMP SITES*	RANCHO CORRIDO LLC
COVID RELATED TEMP SITES*	ROMAN CATHOLIC BISHOP SD
COVID RELATED TEMP SITES*	ROUSE PROPERTIES INC

CRITICAL_FAC_CODE	CUSTOMER_NAME
COVID RELATED TEMP SITES*	ROYAL HOSPITALITY INC
COVID RELATED TEMP SITES*	RVN INC
COVID RELATED TEMP SITES*	SALK INSTITUTE
COVID RELATED TEMP SITES*	SALVATION ARMY
COVID RELATED TEMP SITES*	SAN DIEGO FOOD BANK
COVID RELATED TEMP SITES*	SAN DIEGO RESCUE MISSION INC
COVID RELATED TEMP SITES*	SAN LUIS REY MISSION
COVID RELATED TEMP SITES*	SCRIPPS HEALTH
COVID RELATED TEMP SITES*	SCRIPPS MERCY HOSP
COVID RELATED TEMP SITES*	SCRIPPS RESEARCH INSTITUTE
COVID RELATED TEMP SITES*	SCRIPPS-GREEN HOSPITAL
COVID RELATED TEMP SITES*	SD CONVENTION CTR CORP
COVID RELATED TEMP SITES*	SD NEW LIFE BAPTIST CHURCH
COVID RELATED TEMP SITES*	SD YOUTH & COMM SERVICE
COVID RELATED TEMP SITES*	SDLGBT COMMUNITY CENTER
COVID RELATED TEMP SITES*	SEA WORLD LLC
COVID RELATED TEMP SITES*	SHARP CHULA VISTA M C
COVID RELATED TEMP SITES*	SHARP HEALTHCARE
COVID RELATED TEMP SITES*	SHERMAN HGHTS COMM CTR
COVID RELATED TEMP SITES*	SOUTH EAST MEDICAL CENTER
COVID RELATED TEMP SITES*	ST ANTHONYS CHURCH
COVID RELATED TEMP SITES*	ST JAMES CATHOLIC PARISH
COVID RELATED TEMP SITES*	ST VINCENT DE PAUL VLG INC
COVID RELATED TEMP SITES*	SURTI DEVELOPERS LLC
COVID RELATED TEMP SITES*	SWEETWATER UNION HI SCH DIST
COVID RELATED TEMP SITES*	TARGET CORPORATION
COVID RELATED TEMP SITES*	TELEDYNE API INC
COVID RELATED TEMP SITES*	THOUSAND TRAILS INC
COVID RELATED TEMP SITES*	TIFFANY BAGALINI
COVID RELATED TEMP SITES*	TOWNSPEOPLE
COVID RELATED TEMP SITES*	TRUECARE
COVID RELATED TEMP SITES*	UNIVERSAL PROPTY LAP TWO LLC
COVID RELATED TEMP SITES*	UNIVERSITY OF SAN DIEGO
COVID RELATED TEMP SITES*	VA MEDICAL CTR
COVID RELATED TEMP SITES*	VIASAT INC
COVID RELATED TEMP SITES*	VILICUS MANAGEMENT LLC
COVID RELATED TEMP SITES*	WALGREENS
COVID RELATED TEMP SITES*	YMCA OF SAN DIEGO COUNTY
FEDERAL ACCOUNTS	C O MCAS MIRAMAR
FEDERAL ACCOUNTS	C O NAVAL CONSOLID BRIG
FEDERAL ACCOUNTS	CBP AIR
FEDERAL ACCOUNTS	CMDR NAVAL SPEC WARFARE GRP1

CRITICAL_FAC_CODE	CUSTOMER_NAME
FEDERAL ACCOUNTS	COMMANDER NAVY REGION SW
FEDERAL ACCOUNTS	CUSTOMS AND BORDER PROTECTION
FEDERAL ACCOUNTS	FAA
FEDERAL ACCOUNTS	GSA
FEDERAL ACCOUNTS	MCAS MIRAMAR COMMISSARY
FEDERAL ACCOUNTS	MCAS MIRAMAR EXCHANGE
FEDERAL ACCOUNTS	MCAS MIRAMAR RESERVE CENTER
FEDERAL ACCOUNTS	NATIONAL MARINE FISHERIES
FEDERAL ACCOUNTS	NAVAL MEDICAL CENTER
FEDERAL ACCOUNTS	NAVFAC SOUTHWEST
FEDERAL ACCOUNTS	NAVY EXCHANGE
FEDERAL ACCOUNTS	NAVY REGIONL PLANT EQUIP OFC
FEDERAL ACCOUNTS	NAVY RESOURCE MGMT OFFICE
FEDERAL ACCOUNTS	NAVY WARNER SPRINGS TRNG GRP
FEDERAL ACCOUNTS	NOAA MARINE OPS PACIFIC
FEDERAL ACCOUNTS	US BORDER PATROL
FEDERAL ACCOUNTS	US COAST GUARD
FEDERAL ACCOUNTS	US IMM AND NAT SER
FEDERAL ACCOUNTS	US NAVY SHIP SUPPORT UNIT SD
FEDERAL ACCOUNTS	USMC CPEN M00681
FEDERAL ACCOUNTS	USMC MAINTNCE OFFICER
FEDERAL ACCOUNTS	USN CMDG OFF CODE 5
FEDERAL ACCOUNTS	USN CMDG OFF CODE N8
FIRE STATIONS	ALPINE FIRE PROTECTION DIST
FIRE STATIONS	BARONA BAND MSN INDIANS
FIRE STATIONS	BLACK CONTRACTORS ASSOC SD
FIRE STATIONS	BO SUNNYSIDE FIRE PROTECTION
FIRE STATIONS	BORREGO SPGS FIRE DEPT
FIRE STATIONS	CALIFORNIA DEPT FORESTRY
FIRE STATIONS	CAMPO FIRE DEPT
FIRE STATIONS	CAMPO IND RES/FIRE STN
FIRE STATIONS	CAPSTONE FIRE MANAGEMENT INC
FIRE STATIONS	CITY OF CARLSBAD
FIRE STATIONS	CITY OF CHULA VISTA
FIRE STATIONS	CITY OF CORONADO
FIRE STATIONS	CITY OF DEL MAR
FIRE STATIONS	CITY OF EL CAJON
FIRE STATIONS	CITY OF ENCINITAS
FIRE STATIONS	CITY OF ESCONDIDO
FIRE STATIONS	CITY OF IMPERIAL BEACH
FIRE STATIONS	CITY OF LA MESA
FIRE STATIONS	CITY OF LAGUNA NIGUEL

CRITICAL_FAC_CODE	CUSTOMER_NAME
FIRE STATIONS	CITY OF LEMON GROVE
FIRE STATIONS	CITY OF NATIONAL CITY
FIRE STATIONS	CITY OF OCEANSIDE
FIRE STATIONS	CITY OF POWAY
FIRE STATIONS	CITY OF SAN CLEMENTE
FIRE STATIONS	CITY OF SAN DIEGO
FIRE STATIONS	CITY OF SAN MARCOS
FIRE STATIONS	CITY OF SANTEE
FIRE STATIONS	CITY OF SOLANA BEACH
FIRE STATIONS	CITY OF VISTA
FIRE STATIONS	CO OF SAN DIEGO
FIRE STATIONS	DEER SPGS VOL FIRE DEPT
FIRE STATIONS	DEER SPRINGS FIRE PROTECTION
FIRE STATIONS	ELFIN FOREST VLNTEER FD
FIRE STATIONS	JULIAN COMM SERV DIST
FIRE STATIONS	JULIAN CUYMCA FIRE DIST
FIRE STATIONS	JULIAN VOLUNTEER FIRE CO
FIRE STATIONS	LAKESIDE FIRE DEPT
FIRE STATIONS	LAKESIDE FIRE PROTECTION DIS
FIRE STATIONS	LAKESIDE FIRE PROTECTN
FIRE STATIONS	MANZANITA BAND MSN INDIA
FIRE STATIONS	MESA GRANDE B O M I FIRE DPT
FIRE STATIONS	NORTH CNTY DISPATCH JPA
FIRE STATIONS	NORTH COUNTY FIRE
FIRE STATIONS	ORANGE COUNTY FIRE AUTHORITY
FIRE STATIONS	PALA BAND OF MISSION INDIANS
FIRE STATIONS	PAUMA BAND MSN INDIANS
FIRE STATIONS	POTRERO COMM CTR FOUNDATION
FIRE STATIONS	RAMONA MUN WTR DIST
FIRE STATIONS	RANCHO SANTA FE ASSOC
FIRE STATIONS	RANCHO SANTA FE FIRE DIST
FIRE STATIONS	RHO SANTA FE FIRE DEP
FIRE STATIONS	RHO STA FE FIRE DEPT
FIRE STATIONS	RINCON INDIAN RESERVATION
FIRE STATIONS	ROBBY IVY
FIRE STATIONS	RSF FIRE PROTECTION DISTRICT
FIRE STATIONS	SAN DIEGO RURAL FIRE PROTECT
FIRE STATIONS	SAN MIGUEL FIRE PRO DST
FIRE STATIONS	SAN PASQ BAND OF DIEGUENO MI
FIRE STATIONS	SAN PASQUAL ACADEMY
FIRE STATIONS	SANTA YSABEL BAND OF DIEGUEN
FIRE STATIONS	SD CITY FIRE FIGHTERS

CRITICAL_FAC_CODE	CUSTOMER_NAME
FIRE STATIONS	SN MIGUEL FIRE PRO DIST
FIRE STATIONS	STATE OF CAL PARKS DEPT
FIRE STATIONS	STATE OF CALIF
FIRE STATIONS	STATE OF CALIFORNIA
FIRE STATIONS	SYCUAN BAND KUMEYAAY INDIANS
FIRE STATIONS	U S FOREST SERVICE
FIRE STATIONS	USDA-FOREST SERVICE
FIRE STATIONS	VIEJAS BAND OF KUMEYAAY IND
FIRE STATIONS	VLY CTR FIRE PROTECTION
HEALTHCARE/PUBLIC HEALTH	AESTHETICARE MED CORP
HEALTHCARE/PUBLIC HEALTH	AIJ INC
HEALTHCARE/PUBLIC HEALTH	ALICIA SURGERY CENTER LLC
HEALTHCARE/PUBLIC HEALTH	ALTERNATIVES PREGNANCY
HEALTHCARE/PUBLIC HEALTH	ALVARADO PKWY INSTITUTE
HEALTHCARE/PUBLIC HEALTH	ARTEMIS HEADLANDS LLC
HEALTHCARE/PUBLIC HEALTH	ASSISTED HEALTH SYSTEMS
HEALTHCARE/PUBLIC HEALTH	AT HOME CARE SOLUTIONS
HEALTHCARE/PUBLIC HEALTH	BENJAMIN CAMACHO
HEALTHCARE/PUBLIC HEALTH	BEST START BIRTH CENTER
HEALTHCARE/PUBLIC HEALTH	BORREGO COMM HLTH FOUNDATION
HEALTHCARE/PUBLIC HEALTH	CAL CTR FOR REPRODUCTIVE SCI
HEALTHCARE/PUBLIC HEALTH	CALIFORNIA FERTILITY EXPERTS
HEALTHCARE/PUBLIC HEALTH	CARLSBAD UNIF SCH DIST
HEALTHCARE/PUBLIC HEALTH	CARLSBAD VILLAGE ORTHO
HEALTHCARE/PUBLIC HEALTH	CARMEL VALLEY ENDODONTICS
HEALTHCARE/PUBLIC HEALTH	CATH CHARITIES DIOCESE OF SD
HEALTHCARE/PUBLIC HEALTH	CENTRO DE SALUD DE SY
HEALTHCARE/PUBLIC HEALTH	CLEARCHOICE SAN DIEGO
HEALTHCARE/PUBLIC HEALTH	CO OF SAN DIEGO
HEALTHCARE/PUBLIC HEALTH	COAST SURGERY CENTER
HEALTHCARE/PUBLIC HEALTH	CPMS MEDICAL GROUP INC
HEALTHCARE/PUBLIC HEALTH	CRESTWOOD BEHAVIORAL HEALTH
HEALTHCARE/PUBLIC HEALTH	DEL MAR MEDICAL IMAGING
HEALTHCARE/PUBLIC HEALTH	DEL RIO MEDICAL & DENTAL PLZ
HEALTHCARE/PUBLIC HEALTH	DR TAWFILIS
HEALTHCARE/PUBLIC HEALTH	EGOSCUE
HEALTHCARE/PUBLIC HEALTH	EMERALD TRIUNE HOME HEALTH
HEALTHCARE/PUBLIC HEALTH	ENCOMPASS FAMILY & INTERNAL
HEALTHCARE/PUBLIC HEALTH	EXODUS RECOVERY INC
HEALTHCARE/PUBLIC HEALTH	EYE PHYSICIANS MED GRP
HEALTHCARE/PUBLIC HEALTH	EYE SURGERY CTR
HEALTHCARE/PUBLIC HEALTH	FRIENDSHIP DEVELOPMENT SVCS

CRITICAL_FAC_CODE	CUSTOMER_NAME
HEALTHCARE/PUBLIC HEALTH	GARDEN VIEW COURT LLC
HEALTHCARE/PUBLIC HEALTH	GIL Q GALLOWAY MD INC
HEALTHCARE/PUBLIC HEALTH	GROSSMONT SURGERY CTR
HEALTHCARE/PUBLIC HEALTH	HERALD CHRISTIAN HEALTH CNTR
HEALTHCARE/PUBLIC HEALTH	JOHN QIAN MD INC
HEALTHCARE/PUBLIC HEALTH	KPAP INC
HEALTHCARE/PUBLIC HEALTH	LA JOLLA ORTHOPAEDIC SURGERY
HEALTHCARE/PUBLIC HEALTH	LA MAESTRA FAMILY CLINIC INC
HEALTHCARE/PUBLIC HEALTH	LA MAESTRA FOUNDATION
HEALTHCARE/PUBLIC HEALTH	LAGUNA NIGUEL SURGERY CENTER
HEALTHCARE/PUBLIC HEALTH	LINDA VISTA HEALTH CARE CTR
HEALTHCARE/PUBLIC HEALTH	LUIS CONTRERAS
HEALTHCARE/PUBLIC HEALTH	MISSION MEDICAL INVES LLC
HEALTHCARE/PUBLIC HEALTH	MISSION VALLEY OPSC LP
HEALTHCARE/PUBLIC HEALTH	MSN AMBULATORY SURGICAL
HEALTHCARE/PUBLIC HEALTH	MUNISH BATRA MDPC
HEALTHCARE/PUBLIC HEALTH	NAVAJO LLC
HEALTHCARE/PUBLIC HEALTH	NEW RESTORATION MINISTRIES
HEALTHCARE/PUBLIC HEALTH	NO CTY GASTROENTEROLOGY
HEALTHCARE/PUBLIC HEALTH	NORTH COAST SURGERY CTR
HEALTHCARE/PUBLIC HEALTH	NORTH COUNTY SURGERY CENTER
HEALTHCARE/PUBLIC HEALTH	OTAY LAKES SURGERY CENTER
HEALTHCARE/PUBLIC HEALTH	PACIFIC ONCOLOGY
HEALTHCARE/PUBLIC HEALTH	PACIFIC SURGERY CENTER
HEALTHCARE/PUBLIC HEALTH	PRICE CHARITIES
HEALTHCARE/PUBLIC HEALTH	RAZAVI CORP
HEALTHCARE/PUBLIC HEALTH	ROBERT CORRY
HEALTHCARE/PUBLIC HEALTH	S C MEDICAL PLAZA
HEALTHCARE/PUBLIC HEALTH	SACRED HEART HLTHCR PROV INC
HEALTHCARE/PUBLIC HEALTH	SAN CLEMENTE MEDICAL BLDG
HEALTHCARE/PUBLIC HEALTH	SAN DIEGO ENDOSCOPY CTR
HEALTHCARE/PUBLIC HEALTH	SAN DIEGO FACE & NECK
HEALTHCARE/PUBLIC HEALTH	SAN DIEGO FERTILITY CENTER
HEALTHCARE/PUBLIC HEALTH	SC PROFESSIONAL PLAZA LLC
HEALTHCARE/PUBLIC HEALTH	SCHOEMANN PLASTIC SURGERY
HEALTHCARE/PUBLIC HEALTH	SCRIPPS HEALTH
HEALTHCARE/PUBLIC HEALTH	SCRIPPS MEM - ENCINITAS
HEALTHCARE/PUBLIC HEALTH	SD COMPREHENSIVE PAINMGMT
HEALTHCARE/PUBLIC HEALTH	SD MUSCULOSKELETAL INSTITUTE
HEALTHCARE/PUBLIC HEALTH	SERVING SENIORS
HEALTHCARE/PUBLIC HEALTH	SEVILLE PLAZA PROPCO LLC
HEALTHCARE/PUBLIC HEALTH	SO CALIFORNIA LIVER CENTERS

CRITICAL_FAC_CODE	CUSTOMER_NAME
HEALTHCARE/PUBLIC HEALTH	SOLUTIONS IN RECOVERY
HEALTHCARE/PUBLIC HEALTH	SOUTH EAST MEDICAL CENTER
HEALTHCARE/PUBLIC HEALTH	SPECIALTY OBSTETRICS OF SD
HEALTHCARE/PUBLIC HEALTH	ST PAULS EPISCOPAL HOME
HEALTHCARE/PUBLIC HEALTH	STUART B KIPPER MD
HEALTHCARE/PUBLIC HEALTH	SUMMIT MANAGEMENT
HEALTHCARE/PUBLIC HEALTH	SURGE CENTER OF SD LLC
HEALTHCARE/PUBLIC HEALTH	SURGICAL CENTER OF SAN DIEGO
HEALTHCARE/PUBLIC HEALTH	TERI INC
HEALTHCARE/PUBLIC HEALTH	THE A R C OF SAN DIEGO
HEALTHCARE/PUBLIC HEALTH	THE CTR FOR ENDOSCOPY
HEALTHCARE/PUBLIC HEALTH	THE VINE
HEALTHCARE/PUBLIC HEALTH	THERAPY SPECIALISTS
HEALTHCARE/PUBLIC HEALTH	TOGETHER WE GROW
HEALTHCARE/PUBLIC HEALTH	TRIUMSHIRE MANAGEMENT INC
HEALTHCARE/PUBLIC HEALTH	TRUECARE
HEALTHCARE/PUBLIC HEALTH	UCMP LLC
HEALTHCARE/PUBLIC HEALTH	UCSD
HEALTHCARE/PUBLIC HEALTH	UTC SURGI CENTER
HEALTHCARE/PUBLIC HEALTH	VISTA COMMUNITY CLINIC
HEALTHCARE/PUBLIC HEALTH	W A T INVESTMENTS LLC
HEALTHCARE/PUBLIC HEALTH	ANC CORPORATION
HEALTHCARE/PUBLIC HEALTH	ARDENT HOSPICE& PAL CARE INC
HEALTHCARE/PUBLIC HEALTH	CULTURE OF LIFE FAMILY SVCS
HEALTHCARE/PUBLIC HEALTH	DUNYA ANTWAN
HEALTHCARE/PUBLIC HEALTH	ESC CHIROPRACTIC OFFICE
HEALTHCARE/PUBLIC HEALTH	GROSSMONT HOSPITAL CORP
HEALTHCARE/PUBLIC HEALTH	HOME OF GUIDING HANDS
HEALTHCARE/PUBLIC HEALTH	HOSPICE OF THE COAST INC
HEALTHCARE/PUBLIC HEALTH	MARGUERITE HOLDINGS LLC
HEALTHCARE/PUBLIC HEALTH	PHILIP D SZOLD MD INC
HEALTHCARE/PUBLIC HEALTH	SH & PC-SD LLC
HEALTHCARE/PUBLIC HEALTH	STONECREST CA HOLDING LLC
HEALTHCARE/PUBLIC HEALTH	TERI INC
HEALTHCARE/PUBLIC HEALTH	THE ELIZABETH HOSPICE
HEALTHCARE/PUBLIC HEALTH	UNI CARE HOME HEALTH INC
HEALTHCARE/PUBLIC HEALTH	UNICARE HOSPICE INC
HEALTHCARE/PUBLIC HEALTH	VITAS HEALTHCARE
HEALTHCARE/PUBLIC HEALTH	WESTCOAST HEALTHCARE LLC
HOSPICE	ALPHA PROJECT
HOSPICE	EXPANDING HORIZONS
HOSPICE	FALLBROOK FOOD PANTRY

CRITICAL_FAC_CODE	CUSTOMER_NAME
HOSPICE	HEARTH HOUSE INC
HOSPICE	HOSPICE OF THE NO COAST
HOSPICE	NATIONAL SEARCH ASSOC
HOSPICE	SD YOUTH & COMM SERVICE
HOSPICE	ST VINCENT DE PAUL VLG INC
HOSPICE	THE SOUTH RESOURCE CTR INC
HOSPITALS	ALVARADO HOSPITAL LLC
HOSPITALS	CO OF SAN DIEGO
HOSPITALS	GROSSMONT HOSPITAL CORP
HOSPITALS	KAISER PERMANENTE
HOSPITALS	MISSION HOSPITAL
HOSPITALS	PALOMAR HEALTH
HOSPITALS	PARADISE VALLEY HOSP
HOSPITALS	PT LOMA CONVALESCENT HSPTL
HOSPITALS	RADY CHILDREN'S HOSPITAL-SD
HOSPITALS	SADDLEBACK MEMORIAL MED CTR
HOSPITALS	SCRIPPS MEM - ENCINITAS
HOSPITALS	SCRIPPS MEM HOSP - LJ
HOSPITALS	SCRIPPS MERCY HOSP
HOSPITALS	SCRIPPS MERCY HOSP - CV
HOSPITALS	SCRIPPS-GREEN HOSPITAL
HOSPITALS	SHARP CHULA VISTA M C
HOSPITALS	SHARP CORONADO HOSPITAL
HOSPITALS	SHARP MEMORIAL HOSPITAL
HOSPITALS	TRI CITY MEDICAL CTR
HOSPITALS	UCSD MEDICAL CENTER
HOSPITALS	VA MEDICAL CTR
HOSPITALS	VENCOR HOSPITALS OF CALIFORN
HOSPITALS	ZOOLOGICAL SOCIETY SAN DIEGO
PRISONS	CO OF SAN DIEGO
PRISONS	STATE OF CALIFORNIA
PUBLIC HEALTH DEPARTMENTS	CO OF SAN DIEGO
POLICE	CALIF HIGHWAY PATROL
POLICE	CALTRANS
POLICE	CITY OF CHULA VISTA
POLICE	CITY OF CORONADO
POLICE	CITY OF EL CAJON
POLICE	CITY OF ESCONDIDO
POLICE	CITY OF LA MESA
POLICE	CITY OF LEMON GROVE
POLICE	CITY OF NATIONAL CITY
POLICE	CITY OF OCEANSIDE

CRITICAL_FAC_CODE	CUSTOMER_NAME
POLICE	CITY OF SAN DIEGO
POLICE	CITY OF SAN MARCOS
POLICE	CITY OF VISTA
POLICE	CO OF SAN DIEGO
POLICE	COUNTY OF ORANGE
POLICE	LOS COYOTES INDIAN RESVRN
POLICE	RINCON INDIAN RESERVATION
POLICE	SD UNIFIED PORT DIST
PRISONS	STATE OF CALIFORNIA
SCHOOLS	ALBERT EINSTEIN ACADEMY
SCHOOLS	ALPINE UNION SCH DIST
SCHOOLS	ANAERGIA SERVICES LLC
SCHOOLS	BONSALL UNIFIED SCHOOL DISTRICT
SCHOOLS	BORREGO UNIF SCH DIST
SCHOOLS	CAJON VLY UNION SCH DIST
SCHOOLS	CAPISTRANO UNIF SCHOOL DIST
SCHOOLS	CARDIFF SCHOOL DIST
SCHOOLS	CARLSBAD UNIF SCH DIST
SCHOOLS	CHULA VISTA ELEM SCH DIST
SCHOOLS	CIRCLE OF CARE HOSPICE LLC
SCHOOLS	CITY OF OCEANSIDE
SCHOOLS	CORONADO UNIF SCH DIST
SCHOOLS	DARNALL SCHOOL
SCHOOLS	DEHESA SCHOOL DISTRICT
SCHOOLS	DEL MAR UNION SCH DIST
SCHOOLS	ENCINITAS UN SCH DIST
SCHOOLS	ENCINITAS UNION SCH DIST
SCHOOLS	ESCONDIDO CHARTER
SCHOOLS	ESCONDIDO CHARTER HIGH SCHL
SCHOOLS	ESCONDIDO UN SCH DIST
SCHOOLS	ESCONDIDO UNION HI SCH DIS
SCHOOLS	FALLBROOK UN HI SCH DIS
SCHOOLS	FALLBROOK UN SCH DIST
SCHOOLS	FRANCIS PARKER SCHOOL
SCHOOLS	FRANCIS W PARKER SCHOOL
SCHOOLS	FRED WHITE
SCHOOLS	GOMPERS PREPARATORY ACADEMY
SCHOOLS	GROSSMONT UNION HIGH SCHOOL DIST
SCHOOLS	GRSMT COMM COLL DIST
SCHOOLS	GRSMT UN HI SCH DIST
SCHOOLS	GUAJOME PARK ACADEMY
SCHOOLS	HARRIET TUBMAN VLG CHARTER

CRITICAL_FAC_CODE	CUSTOMER_NAME
SCHOOLS	HELIX CHARTER HIGH SCHOOL
SCHOOLS	HERITAGE DIGITAL ACADEMY
SCHOOLS	HIGH TECH HIGH
SCHOOLS	HILARIO ARREDONDO RODRIGUEZ
SCHOOLS	JAMUL-DULZURA SCH DIST
SCHOOLS	JULIAN CHARTER SCHOOL
SCHOOLS	JULIAN UNION HI SCH DIST
SCHOOLS	JULIAN UNION SCHOOL DISTRICT
SCHOOLS	KING CHAVEZ ACADEMY OF EXCEL
SCHOOLS	L J COUNTRY DAY SCHOOL
SCHOOLS	LA MESA SPR VLY SCH DIS
SCHOOLS	LAKESIDE UNION SCH DIST
SCHOOLS	LEMON GROVE SCH DIST
SCHOOLS	MCGILL SCHOOL OF SUCCESS
SCHOOLS	MIRACOSTA COMM COL DIST
SCHOOLS	MISSION SAN ANTONIO
SCHOOLS	MT EMPIRE UNIF SCH DIST
SCHOOLS	NATIONAL SCHOOL DIST
SCHOOLS	NATIONAL UNIVERSITY
SCHOOLS	OCEANSIDE UNIF SCH DIST
SCHOOLS	PALOMAR COMM COLLEGE
SCHOOLS	POWAY UNIF SCH DIST
SCHOOLS	RAMONA UNIF SCH DIST
SCHOOLS	RHO STA FE SCHOOL DIST
SCHOOLS	SADLBK VLY UNF SCH DST
SCHOOLS	SAN DIEGUITO HI SCH DIS
SCHOOLS	SAN MARCOS UNIF SCH DIS
SCHOOLS	SAN PASQUAL UN SCHL DIS
SCHOOLS	SAN YSIDRO SCH DIST
SCHOOLS	SANTEE SCH DIST
SCHOOLS	SD CNTY OFC OF EDUCATION
SCHOOLS	SD UNIF SCH DIST
SCHOOLS	SDCCD
SCHOOLS	SO ORANGE CNTY COM COL DIST
SCHOOLS	SOLANA BEACH SCH DIST
SCHOOLS	SOUTH BAY UNION SCH DIST
SCHOOLS	SOUTHWESTERN COMM COLLEGE
SCHOOLS	SPENCER VALLEY SCHOOL
SCHOOLS	SPRINGALL ACADEMY
SCHOOLS	SWEETWATER UNION HI SCH DIST
SCHOOLS	THOMAS MURRAY
SCHOOLS	UCSD

CRITICAL_FAC_CODE	CUSTOMER_NAME
SCHOOLS	VALLECITOS SCHOOL
SCHOOLS	VISTA UNIF SCH DIST
SCHOOLS	VLY CTR PAUMA UNIF SCH DIST
SCHOOLS	WARNER UN SCH DIST
SDGE CRITICAL	SDG&E
SDGE CRITICAL	SDG&E - SDSU DLP
SDGE CRITICAL	SDG&E 018461100
SDGE CRITICAL	SDG&E 018461210
SDGE CRITICAL	SDG&E 018461211
SDGE CRITICAL	SDG&E 018461220
SDGE CRITICAL	SDG&E 018461230
SDGE CRITICAL	SDG&E 018461240
SDGE CRITICAL	SDG&E 018461241
SDGE CRITICAL	SDG&E 018461260
SDGE CRITICAL	SDG&E 018461270
SDGE CRITICAL	SDG&E 018461310
SDGE CRITICAL	SDG&E 018461311
SDGE CRITICAL	SDG&E 018461330
SDGE CRITICAL	SDG&E 018461380
SDGE CRITICAL	SDG&E 018461500
SDGE CRITICAL	SDG&E 018461732
SDGE CRITICAL	SDG&E 018461740
SDGE CRITICAL	SDG&E 018461780
SDGE CRITICAL	SDG&E 050600000
SDGE CRITICAL	SDG&E 058210000
SDGE CRITICAL	SDG&E 058360000
SDGE CRITICAL	SDG&E 058450000
SDGE CRITICAL	SDG&E 085700000
SDGE CRITICAL	SDG&E 087500000
SDGE CRITICAL	SDG&E 088730000
SDGE CRITICAL	SDG&E 392124100
SDGE CRITICAL	SDG&E 393511100
SDGE CRITICAL	SDG&E 393515100
SDGE CRITICAL	SDG&E 393515400
SDGE CRITICAL	SDG&E 536400000
SDGE CRITICAL	SDG&E 592124100
SDGE CRITICAL	SDG&E 593021300
SDGE CRITICAL	SDG&E CO OF SAN DIEGO DLP
SDGE CRITICAL	SDG&E/PACIFIC BELL DLP
SDGE CRITICAL	SDGE
SDGE CRITICAL	SDGE IHD 11
SDGE CRITICAL	SDGE LOAD RESEARCH

CRITICAL_FAC_CODE	CUSTOMER_NAME
SDGE CRITICAL	SDGE TES
SDGE CRITICAL	SDGE/OTAY MESA MTRSTA
SDGE CRITICAL	SDGE/SCE
SDGE CRITICAL	SDGL CAPITAL LLC
SKILLED NURSING/NURSING HOME	ABSOLUTE CARE HEALTH SYSTEMS
SKILLED NURSING/NURSING HOME	ACCENTCARE HOME HEALTH OF CA
SKILLED NURSING/NURSING HOME	ADVANTAGE HEALTH SYSTEMS
SKILLED NURSING/NURSING HOME	AEGIS ASSISTED LIVING LLC
SKILLED NURSING/NURSING HOME	AETAS HEALTH SERVICES
SKILLED NURSING/NURSING HOME	ALEXANDER LIMPIN
SKILLED NURSING/NURSING HOME	ALPINE SPECIAL TREATMENT CTR
SKILLED NURSING/NURSING HOME	ALZHEIMER'S FAMILY CTR
SKILLED NURSING/NURSING HOME	AMERICAN HEALTH SVCS OF SD
SKILLED NURSING/NURSING HOME	AMERICARE ADHC INC
SKILLED NURSING/NURSING HOME	ANCHOR DOWN OWNER ASSC INC
SKILLED NURSING/NURSING HOME	ARBA GROUP FACILITIES OPERAT
SKILLED NURSING/NURSING HOME	ASD6 LLC
SKILLED NURSING/NURSING HOME	AVIYA HOSPICE INC
SKILLED NURSING/NURSING HOME	BALBOA HEALTHCARE INC
SKILLED NURSING/NURSING HOME	BAYVIEW O P CHURCH
SKILLED NURSING/NURSING HOME	BERNARDO HEIGHTS HEALTH CARE
SKILLED NURSING/NURSING HOME	BIRCH HOLDINGS LLC
SKILLED NURSING/NURSING HOME	BORREGO COMM HLTH FOUND
SKILLED NURSING/NURSING HOME	BRIGHTON PLACE EAST
SKILLED NURSING/NURSING HOME	BRIGHTON PLACE SVC
SKILLED NURSING/NURSING HOME	BRIGHTSTAR LLC
SKILLED NURSING/NURSING HOME	CA DEPT OF VETERAN AFFAIRS
SKILLED NURSING/NURSING HOME	CAPISTRANO BEACH CARE CENTER
SKILLED NURSING/NURSING HOME	CASA DE LAS CAMPANAS
SKILLED NURSING/NURSING HOME	CASA PACIFICA
SKILLED NURSING/NURSING HOME	CASA PACIFICA ADHC
SKILLED NURSING/NURSING HOME	CASA PALMERA
SKILLED NURSING/NURSING HOME	CCW LA JOLLA LLC
SKILLED NURSING/NURSING HOME	CHURCH OF JESUS CHRIST
SKILLED NURSING/NURSING HOME	CITY HEIGHTS HEALTH ASSOC
SKILLED NURSING/NURSING HOME	CLAIREMONT HEALTHCARE CENTRE
SKILLED NURSING/NURSING HOME	CLAYDELLE HEALTHCARE INC
SKILLED NURSING/NURSING HOME	CO OF SAN DIEGO
SKILLED NURSING/NURSING HOME	COASTAL THERAPY GROUP
SKILLED NURSING/NURSING HOME	COMMUNITY CONV HOSPITAL
SKILLED NURSING/NURSING HOME	CONTINUING LIFE COMM LLC
SKILLED NURSING/NURSING HOME	COVENANT CARE CALIFORNIA LLC

CRITICAL_FAC_CODE	CUSTOMER_NAME
SKILLED NURSING/NURSING HOME	CRESCENT HEALTH CARE
SKILLED NURSING/NURSING HOME	EAST COUNTY TRANSITIONAL
SKILLED NURSING/NURSING HOME	EC OPCO GROSSMONT GARDENS LP
SKILLED NURSING/NURSING HOME	EC OPCO LAS VILLAS DEL CB LP
SKILLED NURSING/NURSING HOME	EIAD HADDAD
SKILLED NURSING/NURSING HOME	EL DORADO CARE CENTER
SKILLED NURSING/NURSING HOME	ELM HOLDINGS LLC
SKILLED NURSING/NURSING HOME	ESCONDIDO MEDICAL INVESTORS
SKILLED NURSING/NURSING HOME	FALLBROOK HEALTHCARE LLC
SKILLED NURSING/NURSING HOME	FCAW FOUR POINTS LLC
SKILLED NURSING/NURSING HOME	FD 531, LLC
SKILLED NURSING/NURSING HOME	FIVE STAR QUALITY CARE
SKILLED NURSING/NURSING HOME	FRONT PORCH
SKILLED NURSING/NURSING HOME	G H C OF NAT CITY 2 LLC
SKILLED NURSING/NURSING HOME	GABRIEL PERPETUA
SKILLED NURSING/NURSING HOME	GENTIVA
SKILLED NURSING/NURSING HOME	GHC OF KEARNY MESA LLC
SKILLED NURSING/NURSING HOME	GHC OF LA MESA LLC
SKILLED NURSING/NURSING HOME	GHC OF LAKESIDE LLC
SKILLED NURSING/NURSING HOME	GHC OF NATIONAL CITY I LLC
SKILLED NURSING/NURSING HOME	GHC OF SANTEE LLC
SKILLED NURSING/NURSING HOME	GOLDEN LIVING INC
SKILLED NURSING/NURSING HOME	GRANITE HILLS H C
SKILLED NURSING/NURSING HOME	HEBREW HOME
SKILLED NURSING/NURSING HOME	HERITAGE POINTE
SKILLED NURSING/NURSING HOME	HILLCREST MANOR SANITARIUM
SKILLED NURSING/NURSING HOME	IGLESIA DEL SENOR JESUS
SKILLED NURSING/NURSING HOME	INTERIM HEALTH CARE
SKILLED NURSING/NURSING HOME	ITALIAN MAPLE LLC
SKILLED NURSING/NURSING HOME	JACOB HEALTH CARE CTR
SKILLED NURSING/NURSING HOME	JAMES EASTERLY
SKILLED NURSING/NURSING HOME	JEFFERSON HEALTHCARE INC
SKILLED NURSING/NURSING HOME	JEFFREY PINE HLDNGS LLC
SKILLED NURSING/NURSING HOME	KINGDOM HALL
SKILLED NURSING/NURSING HOME	KOA HOLDINGS LLC
SKILLED NURSING/NURSING HOME	LEMON GROVE HEALTH ASSOC LLC
SKILLED NURSING/NURSING HOME	LIFE HEALTH SERVICES
SKILLED NURSING/NURSING HOME	LINERS CORP
SKILLED NURSING/NURSING HOME	LOVING CARE LLC
SKILLED NURSING/NURSING HOME	LUMBER CYCLE
SKILLED NURSING/NURSING HOME	MAXIM HEALTHCARE SERVICES
SKILLED NURSING/NURSING HOME	MEADOWBROOK VILLAGE

CRITICAL_FAC_CODE	CUSTOMER_NAME
SKILLED NURSING/NURSING HOME	MISSION HOME HEALTH INC
SKILLED NURSING/NURSING HOME	MISSION TRAILS HEALTH CARE
SKILLED NURSING/NURSING HOME	MODERN HOME HEALTH CARE INC
SKILLED NURSING/NURSING HOME	MOJ PROPERTIES LLC
SKILLED NURSING/NURSING HOME	MONTERA MSL LLC
SKILLED NURSING/NURSING HOME	MOUNT MIGUEL COVNT VLG
SKILLED NURSING/NURSING HOME	MTN SHADOWS SUPPORT GRP
SKILLED NURSING/NURSING HOME	MYRNA ARCELAO
SKILLED NURSING/NURSING HOME	NAUTILUS HEALTHCARE INC
SKILLED NURSING/NURSING HOME	OLIVE HOLDINGS LLC
SKILLED NURSING/NURSING HOME	PAC REGENT CONDO ASSOC
SKILLED NURSING/NURSING HOME	PACIFICA EASTLAKE LLC
SKILLED NURSING/NURSING HOME	PALOMAR HEIGHTS CARE CTR
SKILLED NURSING/NURSING HOME	PARKWAY OPERATIONS LLC
SKILLED NURSING/NURSING HOME	POMERADO OPERATIONS LLC
SKILLED NURSING/NURSING HOME	POPLAR HOLDINGS LLC
SKILLED NURSING/NURSING HOME	PORTSIDE HEALTHCARE INC
SKILLED NURSING/NURSING HOME	PREGNANCY CARE CENTER
SKILLED NURSING/NURSING HOME	REDWOOD SNR HOMES & SERVICES
SKILLED NURSING/NURSING HOME	REDWOOD TERR LUTH HOME
SKILLED NURSING/NURSING HOME	REGUS GROUP
SKILLED NURSING/NURSING HOME	REO VISTA HEALTH CARE CENTER
SKILLED NURSING/NURSING HOME	SAMUEL HOROWITZ INC
SKILLED NURSING/NURSING HOME	SAN DIEGO NEW CHURCH
SKILLED NURSING/NURSING HOME	SD CHRISTIAN FOUNDATION
SKILLED NURSING/NURSING HOME	SEACREST VILLAGE RB
SKILLED NURSING/NURSING HOME	SHARP MEMORIAL HOSPITAL
SKILLED NURSING/NURSING HOME	SO CAL PRESBYTERIAN HMS
SKILLED NURSING/NURSING HOME	ST PAUL HEALTH CARE CTR
SKILLED NURSING/NURSING HOME	ST PAULS EPISCOPAL HOME
SKILLED NURSING/NURSING HOME	SUN AND SEA ASSISTED LIVING
SKILLED NURSING/NURSING HOME	SUNLAND HOME FOUNDATION
SKILLED NURSING/NURSING HOME	SUNRISE ASSISTED LIVING
SKILLED NURSING/NURSING HOME	THE MUSIC THERAPY CENTER INC
SKILLED NURSING/NURSING HOME	THE POOR SISTERS OF NAZ
SKILLED NURSING/NURSING HOME	THE ROYAL HOME
SKILLED NURSING/NURSING HOME	VIBRA HOSPITAL OF SAN DIEGO
SKILLED NURSING/NURSING HOME	VILLA RHO BRDO HEALTH
SKILLED NURSING/NURSING HOME	VILLAGE SQ HEALTHCARE CTR
SKILLED NURSING/NURSING HOME	VISTA DEL MAR CARE CTR
SKILLED NURSING/NURSING HOME	VISTA KNOLL
SKILLED NURSING/NURSING HOME	VISTA POST ACUTE CENTER LLC

CRITICAL_FAC_CODE	CUSTOMER_NAME
SKILLED NURSING/NURSING HOME	VOLUNTEERS OF AMERICA
SKILLED NURSING/NURSING HOME	WEST ESCONDIDO HEALTHCARE
SKILLED NURSING/NURSING HOME	WINDSOR CARE CTR NC INC
SENIOR CENTERS, INDP LIVING & HOMELESS SHELTERS	4TH DIST SENIOR RESOURCE CTR
SENIOR CENTERS, INDP LIVING & HOMELESS SHELTERS	A BETTER HOME INSPECTION
SENIOR CENTERS, INDP LIVING & HOMELESS SHELTERS	A TRUSTED HOME CARE
SENIOR CENTERS, INDP LIVING & HOMELESS SHELTERS	AFFORDABLE AND HOME CARE SVC
SENIOR CENTERS, INDP LIVING & HOMELESS SHELTERS	ALL HEART HOME CARE
SENIOR CENTERS, INDP LIVING & HOMELESS SHELTERS	ALLIANCE OF ABILITIES
SENIOR CENTERS, INDP LIVING & HOMELESS SHELTERS	ALZHEIMER'S FAMILY CTR
SENIOR CENTERS, INDP LIVING & HOMELESS SHELTERS	ASRV LLC
SENIOR CENTERS, INDP LIVING & HOMELESS SHELTERS	ASSERTIVE CARE AT HOME INC
SENIOR CENTERS, INDP LIVING & HOMELESS SHELTERS	AVENUE HOME CARE LLC
SENIOR CENTERS, INDP LIVING & HOMELESS SHELTERS	BEACONS INC
SENIOR CENTERS, INDP LIVING & HOMELESS SHELTERS	BRIGHT STAR CARE
SENIOR CENTERS, INDP LIVING & HOMELESS SHELTERS	CARMEL VALLEY SENIOR LIVING
SENIOR CENTERS, INDP LIVING & HOMELESS SHELTERS	CCBA SENIOR GARDENS
SENIOR CENTERS, INDP LIVING & HOMELESS SHELTERS	CHAMBERS SENIOR RESIDENCES
SENIOR CENTERS, INDP LIVING & HOMELESS SHELTERS	CHULA VISTA SENIOR LIVING LP
SENIOR CENTERS, INDP LIVING & HOMELESS SHELTERS	CITY OF VISTA
SENIOR CENTERS, INDP LIVING & HOMELESS SHELTERS	CO OF SAN DIEGO
SENIOR CENTERS, INDP LIVING & HOMELESS SHELTERS	COAST CARE PARTNERS
SENIOR CENTERS, INDP LIVING & HOMELESS SHELTERS	COMPREHENSIVE ED SERVICES
SENIOR CENTERS, INDP LIVING & HOMELESS SHELTERS	CREEL INDUSTRIES
SENIOR CENTERS, INDP LIVING & HOMELESS SHELTERS	EASTER SEALS SOUTHERN CALIF
SENIOR CENTERS, INDP LIVING & HOMELESS SHELTERS	EC OPCP LA MESA LP
SENIOR CENTERS, INDP LIVING & HOMELESS SHELTERS	ELDER LAW AND ADVOCACY
SENIOR CENTERS, INDP LIVING & HOMELESS SHELTERS	EXPERIENCED IN HOME CARE INC
SENIOR CENTERS, INDP LIVING & HOMELESS SHELTERS	FALLBROOK OPCO LLC
SENIOR CENTERS, INDP LIVING & HOMELESS SHELTERS	FIRST PROMISE CARE SVCS LLC
SENIOR CENTERS, INDP LIVING & HOMELESS SHELTERS	GENESIS INTRNTL SERVICES INC
SENIOR CENTERS, INDP LIVING & HOMELESS SHELTERS	GREEN TREE HOME CARE LLC
SENIOR CENTERS, INDP LIVING & HOMELESS SHELTERS	HISC 158 INC
SENIOR CENTERS, INDP LIVING & HOMELESS SHELTERS	HOME CARE ASSISTANCE LLC
SENIOR CENTERS, INDP LIVING & HOMELESS SHELTERS	HOME CARE SPECIALISTS LLC
SENIOR CENTERS, INDP LIVING & HOMELESS SHELTERS	HOMEFIELD SH MANAGEMENT LLC
SENIOR CENTERS, INDP LIVING & HOMELESS SHELTERS	INDEPENDENT OPTIONS INC
SENIOR CENTERS, INDP LIVING & HOMELESS SHELTERS	INGLEWOOD COMMUNITY ADHC
SENIOR CENTERS, INDP LIVING & HOMELESS SHELTERS	JAC BOUL REVIT ALLIANCE
SENIOR CENTERS, INDP LIVING & HOMELESS SHELTERS	KTRE 3 LLC
SENIOR CENTERS, INDP LIVING & HOMELESS SHELTERS	KTRE5 LLC
SENIOR CENTERS, INDP LIVING & HOMELESS SHELTERS	LA JOLLA COMMUNITY CENTER

CRITICAL_FAC_CODE	CUSTOMER_NAME
SENIOR CENTERS, INDP LIVING & HOMELESS SHELTERS	LIVING INDEPENDENTLY
SENIOR CENTERS, INDP LIVING & HOMELESS SHELTERS	OLIVER HOME CARE LLC
SENIOR CENTERS, INDP LIVING & HOMELESS SHELTERS	OSL OPERATION LLC
SENIOR CENTERS, INDP LIVING & HOMELESS SHELTERS	PROVIDENCE ROYAL OAKS SM LLC
SENIOR CENTERS, INDP LIVING & HOMELESS SHELTERS	QUALICARE FAMILY HOME CARE
SENIOR CENTERS, INDP LIVING & HOMELESS SHELTERS	R B JOSLYN SR CENTER
SENIOR CENTERS, INDP LIVING & HOMELESS SHELTERS	REDWOOD ELDERLINK
SENIOR CENTERS, INDP LIVING & HOMELESS SHELTERS	RIENDA SERVICES INC
SENIOR CENTERS, INDP LIVING & HOMELESS SHELTERS	SAGECREST PLANNING & ENVIRONMENTAL
SENIOR CENTERS, INDP LIVING & HOMELESS SHELTERS	SAN DIEGO CARE PLACEMENT
SENIOR CENTERS, INDP LIVING & HOMELESS SHELTERS	SAN DIEGO COMPANION RABBIT
SENIOR CENTERS, INDP LIVING & HOMELESS SHELTERS	SAN DIEGO OASIS
SENIOR CENTERS, INDP LIVING & HOMELESS SHELTERS	SEA COAST HOME HEALTH CARE
SENIOR CENTERS, INDP LIVING & HOMELESS SHELTERS	SENIOR KEEPERS IN HOME CARE
SENIOR CENTERS, INDP LIVING & HOMELESS SHELTERS	SH 5 ENCINITAS LLC
SENIOR CENTERS, INDP LIVING & HOMELESS SHELTERS	SHADOW GLEN HOA
SENIOR CENTERS, INDP LIVING & HOMELESS SHELTERS	SILVERADO SENIOR LIVING INC
SENIOR CENTERS, INDP LIVING & HOMELESS SHELTERS	SR24 AND SR25 EXCHANGE LLC
SENIOR CENTERS, INDP LIVING & HOMELESS SHELTERS	SUPPORT & INDEPENDENT LIVING
SENIOR CENTERS, INDP LIVING & HOMELESS SHELTERS	THE AUTISM GROUP INC
SENIOR CENTERS, INDP LIVING & HOMELESS SHELTERS	TRITON SENIOR LIVING LLC
SENIOR CENTERS, INDP LIVING & HOMELESS SHELTERS	VETACT LLC
SENIOR CENTERS, INDP LIVING & HOMELESS SHELTERS	VIETNAM VETERANS OF S D
SENIOR CENTERS, INDP LIVING & HOMELESS SHELTERS	VIETNAM VETERANS OF SD
SENIOR CENTERS, INDP LIVING & HOMELESS SHELTERS	VSI TECHNOLOGIES
SENIOR CENTERS, INDP LIVING & HOMELESS SHELTERS	WILLIAMS QUEST INC
TRIBAL GOVERNMENT	BARONA BAND MSN INDIANS
TRIBAL GOVERNMENT	BARONA BAND OF MSN INDIANS
TRIBAL GOVERNMENT	CAMPO BAND OF MSN INDIANS
TRIBAL GOVERNMENT	CUYAPAIPE RESERVATION
TRIBAL GOVERNMENT	INAJA BAND OF MISSION INDIAN
TRIBAL GOVERNMENT	LA JOLLA BAND OF INDIANS
TRIBAL GOVERNMENT	LA JOLLA CAPITAL GROUP LLC
TRIBAL GOVERNMENT	MANZANITA BAND MSN INDIA
TRIBAL GOVERNMENT	PALA BAND OF MISSION INDIANS
TRIBAL GOVERNMENT	PAUMA BAND MSN INDIANS
TRIBAL GOVERNMENT	RINCON INDIAN RESERVATION
TRIBAL GOVERNMENT	SAN PASQ BAND OF DIEGUENO MI
TRIBAL GOVERNMENT	SANTA YSABEL BAND OF DIEGUEN
TRIBAL GOVERNMENT	STHRN CAL TRIBAL CHAIRMAN
TRIBAL GOVERNMENT	SYCUAN BAND KUMEYAAY INDIANS
TRIBAL GOVERNMENT	SYCUAN BAND OF KUMEYAAY

CRITICAL_FAC_CODE	CUSTOMER_NAME
TRIBAL	BARONA BAND MSN INDIANS
TRIBAL	BARONA TRIBAL COUNCIL
TRIBAL	BARONA TRIBAL GAMING AUTH
TRIBAL	CAMPO BAND MSN INDIANS
TRIBAL	CAMPO BAND OF MSN INDIANS
TRIBAL	CAMPO INDIAN RESERVATN
TRIBAL	CAMPO MATERIALS
TRIBAL	CASINO PAUMA
TRIBAL	GOLDEN ACORN CASINO
TRIBAL	HARRAHS RINCON CASINO & RSRT
TRIBAL	JAMES HUNTER
TRIBAL	KUMEYAAY WIND LLC
TRIBAL	LA JOLLA BAND OF INDIANS
TRIBAL	LA POSTA BAND OF MSN INDIANS
TRIBAL	LOS COYOTES GREENHOUSE
TRIBAL	LOS COYOTES INDIAN RESVRN
TRIBAL	MANZANITA BAND MSN INDIA
TRIBAL	MANZANITA INDIAN RES
TRIBAL	MESA GRANDE BAND MSN INDIANS
TRIBAL	MESA GRANDE INDIAN HOUSING
TRIBAL	PALA BAND OF MISSION INDIANS
TRIBAL	PALA ENTERTAINMENT CENTER
TRIBAL	PAUMA BAND MSN INDIANS
TRIBAL	PAUMA TRIBAL HALL
TRIBAL	PAUMA TRIBE
TRIBAL	RINCON GAMING ENTERPRISE
TRIBAL	RINCON INDIAN RESERVATION
TRIBAL	SAN PASQ BAND OF DIEGUENO MI
TRIBAL	SYCUAN
TRIBAL	SYCUAN BAND KUMEYAAY INDIANS
TRIBAL	SYCUAN BAND OF KUMEYAAY
TRIBAL	SYCUAN HEALTH CENTER
TRIBAL	SYCUAN TRIBAL DEVELOPMENT CO
TRIBAL	VALLEY VIEW CASINO
TRIBAL	VIEJAS BAND OF KUMEYAAY IND
TRIBAL	VIEJAS CASINO AND TRF CLB
TRIBAL	VIEJAS INDIANS SCHOOL
TRIBAL	VIEJAS OUTLET CENTER
TRIBAL	VIEJAS TRIBAL COUNCIL
TRANSPORTATION	1ST COAST CARGO INC
TRANSPORTATION	A C TOWING INC
TRANSPORTATION	A TO Z ENTERPRISES INC

CRITICAL_FAC_CODE	CUSTOMER_NAME
TRANSPORTATION	A1 RV REPAIRS & SERVICES
TRANSPORTATION	ABF FREIGHT SYSTEMS INC
TRANSPORTATION	ACE AVIATION SVC INC
TRANSPORTATION	ACE RELOCATION SYSTEMS
TRANSPORTATION	ADAMS TOWING
TRANSPORTATION	ADEPT PROCESS SERVICES
TRANSPORTATION	ADMIRALTY MARINE
TRANSPORTATION	ADVANCED SHUTTLE SVCS LLC
TRANSPORTATION	ADVANTAGE TOWING
TRANSPORTATION	AERONET INC
TRANSPORTATION	AEROTRACK INC
TRANSPORTATION	AEROWELD INC
TRANSPORTATION	AGA INVESTMENTS
TRANSPORTATION	AGAU HOLDINGS LLC
TRANSPORTATION	AHM LLC
TRANSPORTATION	AIRPORT SELF STORAGE LLC
TRANSPORTATION	AIRWAYS OWNERS ASSOC
TRANSPORTATION	AIRWORLD LLC
TRANSPORTATION	ALBERT CRUZ
TRANSPORTATION	ALEX MARTINEZ
TRANSPORTATION	ALL STREET TOWING
TRANSPORTATION	A-LOGISTICS AND TRADING CORP
TRANSPORTATION	ALVIN BANTAD
TRANSPORTATION	AM MEX INTERNATIONAL
TRANSPORTATION	AME TWNG & AUTO DSM INC
TRANSPORTATION	AMERICAN CARGOSERVICE
TRANSPORTATION	AMIR ETEMADZADEH
TRANSPORTATION	AMTRAK
TRANSPORTATION	AMUZA INC
TRANSPORTATION	ANDREA RUBIN
TRANSPORTATION	ANGELOS TOWING
TRANSPORTATION	ANGELO'S TOWING
TRANSPORTATION	ANGELUCCI SOLAR HOLDINGS
TRANSPORTATION	ARCES IMPORT CORP
TRANSPORTATION	ASAP TOWING
TRANSPORTATION	ATLANTIC AVIATION CAM
TRANSPORTATION	ATLAS FREIGHT
TRANSPORTATION	BAJA FREIGHT FORWARDING
TRANSPORTATION	BARILOCHE ADVENTURA LTD
TRANSPORTATION	BBS GLOBAL TRADING
TRANSPORTATION	BENDER CCP INC
TRANSPORTATION	BIG BAY MARINE SERVICES

CRITICAL_FAC_CODE	CUSTOMER_NAME
TRANSPORTATION	BILL HAY INTERNATIONAL
TRANSPORTATION	BILL'S GOING TOWING INC
TRANSPORTATION	BIOCAIR
TRANSPORTATION	BLACK TIGER LIMO
TRANSPORTATION	BNSF RAILWAY COMPANY
TRANSPORTATION	BRICEHOUSE INC
TRANSPORTATION	BROOKE PAPER SCISSORS
TRANSPORTATION	BUBBLES BOUTIQUE INC
TRANSPORTATION	C & D TOWING SPECIALISTS
TRANSPORTATION	C R Q HANGAR 12 LLC
TRANSPORTATION	CAHUENGA ASSOCIATES II
TRANSPORTATION	CAL MEEKER
TRANSPORTATION	CALIF MARINE CLEANING
TRANSPORTATION	CALTRANS
TRANSPORTATION	CANNON PACIFIC SERVICES INC
TRANSPORTATION	CARLSBAD AIR SERVICE INC
TRANSPORTATION	CARLSBAD JET CENTER
TRANSPORTATION	CAROLYN GODING
TRANSPORTATION	CASUAL CASCADE DE LLC
TRANSPORTATION	CAVALIER FORWARDING INC
TRANSPORTATION	CEDAR TOWING
TRANSPORTATION	CERTIFIED TRANSPORTATION SRV
TRANSPORTATION	CHARLES BUEL
TRANSPORTATION	CHP LOGISTICS INC
TRANSPORTATION	CHRISTOPHER LOUGHRIDGE
TRANSPORTATION	CHUCK HALL AVIATION
TRANSPORTATION	CHULA VISTA MARINA
TRANSPORTATION	CIRCLE AIR GROUP LLC
TRANSPORTATION	CIRCLE S PRODUCTIONS INC
TRANSPORTATION	CITY OF CORONADO
TRANSPORTATION	CITY OF SAN DIEGO
TRANSPORTATION	CLANCY'S TOWING
TRANSPORTATION	CO OF SAN DIEGO
TRANSPORTATION	COASTAL PRIDE TOWING INC
TRANSPORTATION	COMMERCIAL TRANSPORT CONCEPT
TRANSPORTATION	COMPLETE LOGISTICS CO
TRANSPORTATION	COUTURE FORMAL
TRANSPORTATION	CROWLEY MARINE SERVICES INC
TRANSPORTATION	CROWNAIR
TRANSPORTATION	CRUISEAIR AVIATION INC
TRANSPORTATION	CRYSTAL FORWARDING
TRANSPORTATION	CS SAILS INC

CRITICAL_FAC_CODE	CUSTOMER_NAME
TRANSPORTATION	CURL CRAFT LLC
TRANSPORTATION	CURTISS WRIGHT ELECTRO MECH
TRANSPORTATION	CYMSE BROKERS
TRANSPORTATION	CYTOLOGISTICS
TRANSPORTATION	DANA POINT MARINA CO
TRANSPORTATION	DANA WEST MARINA
TRANSPORTATION	DANA WEST YACHT CLUB
TRANSPORTATION	DANIEL LAMONTAGNE
TRANSPORTATION	DAVE STILLINGER
TRANSPORTATION	DHL GLOBAL FORWARDING
TRANSPORTATION	DICK'S TOWING
TRANSPORTATION	DMC & ASSOCS
TRANSPORTATION	DONALD L MELOCHE
TRANSPORTATION	DONALD MELOCHE
TRANSPORTATION	DOWNTOWN PEDICABS
TRANSPORTATION	DRISCOLL MARINA
TRANSPORTATION	DSV AIR & SEA INC
TRANSPORTATION	E WATKINS
TRANSPORTATION	EAX WORLDWIDE LLC
TRANSPORTATION	ELEANOR BEADLE
TRANSPORTATION	ENRIQUE SANCHEZ
TRANSPORTATION	ENTERPRISE TOWING
TRANSPORTATION	ETHYL BENNETT
TRANSPORTATION	EVELYN RAMSEIER
TRANSPORTATION	EX EX PM LLC
TRANSPORTATION	EXCELLENT SERVICE & TOWING
TRANSPORTATION	EXPEDITE TOWING
TRANSPORTATION	EXPORTALIA CUSTOMS BROKER
TRANSPORTATION	FACT INC
TRANSPORTATION	FALLBROOK AG-PRO
TRANSPORTATION	FIDDLERS COVE MARINA & RV
TRANSPORTATION	FIRST FLIGHT CORPORATION
TRANSPORTATION	FIRST STUDENT TRANSPORT
TRANSPORTATION	FLAT TOP POWER ASSOC
TRANSPORTATION	FLYING DOG HANGAR LLC
TRANSPORTATION	FORWARD AIR
TRANSPORTATION	FRANCISCO GOMEZ
TRANSPORTATION	FRITZ MEHRER
TRANSPORTATION	G B CAPITAL HOLDINGS LLC
TRANSPORTATION	G GLOBAL LOGISTICS INC
TRANSPORTATION	GANN LOGISTICS
TRANSPORTATION	GARY AND MARY WEST PACE

CRITICAL_FAC_CODE	CUSTOMER_NAME
TRANSPORTATION	GARY PELZER
TRANSPORTATION	GEORGE MOUAWAD
TRANSPORTATION	GIBBS FLYING SERVICE
TRANSPORTATION	GILLESPIE AIR CENTER
TRANSPORTATION	GILLESPIE FIELD PARTNRS
TRANSPORTATION	GIZELLE INVESTMENT INC
TRANSPORTATION	GLOBAL AUTO LOGISTICS LLC
TRANSPORTATION	GLOBAL BROKERAGE SOLUTIONS
TRANSPORTATION	GLOBAL PACKAGING SOLTN INC
TRANSPORTATION	GONZALEZ TOWING
TRANSPORTATION	GONZALO PADILLA
TRANSPORTATION	GREAT VALUE LLC
TRANSPORTATION	GREATER SD BUS DEV COUNCIL
TRANSPORTATION	GREITZER BROKERS INC
TRANSPORTATION	GREYHOUND LINES INC
TRANSPORTATION	GT CARRIERS
TRANSPORTATION	GUARDIAN TOWING INC
TRANSPORTATION	GUILLERMO ADAME
TRANSPORTATION	GUILLERMO LIZARRAGA
TRANSPORTATION	HAN CHUA
TRANSPORTATION	HANGER SEVEN LLC
TRANSPORTATION	HARBOR ISLAND WEST MAR
TRANSPORTATION	HIGH SEAS MARINE ENTERPRISES
TRANSPORTATION	HOANG VAN CARGO
TRANSPORTATION	HOME EXPRESS DELIVERY SERVIC
TRANSPORTATION	HOSSEIN JALEHMAFMOUDI
TRANSPORTATION	HUDSON MARINE MGMNT INC
TRANSPORTATION	HUSKS UNLIMITED INC
TRANSPORTATION	ID ENTERPRISE
TRANSPORTATION	IGNACIO MONTIEL
TRANSPORTATION	INTEGRATED AIRLINE SERVICES
TRANSPORTATION	INTEGRATED MARINE SVC INC
TRANSPORTATION	INTERNATIONAL CUSTOMS BROKER
TRANSPORTATION	INTERNATIONAL LOGISTICS LLC
TRANSPORTATION	INTERSTATE GROUP LLC
TRANSPORTATION	INTRNL AUTO BROKERS INC
TRANSPORTATION	IPT OTAY LOGISTICS CENTER LP
TRANSPORTATION	IRIS LOGISTICS LLC
TRANSPORTATION	IRONSMITH INC
TRANSPORTATION	JACK MATTHIAS
TRANSPORTATION	JAMES RUTLEDGE
TRANSPORTATION	JAS FORWARDING USA

CRITICAL_FAC_CODE	CUSTOMER_NAME
TRANSPORTATION	JB JK CORP III
TRANSPORTATION	JEFF TISDALE ENTERPRISES INC
TRANSPORTATION	JESUS GARCIA
TRANSPORTATION	JET SOURCE INC
TRANSPORTATION	JFAT LLC
TRANSPORTATION	JILL HASSE
TRANSPORTATION	JIMSAIR AVIATION SVCS
TRANSPORTATION	JIVAN INVESTMENT INC
TRANSPORTATION	JMAC LOGISTICS INC
TRANSPORTATION	JOE DAVIES
TRANSPORTATION	JOHN LLOYD & ASSOCIATES
TRANSPORTATION	JOHN WATKINS
TRANSPORTATION	JUAN CORTEZ JR
TRANSPORTATION	JUSTIN WOOLSEY
TRANSPORTATION	JV BROKERS INC
TRANSPORTATION	JV INTER SOLUTIONS INC
TRANSPORTATION	K & O ENTERPRISES LLC
TRANSPORTATION	K LINE AIR INC
TRANSPORTATION	K P I LOGISTICS INC
TRANSPORTATION	K SKY LOGISTICS INC
TRANSPORTATION	KEN MCKEON
TRANSPORTATION	KGL AMERCIA INC
TRANSPORTATION	KINDER MORGAN ENERGY PARTNER
TRANSPORTATION	KNOWLEDGE CITY
TRANSPORTATION	KRAUSS HELICOPTERS
TRANSPORTATION	KUEHNE AND NAGEL INC
TRANSPORTATION	L18 AIRPARK LLC
TRANSPORTATION	LAKESIDE SERVICE & TOW LLC
TRANSPORTATION	LANCAIR CORPORATION
TRANSPORTATION	LAS DOS CALIFORNIAS
TRANSPORTATION	LEONOR FERRER
TRANSPORTATION	LLJ BARRIO VENTURES
TRANSPORTATION	LOGIPIA AMERICA CORP
TRANSPORTATION	LOGIX SALES LLC
TRANSPORTATION	LOTHLORIEN PARTNERS INC
TRANSPORTATION	LUIS LARA
TRANSPORTATION	LYFT INC
TRANSPORTATION	M&G FORWARDING LLC
TRANSPORTATION	MACKENZIE AVIATION INC
TRANSPORTATION	MAINFREIGHT INC
TRANSPORTATION	MARIANA VINCENT
TRANSPORTATION	MARINA CORTEZ INC

CRITICAL_FAC_CODE	CUSTOMER_NAME
TRANSPORTATION	MARINA VILLAGES LTD
TRANSPORTATION	MAXXUM EXPO LOGISTICS INC
TRANSPORTATION	MEADIOCRITY MEADERY LLC
TRANSPORTATION	MEL CAIN
TRANSPORTATION	MEX PRO LOGISTICS
TRANSPORTATION	MEXPORT LOGISTICS INC
TRANSPORTATION	MEYERS LOGISTICS
TRANSPORTATION	MICHELE TERRY-LLOYD
TRANSPORTATION	MICHIGAN LOGISTICS SOLUTIONS
TRANSPORTATION	MIGHTY TRUCKING & SERVICES
TRANSPORTATION	MIGUEL HERNANDEZ
TRANSPORTATION	MITRE AVIATION
TRANSPORTATION	MONICA GOMEZ
TRANSPORTATION	MOUNTAIN WEST TOWING INC
TRANSPORTATION	MSE EXPRESS AMERICA INC
TRANSPORTATION	MTS
TRANSPORTATION	MYF PROPERTIES LLC
TRANSPORTATION	NANCAR INC
TRANSPORTATION	NATMI LPF CORE LLC
TRANSPORTATION	NEUTRONICS ENTERPRISES
TRANSPORTATION	NK TOWING AND ROADSIDE SERVI
TRANSPORTATION	NO COUNTY TRANSIT DIST
TRANSPORTATION	NORMAN KRIEGER INC
TRANSPORTATION	NORTH COUNTY STUDENT TRANSP
TRANSPORTATION	ON TIME PERMITS LLC
TRANSPORTATION	ONE STOP AVIATION
TRANSPORTATION	OTAY BORDER PROPERTY LLC
TRANSPORTATION	P T S
TRANSPORTATION	PA LOGISTICS SERVICES INC
TRANSPORTATION	PACBLUE LOGISTICS LLC
TRANSPORTATION	PACIFIC AUTOW
TRANSPORTATION	PACIFIC CHEMICAL LABS INC
TRANSPORTATION	PACIFIC TOWING & RECOVERY
TRANSPORTATION	PALOMAR PREMIER HANGER 4 LLC
TRANSPORTATION	PANASONIC LOGISTICS SOLUTION
TRANSPORTATION	PASHA AUTOMOTIVE SERVICES
TRANSPORTATION	PAXTON SHREVE & HAYS INC
TRANSPORTATION	PCM LOGISTICS LLC
TRANSPORTATION	PIER 32 MARINA LLC
TRANSPORTATION	PLATINUM LOGISTICS WY INC
TRANSPORTATION	POINT LOMA MARINA LLC
TRANSPORTATION	POWAY GROUP INC

CRITICAL_FAC_CODE	CUSTOMER_NAME
TRANSPORTATION	PREMIER TWO 1 FOUR LLC
TRANSPORTATION	PREMIERE WEST LEASING
TRANSPORTATION	PRIORITY CARGO EXPEDITORS
TRANSPORTATION	PRO TRAFFIC SERVICES INC
TRANSPORTATION	QUALITY TOWING
TRANSPORTATION	R & R INT'L FREIGHT INC
TRANSPORTATION	R L JONES
TRANSPORTATION	RESCUE TOWING & RECOVERY
TRANSPORTATION	RICHARD MORGAN
TRANSPORTATION	ROAD ONE TOWING
TRANSPORTATION	ROADWAY AUTO TOWING
TRANSPORTATION	ROBERT SCHMALFELDT
TRANSPORTATION	RO-CO
TRANSPORTATION	ROLANDO ROMERO
TRANSPORTATION	ROY MILLER FREIGHT INC LINE
TRANSPORTATION	ROYAL JET INC
TRANSPORTATION	ROYAL LINES CHARTER LLC
TRANSPORTATION	RUBEN GONZALEZ
TRANSPORTATION	RUFFO DE ALBA FORWARDERS LP
TRANSPORTATION	RYDER INTERGRATED LOGISTIC
TRANSPORTATION	S & R TOWING INC
TRANSPORTATION	S D TRANSIT CORP
TRANSPORTATION	SADDLE CREEK CORP
TRANSPORTATION	SAFARI AVIATION OF CA INC
TRANSPORTATION	SAI LOGISTICS EXPORTS INC
TRANSPORTATION	SALAZAR FORWARDINGSPECIALIST
TRANSPORTATION	SAN DIEGO BOAT MOVERS
TRANSPORTATION	SAN DIEGO HELICOPTER SERVICE
TRANSPORTATION	SAN DIEGO TROLLEY INC
TRANSPORTATION	SANDAG
TRANSPORTATION	SANGBIN IM
TRANSPORTATION	SCHIESS CONSTR LOGISTICS INC
TRANSPORTATION	SCRRA METROLINK
TRANSPORTATION	SD & IMP VLY RAILROAD
TRANSPORTATION	SD AIR FREIGHT SRVC INC
TRANSPORTATION	SD CTY REGIONAL AIRPORT AUTH
TRANSPORTATION	SD UNIFIED PORT DIST
TRANSPORTATION	SEABRIGHT AT CARLSBAD
TRANSPORTATION	SEAFORTH MARINA
TRANSPORTATION	SELIM ASLAN
TRANSPORTATION	SENATOR INTERNATIONAL
TRANSPORTATION	SEPULVEDAS INT CORPORATION

CRITICAL_FAC_CODE	CUSTOMER_NAME
TRANSPORTATION	SERGIO OJEDA
TRANSPORTATION	SEVERIN MOBILE TOWING INC
TRANSPORTATION	SEVERIN TOWING
TRANSPORTATION	SFPP L P
TRANSPORTATION	SHELTER COVE MARINA
TRANSPORTATION	SHM SOUTH BAY LLC
TRANSPORTATION	SHM SUNROAD LLC
TRANSPORTATION	SICA FORWARDING & FREIGHT
TRANSPORTATION	SIGNATURE TOWING
TRANSPORTATION	SILVER RIDGE FORWARDING INC
TRANSPORTATION	SJ TOWING INC
TRANSPORTATION	SOL TRANSPORTATION INC
TRANSPORTATION	SOLITA HINES
TRANSPORTATION	SONENDO INC
TRANSPORTATION	SOUTHERN TIRE MART LLC
TRANSPORTATION	SPACE BORDER LOGISTICS
TRANSPORTATION	SPIDERS AIR SERV
TRANSPORTATION	STARRUE INCORPORATED
TRANSPORTATION	STATE OF CALIFORNIA
TRANSPORTATION	STOLY VENTURES
TRANSPORTATION	SUN HARBOR MARINA
TRANSPORTATION	SUNBELT TOWING INC
TRANSPORTATION	SUNDANCE STAGE LINES
TRANSPORTATION	SURERIDE CHARTER INC
TRANSPORTATION	SURERIDE INC
TRANSPORTATION	TAG A LONG SAN DIEGO LLC
TRANSPORTATION	TAPATIO AUTO WRECKING INC
TRANSPORTATION	TETON JET INC
TRANSPORTATION	THE EVENT HOUSE
TRANSPORTATION	THE SAN DIEGO MOORING CO
TRANSPORTATION	THOMAS K CLARK
TRANSPORTATION	THOMAS MINICHIELLO
TRANSPORTATION	TIDE WATER INC
TRANSPORTATION	TIM SWIFT
TRANSPORTATION	TJC LOGISTICS
TRANSPORTATION	TONKA TOW
TRANSPORTATION	TOTAL AVIATION SRVS
TRANSPORTATION	TOWING SAN DIEGO INC
TRANSPORTATION	TOYOTA TSUSHO AMERICA INC
TRANSPORTATION	TPBP HOLDINGS (DE) LLC
TRANSPORTATION	TRAFFIC TECH INC
TRANSPORTATION	TRANS LOGISTICS LLC

CRITICAL_FAC_CODE	CUSTOMER_NAME
TRANSPORTATION	TRANS WEST EXPRESS
TRANSPORTATION	TRAVELERS CONVENIENCE INC
TRANSPORTATION	TREPTE IND PARK LTD
TRANSPORTATION	TRES ESTRELLAS DE ORO
TRANSPORTATION	TRI STAR INTERNTL FORWARDING
TRANSPORTATION	TRUMP CARD HOLDINGS LLC
TRANSPORTATION	UEBER HAUN I LLC
TRANSPORTATION	UNITED CALIFORNIA FREIGHT
TRANSPORTATION	UPS SUPPLIES CHAIN SOLUTIONS
TRANSPORTATION	US CAB COMPANY
TRANSPORTATION	US OCEAN SAFETY INC
TRANSPORTATION	USA CAB COMPANY
TRANSPORTATION	VELOCITY CEA SD LLC
TRANSPORTATION	VFR IMPORT EXPORT INC
TRANSPORTATION	VINTAGE MARINA PARTNERS LP
TRANSPORTATION	VINTAGE POINT PARTNERS LP
TRANSPORTATION	VIP PEDICABS LLC
TRANSPORTATION	VISUAL PAK SAN DIEGO
TRANSPORTATION	VMA LOGISTICS AND DIST INC
TRANSPORTATION	WASATCH CORNERSTONE HOLDINGS
TRANSPORTATION	WESCO SALES CORPORATION
TRANSPORTATION	WEST COAST JET SERVICES
TRANSPORTATION	WESTERN FLIGHT INC
TRANSPORTATION	WESTERN TOWING
TRANSPORTATION	WESTONE LOGISTICS LLC
TRANSPORTATION	WHEELS LABS INC
TRANSPORTATION	WHIRL WIND
TRANSPORTATION	WILLIAM GAMBLE
TRANSPORTATION	WILLIAM MACLEOD
TRANSPORTATION	WILLSON SHIPPING INC
TRANSPORTATION	WINGS-N-WRENCHES DIY LLC
TRANSPORTATION	WOODS WESTERN WORLD INC
TRANSPORTATION	XPO LOGISTICS/LAST MILE
TRANSPORTATION	YACHUAN CHENG
TRANSPORTATION	YELLOW CAB OF SAN DIEGO
TRANSPORTATION	YELLOW FREIGHT SYSTEM
TRANSPORTATION	YUEMA INTL LOGISTICS USA CO
TRANSPORTATION	YVONNE ABERLE
UTILITIES	CALPEAK POWER LLC
UTILITIES	CARLSBAD ENERGY CENTER LLC
UTILITIES	CV ENERGY CENTER LLC
UTILITIES	ESC ENERGY CENTER LLC

CRITICAL_FAC_CODE	CUSTOMER_NAME
UTILITIES	LS POWER ASSOCIATES LP
UTILITIES	ORANGE GROVE ENERGY LP
UTILITIES	OTAY MESA ENERGY CENTER LLC
UTILITIES	SOUTHERN CALIFORNIA EDISON
VOTING CENTERS	CITY OF CORONADO
VOTING CENTERS	CITY OF EL CAJON
VOTING CENTERS	CITY OF ENCINITAS
VOTING CENTERS	CITY OF ESCONDIDO
VOTING CENTERS	CITY OF LA MESA
VOTING CENTERS	CITY OF OCEANSIDE
VOTING CENTERS	CITY OF SAN DIEGO
VOTING CENTERS	CITY OF SAN MARCOS
VOTING CENTERS	CO OF SAN DIEGO
VOTING CENTERS	NIXON DEVELOPMENT LLC
VOTING CENTERS	SD UNIF SCH DIST
WATER & WASTEWATER SYSTEMS	BARONA BAND MSN INDIANS
WATER & WASTEWATER SYSTEMS	BARONA TRIBAL COUNCIL
WATER & WASTEWATER SYSTEMS	BORDEN RANCHES
WATER & WASTEWATER SYSTEMS	BORREGO WATER DISTRICT
WATER & WASTEWATER SYSTEMS	BOY SCOUTS - SDIC
WATER & WASTEWATER SYSTEMS	CAL DEPT OF FISH & GAME
WATER & WASTEWATER SYSTEMS	CALTRANS
WATER & WASTEWATER SYSTEMS	CAMPO BAND OF MSN INDIANS
WATER & WASTEWATER SYSTEMS	CITY OF CARLSBAD
WATER & WASTEWATER SYSTEMS	CITY OF CHULA VISTA
WATER & WASTEWATER SYSTEMS	CITY OF CORONADO
WATER & WASTEWATER SYSTEMS	CITY OF DANA POINT
WATER & WASTEWATER SYSTEMS	CITY OF DEL MAR
WATER & WASTEWATER SYSTEMS	CITY OF ESCONDIDO
WATER & WASTEWATER SYSTEMS	CITY OF IMPERIAL BEACH
WATER & WASTEWATER SYSTEMS	CITY OF MISSION VIEJO
WATER & WASTEWATER SYSTEMS	CITY OF NATIONAL CITY
WATER & WASTEWATER SYSTEMS	CITY OF OCEANSIDE
WATER & WASTEWATER SYSTEMS	CITY OF POWAY
WATER & WASTEWATER SYSTEMS	CITY OF S J CAPISTRANO
WATER & WASTEWATER SYSTEMS	CITY OF SAN CLEMENTE
WATER & WASTEWATER SYSTEMS	CITY OF SAN DIEGO
WATER & WASTEWATER SYSTEMS	CITY OF SAN MARCOS
WATER & WASTEWATER SYSTEMS	CITY OF VISTA
WATER & WASTEWATER SYSTEMS	CO OF SAN DIEGO
WATER & WASTEWATER SYSTEMS	DESCANSO COMM WATR DIST
WATER & WASTEWATER SYSTEMS	FPUD - SANITARY

CRITICAL_FAC_CODE	CUSTOMER_NAME
WATER & WASTEWATER SYSTEMS	GOLDEN ACORN CASINO
WATER & WASTEWATER SYSTEMS	HARRISON PARK MUTUAL WATER
WATER & WASTEWATER SYSTEMS	HELIX WATER DISTRICT
WATER & WASTEWATER SYSTEMS	JACUMBA COMM SERV DIST
WATER & WASTEWATER SYSTEMS	JULIAN COMM SERV DIST
WATER & WASTEWATER SYSTEMS	LA JOLLA BAND OF INDIANS
WATER & WASTEWATER SYSTEMS	LAKESIDE IRRIG DIST
WATER & WASTEWATER SYSTEMS	LAZY H WATER COMPANY
WATER & WASTEWATER SYSTEMS	LEUCADIA CNTY WATER DIST
WATER & WASTEWATER SYSTEMS	LOS COYOTES INDIAN RESVRN
WATER & WASTEWATER SYSTEMS	LOS TULES MUT WATER CO
WATER & WASTEWATER SYSTEMS	MESA GRANDE B O M I FIRE DPT
WATER & WASTEWATER SYSTEMS	MESA GRANDE BAND MSN INDIANS
WATER & WASTEWATER SYSTEMS	MOULTON NIGUEL WTR DIST
WATER & WASTEWATER SYSTEMS	OLIVENHAIN MUN WTR DIST
WATER & WASTEWATER SYSTEMS	OTAY WATER DISTRICT
WATER & WASTEWATER SYSTEMS	P V MUTUAL WATER CO
WATER & WASTEWATER SYSTEMS	PADRE DAM MUN WTR DIST
WATER & WASTEWATER SYSTEMS	PALA BAND OF MISSION INDIANS
WATER & WASTEWATER SYSTEMS	PALOMAR MTN MUN WTR DST
WATER & WASTEWATER SYSTEMS	PAUMA BAND MSN INDIANS
WATER & WASTEWATER SYSTEMS	PAUMA VALLEY COMMUNITY
WATER & WASTEWATER SYSTEMS	PAUMA VLY WATER CO
WATER & WASTEWATER SYSTEMS	POSEIDON RSRCS (CHANNELSIDE)
WATER & WASTEWATER SYSTEMS	QUEST HAVEN MUN WTR
WATER & WASTEWATER SYSTEMS	RAINBOW MUN WTR DIST
WATER & WASTEWATER SYSTEMS	RAMONA MUN WTR DIST
WATER & WASTEWATER SYSTEMS	RANCHO PAUMA MNT WTR CO
WATER & WASTEWATER SYSTEMS	RANCHO PAUMA MUT WTR CO
WATER & WASTEWATER SYSTEMS	RANCHO PAUMA MUTUAL WATER CO
WATER & WASTEWATER SYSTEMS	RANCHO SANTA TERESA WATER
WATER & WASTEWATER SYSTEMS	RHO PAUMA MUTUAL WATER CO
WATER & WASTEWATER SYSTEMS	RINCON DEL DIABLO MWD
WATER & WASTEWATER SYSTEMS	RINCON INDIAN RESERVATION
WATER & WASTEWATER SYSTEMS	SAN DIEGUITO WATER DISTRICT
WATER & WASTEWATER SYSTEMS	SAN ELIJO JNT PWR AUTH
WATER & WASTEWATER SYSTEMS	SAN PASQ BAND OF DIEGUENO MI
WATER & WASTEWATER SYSTEMS	SDCWA
WATER & WASTEWATER SYSTEMS	SERJ MUTUAL WATER COMPANY
WATER & WASTEWATER SYSTEMS	SO COAST WATER DISTRICT
WATER & WASTEWATER SYSTEMS	STA MARGARITA WTR DIST
WATER & WASTEWATER SYSTEMS	STATE OF CA/PARKS & REC

CRITICAL_FAC_CODE	CUSTOMER_NAME
WATER & WASTEWATER SYSTEMS	STATE OF CALIFORNIA
WATER & WASTEWATER SYSTEMS	SUMMIT EST MUTUAL WATER
WATER & WASTEWATER SYSTEMS	SWEETWATER AUTHORITY
WATER & WASTEWATER SYSTEMS	SYCUAN BAND KUMEYAAY INDIANS
WATER & WASTEWATER SYSTEMS	USDA-FOREST SERVICE
WATER & WASTEWATER SYSTEMS	USMC CPEN M00681
WATER & WASTEWATER SYSTEMS	VALLECITOS WTR DIST
WATER & WASTEWATER SYSTEMS	VISTA IRRIGATION DIST
WATER & WASTEWATER SYSTEMS	VLY CENTER MUN WTR DIST
WATER & WASTEWATER SYSTEMS	WEST CUCA MUTUAL WATER CO
WATER & WASTEWATER SYSTEMS	YUIMA MUN WATER DIST
WATER & WASTEWATER SYSTEMS	ZOOLOGICAL SOCIETY SAN DIEGO

Note: Asterisk (*) indicates COVID-19 related temporary sites, including: housing, testing, vaccination administering, etc.)

Attachment D: Detailed Progress Report on Key Areas of Improvement

Detailed Progress Report on Key Areas of Improvement

Table of Contents

1 SDGE-21- 01 Ignition Sources in Risk Modeling and Mitigation

SDGE-21- 01	*Inadequate transparency in accounting for ignition sources in risk modeling and mitigation selection*	*SDG&E must fully explain: 1. How third-party ignition sources feed into SDG&E's risk models; 2. How ignition sources impact SDG&E's mitigation selection process, including: a. How SDG&E prioritizes ignition sources; b. If SDG&E treats third-party ignition sources that are not under SDG&E's direct control differently than other ignition sources, and if so, how; c. How SDG&E targets its mitigations efforts to reduce ignitions that are more likely to result in catastrophic wildfire conditions.*

SDG&E has been working to develop Probability of Failure (PoF) and Probability of Ignition (PoI) models with more granularity at the asset and ignition source level. The granularity of select models are also calculated at the hourly level, which is important for third-party sources, like animal or balloon, that typically occur at certain times of the day. SDG&E has a roadmap for the development of those models and has prioritized them based on evaluating the most recurring types of ignitions including those that are wind-driven to support risk mitigation efforts, both to support real-time decision making and long-term planning. To date, SDG&E has developed a model to predict conductor-related failures and ignitions, and is working on developing models designed to predict ignitions from third party sources such as vegetation contacts, vehicle contacts, balloon contacts, and animal contacts. Updates on the remedies identified for this area of improvement are further outlined below:

1. How third-party ignition sources feed into SDG&E's risk models

SDG&E continues to refine its modeling documentation to provide more clarity about how various ignition sources (including third-party sources) feed into SDG&E's risk models. The new machine learning POI modeling effort is relatively new and actively being developed, therefore documentation is being created alongside the models themselves. SDG&E's Electric Reliability team reviews and audits every outage and tags the appropriate outage cause. SDG&E's Fire Science and Coordination Team responds to ignitions and through the Ignitions Management Program follows up on potential causes to prevent future ignitions. SDG&E's PoF and PoI modeling is developed based on event data collected from historical outages and ignitions, data points that are designated by the specific source of the outage/ignition event. This data is then utilized to develop, train, and test machine learning predictive models for individual ignition drivers, as well as asset classes. The ignition sources actively being modeled include both non-third-party sources (equipment failure) and third-party ignition sources (vegetation, vehicle, animals, balloon). This modeling effort is being approached as an iterative process; therefore, continual model enhancement and improved model versions are to be expected over time.

2. How ignition sources impact SDG&E's mitigation selection process, including

a. How SDG&E prioritizes ignition sources

Reference the 2022 WMP Update Section 7.3.7.4.1 Ignition Management Program

SDG&E's mitigation initiatives attempt to address overall ignition risks regardless of the cause, as it would be challenging and inefficient to shift programs frequently based on the cause. Additionally, the consequences of ignitions could be as catastrophic regardless of the cause of the ignition. SDG&E's ultimate goal is to lower the overall ignition potential across all cause categories, prioritizing sections of the system that show the highest potential ignition risks from any and all ignition sources[1].

b. If SDG&E treats third-party ignition sources that are not under SDG&E's direct control differently than other ignition sources, and if so, how

SDG&E primarily focuses its mitigation efforts on targeting ignitions that are within its control; but as a result of those mitigations, third-party ignition sources may also be further mitigated. For example, SDG&E's traditional hardening program has focused on the mitigation of conductor failures by replacing small copper wire with larger aluminum wire and additional spacing, along with the replacement of wood poles to steel poles to further reduce equipment-related failures. The replacement of wood to steel poles helps to reduce likelihood of ignition sources related to third party sources, particularly vehicle contacts. Thereby, focusing on mitigating 'controllable' ignition sources as done with the traditional hardening mitigation can also provide benefits for reducing third-party ignitions such as vehicle contacts due to increased resiliency of steel poles relative to wood poles. Another example would be CMP inspections. For example, proper signage prevents people from tampering with hot equipment.

c. How SDG&E targets its mitigations efforts to reduce ignitions that are more likely to result in catastrophic wildfire conditions.

SDG&E uses risk-informed decision making in the selection of risk mitigations.

SDG&E's WiNGS Planning model, a tool utilized to assess risk and mitigation effectiveness across its service territory, calculates the ignition likelihood at the circuit-segment level. The ignition likelihood metric calculated utilizes the total count of ignitions across a specified span of time, and factors in the specific likelihood of that ignition turning into a catastrophic wildfire (utilizing historical wildfire data), in order to compute the likelihood of a significant wildfire occurring for each individual circuit-segment. This being done agnostic to the individual ignition sources. The likelihood of a significant wildfire metric is then utilized to calculate the total significant wildfire risk of a circuit-segment, thereby helping support the prioritization process in selecting mitigations.

SDG&E's WiNGS Planning model also computes the significant wildfire likelihood reduction associated to each considered mitigation strategy. This likelihood metric helps assess the effectiveness of each mitigation for a circuit-segment, thereby helping support the mitigation planning and decision making associated to each part of the system. This is done for each mitigation utilizing the highest quality data

[1] Refer to section 6.7 for additional discussion.

available, including subject matter expert input into specific risk driver reduction percentages and data collected from efficacy studies.

SDG&E relies on the WRRM/Technosylva conditional impact value to help assess the consequence of an ignition if it were to occur. The conditional impact value gets utilized within the Multi-Attribute Value Framework (MAVF) function of the wildfire risk component of the WiNGS Planning model. This in turn helps the prioritization of mitigation efforts by identifying the highest risk circuit-segments in the system that are comparatively more likely to result in a catastrophic wildfire.

SDG&E plans to improve WiNGS-Planning model with new datasets as they become available and integrate models such as PoI models.

2 SDGE-21- 02 Wildfire Risk Modeling

SDGE-21- 02	*Lack of consistency in approach to wildfire risk modeling across utilities*	*The utilities must collaborate through a working group facilitated by Energy Safety to develop a more consistent statewide approach to wildfire risk modeling. After the WSD completes its evaluation of all the utilities' 2021 WMP Updates, it will provide additional detail on the specifics of this working group. A working group to address wildfire risk modeling will allow for:* *1. Collaboration among the utilities;* *2. Stakeholder and academic expert input; and* *3. Increased transparency.*

The utilities have prepared a joint response to this Remedy. This response describes working group activities which have occurred since the utilities submitted their Progress Reports on November 1, 2021.

Energy Safety established an initial schedule of bi-weekly working group meetings, starting October 20, 2021 and running through January 19, 2022, on various risk-modeling related topics such as modeling components, algorithms, data and impacts of other issues on modeling such as climate change and ingress/egress. However, based on input during the Wildfire Risk Modeling Workshop on October 5-6, 2021, as well as the first Working Group Meeting on October 27, 2021, Energy Safety subsequently issued a revised schedule and topics for the Working Group moving forward. A final version of schedule and topics was posted on November 8, 2021, which included comments on the October 5-6, 2021 workshop on November 6, 2021. The current working group schedule is:

Cadence:

- 2021 – Meet every 3 weeks
- 2022 – Meet monthly (except February)

Meetings are scheduled for Wednesday afternoons for a length of three hours.

Topics:

2021	
10/27	Meeting Logistics; modeling baselines, alignment, and past collaboration
11/17	Fire consequence (drivers, meteorology/climatology, environment, and fuels data)
12/8	Likelihood of asset risk events and ignitions (data, inputs, and risk drivers relating to assets, faults/outages/ignitions)

2022	
1/12	Likelihood of vegetation risk events and ignitions (data, inputs, and risk drivers)
3/2	PSPS likelihood (data, inputs, and risk drivers)
4/6	PSPS consequence and reliability analysis and impacts (including potential safety issues, power quality impacts)
5/4	Modeling algorithms, including confidences (machine learning, weather modeling, fire behavior modeling)
6/1	Modeling components, linkages, interdependencies
7/6	Smoke and suppression impacts
8/3	Climate change impacts and ingress/egress
9/7	Finalize risk modeling guidelines

The utilities are collaborating through the working group with Energy Safety, and stakeholders and have already dedicated and will continue to dedicate substantial time and resources to the working group. The utilities believe that there will be increased transparency for Energy Safety and stakeholders through the working group process.

On November 17, 2021, December 8, 2021, and January 12, 2022, meetings were held to discuss fire consequence, likelihood of asset risk events and ignitions, and likelihood of vegetation risk events and ignitions, respectively. Energy Safety provided an agenda before each meeting which listed discussion topics and tentative time allotments. The meetings followed the agenda in a "Question and Answer" discussion format with utility subject matter experts.

The utilities look forward to future sessions with Energy Safety and stakeholders to promote continued collaboration, incorporate additional expert input, and increase transparency in order to help better realize our shared goal of reducing wildfire and PSPS risks.

3 SDGE-21- 03 Effectiveness of Covered Conductor

SDGE-21- 03	*Limited evidence to support the effectiveness of covered conductor*	*The utilities[2] must coordinate to develop a consistent approach to evaluating the long-term risk reduction and cost-effectiveness of covered conductor deployment, including:* *1. The effectiveness of covered conductor in the field in comparison to alternative initiatives.* *2. How covered conductor installation compares to other initiatives in its potential to reduce PSPS risk.*

The utilities joint response to this Issue/Remedy can be found in Attachment H of the 2022 WMP UPdate.

[2] Here “utilities” refers to SDG&E and PG&E, SCE, PacifiCorp, BVES, and Liberty Utilities; although this may not be the case every time “utilities” is used throughout this progress report.

4 SDGE-21- 04 Effectiveness of Enhanced Clearances

SDGE-21- 04	*Inadequate joint plan to study the effectiveness of enhanced clearances*	*SDG&E, PG&E, and SCE will participate in a multi-year vegetation clearance study. The WSD will confirm the details of this study in due course. The objectives of this study are to: 1. Establish uniform data collection standards. 2. Create a cross-utility database of tree-caused risk events (i.e., outages and ignitions caused by vegetation contact). 3. Incorporate biotic and abiotic factors[3] into the determination of outage and ignition risk caused by vegetation contact. 4. Assess the effectiveness of enhanced clearances. In preparation for this study and the eventual analysis, SDG&E must collect the relevant data; the required data are currently defined by the WSD Geographic Information System (GIS Data Reporting Standard for California Electrical Corporations - V2).*

The utilities joint response to this Issue/Remedy can be found in Attachment I of the 2022 WMP Update.

SDG&E, PG&E, and SCE (jointly, investor-owned utilities or IOUs) have begun collaboration on a vegetation clearance study. This is expected to be a multi-year effort which will benchmark vegetation management practices and data collection methodologies across IOUs in order to help develop uniform data standards. Bi-weekly meetings began on September 9,2021 and eight meetings have been held to date, with attendees from the IOUs and Energy Safety at each meeting.

The IOUs are focused on addressing the required remedies of this study, which include:

- Establish uniform data collection standards
- Create a cross-utility database of tree-caused risk events (i.e., outages and ignitions caused by vegetation contact)
- Incorporate biotic and abiotic factors4 into the determination of outage and ignition risk caused by vegetation contact
- Assess the effectiveness of enhanced clearances

Initial meetings began with each utility discussing their existing data collection standards and early analysis of enhanced vegetation clearances. The IOUs discussed definitions being used and began to standardize definitions including “enhanced clearance,” “inventory tree,” “tree-caused risk event,” and “post-trim clearance.” The different types and methods of creating a cross-utility database of tree-caused risk events were reviewed. There are pros and cons to the various methods discussed, with more work to be completed in the future on the format and location of this database.

[3] Biotic factors include all living things (e.g., an animal or plant) that influence or affect an ecosystem and the organisms in it; abiotic factors include all nonliving conditions or things (e.g., climate or habitat) that influence or affect an ecosystem and the organisms in it.

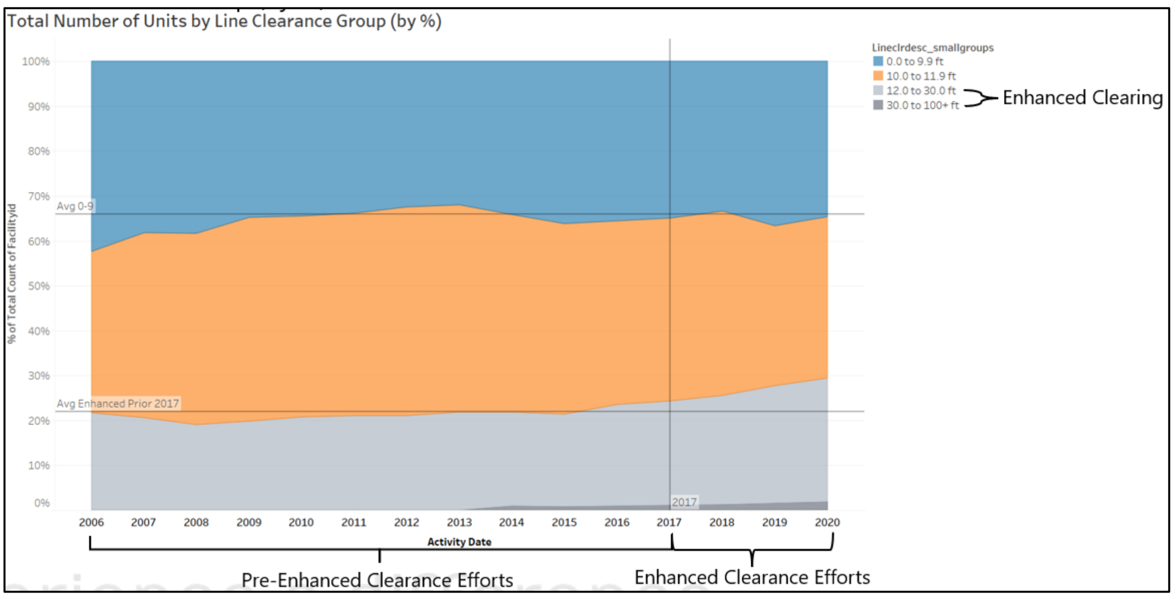
[4] Biotic factors include all living things (e.g., an animal or plant) that influence or affect an ecosystem and the organisms in it; abiotic factors include all nonliving conditions or things (e.g., climate or habitat) that influence or affect an ecosystem and the organisms in it.

The most recent meetings, which took place after the November 1st Progress Report, focused on each IOU demonstrating its current analysis around the effectiveness of enhanced clearances.

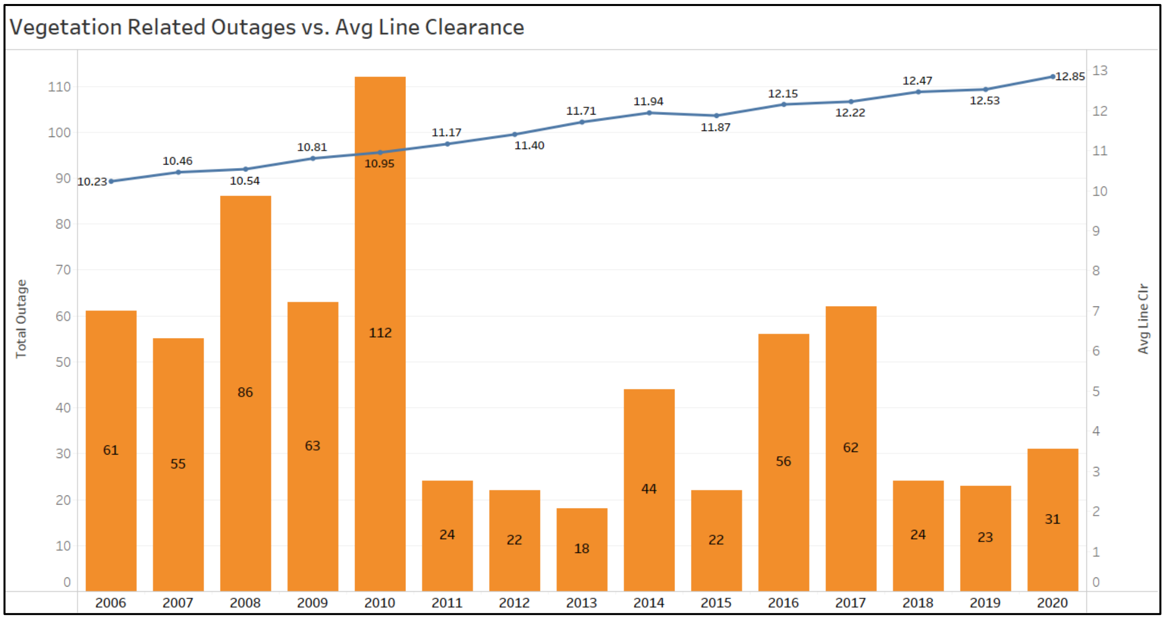
Initial analysis focus on outage/interruption events as these are precursors to ignition events. Ignition data does not have a sufficient population sample size to evaluate at this time. These initial analyses are presented below for each IOU:

SDG&E

Initial analysis performed by SDG&E studied the relationship between line clearance and vegetation related outages on the system. The outages being studied are related to unplanned forced outages, excluding instances where the line is de-energized for safety to allow crews to work in the area. The IOUs have defined enhanced clearance as trimming the vegetation at least twelve feet from the energized conductor. Enhanced clearance efforts ramped up beginning in 2017, as shown in the graph below, where the percent of SDG&E's inventory trees trimmed to enhanced clearances increased to near 30%.



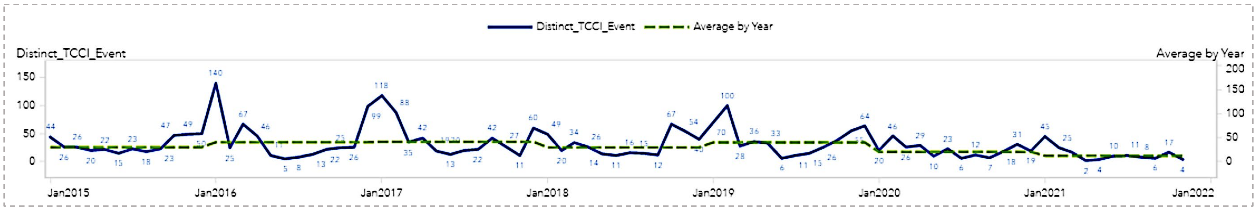
SDG&E sees an increase in average line clearance over time, with a related relative decrease in vegetation related outages over time. This decrease in vegetation related outages will likely lead to fewer events that could result in an ignition leading to a wildfire.



SCE

In late 2018, consistent with D.17-12-024 which amended GO 95 to increase recommended clearance distances at time of trimming in HFRA, SCE implemented enhanced clearance programs to achieve greater trimming distances. For purposes of this analysis and considering the time to operationalize enhanced clearances to establish SCE's Grid Resiliency Clearance Distances across SCE's service territory, the "pre-enhanced" time frame is considered to be 2015-2019, and "post-enhanced" is focused on 2020 and future years. Outage data in the table/chart represent tree-related events (circuit interruptions) on SCE's distribution system confirmed by SCE field verification as grow-in, blow-in and fall-in events.

This data highlights a decrease in outages associated with vegetation caused events since the advent of SCE's enhanced clearances. Details about the reported events include confirmed tree-related events by SCE field verification, and are categorized by Grow-In, Blow-In and Fall-In events. Approximately 100 TCCI "categories" are reduced to 6 primary categories: Grow-In, Blow-In, Fall-In, Human Caused, No Cause/Not tree related, and Uncategorized. Some events initially reported as a TCCI by SCE's outage management system could fall into categories that are not indicative of a TCCI once they are investigated and verified in the field. These include Human Caused, No Cause/Not Tree Related, and Uncategorized (the data below does not include these categories). Legacy data was updated to new data collection standards rolled out in 2021. Complete year-to-year outage data is available from 2015 to present and complete enhanced clearance data is available from 2020 to present. This data reflects distribution related events only, as there are no transmission related events of record. Though SCE has tracked TCCIs since 2015, it has only recently made advancements in its work management system that allows SCE to associate specific outage events with the individual/specific trees in its inventory. Outage data was not associated until 2021. Through this joint study, and over the next few years, SCE expects to find more substantial evidence supporting the positive effectiveness of enhanced clearances and the reduction in tree related events.

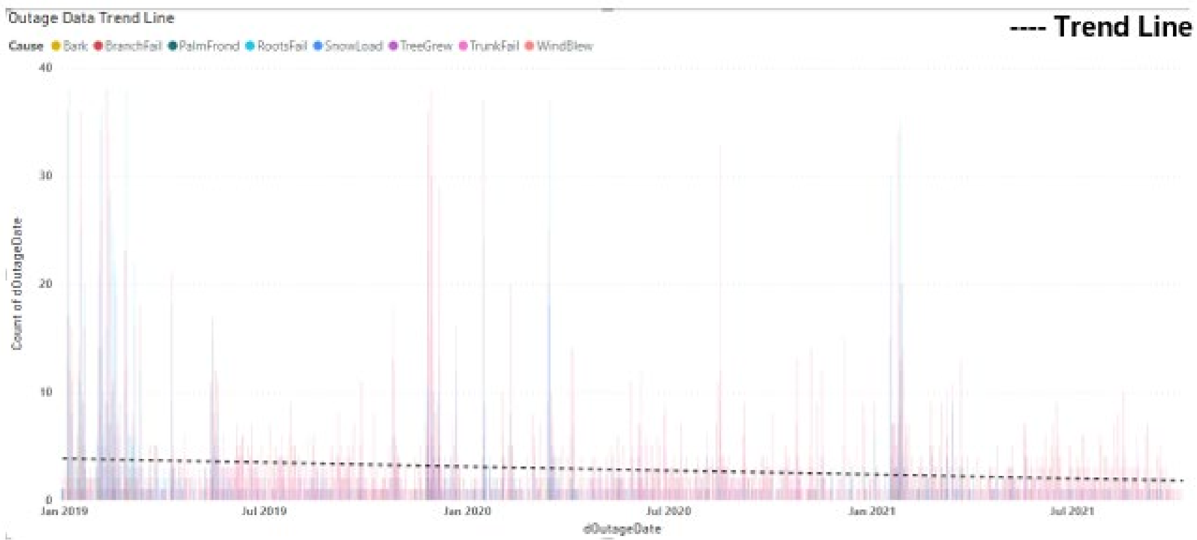


Average Events Pre & Post Enhanced Clearances

Average Events Pre and Post Enhanced Clearances	Pre-Enhanced Clearances	Post Enhanced Clearances	Difference
	2015-2019 Avg TCCIs per Year	2020-2021 Avg TCCIs per Year	
HFRA	148.4	61.5	-59%
Non-HFRA	289.2	136	-53%
All	437.6	197.5	-55%

PG&E

PG&E’s Enhanced Vegetation Management (EVM) program began in January of 2019 and the image below illustrates the beginning of enhanced clearances toward the end of 2021, or approximately three years of data, but the outages are representative of the entire service territory. The graph shows outage data confirmed as tree-related events and the distinct causes of the outage (Bark, BranchFail, PalmFrond, RootsFail, TreeGrew, WindBlew). Trend line analysis shows a decrease over the three-year period in outage counts associated with these tree-related causes. This is for Distribution conductor only and outage counts were capped at 40 per day to remove outliers in data. With outliers still represented, the trend analysis also shows a decrease in tree-related causes, but it is more difficult to read in this particular format. This data is preliminary and the decreases in tree-related causes cannot be attributed solely to enhanced clearances without further examination.



Summary

The early analysis of each IOU demonstrates that after implementing enhanced clearances the number of vegetation-related outages has decreased.

The IOUs will begin 2022 by initiating a process for soliciting proposals from third-party vendors that can assist with achieving and validating the objectives of the study. Now that each utility's current methods have been reviewed and understood, the process of beginning to standardize data collection and creating a cross-utility database of tree-caused risk events will begin. As preliminary discussions lead to the analysis of vegetation events as the key metric for effectiveness, over the course of this extended study the IOUs may confirm or adjust effectiveness metrics and work towards a more uniform standard for measuring the efficacy of expanded clearances. Part of these discussions included the types of biotic and abiotic factors that can affect the risk of vegetation contact including tree genus/species, tree health, soil composition, storm conditions, Santa Ana winds, etc. The IOUs believe that biotic and abiotic factors can be extracted from existing data sets. Additionally, in partnering with their consultant, the IOUs will begin to examine whether the correlation between enhanced clearances and the lower number of tree-caused outage events may be attributable to other factors beyond clearances, such as the management of hazard trees and the installation of covered conductor. The joint study will look into whether, and to what extent, other mitigations can be effectively parsed out so as to focus in on the effects of enhanced clearances, and to that end, what additional data may need to be included in the joint data base (such as the presence of a covered circuit segment) to allow for filtering.

Each IOU will collect the relevant data identified by Energy Safety for the purposes of this study.

5 SDGE-21- 05 Vegetation Species and Record Keeping

SDGE-21- 05	*Incomplete identification of vegetation species and record keeping*	*SDG&E must:* *1. Use scientific names in its reporting (as opposed to common names). This change will be reflected in the upcoming updates to the WSD GIS Reporting Standard.* *2. Add genus and species designation input capabilities into its systems which track vegetation (e.g., vegetation inventory system and vegetation-caused outage reports).* *3. Identify the genus and species of a tree that has caused an outage[5] or ignition[6] in the Quarterly Data Reports (QDRs) (in these cases, an unknown "sp." designation is not acceptable).* *4. If the tree's species designation is unknown (i.e., if the inspector knows the tree as "Quercus" but is unsure whether the tree is, for example, Quercus kelloggii, Quercus lobata, or Quercus agrifolia), it must be recorded as such. Instead of simply "Quercus," use "Quercus sp." If referencing multiple species within a genus use "spp." (e.g., Quercus spp.).[7]* *5. Teach tree species identification skills in its VM personnel training programs, both in initial and continuing education.* *6. Encourage all VM personnel identify trees to species in all VM activities and reporting, where possible.*

SDG&E has begun implementing remedies to address incomplete identification of vegetation species and record keeping. Progress on the six required remedies is provided below:

1. SDG&E is in the process of working with its IT Designer to create a specific data field within the tree record of the inventory database to record Genus and species which will provide additional reporting capability. SDG&E expects this to be complete by Quarter 1, 2022.
2. Genus and species designation is in-progress for the vegetation inventory database as described in item 1 above. As an interim step, SDG&E has begun recording the genus and species of each tree associated with an outage within a miscellaneous comments field with the tree record and separately on a tracking spreadsheet.
3. SDG&E has begun recording the genus and species of each tree associated with an outage on a tracking spreadsheet. This information will be used to populate these fields in future Quarterly Data Reports.

[5] WSD GIS Data Reporting Standard Version 2, Transmission Vegetation Caused Unplanned Outage (Feature Class), Section 3.4.5 & Distribution Vegetation Caused Unplanned Outage (Feature Class), Section 3.4.7.

[6] WSD GIS Data Reporting Standard Version 2, Ignition (Feature Class), Section 3.4.3.

[7] Jenks, Matthew A. (undated, from 2012 archived copy), "Plant Nomenclature," Department of Horticulture and Landscape Architecture, Purdue University, accessed May 18, 2021: https://archive.ph/20121211140110/http:/www.hort.purdue.edu/hort/courses/hort217/Nomenclature/description.htm.

4. SDG&E will follow this requirement as an element to item 3 above.
5. All vegetation management tree inspectors are required to have education and/or experience in a field related to vegetation management, tree biology, natural resources, etc. Once employed, inspectors receive on-the-job species identification training related to utility arboriculture.
6. SDG&E will determine the applicability of species identification in conjunction with its other vegetation activities and encourage personnel to identify genus/species. Third-party pre-inspection auditing scope will be expanded to include validation of genus/species.

6 SDGE-21- 06 Quantitative Analysis to Identify "at-risk" Species

SDGE-21- 06	*Limited evidence of quantitative analysis to identify "at-risk" species*	*SDG&E must:* *1. Describe its methodologies for determining what species it considers "at-risk."* *2. Explain in complete detail why discrepancies exist between the genera with the highest number of outages per 1000 trees per year and SDG&E's "targeted species identified as a higher risk due to growth potential, failure characteristics and relative outage frequency."[8]* *3. Define quantitative threshold values (whether a standard value, a range of values, or an example of a typical value) for the criteria used to define a tree as "at-risk."*

1. Methodologies for determining what species SDG&E considers "at-risk".

SDG&E has identified five primary "at-risk" species, including palm, eucalyptus, sycamore, pine and oak, because they may exhibit one or more of the following criteria:

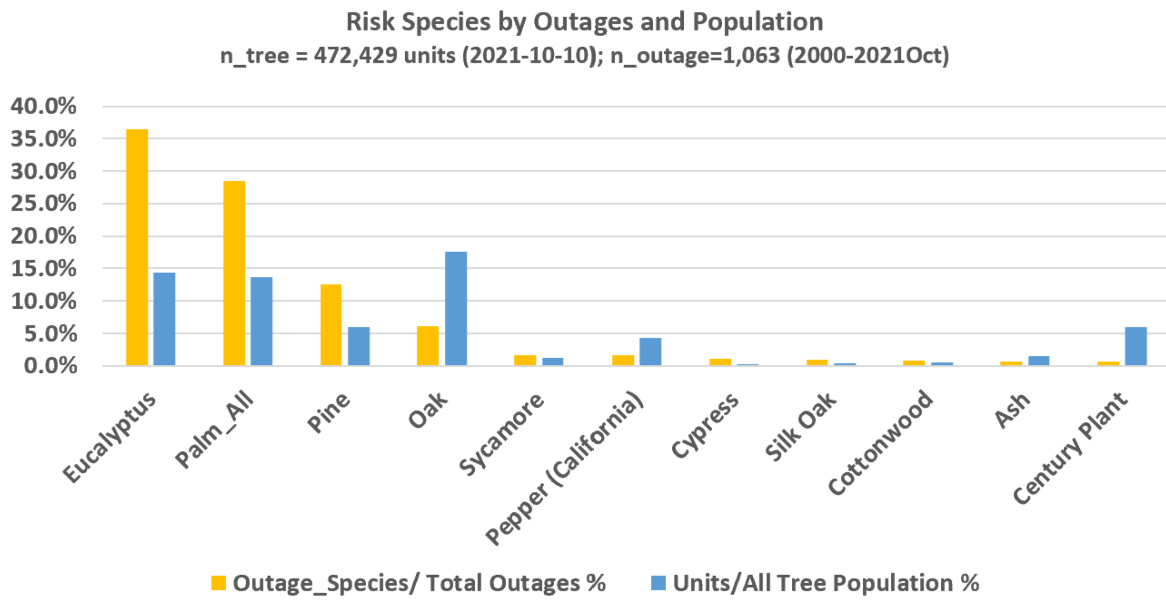
- Fast-growing species
- Species with known characteristics or propensity for branch failure
- Species that represent a high outage frequency per year and species that have a high outage rate relative to the total inventory tree population

It is important to note that SDG&E designates these species as "at risk" to facilitate targeted inspections of these species to better identify if they require enhanced clearances and/or removal. The need for an enhanced clearance is determined at the time of trim and is based on several tree characteristics, including species, location, tree health, and other issues identified by the tree inspector. Thus, simply because a tree has been identified as "at risk" does not mean that it will be trimmed to an enhanced clearance.

SDG&E's methodology is based on the goal of reducing the total number of risk events (vegetation caused outages) to mitigate wildfire risk. As shown in Chart 6.1 below, the top five tree species—which SDG&E has identified as "at risk"—are associated with 85.1% of all vegetation caused outages, while the total amount of species units represents 52.9% of SDG&E's entire inventory tree population. SDG&E has teamed with scientists from San Diego Supercomputer Center (SDSC) to further refine its vegetation data to focus on reducing outages caused by these species, which should mitigate overall vegetation outages and the risk of potential associated vegetation-related ignitions.

Chart 6.1: Risk Species by Percentage of Outages (Top 10) and Its Population

[8] SDG&E 2021 WMP Update, p. 278.



Note: the total inventory unit count is based on SDG&E's inventory tree database and reflects current tree inventory.

In the graph above, an orange bar taller than the blue bar represents an instance where there is a disproportionate number of outages relative to the species' total population. These instances also represent the species that have higher outage risk per unit or per 1000 units. The associative annualized data points can be found in Chart 6.2 below under the column titled, "Average Outage Rate Per 1000 Inventory Units." However, when the total species population (the denominator of the equation) is very small this metric yields a very high outage rate per 1000 units. Focusing on preventing outages for these species—such as century plant or cypress—will have less impact on reducing the overall number of outages. Therefore, the metric, Average Outage Rate Per 1000 Inventory Units, should be utilized collaboratively with "Average Outage Per Year" when determining outage risk.

As seen in Chart 6.1, Oak and Sycamore can be categorized as species where the average number of outages per 1,000 inventory trees are not as high compared to other tree types. SDG&E Vegetation Management also considers qualitative measures including anecdotal evidence, industry knowledge, and known species characteristics in its consideration of "at risk" species. For instance, oak and sycamore trees have a known propensity for branch failure, which could lead to increased chance of vegetation/line contact. Certified Arborists and line-clearance-qualified-tree-trimmers apply this knowledge when determining which species should be targeted for enhanced clearances and removal to prevent outages. As previously stated, however, while inspectors use this knowledge when assessing a tree for removal or trim, the ultimate determination regarding the need for enhanced clearance and/or removal is made at the time of trim, based on a holistic review of the tree.

2. **Explain in complete details why discrepancies exist between the genera with the highest number of outages per 1000 trees per year and SDG&E's "targeted species identified as a higher risk due to growth potential, failure characteristics and relative outage frequency".**

As explained above, SDG&E uses various criteria to determine its targeted at-risk species. Correlation with higher outage frequency is a good indication that a tree poses a higher risk to electrical infrastructure, however SDG&E uses qualitative characteristics to identify high-risk trees as well. This qualitative assessment, based on the expertise of SDG&E's certified arborists and line-clearance-qualified-tree-trimmers, explains some of the discrepancies between the genera with the highest number of outages per 1000 trees per year and SDG&E's list of five targeted "at risk" species.

Since submitting the 2021 WMP update, SDG&E has continued to refine its study of enhanced tree clearances and tree-related outages with updated data to better understand its assessment of targeted species. SDG&E has collaborated with the San Diego Supercomputing Team in this initiative. Chart 6.2 was created using updated data points to compare with the excerpted table previously prepared by Mussey Grade Road Alliance (MGRA) (see Chart 6.3 below).[9] In Chart 6.2, SDG&E calculated the "Average Inventory Per Year" based on the number of inventory tree units[10] in each year from 2000 to 2020. Queries for trees trimmed in Chart 6.2 were also refined to remove unrelated work orders. Chart 6.2 thus updates certain incomplete data points previously used by MGRA. In MGRA's analysis, tree units trimmed represent only a portion of the total inventory units of the species. This explains the discrepancies between the two studies. The revised, corrected "Average Inventory Per Year" in Chart 6.2 compared to the "Average Inventory" in MGRA Chart 6.3 explains differences in the relative average outages per 1000 inventory trees.

[9] Comments of Mussey Grade Road Alliance on SDG&E's Wildfire Mitigation Plan at 40.

[10] Inventory units by species: each inventory tree is inspected at least once every year, the number of units that were inspected in each year represents the inventory units of each species, which was determined in the previous year. During the cycle of on-going inspection in the current year, some of the inventory trees could be removed and new trees were added to the inventory database. The overall total tree inventory has been consistent.

Chart 6.2: 2000-2020 Risk Species Statistics and Threshold[11]

No.	Name	Average Inventory Per Year (Unit)	Average Trees Trimmed Per Year (Unit)	Average Outages Per Year	Total Outages	% of Total Outages	Avg. Outages Per 1000 Inventory Units Per Year
1	Eucalyptus	80,636	44,193	18.10	380	36.2%	0.22
2	Palm	33,592	17,206	14.29	300	28.6%	0.43
3	Pine	30,697	10,407	6.29	132	12.6%	0.20
4	Oak	69,290	17,704	3.10	65	6.2%	0.04
5	Sycamore	5,904	2,815	0.76	17	1.6%	0.13
6	Pepper (California)	16,996	7,491	0.81	16	1.5%	0.05
7	Cypress	1,476	425	0.52	11	1.0%	0.35
8	Silk Oak	2,351	1,450	0.43	9	0.9%	0.18
9	Cottonwood	3,913	1,792	0.43	9	0.9%	0.11
10	Century Plant	11,002	317	0.33	7	0.7%	0.03
11	Ash	7,562	4,309	0.33	7	0.7%	0.04
12	Avocado	24,238	10,947	0.29	6	0.6%	0.01
13	Tamarisk/Salt Cedar	2,059	1,244	0.29	6	0.6%	0.14
14	Willow	13,937	8,128	0.29	6	0.6%	0.02
23	Ficus	3,605	1,395	0.14	3	0.3%	0.04

Chart 6.3: MGRA Species and Outage Frequency

Species	Average Inventory	Average Outages per year	Total Outages	% of total outages	Outages per 1000 trees per year
Eucalyptus	48116	25.50	459	41.90%	0.53
Palm	11223	12.50	225	20.50%	1.11
Pine	11509	8.11	146	13.30%	0.70
Oak	19510	3.72	67	6.10%	0.19
Sycamore	3118	1.11	20	1.80%	0.36
Pepper (California)	8462	0.94	17	1.60%	0.11
Cottonwood	1931	0.72	13	1.20%	0.37
Avocado	11838	0.72	13	1.20%	0.06
Cypress	473	0.67	12	1.10%	1.42
Ash	4706	0.61	11	1.00%	0.13
Century Plant	401	0.50	9	0.80%	1.25
Ficus	1587	0.50	9	0.80%	0.32
Willow	9099	0.50	9	0.80%	0.05
Silk Oak	1578	0.44	8	0.70%	0.28
Tamarisk/Salt Cedar	1310	0.39	7	0.60%	0.30

Table 9 - Copied from MGRA Q3 Comments (Footnote 56). Recalculation of SDG&E Table 24. Columns have been added for total number of outages and for outages per 1000 trees per year. Only plants causing more than 6 outages in the 18 year study period are included. Color coding is based upon number of outages per year per 1,000 trees: Red: >1.00, Yellow: 0.5 to 1.0, No color, 0.3 to 0.5, and Green, < 0.3.

[11] All calculations in this table are based on historical data from Year 2000 to 2020.

As shown in Chart 6.2, Palm has the highest average outage rate, 0.43 per 1,000 inventory units; Cypress (highlighted in yellow in Chart 6.2) has the second highest annualized average outage rate, 0.35 per 1,000 inventory units. This is because the inventory unit of Cypress only represents 0.3% of total tree inventory, which is much smaller than the other five risk species. For Century Plant, about 317 units were trimmed annually, which represents 2.9% of its average annual inventory; Century Plant's average outage rate per 1,000 inventory units is 0.03 (compared to a much higher rate of 1.25 in MGRA's initial analysis).

3. **Define quantitative threshold values (whether a standard value, a range of values, or an example of a typical value) for the criteria used to define a tree as "at-risk".**

To quantify the threshold, two main metrics can be used to define "at-risk" species based on historical outage data (2000-2020): Average Outages Per Year (AOPY) and Average Outage Rate Per 1000 Inventory Units (AORPI). When using AORPI to assess the risk, AOPY should be utilized collaboratively. Hence, "At risk" is defined as AOPY >=1; or AORPI > 0.1 and AOPY >=0.7. SDG&E will continue to monitor the changes over time.

7 SDGE-21- 07 Quantified Vegetation Management Compliance Targets

SDGE-21- 07	*Need for quantified vegetation management (VM) compliance targets*	*SDG&E must define quantitative targets for all VM initiatives in Table 12. If quantitative targets are not applicable to an initiative, SDG&E must fully justify this, define goals within that initiative, and include a timeline in which it expects to achieve those goals.*

Ten of the 20 VM initiatives in Table 12 are related to and covered under one or more of the other 10 VM initiatives. Therefore, they are not individually and separately quantified or qualified. Of the remaining 10 VM initiatives, 4 can be quantified and 6 can be qualified.

UPDATE: Based on a consensus agreement between SDG&E and Energy Safety in a meeting January 11, 2022, SDG&E will begin quantifying two additional initiatives in Sections 7.3.5.13 and 7.3.5.16 of the 2022 WMP Update.

The 6 initiatives that are not quantifiable include:

Section 7.3.5.1 of the 2022 WMP Update- Throughout the year, Vegetation Management (VM) participates in multiple community and outreach events including fire preparedness webinars, wildfire safety fairs, presentations, tree plantings, customer engagements, etc. Many of these events are ad hoc and typically not pre-planned or scheduled by Vegetation Management nor tracked by metrics such as number of participants. Vegetation Management's goal is to continue to participate in all related applicable and related outreach events to message its tree operations with customers and stakeholders, and support safety and reliability goals. SDG&E expects to complete these goals annually as they occur.

Section 7.3.5.7 of the 2022 WMP Update - VM does not currently have quantifiable goals for the use of technologies such as LiDAR. SDG&E continues to research the potential integration of LiDAR into its tree operations through use cases. In Q3 2021, the SDG&E Innovation Team completed the Final Readout on the LiDAR Proof of Concept (PoC) for developing an enterprise-wide solution in its use of LiDAR and AI. This readout summarized analysis outcomes for vegetation clearance. Following the readout, the team collaborated with others to plan and frame the scaling of a solution to support storage, analysis and visualization of critical LiDAR data. For Q1 2022, SDG&E aims to capture the new LiDAR flight data for the HFTD and begin analyzing the relative data.

Section 7.3.5.13 of the 2022 WMP Update - VM performs QA/QC on a sample of all its completed work activities. Audits are ongoing throughout the year. SDG&E continues its routine QA/QC program by performing random sampling audits on a sample population of all completed VM activities including pre-inspection, tree trimming, and pole brushing. Audit consists of a 15% sample of each completed activity. Vegetation Management additionally audits 100% of all completed hazard-tree trimming in the HFTD and 100% of all completed tree removals in the HFTD to ensure full compliance with the scope of work. As part of the company's "doubling-down" initiative for fire preparedness in advance of fire season, VM also performed a QA/QC audit on a sample of all FiRM (Fire Risk Mitigation) project work completed in 2021. SDG&E did not identify any non-compliant tree/line clearance findings as a result of this audit. SDG&E will begin to quantify completed audits using its Master Schedule of activities beginning in 2022.

UPDATE: Based on a consensus agreement between SDG&E and Energy Safety in a meeting January 11, 2022, SDG&E will begin quantifying this initiative in the WMP 2022 Update by recording the number of assets and percentage of completed work audited.

Section 7.3.5.14 of the 2022 WMP Update - Contractor training is the responsibility of the contractor company. SDG&E requires its contractors to complete annual training including hazard tree assessment, customer service, and environmental. The inaugural line-clearance tree trimming training class sponsored by SDG&E and the Utility Arborist Association was completed in Q3 2021. Ten individuals currently employed with the California Conservation Corps successfully completed the course. The success of this program has spurred the planning of additional local tree trimming training classes that will take place in the future. This program will also be expanded in Q1 2022 to develop a similar training course for Pre-inspection.

Section 7.3.5.16 of the 2022 WMP Update - Vegetation Management considers trees for remediation (expanded clearance or removal) throughout the service territory, and targets species in the HFTD with known fast-growing and/or hazard characteristics. The volume of work and number of trees subject to trimming or removal can only definitively be known upon completion of the pre-inspection activities as each tree changes year to year based on tree growth, environmental conditions, etc.

UPDATE: Based on a consensus agreement between SDG&E and Energy Safety in a meeting January 11, 2022, SDG&E will begin quantifying this initiative in the WMP 2022 Update by recording the number of off-cycle HFTD patrols completed before peak fire season within the Vegetation Management Areas (VMA) and associated HFTD line miles.

SDG&E has fully integrated its team of internal company Patrollers to perform the specialized hazard tree inspections within the HFTD. Currently, this second, annual hazard tree patrol in the HFTD is scheduled to occur 6 months (mid-cycle) following the routine tree inspection activity. SDG&E has begun to refine the schedule of the annual HFTD patrol activity such that they occur within the quarter (June-Aug) preceding September, the month the Santa Ana wind season typically begins. This schedule adjustment will begin in 2022. Until that time the current off-cycle HFTD patrol schedule will continue. During routine inspection and special patrols within the HFTD, the team of Pre-inspectors and Patrollers continue to assess all trees within the strike zone for hazard characteristics that require trimming or removal to avoid conflict with the power lines.

As part of its tree removal/replacement program and it's "Right Tree, Right Place" initiative, SDG&E continues to offer customers trees that are compatible to plant near power lines. As part of the company sustainability initiative, SDG&E set a goal of planting 10K trees in 2021. By the end of Q3, 2021 approximately 9500 trees had been given away and planted in collaboration with a multitude of stakeholders including customers, HOAs, cities, tribal lands, and state and federal agencies.

Section 7.3.5.19 of the 2022 WMP Update - SDG&E integrated the Vegetation Risk Index (VRI) GIS layer into the mobile application (Epoch) of its work management system in Q3 2021. This will bring added risk ignition visibility to VM contractors in the field. The components of the VRI include the Vegetation

Management inventory tree data, outage frequency history, and meteorology. Veg Management can utilize this information in its decision-making for all HFTD inspections as well as any specialized VRI or PSPS patrols. With the new Epoch system, Vegetation Management now also has the ability to capture the accurate GPS (latitude/longitude) location of its inventory trees. Vegetation Management has also begun to track and record the Genus/species in its database for each tree associated with an outage. Updates to the VM inventory database will be ongoing as refinements are identified for business and regulatory requirements, and as technology and updates to the system become available.

8 SDGE-21- 08 Non-Communicative Remote-Controlled Switches

SDGE-21- 08	*Non-communicative remote-controlled switches*	*SDG&E must:* *1. Discuss its plans to take system level proactive steps to validate that existing SCADA switches remain fully functional.* *2. Discuss its plans to ensure that newly installed SCADA switches are fully functional.* *3. Describe the steps it is taking to increase and improve inspections and testing of SCADA switches.*

This issue was closed with SDG&E's response during the November 1 progress report. During SDG&E's 2021 PSPS event November 24-26, no SCADA switches were non-communicative resulting in the de-energization of additional customers or missed PSPS notifications. SDG&E's response from November 1st is provided below for reference.

The issue description for SDGE-8 utilizes a line from a SDG&E PSPS post-event report that broadly states that missed PSPS-related notifications "may be attributed to non-communicative SCADA switches." However, this is not the only reason why PSPS-related notifications can be missed. Due to the quick turnaround of the PSPS post event report, full audits and research of these items had not yet completed at the time of SDG&E's initial analysis as cited by the Action Statement. After review of these PSPS events, only three items were related to an inoperable SCADA switch and the rest were related to unexpected impacts from weather. Overall, SDG&E has maintained a very reliable 98% communication rate in its fleet of SCADA enabled devices.

SDG&E takes system-level proactive steps to validate that existing SCADA switches remain fully functional. SDG&E has internal operating procedures that call for testing SCADA switches in the fire area annually. SDG&E's maintenance procedure provides the guidelines for uniform inspection and maintenance performed at least every six years, and battery replacements every three years on all line SCADA devices.

SDG&E has similar procedures to confirm that newly installed SCADA switches are fully functional. Newly installed SCADA equipment requires a standardized operational test procedure involving tests of local and remote operations, fault indications, and alarm systems to ensure full functionality before it is placed into service.

SDG&E has taken additional steps to improve the inspections and testing of SCADA switches to minimize customer impacts of devices being inoperable during PSPS events. SDG&E instituted new processes during the 2020 PSPS season that included identifying bypassed devices and devices out of communication within the HFTD. In 2021 SDG&E has identified 33 such devices and has repaired 30 to date, restoring their remote functionality. Any device that cannot be repaired and is forecasted to be impacted by a PSPS event will have mitigation measures applied. These measures include stationing a qualified electrical worker at the device to perform manual switching or adjusting the forecasted customer notification list.

These responses demonstrate that SDG&E has existing procedures and has developed enhancements to these procedures to ensure that SCADA devices remain fully functional throughout the year. SDG&E has completed the remedies required and considers issue SDGE-21-08 completed.

9 SDGE-21- 09 SDG&E's Decision-Making Process

SDGE-21- 09	*Inadequate transparency associated with SDG&E's decision-making process*	*SDG&E must:* *1. Elaborate on its decision-making process to include a thorough overview of its initiative selection procedure. The overview must show the rankings of the relative decision-making factors (e.g., planning and execution lead times, resource constraints, etc.) and pinpoint where quantifiable risk reductions and RSE estimates are considered in the initiative selection process. The WSD recommends a cascading, dynamic "if-then" style flowchart to effectively demonstrate this prioritization process and satisfy this requirement.* *2. Using the newly developed decision-making overview, demonstrate that its undergrounding projects are a reasonable and effective use of resources to achieve risk reduction compared to other mitigation alternatives*

To address the improvement opportunity identified in this area, SDG&E is currently developing its decision-making flow. Such process flow charts are intended to cover the key remedies identified and will be presented in the 2022 WMP update to provide greater clarity around how risk factors are considered in decision-making.

To address the recommendations in action statement SDGE-21-09, flowcharts of the three largest categories of work were created. These flowcharts show at a high level the decision-making process and how work is implemented for the following categories:

1. Grid Hardening: See Sections 4.5.1.7 and 7.3.3 of the 2022 WMP Update for decision-tree flowcharts highlighting how the WiNGS-Planning model is used along with other factors to inform scoping and selection of underground versus covered conductor projects.

2. Asset Management and Inspections: See Section 7.3.4 of the 2022WMP Update for a decision-tree flowchart documenting the general process with a specific highlight around how remediation is prioritized based on findings from inspections.

3. Vegetation Management and Inspections: See Section 7.3.5 of the 2022 WMP Update for a decision-tree flowchart documenting the general process with a specific highlight around how remediation (tree trimming/pole brushing) is prioritized based on findings from our inspections.

10 SDGE-21- 10 Prioritization of HFTD in Undergrounding & Covered Conductor Mitigation Efforts

SDGE-21- 10	*Insufficient detail regarding prioritization of HFTD in undergrounding and covered conductor mitigation efforts*	*SDG&E must fully demonstrate that its undergrounding and covered conductor mitigation efforts are focused on efficiently reducing wildfire risk and PSPS events, including a description of how SDG&E determines the order in which circuit segments are scheduled for mitigation.*

SDG&E first installed covered conductor in 2020 on spans that qualified for OH hardening based on the FiRM and PRiME risk models. This prioritization targeted small copper conductor, with locations ranked by running SDG&E's Wildfire Risk Reduction Model (WRRM). Within this scope, the first covered conductor locations also accounted for accessibility to SDG&E work sites to gain experience. Covered Conductor work in the 2021-2022 construction years marked a transition in prioritization where projects that met the FiRM and/or PRiME prioritization through WRRM were also supported by the risk spend efficiency calculations developed in the WiNGS model.

2020-2021 Undergrounding work focused on locations that allowed community-critical facilities to remain powered during PSPS events. This was accomplished through an infrastructure assessment feasibility of PSPS impacted communities. Like overhead scope, SDG&E began utilizing the WiNGS model as additional data to support scoping for 2021-2022 undergrounding projects. These legacy projects were validated against the WiNGS model. Underground scope in 2023 will follow the full segment approach for wildfire mitigation using the WiNGS model. These WiNGS-identified locations were both highly ranked for wildfire risk and assessed to have minimal constraints to project timelines.

The WiNGS model encompasses segments within the HFTD and segments that have had a history of PSPS performed on them, thus prioritizing the segments most at risk for future wildfire and/or PSPS events. The order of the selection of segments to mitigate per the WiNGS model is assessed based on the resulting model output factors, most notably the baseline risk metrics and the RSE calculations associated with each considered mitigation, as well as subsequent consultations with internal electric system hardening (ESH) team for other considerations such as engineering feasibility, land constraints, etc. Figure 4-30 in Section 4.5.1.7 of the 2022 WMP Update shows the WiNGS model inputs, the data integration and analysis, and resulting outputs that support grid hardening scoping decisions. Other factors that affect grid hardening scope prioritization are depicted in Figure 7-4 in Section 7.3.3 of the 2022 WMP Update.

11 SDGE-21- 11 RSE Values Vary Across Utilities

SDGE-21- 11	*RSE values vary across utilities*	*The utilities must collaborate through a working group facilitated by Energy Safety to develop a more standardized approach to the inputs and assumptions used for RSE calculations. After the WSD completes its evaluation of the 2021 WMP Updates, it will provide additional detail on the specifics of this working group. This working group will focus on addressing the inconsistencies between the inputs and assumptions used by the utilities for their RSE calculations, which will allow for:* *1. Collaboration among utilities;* *2. Stakeholder and academic expert input; and* *3. Increased transparency.*

The utilities have prepared a joint response to this Remedy. This response describes working group activities which have occurred since the utilities submitted their Progress Reports on November 1, 2021.

On December 9, 2021, Energy Safety facilitated a public workshop on utility risk spend efficiency (RSE) estimates. Each of the utilities presented the current status of their RSE calculation methodologies, and stakeholders had an opportunity to ask questions of utility representatives as well as RSE experts. RSE experts included Tom Long from The Utility Reform Network (TURN), Fred Hanes, senior utilities engineer from the California Public Utilities Commission (CPUC), and Joseph Mitchell from Mussey Grade Road Alliance (MGRA). The participants discussed RSE calculation methodology best practices and how RSE estimates inform wildfire risk-based decision-making.

At the conclusion of the workshop, Energy Safety requested that the utilities submit reports providing a detailed description on their RSE calculation methodology. Each utility developed a report on their RSE calculation methodology, RSE estimate verification process, and RSE estimate initiative-selection process. These reports were submitted on December 17, 2021.

The utilities look forward to continuing to work with Energy Safety and other stakeholders in pursuit of utility collaboration, expert input, and increased transparency on RSE assumptions, inputs, and calculations.

Attachment E: Measuring Effectiveness of Enhanced Vegetation Management

Sempra Energy®

Vegetation Management
Impact Analysis

***Purpose**:*
This document is intended to provide an understanding that will guide vegetation management optimization.

Edition 1.0
December 2021

Contents

1. Abstract

A study was conducted regarding San Diego Gas & Electric's vegetation management strategies as it relates to historical vegetation-related outages. A deeper look at historical data was used to get an understanding of the general tree population, activities completed (inspections & trims), as well as the distribution of tree characteristics. Many characteristics are captured about trees in inventory such as species, location (High Fire Threat District/Non-High Fire Threat District), and line clearance distance. San Diego Gas & Electric has provided prior analysis regarding vegetation management activities; this analysis looks to quantitatively strengthen prior reports. The goal of this analysis is to understand what factors impact a tree's potential risk of causing an outage with a heavy focus on the impact of enhance clearance distance. Multiple methods are utilized including visual data analysis, statistical tests, and utilizing a machine-learning model to conduct a sensitivity and counterfactual analysis.

2. Introduction

As indicated in the most recent Vegetation Management Action Statement Plan, this study will assess the effectiveness of enhanced line clearance in mitigating wildfire risk by minimizing vegetation-related outages. "The need for enhanced clearance is determined at the time of trim and is based on several tree characteristics, including species, location, tree health, and other issues identified by the tree inspector."

Contact with vegetation, through growth, dropped limbs, and fallen trees, can lead to outages and ignitions. San Diego Gas and Electric (SDG&E) minimizes this risk through an extensive vegetation management program that catalogs, audits, and trims trees near electrical assets.

Vegetation powerline clearances change because of changes in tree growth, health, and external factors. SDG&E will therefore use a data-driven approach to determine the outage risk related to trees that are in the SDG&E inventory.

This research examines the impact of several factors on vegetation-related power outages in SDG&E's Vegetation Management Area. The suggested approach uses a machine-learning predictive model to forecast the predicted tree caused outages based on a range of parameters. This study has two parts to show the analysis' efficacy and dependability.

1. Provide an estimate on the impact of Vegetation Management to date
2. Provide data-driven recommendations to guide effective Vegetation Management strategy in the future

SDG&E specifically tracks trees that are determined to have "the potential to encroach within the minimum clearance required or could otherwise impact the overhead electrical facilities within three years of the inspection date." (2021 Wildfire Mitigation Plan v2). The total inventory of trees tracked year to date is **468,860.**

This analysis will examine historical vegetation management data to provide key insights and recommendations on the program including:

- **Visual data analysis related to historical vegetation management (tree count, line clearance, outages)**
- **Effect of tree species – *Ref: Appendix: 6.1***
- **Effect of HFTD vs. Non-HFTD**
- **Effect of clearance distance (specifically effect of enhanced clearances 2017-2020)**
- **Approach to minimize risk**

3. Methods

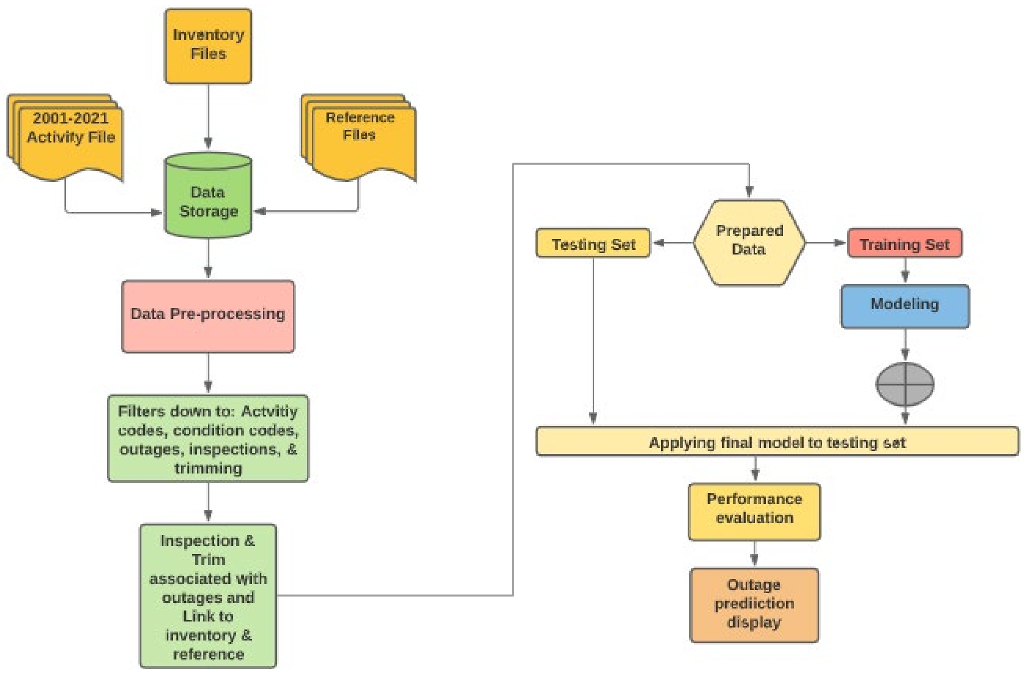
3.1 Data Collection

SDG&E captures biological, dimensional, and geographic data about its vegetation management activities. Data collection methods vary depending on how each tree meets inventory criteria. SDG&E investigates tree-related outages and collects data about species, clearance dimensions, and tree health to identify the cause and determine risk mitigation tactics. (2021 Wildfire Mitigation Plan v2)

This model analyzing a data set of vegetation contact data from 2006 to 2020 to better understand outage events and what factors may impact them. Statistical approaches are used to investigate the link between completed trims and outage incidents for the highest-risk species in both HFTD & Non-HFTD areas.

The analysis includes only outages associated with vegetation. For the modeling dataset, outage events needed to be associated with the tree's most recent event (inspection or trim). An outage that occurred without a preceding inspection or trim event is excluded from the modeling dataset due to the absence of prior data for that tree.

Figure 1: Technical flow-chart of the proposed approach



3.2 Data Processing

3.2.1 Data Cleaning

The first step was to ensure the efficacy of the data set. It is common for real-world datasets such as outage, weather, and geographical information to have a variety of inconsistencies. Data-driven models may also be affected by this type of data. Therefore, it is imperative that the raw data is examined, and suitable actions are taken to avoid potential issues. This issue is critical, as the data pre-processing task may have a significant impact on the performance of subsequent models. Importantly, consistent data is required for correct results.

To counter this potential issue, the data was pre-processed and analyzed using the following actions:

Activity codes: PI (pre-inspection), TT (tree trim), OI (outage incident)

The activity codes that were included in the analysis were PI, TT, and OI which stand for inspection, tree trim, and outage. Other events like adding a tree to inventory, tree inspection audits, and tree trim audits were excluded. Since, all trees in inventory get inspected and if needed, trimmed, by returning these events there was information captured about all trees in inventory. The original dataset from 2001-2021 was 14.3M records, by returning these 3 activity codes it brought the dataset to 12.4M records (87%).

Reduce multiple events per tree: Return last event per year per TreeID
A Tree ID can have multiple activities (inspection & trims) per year. The final dataset includes information from the last activity per Tree ID per year. If a Tree ID had an outage event and the activity prior to the outage is not the last activity of the year, the activity prior to outage is also included. Other variables were generated to capture information regarding number of times a tree was inspected or trimmed in one year. Once this methodology was applied the dataset went from 12.4M to 7.5M records.

Activity date: 2006-2020
The initial dataset included years 2001-2021. Years 2001-2005 were excluded due to lack of confidence in data quality. Year 2021 is excluded from the dataset due to incomplete data. Although there was inspection and trim activities for 2021, there was only outage event information up to Q1. When doing an analysis of data on year aggregates, this significantly brought down outage rate for 2021. Because of this incompleteness 2021 was excluded. Once the year filter was applied the dataset went from 7.5M to 5.5M records.

Outages: Filtered to vegetation related outage codes (318, 322, 324, 326, 420, 426, 428, 430)
Outage events were filtered based on outage codes. The codes listed above are the ones that relate to a vegetation-related outage incident. By studying tree clearance impacts, the outage list needed to be ones where the outage could have possibly been mitigated by a vegetation management activity.

Condition codes: Trimming events filtered to condition codes = CP, CGRP, CDRP
Trim activities need to be paired with condition codes CP (completed pruning), CGRP (completed, green, reliability pruning), or CDRP (completed, dead or dying, reliability pruning). If a trim activity has any code not listed here it was determined as a data quality issue.

As stated previously outage event records were tied to the last activity (inspection or trim) prior to the outage event. The final dataset includes inspection and trim activities per Tree ID per year with outage as a flag variable. For example:

Step 1, return all inspection, trim, and outage data:

Table 1: Data Cleaning Step 1

TreeID	Date	Activity
123	2/1/2019	Inspection
123	3/20/2019	Trim
123	9/10/2019	Outage

Step 2, tie outage to last activity prior to outage event:

Table 2: Data Cleaning Step 2

TreeID	Date	Activity	Outage	Outage Date
123	2/1/2019	Inspection	0	
123	3/20/2019	Trim	1	9/10/2019

Step 3, return last activity per year per Tree Id:

Table 3: Data Cleaning Step 3

TreeID	Date	Activity	Outage	Outage Date
123	3/20/2019	Trim	1	9/10/2019

**These are not all the variables in the dataset, this is to demonstrate data cleaning process. Other variables were generated to capture information by rows that are not returned in final dataset (# of inspections in a year, # of trims in a year, etc.)*

3.2.1 Data Preparation

For creation of the machine-learning model, data needed to be in a particular format. All categorial variables had to be represented by a number and not a string value. A method called one hot encoding was utilized for all categorical variables. For example, the variable *Activity*, was coded into two columns called *Activity_Trim* and *Activity_Inspect*. Depending on the variable value (inspection or trim) one of the columns received a 1 and the other a 0. This was completed for all categorical variables and the dataset increased from 20 columns to 145.

Step 4:

Table 4: Data Cleaning Step 4

TreeID	Date	Activity_Trim	Activity_Inspect	Outage	Outage Date
123	3/20/2019	1	0	1	9/10/2019

3.3 Analysis Methods

3.3.1 Two Proportion Z-Test

To determine the validity of the current mitigation efforts based on enhancement of tree clearance distances, a two-proportion Z-Test was run. The outage rates (# outages/# inventory trees) between pre- and post-enhanced clearing procedures were compared. SDG&E currently utilizes an enhanced clearing procedure of clearing a higher proportion of trees to a 12-foot line clearance distance. The enhanced clearing process was implemented in 2017. Using a two proportion Z-Test allowed SDG&E to see if there was a statistically significant difference between outage rates from 2006-2016 versus 2017-2020.

3.3.2 Modeling & Variable Coefficients

The dataset was used to train a generalize linear model logistic regression model to predict each tree's probability of outage based on the response variable – if a tree did or did not experience an outage. A model of this type assumes that there is a linear relationship between the input features and the occurrence of outages. Prior to training the model, the data was divided into two data sets: a training dataset and a test dataset. The data from 2006 to 2018 was used as the training set and data from 2019-2020 was used as the test set. The output of the prediction given to each tree was a probability of outage score (0-1). The distribution of risk scores among trees was analyzed and a threshold was determined (.15) to classify if a tree was 1– a risk tree (cause outage) or 0- not a risk tree (not cause outage).

Variables used in the model included the following: line clearance distance, tree height, time tree has been in inventory, DBH (diameter at breast height), the last activity conducted on the tree (inspection or trim), species, growth rate, number of units, number of trunks, number of stems, tier, vegetation management area, check-back description, last condition code, number of inspections in current year, number of trims in current year, historical number of inspections, historical number of trims.

With a trained model, the test dataset (2019 to 2020) was utilized to test performance. By testing the model on unseen data, this gave confidence in the results of the model. By having a model that identified a set of high-risk trees from the population, these were then reviewed. Reviewing high risk trees gives SDG&E a better understanding of what variables have a high impact on risk. The impact of variables was understood by reviewing the model coefficients as well as specifically looking at returned high-risk trees by variables in the model.

3.3.3 Down Sampling/Up Sampling

As mentioned previously, the dataset includes tree inspections, tree trims, and outage events from 2006-2020. The modeling dataset includes a total of 5.5M records, of which 429 records are outage events that had a preceding inspection or trim event. The class imbalance of 429 to 5.5M poses a challenge because outages are a rare event, making it hard to predict. To combat this imbalance, down sampling of the no outage event activities, and up sampling of the activities that did have an outage was performed. A package called ROSE from R (an open-source statistical programming language) was utilized. The ROSE package was developed to deal with binary classification problems in the presence of imbalanced classes. Synthetic balanced samples are generated according to ROSE (Random Over-Sampling Examples). Utilizing the package, we established how many total records for the training dataset(1M) as well as what percentage (20%) should be activities with outages. It is important to note that sampling is only done on the training dataset and not the test set. Once we had a sampled dataset the model was trained, and performance was measured using the untouched test dataset.

3.3.4 Sensitivity Analysis

For both the sensitivity and counterfactual analysis data from 2017-2020 was used. Once a model was created with the necessary level of performance, the model was utilized to understand the impact of line clearance distance. A sensitivity analysis was conducted to understand the impact of line clearance distance to number of predicted risk trees returned by the model. First, the model was tested on the counterfactual data and performance was analyzed. The true positive and false negative percentages were calculated. Then, line clearance values were adjusted, and the model was run on the changed data to see the shift in number of risk trees identified. The same percentage of true positives and false negatives were assumed and used to calculate potential outage. Potential outage was compared to actual outage rates to understand impact of line clearance distance. For the sensitivity analysis, line clearance levels were adjusted six times to see the impacts of lengthening line clearance to 7, 9, 11, 13.5, 17.5, and 25 feet. A tree's line clearance was only changed if the tree's current line clearance distance was a lower value than what was being tested.

3.3.5 Counterfactual Analysis

For the Counterfactual Analysis a similar methodology to the sensitivity analysis was used. In the counterfactual analysis, line clearance data from 2017-2020 was adjusted using a more targeted approach. When reviewing the historical data there is a similar distribution of trees at line clearance levels from 2006-2017 (see Figure 4). In 2017, when the enhanced clearance process was established, there starts to be a larger proportion of trees that move to the 12+ feet and greater line clearance distances. This difference grew over time from 2017-2020. To get an understanding of the impact of enhanced clearance to outages, line clearance distances were adjusted for a small portion of trees to have the same distributions prior to 2017. In 2016, 76.4% of trees were cut to less than 12 feet and 23.6% of trees were cut to greater than 12 feet. This distribution was applied to years 2017-2020 and tree risk probability scores were recalculated.

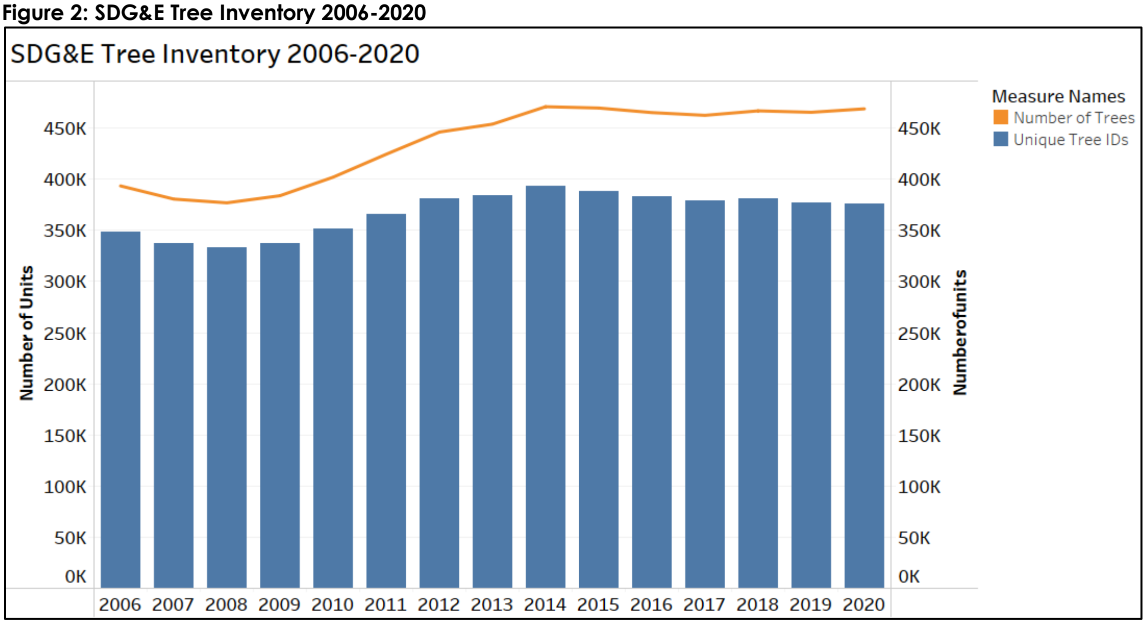
4. Results

4.1 Initial Visual Data Analysis

Before getting to statistical methods and modeling, a crucial step was to understand the dataset. Below are figures that give a better understanding of the number of trees in inventory, historical count of vegetation outage events, and average line clearance distance of the tree population.

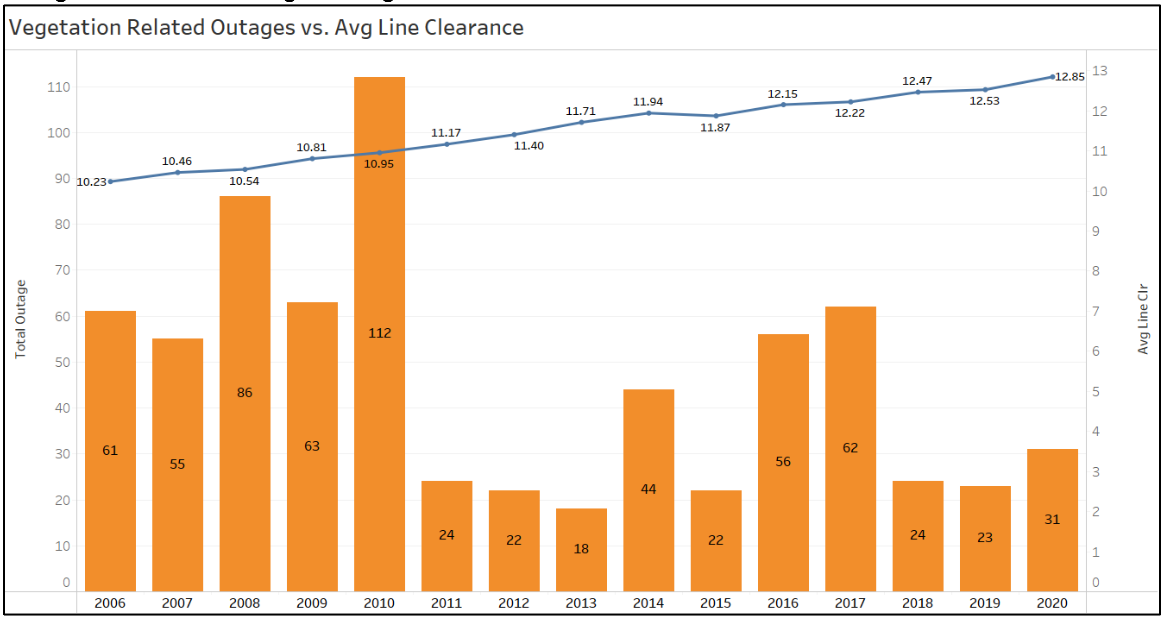
First is Figure 2 showing number of trees managed in SDG&E's inventory from 2006 to 2020. The orange line is total number of trees while the blue bars are count of unique Tree IDs. One Tree ID may represent a multiple number of trees. It is important to note that each event that is reported is on a Tree ID basis. On average from 2006-2020 there were 435,000 total trees in inventory and 367,500 unique Tree IDs, with 2020 being at 468,860 total inventory trees.

Figure 2: SDG&E Tree Inventory 2006-2020



For this set of inventory trees, below is a plot of average line clearance distance per year vs. number of vegetation-related outages.

Figure 3: Vegetation Related Outages vs Avg Line Clearance



Average Line clearance distance has increased over time while vegetation-related outages have trended down over time. The dataset that was leveraged for the creation of a machine-learning model includes outage events that had a tree in inventory with an associated inspection or trim events.

Outages have historically occurred on trees that were not in SDG&E inventory. If a non-inventoried tree is discovered to have caused an outage it then gets added to inventory. On a yearly basis SDG&E is adding and removing trees to their inventory, which is why inventory has gone up over time. The below table shows count of outages related to a tree that was in inventory prior to an outage by year.

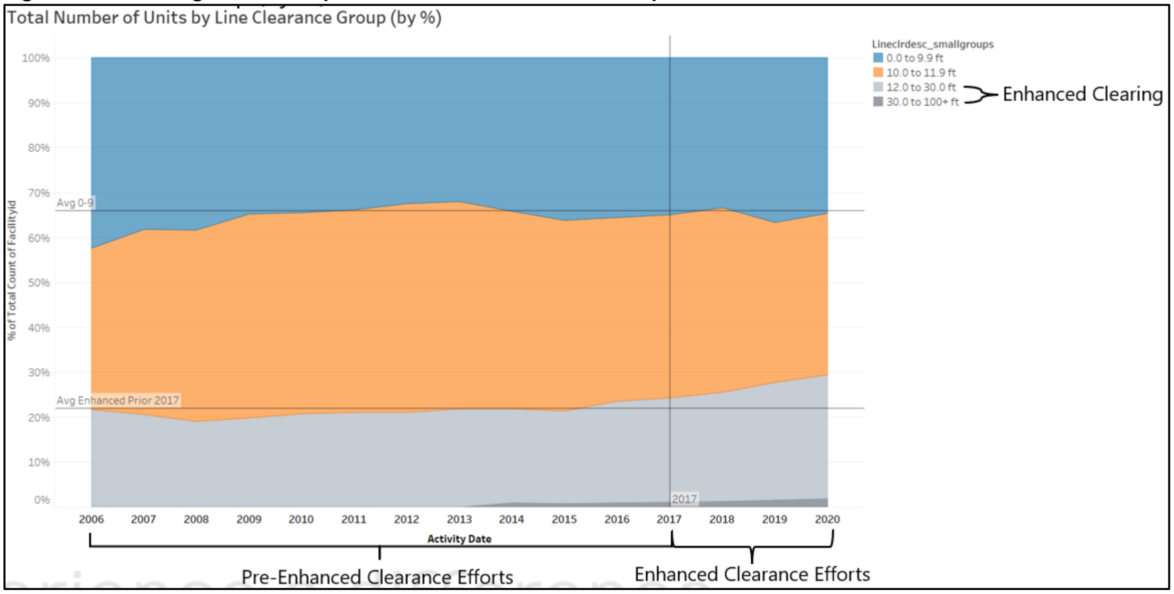
Table 5: Outages by Year (with and without prior Activity)

Year (Outage Date)	Total Outages	Outage w/ Prior Event	Outage No Prior Event	% with No Event
2006	61	49	12	20%
2007	55	35	20	36%
2008	86	45	41	48%
2009	63	34	29	46%
2010	112	54	58	52%
2011	24	16	8	33%
2012	22	17	5	23%
2013	18	15	3	17%
2014	44	31	13	30%
2015	22	18	4	18%
2016	56	35	21	38%
2017	62	36	26	42%
2018	24	20	4	17%
2019	23	15	8	35%
2020	31	21	10	32%

From 2006-2020, on average, 32% of outages occur from trees that are not in inventory. The machine-learning model utilizes outages from trees that were in inventory prior to outage event. This is because information related to the tree is needed prior to the outage event happening for a risk prediction to be generated.

Lastly, as this analysis will focus primarily on line clearance distance; another visualization that is useful to review is Figure 4, the percentage of trees within line clearance groups over time. This chart visualizes the percentage of inventory trees in four line clearance groups 0-9.9, 10.0-11.9, 12.0-30.0, and 30.0-100.

Figure 4: Percentage of Trees by Line Clearance Distance Group



SDG&E's enhanced clearing efforts are clearly seen when plotting the percentage of trees in each clearance group over time. Starting in 2017 there is a larger percentage of trees that move to the grey categories of 12 feet and greater. That distribution continues to grow over time from 2017-2020. In a later section, 4.5, line clearance is specifically analyzed to understand what effect this change had on outage rate.

4.2 Statistical Test, Two Proportion Z-Test

A two proportion Z-test was conducted to test the outage rate difference between 2006-2016 and 2017-2020. A one-tailed two proportion Z-test can be used to compare if one proportion is greater or less than the other. The null hypothesis for the test was that outage rate from 2006-2016 was less than or equal to outage rate from 2017-2020. The alternative hypothesis is that outage rate for 2006-2016 is greater than 2017-2020. The two proportion Z-test proved that the null hypothesis could be rejected, and that the alternative hypothesis could be accepted. The alternative hypothesis again that enhanced clearing years, 2017-2020, had a lower outage rate than 2006-2016. The data below shows a clear advantage in years that followed enhanced line clearance protocols. It can be concluded that the outage rate from 2006-2016 is greater than outage rate from 2017-2020 at a statistically significant level (p-value = .0000002472).

Table 6: Outage Rate 2006-2016

Pre - Enhanced Clearance Efforts			
Year	TreeCount	Outages	Outage Rate
2006	393,455	60	1.52E-04
2007	380,613	55	1.45E-04
2008	376,928	83	2.20E-04
2009	383,893	62	1.62E-04
2010	402,006	111	2.76E-04
2011	424,450	24	5.65E-05
2012	446,128	22	4.93E-05
2013	453,867	18	3.97E-05
2014	470,931	41	8.71E-05
2015	469,637	22	4.68E-05
2016	465,167	56	1.20E-04
Total	**4,667,075**	**554**	**1.19E-04**

Table 7: Outage Rate 2017-2020

Post Enhanced Clearance Efforts			
Year	TreeCount	Outages	Outage Rate
2017	462,479	61	1.32E-04
2018	466,870	23	4.93E-05
2019	465,449	22	4.73E-05
2020	468,860	31	6.61E-05
Total	**1,863,658**	**137**	**7.35E-05**

**Two proportion Z-Test statistical output can be found in the appendix 6.2.1*

It is understood that there are multiple variables that impact outage rate, but this was the first method utilized to gain an initial understanding of the differences in outage rates between two periods of time. With this initial conclusion, the second step was to utilize a machine-learning model to conduct a sensitivity and counterfactual analysis specifically adjusting line clearance distances to see impact to outage rates historically.

4.3 Machine Learning Model

A machine-learning model was generated from the data that was collected, cleaned, and processed described in prior sections. Multiple iterations of models were created and tested during the study and the best performing model was selected. The selected model was then utilized to provide results regarding variables of interest (4.4-4.6) as they relate to outages. When discussing the results of the model, there are two datasets that were used. The first is the test set of data (2019-2020) and the second is the counterfactual data set (2017-2020). The counterfactual dataset is utilized to understand the impacts of the established enhanced clearance process during those years.

As stated in section 3.3.2 the machine-learning model was trained on the training set of data from 2006-2018. To balance the class of events, as outage is a rare occurrence, sampling of the training set was completed and described above in section 3.3.3. Once the final model was selected, it was applied to the test set of data and each tree received a probability risk score ranging from 0-1. By analyzing the distribution of risk scores, a threshold of .15 was established to classify a tree as non-risk (lower than the threshold) or a risk tree (higher than the threshold). The threshold was established by returning as low number of trees as possible but capturing a high percentage of the outage events. The following sections show the results of the performance of the model on the test set and counterfactual data. Specific information related to the machine learning model can be found in the appendix.

4.3.1 Test Set Model Performance

The test set included 753,808 inspection and trim events from 2019 and 2020.

Table 8: Model Performance, Test Set

	No Outage (Predicted)	Outage (Predicted)
No Outage (Actual)	584,071	169,698
Outage (Actual)	7	32
Accuracy	0.77	
Precision	1.89E-4	
Recall	0.82	
F1	3.76E-4	

True positive rate: 32 / (169,698+32) = 1.86E-4
False negative rate: 7 / (584,071+7) = 1.20E-5

For the test dataset, the model returns 22.5% (169,698) of trees as risk trees and captures 82% of trees that had an outage occurrence.

4.3.2 Counterfactual Set Model Performance

The counterfactual data set included 1,511,736 inspection and trim events from 2017-2020

Table 9: Model Performance, Counterfactual Data

	No Outage (Predicted)	Outage (Predicted)
No Outage (Actual)	1,173,285	338,373
Outage (Actual)	13	65
Accuracy	0.77	
Precision	1.92E-04	
Recall	0.83	
F1	3.84E-04	

True positive rate: 65 / (338,373+65) = 1.92E-4
False negative rate: 13 / (1,173,285+13) = 1.11E-5

For the counterfactual dataset, the model returns 22.4% (338,373) of trees as risk trees and captures 83% of trees that had an outage occurrence.

With having a group of risk trees identified (predicted outage), further analysis was done to understand what types of trees were being classified this way. Specific variables that were investigated include tree species, tree location (HFTD vs. Non-HFTD), and line clearance distance.

4.4 Effect of Tree Species

Mussey Grade Road Alliance (MGRA) analyzed SDG&E's vegetation-caused outage data to determine the outages per 1000 trees per year by tree species. MGRA found that palm, cypress, and century plant constituted the highest risk. In a prior report, SDG&E had targeted species as higher risk due to growth potential, failure characteristics, and relative outage frequency. These species included eucalyptus, sycamore, oak, pine, and palm. There was concern that only palms were common to both lists. With further examination although palm, cypress, and century plant do have a high outage per 1000 tree ratios, the population sizes for those species are also much smaller. To be effective at vegetation management, multiple factors need to be considered to manage the highest risk trees, and not only outage rate per 1000 trees.

Commentary was made that "SDG&E must use quantitative data to inform its "at risk" species targeting; qualitive evaluation of a tree's risk does not adequately address the quantitative risk of ignition or outage". By using a machine-learning model, this provides a quantitative approach to the relationship between multiple factors and provides individual trees with a probability of outage score. Two ways the results were used was to give clarity on species risk by reviewing the model variable coefficients related to species as well as the number of risk trees returned for each species.

The machine-learning model, a logistic regression, uses a logistic function to model a binary dependent variable, which in this case is outage (1) or no outage (0). The result is a formula that gives weights to variables which drive the probability score. The weights for each species were analyzed to understand what the model identified as potentially higher risk related to species. The dataset included 93 species. Below in Table 10, are the species that had the top 10 highest positive coefficients which would raise a tree's risk probability score.

Table 10: Model Coefficients by Species

Variable Group	Species Name	Coefficient	Outages (2006-2020)	Total Trees (2020)	% of Total 2020 (468,860)
Species	**Century Plant**	1.49	6	29,771	6.35%
Species	**Cypress**	1.37	8	1,399	0.30%
Species	Orchid	1.3	1	329	0.07%
Species	Birch	1.16	1	106	0.02%
Species	Brush5X5Bamboo	0.87	2	6,739	1.44%
Species	Fir	0.61	1	1,078	0.23%
Species	Tamarisk / Salt Cedar	0.52	6	2,259	0.48%
Species	*Palm-Fan*	0.49	151	27,055	5.77%
Species	BrushVeryFast5x5	0.41	2	7,077	1.51%
Species	*Eucalyptus*	0.35	267	71,382	15.22%

Bold *are from MGRA study, italicized are SDG&E targeted species*

This provides some information on what the model believes to be the riskiest species, but other variables also have an impact to risk which are captured by the machine-learning model. Variables interact with each other, and this also effects the coefficient value. By holistically looking at a risk probability score received by the model we can see what species the model views as risky, after including those other factors.

Again, this was using a test dataset (2019-2020), a probability threshold of .15 was utilized to classify if a tree was a risk-tree or not a risk-tree. Of the 753,847 tree activities in the test set, the model identified 169,698 "risk trees" which accounted for 32 of the 39 outages. The 169,698 were summarized by species to get an understanding of higher- risk species. Below in Table 11 is the top 10 based on a risk metric (Count of Risk Trees*Avg Risk Probability) and included if that group experienced an outage. The table also includes percentage of the total (169,698). These top 10 species accounted for 90% of risk trees returned by the model and 29 of 32 outages in the test dataset.

Table 11: Identified Risk Trees by Species

Species	Count	Pct of Total	Actual Outage	Avg Risk Probability	Risk Metric
Eucalyptus	59,184	34.6%	10	2.82 E-4	16.70
Palm-Fan	26,894	15.7%	11	3.66 E-4	9.84
Pine	28,189	16.5%	4	2.47 E-4	6.96
Oak	13,175	7.7%	1	1.24 E-4	1.63
Sycamore	5,999	3.5%	0	2.51 E-4	1.50
Palm-Feather	8,299	4.8%	1	1.50 E-4	1.25
Pepper (California)	6,045	3.5%	0	1.34 E-4	0.81
Tamarisk/Salt Cedar	2,617	1.5%	0	2.62 E-4	0.69
Cypress	1,617	0.9%	1	1.62 E-4	0.26
Pecan	1,750	1.0%	1	1.92 E-4	0.34

By using a machine-learning model to score individual trees, SDG&E gets a quantitative score related to multiple variables to identify if a tree is high risk. These results quantitatively confirm the species that are believed to be the highest risk.

4.5 Effect of HFTD vs Non-HFTD

High Fire Threat Districts trees are managed more strictly as these designated locations have a higher risk of causing wildfire. Within the analysis it was seen that outage rate is historically lower in HFTD areas (Tier-2 & Tier 3) vs Non-HFTD (see below chart). Non-HFTD trees are a lower proportion of total inventory but have a higher outage rate.

Figure 5: Vegetation Outages by Location (HFTD, Non-HFTD)

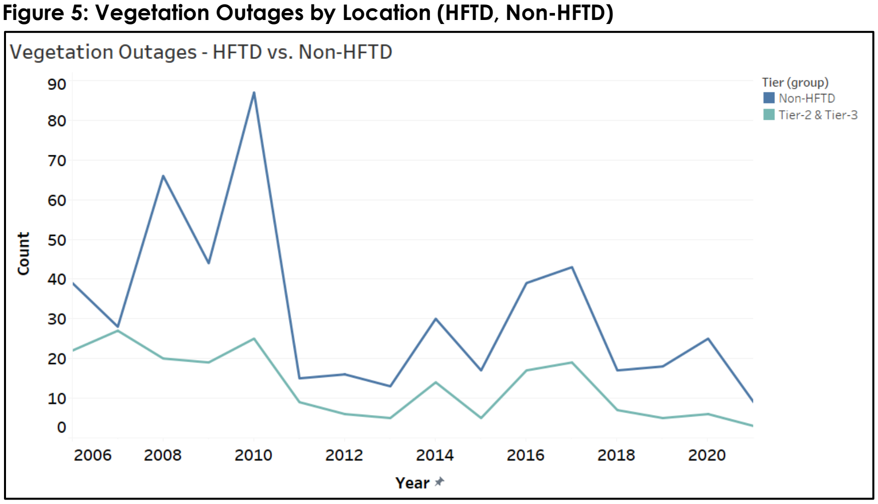


Table 12: Inventory Trees by Location

SDG&E Inventory Trees HFTD vs. Non-HFTD

	HFTD		Non-HFTD	
	# Trees	% of Total	# Trees	% of Total
2006	214,592	54.5%	178,840	45.5%
2007	208,012	54.7%	172,578	45.3%
2008	202,636	53.8%	174,265	46.2%
2009	205,019	53.4%	178,844	46.6%
2010	214,879	53.5%	187,089	46.5%
2011	228,826	53.9%	195,578	46.1%
2012	241,536	54.1%	204,543	45.9%
2013	244,692	53.9%	209,128	46.1%
2014	252,717	53.7%	218,164	46.3%
2015	252,462	53.8%	217,141	46.2%
2016	250,093	53.8%	215,047	46.2%
2017	247,428	53.5%	215,019	46.5%
2018	250,421	53.6%	216,422	46.4%
2019	249,695	53.6%	215,731	46.4%
2020	247,052	52.7%	221,767	47.3%

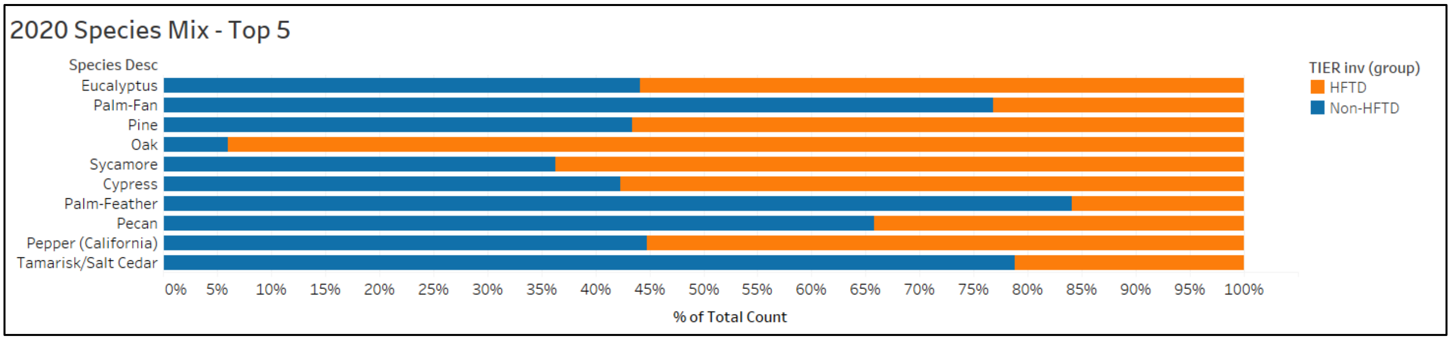
When reviewing the model coefficients, the model also gave more risk to non-HFTD trees.

Table 13: Model Coefficients by Location (HFTD, Non-HFTD)

Variable	Coefficient
Non HFTD	1.21
Tier 2 - HFTD	0.84
Tier 3 - HFTD	NA

There are also different species in different areas related to HFTD and non-HFTD. Again, many factors are related and this is another driver when looking at outage rates regarding location. Below is the 2020 distribution of the top 10 risk species from section 4.3 by HFTD/Non-HFTD.

Figure 6: 2020 Inventory Trees by Species and Location (HFTD, Non-HFTD)



4.6 Effect of Line Clearance Distance

There were three ways that line clearance distance was analyzed to understand its effect to outage rates historically. First a two-proportion z-test was used to statistically prove the difference between outage rates in different periods of time. Second, the machine-learning model was used to conduct a sensitivity and counterfactual analysis to begin to understand how different line clearance distances could have impacted outages historically.

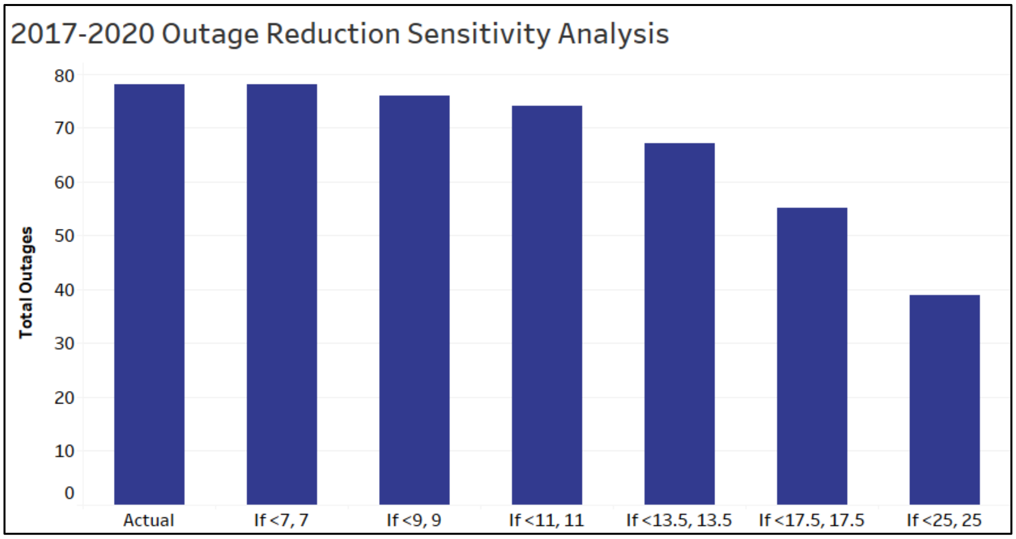
4.6.1 Sensitivity Analysis

For the sensitivity analysis, line clearance distances were lengthened to understand the potential impact to historical outage rates from 2017-2020. Line clearance distances were lengthened to 7, 9, 11, 13.5, 17.5, and 25 feet. Values were only changed if actual line clearance distance were lower than the threshold being tested. After making changes to line clearance distance the model was run on the data to update the risk probability score per Tree Id and see how many risk trees were identified. The true positive and false negative percentage ratios from the actual data were then used to calculate potential outage effects. The below table shows the results when changing line clearance distances:

Table 14: Sensitivity Analysis Results

Sensitivity Analysis	% Of records changed	Risk trees identified by model	Assumed true positive outage rate	Expected Outage (T)	Non risk trees identified by model	Assumed false negative outage rate	Expected Outage (F)	Total Outages	Difference
Actual	0	338,373	1.92E-4	65	1,173,298	1.11E-5	13	78	Baseline
If <7, 7	15%	335,660	1.92E-4	64	1,175,998	1.11E-5	13	78	(0)
If <9, 9	35%	330,234	1.92E-4	63	1,181,424	1.11E-5	13	76	(2)
If <11, 11	73%	319,595	1.92E-4	61	1,192,063	1.11E-5	13	74	(4)
If <13.5, 13.5	86%	288,906	1.92E-4	53	1,222,752	1.11E-5	14	67	(11)
If <17.5, 17.5	92%	235,561	1.92E-4	41	1,276,097	1.11E-5	14	55	(23)
If <25, 25	98%	153,119	1.92E-4	24	1,358,539	1.11E-5	15	39	(39)

Figure 7: Sensitivity Analysis Results – Outage Count Reduction



This shows that when trees are brought up to non-enhanced levels (7-11) there is smaller impact to outage reduction. When tree line clearances are brought to above 12 (13.5+), there starts to be a significant impact to potential outage reduction.

4.3.3 Counterfactual

A counterfactual analysis was done for a more direct understanding of how many outages were avoided in 2017-2020 by establishing an enhanced clearance protocol. Like the sensitivity analysis, line clearance distances were changed, the model was rerun to update probability risk scores and see impact to number of risk trees identified. Once risk trees were identified, the true positive and false negative rates from the original data were used to calculated expected outage. Data from 2016 was used to set the baseline percentage distribution of trees that did or did not have enhanced clearance (+12). As stated in section 3.3.5, 76.4% of trees were cut to less than 12 feet and 23.6% of trees were cut to greater than 12 feet prior to that year. Below is a chart showing how the counterfactual data was changed to see impacts of enhanced clearing:

Table 15: Counterfactual Data Percentage Groups by Year

Year	Actual Data		Counterfactual Data		% Trees Changed
	<12 feet	>12 feet	<12 feet	>12 feet	
2016	**76.4%**	**23.6%**	**Baseline**		
2017	**75.7%**	**24.3%**	**76.4%**	**23.6%**	**0.7%**
2018	**74.5%**	**25.5%**	**76.4%**	**23.6%**	**1.9%**
2019	**72.3%**	**27.7%**	**76.4%**	**23.6%**	**4.1%**
2020	**70.6%**	**29.4%**	**76.4%**	**23.6%**	**5.8%**

For years 2017-2020 the risk probability was rerun using updated line clearances for changed observations and the number of risk trees identified was returned:

Table 16: Risk Trees Returned with Changed Counterfactual Data

	No Outage (Predicted)	Outage (Predicted)
No Outage (Actual)	1,152,990	358,668
Outage (Actual)	13	65

Table 17: Counterfactual Data Percentage Groups by Year

Sensitivity Analysis	# Records Changed	Risk trees identified by model	Assumed true positive outage rate	Expected Outage (T)	Non risk trees identified by model	Assumed false negative outage rate	Expected Outage (F)	Total Outages	Difference
2017-2020	0	338,373	1.92E-4	65	1,173,298	1.11E-5	13	78	Baseline
Counterfactual	47,868	358,668	1.92E-4	69	1,152,990	1.11E-5	13	82	**4**

For years 2017-2020 the risk probability score was recalculated for each observation using updated line clearance values for 47K changed records. With the new probability scores the same risk threshold of .15 was used to identify a non-risk or risk tree. When adjusting for enhanced line clearance, the model returned 358,688 risk trees (20,295 additional). The true positive outage rate and false negative outage rates were then used to calculate potential outage mitigation without enhanced clearing. By implementing enhanced clearing, the model identified that potentially four outages were mitigated.

4.7 Approach to Minimize Risk

SDG&E's process is to inspect every tree in inventory on a yearly basis. From this inspection a decision is made regarding a tree's need to be trimmed. This analysis has generally shown that greater line clearance reduces a tree's risk of causing a vegetation-related outage. By targeting the riskiest trees based on several factors (species, location, etc.) SDG&E can continue to reduce to number of vegetation-related outages on a yearly basis. To maximize their effectiveness on additional inspections and trims, SDG&E may utilize the risk probability score generated by the machine-learning model to target at-risk trees.

5. Conclusion

A data-driven approach was proposed for predicting the risk probability score on a per tree basis for SDG&E's tree inventory. Based on this study, the following conclusions can be drawn.

1) In order to develop a practical approach, various types of information including historical records of outages, inventory, species, and clearance distance variables should be obtained and processed.

2) As vegetation-related outages have a complex nature with several factors influencing their occurrence, utilizing simplistic approaches such as calculating the average KPIs is not the most effective strategy. More sophisticated approaches are needed. Moreover, since outages are caused by a variety of factors that are subject to change over time, a machine-learning model that takes all these factors into consideration proves to be more useful.

3) For predicting vegetation outages, a machine learning-model is not perfect but can be useful in identifying which trees have the highest risk of causing an outage. The machine-learning model can also be used to understand past vegetation activity to outages. The vegetation management team at SDG&E can leverage this in the future.

5.1 Effect of Location (HFTD and Non-HFTD)

The analysis revealed that the outage rate has traditionally been lower in HFTD locations (Tier 2 & Tier 3) than in non-HFTD areas. While non-HFTD trees account for a smaller proportion of overall inventory, they have a higher rate of outages. Additionally, there are distinct species in distinct places associated with HFTD and non-HFTD, which influences outages. When these variables are considered, location is a critical factor to consider when calculating outage rates and designing mitigation strategies.

5.2 Effect of Tree Species

The analysis calculated a quantitative score based on various criteria to determine whether a particular tree species poses a greater risk than other species. Using a probability threshold of .15 to determine whether a tree activity constituted at risk (predicted outage). A tree appeared multiple times in the test dataset because there are multiple years of data. Of the 753,847 tree activities that were included in the test set, the results revealed 169,698 activities as predicted outages. These accounted for 32 of the 39 actual outages. These findings quantitatively demonstrate that some species are more dangerous than others. Eucalyptus, Palm-Fan, Pine, Oak, Sycamore, Palm-Feather, Pepper (California), Tamarisk/Salt Cedar, Cypress, and Pecan are the top ten species (by count) detected by the model. These top ten species accounted for 90% of predicted outage causing trees. SDG&E can include this information into its decision-making about the appropriate pruning and line clearance processes.

5.3 Effect of Line Clearance

There is a smaller impact on outage reduction when trees are trimmed up to non-enhanced levels (7-11ft). When tree line clearance exceeds 12 ft (13.5+ ft), there is a large impact on possible outage reduction. With a maximum test improvement of 25 feet, outages were reduced by nearly 50%. As a result, it can be conclusively determined based on using the sensitivity analysis that better line clearance methods can greatly minimize outages.

5.4 Approach to Minimize Risk

There is no single variable that may be regarded the primary cause of vegetation-related outages. A holistic strategy that considers all relevant elements yields the greatest results. The model used to analyze both the training and test data considered several factors as well as the effect of each variable on the others. SDG&E can use this holistic approach to plan future mitigation actions aimed at reducing, if not eliminating, vegetation-related outages.

6. Appendix

Additional information relevant to the study and background.

6.1 Relevant Terms

The following are relevant terms related to this research:

- **Tier 3 High Fire Threat District** – Per the CPUC Fire-Threat Map, the "Tier 3 fire-threat areas depict areas where there is an extreme risk (including likelihood and potential impacts on people and property) from utility associated wildfires." For the purposes of this study, Tier 3 represents all of the Tier 3 HFTD area within SDG&E's service territory.

- **Tier 2 High Fire Threat District** – – Per the CPUC Fire-Threat Map, the "Tier 2 fire-threat areas depict areas where there is an elevated risk (including likelihood and potential impacts on people and property) from utility associated wildfires." For the purposes of this study, Tier 2 represents all of the Tier 2 HFTD area within SDG&E's service territory

- **Locations outside the High Fire Threat District** - Locations outside the High Fire Threat District – All other areas within SDG&E's service territory that are not part of the Tier 2 or Tier 3 HFTD

- **Risk Event** – All overhead system faults, meaning any overhead electrical fault caused by foreign object in line, equipment failure, other or of undetermined cause that impacts the primary electric distribution system (12kV and 4kV systems). An electrical fault includes some kind of electrical system short that results in energy created in the form of heat, this is different from outages that can be a result of openings in absence of electrical faults.

- **EPOCH System** - The work management system used by vegetation management personnel to input records of vegetation management work

- **FACILITYID** = ID associated to an Inventory Tree
  - One FACILITY ID or Inventory Tree can have multiple units
  - For accurate average calculations this needs to be considered

- **Species –** A natural group of trees in the same genus made up of similar individuals. For the purposes of this study, the common name is used in place of species to match existing data.

- **Outage Vegetation Code Definitions**
  - 318: Tree contact due to growth/encroachment
  - 322: Detached tree branch contact
  - 324: Palm tree contact
  - 326: Detached palm frond contact
  - 420: Tree contact (weather related)
  - 426: Detached tree branch contact (weather related)
  - 428: Palm tree contact (weather related)
  - 430: Detached palm frond contact (weather related)

- **Completed Trim** – An inventory tree that was trimmed in a specific year to a specific post trim clearance level

- **Inventory Tree** – A tree that has the potential to encroach within the minimum clearance required and/or could otherwise impact the overhead electrical facilities within three years of the inspection date

6.2 Technical Charts

6.2.1 2-sample z test

2-sample test for equality of proportions with continuity correction

data: c(554, 137) out of c(4667075, 1863658)
X-squared = 25.285, df = 1, p-value = 2.472e-07
alternative hypothesis: greater
95 percent confidence interval:
3.156886e-05 1.000000e+00
sample estimates:
prop 1 prop 2
1.187039e-04 7.351134e-05

6.2.2 Machine Learning Model

Row	Est.	S.E.	z val.	p
(Intercept)	13.78	1458.28	0.01	0.99
Last_activity_PI1	-17.32	1458.28	-0.01	0.99
Last_activity_TT1				
SPECIES_DESC_1	-16.08	1915.43	-0.01	0.99
SPECIES_DESC_Acacia	0.07	0.04	1.86	0.06
SPECIES_DESC_Ailanthus	-16.37	107.31	-0.15	0.88
SPECIES_DESC_Alder	-16.97	144.88	-0.12	0.91
SPECIES_DESC_Araucaria	-17.88	141.47	-0.13	0.90
SPECIES_DESC_Ash	-1.48	0.04	-40.07	0.00
SPECIES_DESC_Aspen	-16.64	1079.23	-0.02	0.99
SPECIES_DESC_Avocado	-2.00	0.04	-50.60	0.00
SPECIES_DESC_Bay	-16.75	920.59	-0.02	0.99
SPECIES_DESC_Birch	1.16	0.08	15.38	0.00
SPECIES_DESC_Bottlebrush	-16.92	140.63	-0.12	0.90
SPECIES_DESC_Bottletree	-16.70	282.64	-0.06	0.95
SPECIES_DESC_BrisbaneBox	-16.99	99.97	-0.17	0.87
SPECIES_DESC_Brush5X5Bamboo	0.87	0.04	21.05	0.00
SPECIES_DESC_BrushFast5x5	-15.82	77.37	-0.20	0.84
SPECIES_DESC_BrushFast5X5Palm	-14.83	479.14	-0.03	0.98
SPECIES_DESC_BrushMed5x5	-15.82	72.26	-0.22	0.83
SPECIES_DESC_BrushSlow5x5	-15.75	114.47	-0.14	0.89
SPECIES_DESC_BrushSlow5X5GiantBOP	-15.83	1658.96	-0.01	0.99
SPECIES_DESC_BrushVeryFast5x5	0.41	0.05	7.80	0.00
SPECIES_DESC_CamphorTree	-17.07	114.82	-0.15	0.88
SPECIES_DESC_Carob	-17.29	199.29	-0.09	0.93
SPECIES_DESC_CarrotWood	-16.99	80.61	-0.21	0.83
SPECIES_DESC_Casuarina	0.34	0.07	5.08	0.00
SPECIES_DESC_Catalpa	-16.84	381.57	-0.04	0.96
SPECIES_DESC_Cedar	-0.06	0.06	-1.08	0.28
SPECIES_DESC_CenturyPlant	1.49	0.05	30.61	0.00
SPECIES_DESC_Cherry	-16.97	473.71	-0.04	0.97
SPECIES_DESC_Chinaberry	-17.08	122.90	-0.14	0.89
SPECIES_DESC_Citrus	-16.02	110.75	-0.14	0.89
SPECIES_DESC_Coral	0.13	0.06	2.15	0.03
SPECIES_DESC_Cottonwood	-0.17	0.04	-4.04	0.00
SPECIES_DESC_CowItch	-17.20	638.16	-0.03	0.98
SPECIES_DESC_Crapemyrtle	-16.68	359.77	-0.05	0.96
SPECIES_DESC_Cypress	1.37	0.04	33.33	0.00
SPECIES_DESC_DeodaraCedar	-1.56	0.06	-25.22	0.00
SPECIES_DESC_Elderberry	-16.86	128.29	-0.13	0.90
SPECIES_DESC_Elm	-2.44	0.06	-43.87	0.00
SPECIES_DESC_Eucalyptus	0.35	0.02	15.10	0.00
SPECIES_DESC_Eugenia	-16.79	92.07	-0.18	0.86
SPECIES_DESC_EvergreenPear	-16.72	168.20	-0.10	0.92
SPECIES_DESC_Ficus	-17.79	70.21	-0.25	0.80
SPECIES_DESC_Fir	0.61	0.07	8.94	0.00

SPECIES_DESC_FlossSilk	-16.97	258.95	-0.07	0.95
SPECIES_DESC_GiantBirdofParadise	-17.07	148.74	-0.11	0.91
SPECIES_DESC_Ginko	-16.81	1013.19	-0.02	0.99
SPECIES_DESC_Hackberry	-16.67	640.35	-0.03	0.98
SPECIES_DESC_ItalianCypress	-16.30	69.46	-0.23	0.81
SPECIES_DESC_Jacaranda	-1.35	0.04	-31.48	0.00
SPECIES_DESC_Juniper	-16.85	157.36	-0.11	0.91
SPECIES_DESC_Koelreuteria	-17.04	135.38	-0.13	0.90
SPECIES_DESC_Liquidambar	-1.73	0.05	-32.81	0.00
SPECIES_DESC_Locust	-16.51	89.66	-0.18	0.85
SPECIES_DESC_Loquat	-16.35	315.17	-0.05	0.96
SPECIES_DESC_Macadamia	-16.55	146.21	-0.11	0.91
SPECIES_DESC_Magnolia	-16.91	130.89	-0.13	0.90
SPECIES_DESC_Maple	-17.17	222.71	-0.08	0.94
SPECIES_DESC_Melaleuca	-17.44	65.64	-0.27	0.79
SPECIES_DESC_Mesquite	-17.01	216.47	-0.08	0.94
SPECIES_DESC_Mimosa	-16.65	289.99	-0.06	0.95
SPECIES_DESC_Mulberry	-16.92	80.22	-0.21	0.83
SPECIES_DESC_Myoporum	-16.93	101.08	-0.17	0.87
SPECIES_DESC_NewZealandXMasTree	-17.52	337.51	-0.05	0.96
SPECIES_DESC_Oak	-0.46	0.03	-17.47	0.00
SPECIES_DESC_Oleander	-16.80	286.93	-0.06	0.95
SPECIES_DESC_Olive	-16.86	57.21	-0.29	0.77
SPECIES_DESC_Orchid	1.30	0.07	17.39	0.00
SPECIES_DESC_OtherFast	-17.20	229.91	-0.07	0.94
SPECIES_DESC_OtherMedium	-16.70	74.22	-0.23	0.82
SPECIES_DESC_OtherSlow	-16.64	113.80	-0.15	0.88
SPECIES_DESC_PalmDate	-0.63	0.04	-14.28	0.00
SPECIES_DESC_PalmFan	0.49	0.03	18.87	0.00
SPECIES_DESC_PalmFeather	-0.35	0.03	-12.31	0.00
SPECIES_DESC_Paloverde	-16.94	244.62	-0.07	0.94
SPECIES_DESC_Pecan	0.30	0.04	7.01	0.00
SPECIES_DESC_PepperBrazilian	-17.38	50.86	-0.34	0.73
SPECIES_DESC_PepperCalifornia	-1.10	0.03	-37.77	0.00
SPECIES_DESC_Pine	0.27	0.03	10.52	0.00
SPECIES_DESC_Pittosporum	-17.08	116.93	-0.15	0.88
SPECIES_DESC_Plum	-16.69	351.67	-0.05	0.96
SPECIES_DESC_Podocarpus	-17.44	100.57	-0.17	0.86
SPECIES_DESC_Poplar	-16.81	168.79	-0.10	0.92
SPECIES_DESC_Privet	-16.66	255.89	-0.07	0.95
SPECIES_DESC_Redwood	-17.60	259.86	-0.07	0.95
SPECIES_DESC_Rubber	-0.08	0.07	-1.14	0.26
SPECIES_DESC_SilkOak	-0.57	0.04	-13.69	0.00
SPECIES_DESC_Sumac	-16.05	179.36	-0.09	0.93
SPECIES_DESC_Sycamore	0.30	0.03	10.12	0.00
SPECIES_DESC_TamariskSaltCedar	0.52	0.04	13.85	0.00
SPECIES_DESC_Tipu	-17.48	144.83	-0.12	0.90
SPECIES_DESC_Tulip	-16.47	1229.70	-0.01	0.99
SPECIES_DESC_Walnut	-16.74	182.37	-0.09	0.93
SPECIES_DESC_Willow				
GROWTHRATE_FAST	0.39	0.01	36.87	0.00
GROWTHRATE_MED	0.34	0.01	27.20	0.00
GROWTHRATE_SLOW	0.36	0.02	22.52	0.00
GROWTHRATE_VFST				
NUMBEROFUNITS_multiple	-0.70	0.02	-40.91	0.00
NUMBEROFUNITS_single				
NUMBEROFTRUNKS_multiple	-0.13	0.01	-11.16	0.00
NUMBEROFTRUNKS_single				
NUMBEROFSTEMS_multiple	-14.92	152.85	-0.10	0.92
NUMBEROFSTEMS_single				
TRAFFICIND_inv_N	-0.15	0.01	-17.51	0.00
TRAFFICIND_inv_Y				
TIER_inv_NonHFTD	1.21	0.01	95.06	0.00
TIER_inv_Tier2	0.84	0.01	70.68	0.00
TIER_inv_Tier3				

VMACD_inv_2	0.07	0.02	3.45	0.00
VMACD_inv_3	-0.63	0.02	-34.13	0.00
VMACD_inv_4	-0.36	0.02	-19.42	0.00
VMACD_inv_5	0.06	0.02	3.31	0.00
VMACD_inv_6	-0.63	0.02	-33.26	0.00
VMACD_inv_7				
CHKBK_DESC_OpenwireSecondary	-1.68	0.04	-39.90	0.00
CHKBK_DESC_PrimaryDistribution	0.02	0.03	0.61	0.54
CHKBK_DESC_SSCSecondary	-17.07	183.36	-0.09	0.93
CHKBK_DESC_StandAloneTransmission	-2.00	0.06	-35.61	0.00
CHKBK_DESC_Transmission				
lineclrdist	-0.07	0.00	-76.86	0.00
Treeheight_value	0.03	0.00	183.49	0.00
TREEAGE	-0.01	0.00	-6.42	0.00
condition_	0.35	0.04	9.42	0.00
condition_CompletedPruning	-17.55	1458.28	-0.01	0.99
condition_CompletedDeadorDyingReliabilityPruning	-16.71	1458.28	-0.01	0.99
condition_CompletedGreenReliabilityPruning	-18.71	1458.28	-0.01	0.99
condition_DeleteTree	1.54	0.04	41.21	0.00
condition_MemoPIRequiresPrune	0.17	0.08	2.18	0.03
condition_Other	1.68	0.06	28.76	0.00
condition_PIClear	-0.57	0.04	-15.69	0.00
condition_PIPendingRemoval	-17.27	113.20	-0.15	0.88
condition_PIRequiresPrune	-0.08	0.04	-2.28	0.02
condition_PIGreenReliabilityPruning				
avgdbh	0.03	0.00	115.90	0.00
curyr_count_ins	0.26	0.01	49.99	0.00
curyr_count_trim	0.42	0.01	61.15	0.00
hist_ins	-0.00	0.00	-0.79	0.43
hist_trim	0.07	0.00	57.68	0.00

Attachment F: Joint IOU Response to Action Statement-Risk Modeling

Joint IOU Response to Action Statement SDGE-21-02 Risk Modeling

Utility #: SDGE-21-02

Issue title: *Lack of consistency in approach to wildfire risk modeling across utilities.*

Issue description: *The utilities do not have a consistent approach to wildfire risk modeling. For example, in their wildfire risk models, utilities use different types of data, use their individual data sets in different ways, and use different third-party vendors. Energy Safety recognizes that the utilities have differing service territory characteristics, differing data availability, and are at different stages in developing their wildfire risk models. However, the utilities face similar enough circumstances that there should be some level of consistency in statewide approaches to wildfire risk modeling.*

Remedies required and alternative timeline if applicable: *The utilities[1] must collaborate through a working group facilitated by Energy Safety[2] to develop a more consistent statewide approach to wildfire risk modeling. After Energy Safety completes its evaluation of all the utilities' 2021 WMP Updates, it will provide additional detail on the specifics of this working group.*

A working group to address wildfire risk modeling will allow for:

1) Collaboration among the utilities;
2) Stakeholder and academic expert input; and
3) Increased transparency.

Response to SDGE-21-02

The utilities have prepared a joint response to this Remedy. This response describes working group activities which have occurred since the utilities submitted their Progress Reports on November 1, 2021.

Energy Safety established an initial schedule of bi-weekly working group meetings, starting October 20, 2021 and running through January 19, 2022, on various risk-modeling related topics such as modeling components, algorithms, data and impacts of other issues on modeling such as climate change and ingress/egress. However, based on input during the Wildfire Risk Modeling Workshop on October 5-6, 2021, as well as the first Working Group Meeting on October 27, 2021, Energy Safety subsequently issued a revised schedule and topics for the Working Group moving forward. A final version of schedule and topics was posted on November 8, 2021, which included comments on the October 5-6, 2021 workshop on November 6, 2021. The current working group schedule is:

Cadence:

- 2021 – Meet every 3 weeks

[1] Here "utilities" refers to San Diego Gas & Electric Company (SDG&E) and PG&E, Southern California Edison Company (SCE), PacifiCorp, Bear Valley Electric Service, Inc. (BVES), and Liberty Utilities; although this may not be the case every time "utilities" is used through the document.

[2] The WSD transitioned to the Office of Energy Infrastructure Safety (Energy Safety) on July 1, 2021.

- 2022 – Meet monthly (except February)

Meetings are scheduled for Wednesday afternoons for a length of three hours.

Topics:

2021	
10/27	Meeting Logistics; modeling baselines, alignment, and past collaboration
11/17	Fire consequence (drivers, meteorology/climatology, environment, and fuels data)
12/8	Likelihood of asset risk events and ignitions (data, inputs, and risk drivers relating to assets, faults/outages/ignitions)

2022	
1/12	Likelihood of vegetation risk events and ignitions (data, inputs, and risk drivers)
3/2	PSPS likelihood (data, inputs, and risk drivers)
4/6	PSPS consequence and reliability analysis and impacts (including potential safety issues, power quality impacts)
5/4	Modeling algorithms, including confidences (machine learning, weather modeling, fire behavior modeling)
6/1	Modeling components, linkages, interdependencies
7/6	Smoke and suppression impacts
8/3	Climate change impacts and ingress/egress
9/7	Finalize risk modeling guidelines

The utilities are collaborating through the working group with Energy Safety and stakeholders and have already dedicated and will continue to dedicate substantial time and resources to the working group. The utilities believe that there will be increased transparency for Energy Safety and stakeholders through the working group process.

On November 17, 2021 and December 8, 2021 meetings were held to discuss “Fire Consequence”, and “Likelihood of asset risk events and ignitions” respectively. Energy Safety provided an agenda before each meeting which listed discussion topics and tentative time allotments. The meetings followed the agenda in a “Question and Answer” discussion format with utility subject matter experts.

On January 11, 2022, Energy Safety postponed the working group session scheduled for January 12, and informed that the working group schedule would pick back up on March 2, 2022 with the topic of “Likelihood of vegetation risk events and ignitions”.

The utilities look forward to future sessions with Energy Safety and stakeholders to promote continued collaboration, incorporate additional expert input, and increase transparency in order to help better realize our shared goal of reducing wildfire and PSPS risks.

Attachment G: Joint IOU Response to Action Statement-RSE

Joint IOU Response to Action Statement SDGE-21-11
Risk Spend Efficiency

Utility #: SDGE-21-11
Issue title: *RSE values vary across utilities.*

Issue description: *Comparatively SCE and SDG&E can, at a base level, verify their calculated RSEs with historical and experimental pilot data. Energy Safety raises a concern that there are stark variances in RSE estimates, sometimes on several orders of magnitude, for the same initiatives calculated by different utilities. For example, PG&E's RSE for covered conductor installation was 4.08,[1] SDG&E's RSE was 76.73,[2] and SCE's RSE was 4,192.[3] These drastic differences reveal that there are significant discrepancies between the utilities' inputs and assumptions, which further support the need for exploration and alignment of these calculations.*

Remedies required and alternative timeline if applicable: *The utilities[4] must collaborate through a working group facilitated by Energy Safety[5] to develop a more standardized approach to the inputs and assumptions used for RSE calculations. After Energy Safety completes its evaluation of the 2021 WMP Updates, it will provide additional detail on the specifics of this working group.*

This working group will focus on addressing the inconsistencies between the utilities' inputs and assumptions, used for their RSE calculations, which will allow for:

1) Collaboration among utilities,
2) Stakeholder and academic expert input, and
3) Increased transparency.

Response to SDGE-21-11
The utilities have prepared a joint response to this Remedy. This response describes working group activities which have occurred since the utilities submitted their Progress Reports on November 1, 2021.

On December 9, 2021, Energy Safety facilitated a public workshop on utility risk spend efficiency (RSE) estimates. Each of the utilities presented the current status of their RSE calculation methodologies, and stakeholders had an opportunity to ask questions of utility representatives as well as RSE experts. RSE experts included Tom Long from The Utility Reform Network (TURN), Fred Hanes, senior utilities engineer from the California Public Utilities Commission (CPUC), and Joseph

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[1] Value from PG&E's Errata (dated March 17, 2021, accessed May 19, 2021: https://www.pge.com/pge_global/common/pdfs/safety/emergency-preparedness/naturaldisaster/wildfires/wildfire-mitigation-plan/2021-Wildfire-Safety-Plan-Errata.pdf.
[2] Value from Table 12 of SDGE's 2021 WMP Update submissions under the "Estimated RSE for HFTD Tier 3" column for "Covered Conductor Installation."
[3] Value from Table 12 of SCE's 2021 WMP Update submissions under the "Estimated RSE for HFTD Tier 3" column for "Covered Conductor Installation."
[4] Here "utilities" refers to PG&E, SDG&E, SCE.
[5] The WSD transitioned to the Energy Safety on July 1, 2021.

Mitchell from Mussey Grade Road Alliance (MGRA). The participants discussed RSE calculation methodology best practices and how RSE estimates inform wildfire risk-based decision-making.

At the conclusion of the workshop, Energy Safety requested that the utilities submit reports providing a detailed description on their RSE calculation methodology. Each utility developed a report on their RSE calculation methodology, RSE estimate verification process, and RSE estimate initiative-selection process. These reports were submitted on December 17, 2021.

The utilities look forward to continuing to work with Energy Safety and other stakeholders in pursuit of utility collaboration, expert input, and increased transparency on RSE assumptions, inputs, and calculations.

Attachment H: Joint IOU Response to Action Statement-Covered Conductor

2022 WMP Update Progress Report

Effectiveness of Covered Conductor

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Issue

The rationale to support the selection of covered conductor as a preferred initiative to mitigate wildfire risk lacks consistency among the utilities, leading some utilities to potentially expedite covered conductor deployment without first demonstrating a full understanding of its long-term risk reduction and cost-effectiveness. The utilities' current covered conductor pilot efforts are limited in scope[1] and therefore fail to provide a full basis for understanding how covered conductor will perform in the field. Additionally, utilities justify covered conductor installation by alluding to reduced PSPS risk but fail to provide adequate comparison to other initiatives' ability to reduce PSPS risk.

Remedies

The utilities[2] must coordinate to develop a consistent approach to evaluating the long-term risk reduction and cost-effectiveness of covered conductor deployment, including: 1. The effectiveness of covered conductor in the field in comparison to alternative initiatives. 2. How covered conductor installation compares to other initiatives in its potential to reduce PSPS risk.

[1] Limited in terms of mileage installed, time elapsed since initial installation, or both. For example, SDG&E's pilot consisted of installing 1.9 miles of covered conductor, which has only been in place for one year.

[2] Here "utilities" refers to SDG&E and PG&E, SCE, PacifiCorp, BVES, and Liberty; although this may not be the case every time "utilities" is used throughout this progress report.

Response

The utilities have prepared a joint response to this Issue/Remedy.

Introduction

In the November 2021 Progress Report, the utilities outlined the approach, assumptions, and preliminary milestones to enable the utilities' to better discern the long-term risk reduction effectiveness of covered conductor to reduce the probability of ignition, assess its effectiveness compared to alternative initiatives, and assess its potential to reduce PSPS risk in comparison to other initiatives. In this report for the 2022 WMP Update, the utilities provide an update on their progress for each of the sub-workstreams, added efforts, and plans for 2022.

Overview

As explained in the November 2021 Progress Report, the utilities believe that long-term effectiveness of covered conductor and its ability to reduce wildfire risk and PSPS impacts (and, in comparison to alternatives) requires multiple sets of information that need to be compiled, assessed, and updated over time. Since the November 2021 Progress Report, the utilities have made progress on each of the following sub-workstreams:

- Benchmarking
- Testing / Studies
- Estimated Effectiveness
- Additional Recorded Effectiveness
- Alternative comparison
- Potential to Reduce PSPS risk
- Costs

The utilities have also initiated discussions with the Institute of Electrical and Electronics Engineers (IEEE) Distribution Reliability Working Group (DRWG) to establish a peer-review process for estimating/measuring the effectiveness of covered conductor. The utilities have obtained additional information from benchmarking, the Phase 1 Testing Report, initial subject matter expert (SME) assessments of effectiveness of alternatives compared to covered conductor, an initial unit cost comparison, and have collected the utilities' estimated and recorded methods and results of covered conductor effectiveness. Each of these efforts are described further below. The information and assessments continue to indicate covered conductor effectiveness between approximately 60 to 90 percent in reducing the drivers of wildfire risk, consistent with past benchmarking, testing and utility estimates. The utilities plan to continue each sub-workstream in 2022 to obtain new test data, conduct further benchmarking, improve methods for estimating and measuring effectiveness, and further the alternative assessments and unit cost comparisons. Below, the utilities describe the progress made on each sub-workstream and steps planned to continue this effort in 2022.

Background

Covered conductor is a widely accepted term to distinguish from bare conductor. The term indicates that the installed system utilizes conductor manufactured with an internal semiconducting layer and external insulating UV resistant layers 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 utilities in the world use the terms "covered conductor," "insulated conductor," or "coated conductor" interchangeably. Covered conductor is a generic name for many sub-categories of conductor design and field construction arrangement. In the U.S., a few types of covered conductor are as follows:

- Tree wire
    - Term was widely used in the U.S. in 1970s
    - Associated with a simple one-layer insulated design
    - Used to indicate cross-arm construction
- Spacer cable
    - Associated with construction using trapezoidal insulated spacers and a high strength messenger line for suspending covered conductor
- Aerial bundled cable (ABC)
    - Tightly bundled insulated conductor, usually with a bare neutral conductor

The current type of covered conductor being installed in each of the utilities' service areas is an extruded multi-layer design of protective high-density or cross-linked polyethylene material. In this report, "covered conductor" refers generally to a system installed on cross-arms, in a spacer cable configuration, or as ABC. Table 1, below, provides a snapshot of the approximate amount and types of covered conductor installed in the utilities' service areas.

Table 1: Covered Conductor Type and Approximate Circuit Miles Deployed by Utility

Utility	First covered conductor installation (year)	Type of covered conductor installed	Approx. miles of covered conductor deployed through 2021	Notes
SCE	2018 Installed Historically Installed Historically	Covered Conductor Tree Wire ABC	2,900 50 64	Includes WCCP and Non-WCCP
PG&E	CC end of 2017, beginning of 2018 TW installed historically	Covered Conductor ABC	883 3	Primary distribution overhead only
SDG&E	2020	Covered Conductor Tree Wire Spacer Cable	22 2 6	
Liberty	2019	Covered Conductor Spacer Cable	9 2	
Pacificorp	2007	Spacer Cable	53	
Bear Valley	2018	Covered Conductor	20	

Workstream Scope

The overall focus is on the long-term effectiveness of covered conductor to reduce wildfire risk and PSPS impacts in comparison to alternatives. The outcome of this workstream is not to determine the scope of covered conductor nor is this effort intended to compare system hardening decisions that utilities have made and will make. Instead, the outcome of this effort is intended to produce (and update over time) a consistent understanding of the effectiveness of covered conductor, in comparison with alternatives to mitigate wildfire risk at the driver level and to reduce PSPS impacts. Utilities can then use these improved sets of information in their decision making. As part of this effort, the utilities anticipate there will likely be lessons the utilities can learn from one another such as construction methods, engineering/planning, execution tactics, etc. that can help improve each utilities' deployment of covered conductor but this is not the focus of this workstream. Additionally, and as further described below, the costs of covered conductor deployment differ based on numerous factors including, for example, the utilities' covered conductor system design, types and amounts of structure/equipment replacements, topography, scale of deployment, resource availability and other operational constraints. This effort is not intended to compare nor contrast costs across all different variations and instead presents an initial high-level covered conductor capital cost per circuit mile comparison with descriptions of the factors that lead to higher or lower costs.

Benchmarking

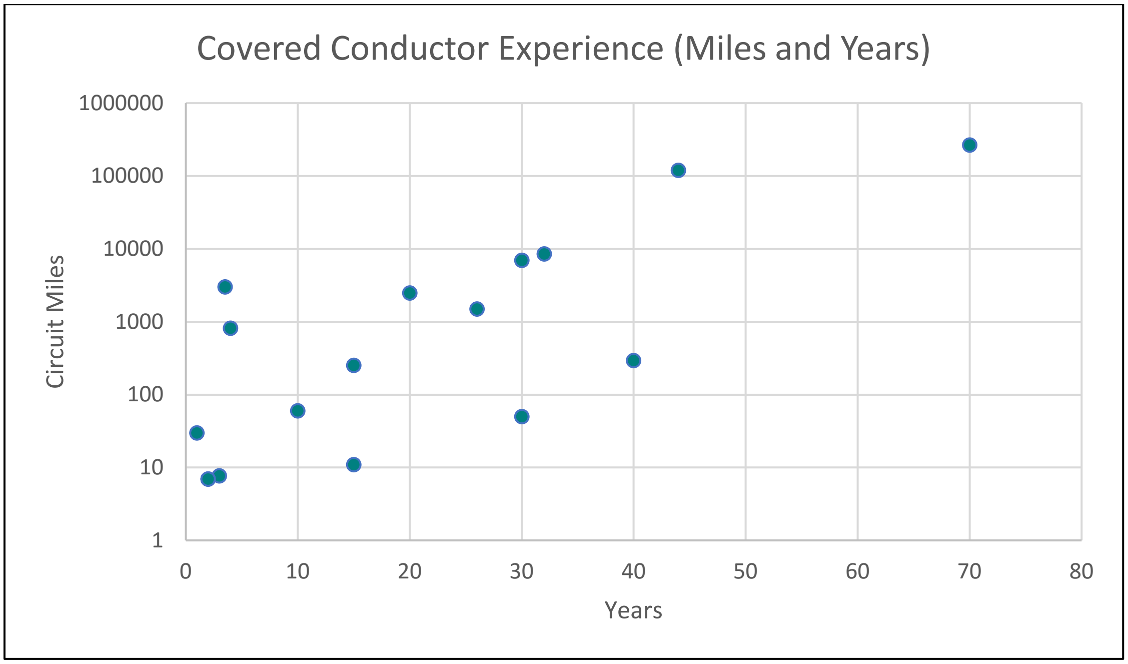
Each of the utilities' covered conductor programs have been informed by benchmarking. Benchmarking is a useful process to obtain insights, lessons learned, and continually improve performance. SCE, for example, previously researched covered conductor use in the U.S., Europe, Asia, and Australia. SCE benchmarked directly with 13 utilities abroad and in the U.S. and surveyed 36 utilities on covered conductor usage.[3] These efforts helped inform SCE's Wildfire Covered Conductor Program (WCCP). The utilities, as part of this joint working group, have conducted additional benchmarking. First, the utilities developed a survey consisting of 24 questions that focused on covered conductor usage, performance metrics, conductor applications, and system protection. The survey was then sent to approximately 150 to 200 utilities in the U.S. and abroad. To date, 19 utilities participated in the benchmarking survey[4] and are listed below.

1. American Electric Power
2. Ausnet Services
3. Bear Valley Electric Service, Inc.
4. Duke Energy
5. Essential Energy
6. Eversource Energy (CT)
7. Korean Electric Power Corporation
8. Liberty
9. National Grid
10. Pacific Gas and Electric Company
11. PacifiCorp
12. Portland General
13. Powercor
14. Puget Sound Energy
15. San Diego Gas & Electric
16. Southern California Edison
17. TasNetworks
18. Tokyo Electric Power Company
19. Xcel Energy

[3] See SCE's Covered Conductor Compendium that was included in the November 1, 2021 Progress Report.
[4] See Covered Conductor Survey Results in Appendix A.

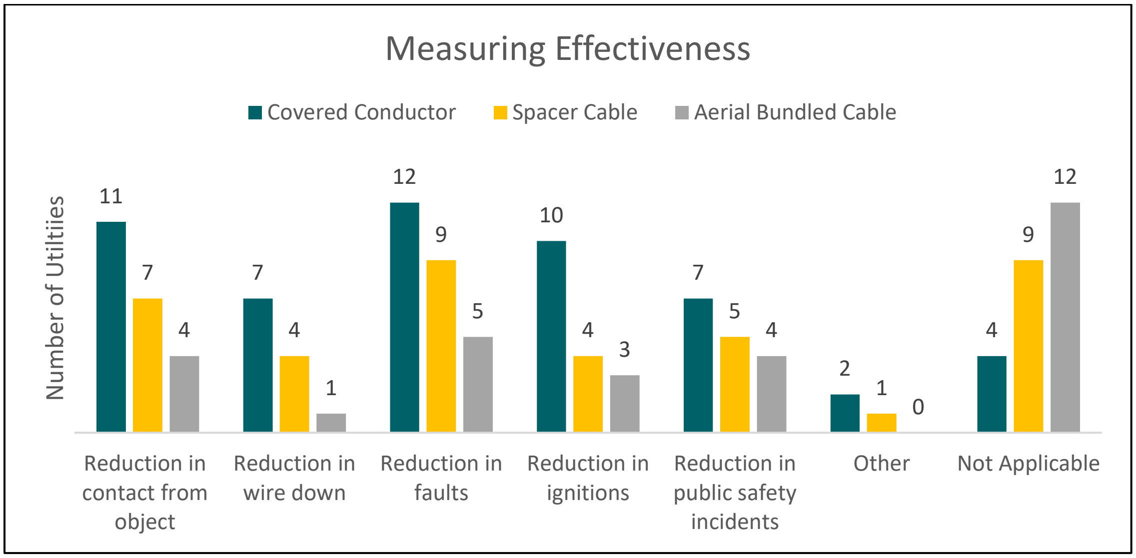
Approximately 90% of participants indicated the usage of bare conductor and covered conductor in their distribution systems. Respondents using spacer cable and aerial bundled cable were at 58% and 47%, respectively. Note that while covered conductor designs varied among the utilities, the majority (63%) of utilities use the three-layer jacket design. There was also a wide range of experience among respondents in terms of the number of years and miles installed, as shown in Figure 1.

Figure 1: Covered Conductor (Open-crossarm and Spacer) Experience Among Respondents



Drivers for covered conductor deployment can vary by utility. Typical drivers include wildfire mitigation, reliability improvements, or reduction in public safety risk for contact with downed conductors. The utilities' performance metrics will differ depending on their associated drivers. The majority of utilities base the covered conductor's effectiveness in its ability to reduce faults and ignitions from contact-from-objects (CFO). These metrics are related to reliability and wildfire mitigation. Some utilities also measure the reduction in wire downs and public safety incidents to measure the covered conductor's effectiveness, which can be connected to public safety risk or ignition drivers. Figure 2 illustrates the number of utilities using each metric to monitor the effectiveness of covered conductor, spacer cable, and aerial bundled cable.

Figure 2: Covered Conductor Performance Metrics In Use by Utilities



While most utilities do not differentiate outages or ignitions between bare conductor and covered conductor, 84% of respondents reported that the use of covered conductor has reduced faults. Furthermore, 53% of respondents reported that covered conductor has reduced ignitions or ignition drivers. The remaining 47% of utilities do not track ignition data, had no prior ignitions, or do not have covered conductor in their system.

Approximately 80% of utilities reported undergrounding as an alternative to covered conductor. About 40% of utilities consider spacer cable while approximately 25% consider aerial bundled cable as alternatives to covered conductor. Typically, spacer cable is utilized in heavily-forested areas or areas with clearance concerns. Aerial bundled cable is normally indicated as used in heavily forested areas. Only 5% of utilities indicated the use of other alternatives, such as line removal/relocation, animal guard, fast isolation device, remote grid, customer buyout, and vegetation management.

In terms of fault detection, most utilities utilize traditional overcurrent protection. The same protection system that is used for bare conductors. Other existing fault detection methodologies include SCADA connected devices, smart meters, and high impedance fault detection. Utilities are also exploring a multitude of different technologies, including early fault detection (EFD), distribution fault anticipation (DFA), open phase detection (OPD), sensitive ground fault, rapid earth fault current limiter (REFCL), downed conductor detection, etc.

Overall, the benchmarking survey provides a high-level overview of each utilities' covered conductor deployment and performance metrics. In 2022, the California Investor-Owned Utilities (IOUs) plan to conduct further deep dives with some respondents to gain a greater understanding of their covered conductor effectiveness, recorded data and methods they use to measure effectiveness, alternatives and new technology that have been evaluated, and their system hardening decision-making processes. The utilities will provide an update on these efforts in their 2023-2025 WMPs.

Testing

Testing workstream objectives are to evaluate, through physical testing, the performance of covered conductors as compared to bare conductors for historically documented failure modes. As an example, testing covered conductor performance in preventing incidental contacts that cause phase-to-phase and phase-to-ground faults caused by vegetation, conductor slapping, wildlife, and metallic balloons.[5] To meet this objective, PG&E, SDG&E, and SCE collaborated on conducting additional research and testing of covered conductor. This effort, now joined by PacifiCorp, BVES and Liberty, has two phases. The first phase, which is now complete, had objectives to identify failure modes for covered conductors, document a utilities' consensus Failure Modes and Effects Analysis (FMEA) for covered conductors, and to collect all previously conducted testing on covered conductor performance that informs on the performance of covered conductor for identified failure modes. Lastly, to perform comparison between covered versus bare conductor performance for failure modes tested. PG&E contracted with Exponent, Inc. (Exponent) to develop a report for Phase 1, which was completed in December 2021, summarized below, and attached as Appendix B to this update. The Phase 1 study was led by Exponent and consisted of a literature review, discussions with SMEs, a failure mode identification workshop, and a gap analysis comparing expected failure modes to currently available test and field data. The outcome of the Phase 1 report identified gaps in previous testing and is informing the scope of laboratory testing that is currently being planned for in the ongoing Phase 2 step of this sub-workstream. As discussed below, SCE, PG&E, and SDG&E are proceeding with testing.

The literature review shows that covered conductors are a mature technology (in use since the 1970s) and have the potential to mitigate several safety, reliability, and wildfire risks inherent to bare conductors. This is due to the reduced vulnerability to arcing/faults afforded by the multi-layered polymeric insulating sheath material. Field experience from around the world, including North America, South America, Europe, Asia, and Australia, consistently shows improvements in reliability, decreases in public safety incidents, and decreases in wildfire-related events that correlate with increased conversion to covered conductor. The Phase 1 report includes data from several utilities that show a reduction of faults, increased reliability, and/or improvements in public safety metrics since the utilities began implementing covered conductor.

While high-level, field-experience-based evidence of covered conductor effectiveness is plentiful, relatively few lab-based studies exist that address specific failure modes or quantify risk reduction relative to bare conductors. A high-level failure mode identification workshop was conducted to identify operative failure modes relevant to overhead distribution systems for both bare and covered conductors. The workshop included SMEs from the six California IOUs and Exponent and identified hazards and failure modes applicable to bare and covered conductors. In total, 10 hazards and 55 unique failure mode / hazard scenario combinations were identified through the failure mode workshop. Of the 10 hazards that affect bare conductors, covered conductors have the potential to mitigate six hazards. Mitigated hazards include tree/vegetation contact, wind-induced contact (such as conductor slapping), third-party damage, animal-related damage, public/worker impact, and moisture. The report includes a risk reduction assessment of the failure modes that affect both bare and covered conductors. The report also summarizes failure modes mitigated by covered conductor. A total of 17 failure modes largely mitigated through the use of covered conductor were identified through the workshop exercise. The common theme among these failure modes is that they are created through contact with third-party objects, vegetation, or other conductors that create phase-to-ground or phase-to-phase faults. The primary failure mode of bare conductors is arcing due to external contact. Laboratory studies and field experience have shown that arcing due to external contact was largely mitigated with covered conductors. Therefore, a corresponding reduction in ignition potential would be expected. The report also summarizes failure modes unique to covered conductor. Several covered-conductor-specific failure modes exist that require operators to consider additional personnel training,

[5] See SCE's Covered Conductor Compendium that was included in the November 1, 2021 Progress Report.

augmented installation practices, and adoption of new mitigation strategies (e.g., additional lightning arrestors, conductor washing programs, etc.). For some failure modes, the report recommends further testing to bolster industry knowledge and to enable more effective risk assessment.

SCE, PG&E and SDG&E are pursuing testing based on the results of the Phase 1 report and SME input. SCE established a test plan for both 17 kV[6] and 35 kV covered conductor designs and expects to conduct approximately 35 testing scenarios that cover various contact-from-object, system strength, flammability, and water ingress scenarios. PG&E is in process of developing a complementary test plan to ensure coverage of failure modes and additional covered conductor types that may not be included in the SCE test plan. SDG&E is assessing conducting, for example, environmental, service life, UV exposure, degradation and mechanical strength tests. The utilities are collaborating on the testing plans to ensure the gaps identified in the Phase 1 report are covered and SME input is considered.[7] SCE began testing on February 1 , 2022 and anticipates its testing and review process to extend for several months. SDG&E and PG&E timelines have not been finalized but are anticipating testing to start around Q2 to Q3 2022. The utilities will collaboratively review and assess the results of the tests. After the test results are reviewed and any issues are addressed (e.g., additional tests), the utilities will prepare a report (or reports in phases as testing is completed) and make the report(s) available. The test results are anticipated to further inform effectiveness of covered conductor and potentially identify any needed changes in design and construction standards to ensure failure modes are further limited by the use of covered conductor. Beyond the testing process, in 2022, the utilities will continue to collaborate on methods to quantify risk reduction of covered conductor relative to bare conductors taking into account the testing results and will establish any next steps for this sub-workstream based on the results of the testing. The utilities will provide an update on these efforts in their 2023-2025 WMPs.

Estimated Effectiveness

Each utility's covered conductor programs are different due to factors such as location, terrain, and existing overhead facilities. Similarly, the utilities are at different phases of installing covered conductor as some have just started deployment while others have deployed hundreds to thousands of miles of covered conductor. These features, amongst others, result in data, calculations, and methods of estimating effectiveness that are different. As such, the utilities have been working on understanding differences and discussing methods for better comparability. While the utilities may differ in their covered conductor approach, the utilities each estimate that covered conductor will reduce wildfire risk. The utilities' estimated covered conductor effectiveness values range from approximately 60 to 90 percent at reducing outages/ignitions and/or the drivers of wildfire risk. Below, the utilities describe their data, analyses, and methods used to estimate the effectiveness of covered conductor to mitigate outages/ignitions and/or the drivers of wildfire risk and present their estimated effectiveness values. Collectively, the utilities summarize next steps to improve consistency of data, calculations and methods.

Covered Conductor Estimated Effectiveness

SCE

SCE's WCCP consists of replacing bare conductor with covered conductor, the installation fire-resistant poles (FRPs) where applicable, wildlife covers (animal safe construction), lighting arresters, and vibration

[6] SCE's 17 kV covered conductor design is the same as other utilities' 15 kV design. Through testing, SCE determined that the 15 kV design can withstand voltages below 17 kV so has named this covered conductor design 17 kV for operational purposes.
[7] SCE, PG&E, and SDG&E are also collaborating on potential cost sharing.

dampers below 3,000 feet. These activities are accounted for when determining the overall mitigation effectiveness of SCE's WCCP. To determine the mitigation effectiveness of WCCP, SCE evaluated the ability for covered conductor and FRPs to address each ignition risk driver. SME judgment was used to determine the mitigation effectiveness of covered conductor; this judgment was informed by benchmarking, analysis, and testing. The following tables explain the reasoning behind the effectiveness values. Table 2, includes only the covered conductor values and not the combined covered conductor and FRP values used in SCE's risk reduction calculation. Table 3 includes only the FRP mitigation effectiveness values. Additionally, mitigation effectiveness values at 0% or that were not applicable were omitted from both tables.

Table 2: SCE Covered Conductor Mitigation Effectiveness Estimate

Driver		Mitigation Effectiveness	Reasoning
D-CFO	Vegetation contact-Distribution	60%	SCE conducted analysis that involved establishing four vegetation sub-drivers based on SCE's experience with vegetation contact. The four sub-drivers are: Heavy Contact (Tree), Heavy Contact (Limb), Light Contact (Frond/Branch), Light Contact (Grow In). SCE analyzed historical vegetation fault data from 2015-2018 and determined that percentage of occurrence between all four sub-drivers. • Heavy Contact (Tree): 30% • Heavy Contact (Limb): 22% • Light Contact (Frond/Branch): 43% • Light Contact (Grow In): 5% SCE testing supported that covered conductor will be 99% effective against both Light Contact drivers, which accounts for 1% of the line potentially being uninsulated at connection points or dead-ends. Additionally, SCE also determined that covered conductor will not be effective against Heavy Contact (Tree) due to being unable to mechanically support the weight of a tree. Covered conductor was determined to be 50% effective against limb contact, conservatively assuming that the limb will exceed the conductor's strength 50% of the time. The overall mitigation effectiveness value for vegetation is based on the weighted average of all four sub-driver and was calculated to be 60%.
D-CFO	Animal contact-Distribution	65%	SCE conducted analysis that involved establishing animal contact sub-drivers in terms of equipment affected. These Animal Contact sub-drivers include Conductor/Wire, Fuse/BLF/Cutout, Terminations,

Driver		Mitigation Effectiveness	Reasoning
			Transformer, etc. The percent of animal contact faults were calculated per sub-driver using 2015-2020 data. Next, SCE used SME knowledge to establish the percent of wildlife covers existing in the system for the applicable sub-driver. Lastly, SCE assigned a preliminary mitigation effectiveness based on SME judgement per sub-driver. Covered conductor is considered 100% effective for Conductor/Wire Animal contact based on testing. Other equipment with associated wildlife covers were assigned a 90% effectiveness to account for the wildlife cover installation required during WCCP. The preliminary mitigation effectiveness was multiplied by the percent of wildlife covers not existing in the system to adjust for the possibility that pre-WCCP structures already have wildlife covers. The weighted average of this adjusted mitigation effectiveness was calculated to be 65%.
D-CFO	Balloon contact-Distribution	99%	Covered conductor is estimated to be 99% effective against contact with metallic balloons. This is supported by testing and accounts for approximately 1% of the line potentially being uninsulated at connection points or dead-ends.
D-CFO	Vehicle contact-Distribution	50%	SCE analyzed the composition of historical wire downs from vehicle collisions and found that nearly all ignitions from a vehicle collision are caused by conductor contact. SCE testing established the covered conductor is effective against conductor-to-conductor contact. However, there is uncertainty regarding the effectiveness of covered conductor during a wire down due to exposed conductor at the dead-end or break-point. To account for this uncertainty, a mitigation effectiveness of 50% was assumed.
D-CFO	Other contact-from-object - Distribution	77%	Analysis found that foreign material accounts for 77% of the “Unspecified” driver, while Ice/Snow accounts for the other 23%. While covered conductor is effective against foreign materials, it is not effective against ice/snow.
D-CFO	Connection device damage or failure - Distribution	90%	Assumption that infrastructure replacement will lead to 90% mitigation effectiveness. Reconductoring with covered conductor will facilitate the replacement of aged hardware. Some hardware used in new installation will also be improved technology.
D-CFO	Unknown contact - Distribution	77%	Weighted average of vegetation contact, animal contact, balloon contact, and other contact.

Driver		Mitigation Effectiveness	Reasoning
D-EFF[8]	Splice damage or failure — Distribution	90%	Assumption that infrastructure replacement will lead to 90% mitigation effectiveness. Reconductoring with covered conductor will facilitate the replacement of aged hardware. Some hardware used in new installation will also be improved technology.
D-EFF	Crossarm damage or failure - Distribution	50%	Covered conductor is estimated to be 50% effective against crossarm failure. Reconductoring with covered conductor will facilitate the replacement of aged crossarms. Additionally, testing illustrated that covered conductor significantly reduced leakage current on the crossarm, reducing the occurrence of damage due to electrical tracking.
D-EFF	Insulator damage or failure- Distribution	90%	Assumption that infrastructure replacement will lead to 90% mitigation effectiveness. Reconductoring with covered conductor will facilitate the replacement of aged insulators.
D-EFF	Wire-to-wire contact / contamination- Distribution	99%	Covered conductor is estimated to be 99% effective against wire-to-wire contact. This is supported by testing and accounts for approximately 1% of the line potentially being uninsulated at connection points or dead-ends.
D-EFF	Conductor damage or failure — Distribution	90%	Assumption that infrastructure replacement will lead to 90% mitigation effectiveness. Reconductoring with covered conductor will facilitate the replacement of aged conductor. Additionally, conductor failure due to faults will also be reduced because: (1) covered conductor will prevent contact-from-object faults from occurring and (2) the covered conductor will have a larger short circuit duty.
D-EFF	Insulator and brushing damage or failure - Distribution	90%	Assumption that infrastructure replacement will lead to 90% mitigation effectiveness. Reconductoring with covered conductor will facilitate the replacement of aged insulators.

Table 3: SCE Fire Resistant Pole Mitigation Effectiveness

Driver		Mitigation Effectiveness	Reasoning
D-EFF	Crossarm damage or failure - Distribution	50%	Replacing existing poles with FRPs will facilitate the replacement of aged wood crossarms with composite crossarms. Additionally, fire-resistant composite poles significantly reduce leakage

[8] EFF represents Equipment / Facility Failure

Driver		Mitigation Effectiveness	Reasoning
			current on the crossarm, reducing the occurrence of damage due to electrical tracking. The improved crossarm design and reduction of leakage current accounts for the 50% effectiveness against crossarm damage or failure.
D-EFF	Conductor damage or failure — Distribution	5%	Replacing poles with FRPs will facilitate the replacement of aged equipment.
D-EFF	Fuse damage or failure - Distribution	5%	Replacing poles with FRPs will facilitate the replacement of aged equipment. The new fuses used will be improved technology.
D-EFF	Switch damage or failure- Distribution	5%	Replacing poles with FRPs will facilitate the replacement of aged equipment. The new switches may be improved technology.
D-EFF	Insulator and bushing damage or failure - Distribution	50%	Replacing poles with FRPs will facilitate the replacement of aged equipment.
D-EFF	Transformer damage or failure - Distribution	50%	Replacing poles with FRPs will facilitate the replacement of aged equipment.

PG&E

PG&E's covered conductor program consists of primary and secondary conductor replacement with covered conductor along with pole replacements, replacement of non-exempt equipment, replacement of overhead distribution line transformers with transformers with FR3 insulating fluid, framing and animal protection upgrades, and vegetation clearing which makes up the entire Overhead Hardening program. PG&E understands the focus of this issue to be centered on covered conductor, however, PG&E's efforts to estimate effectiveness extend to include all elements of its Overhead Hardening program as PG&E considers this approach more complete.

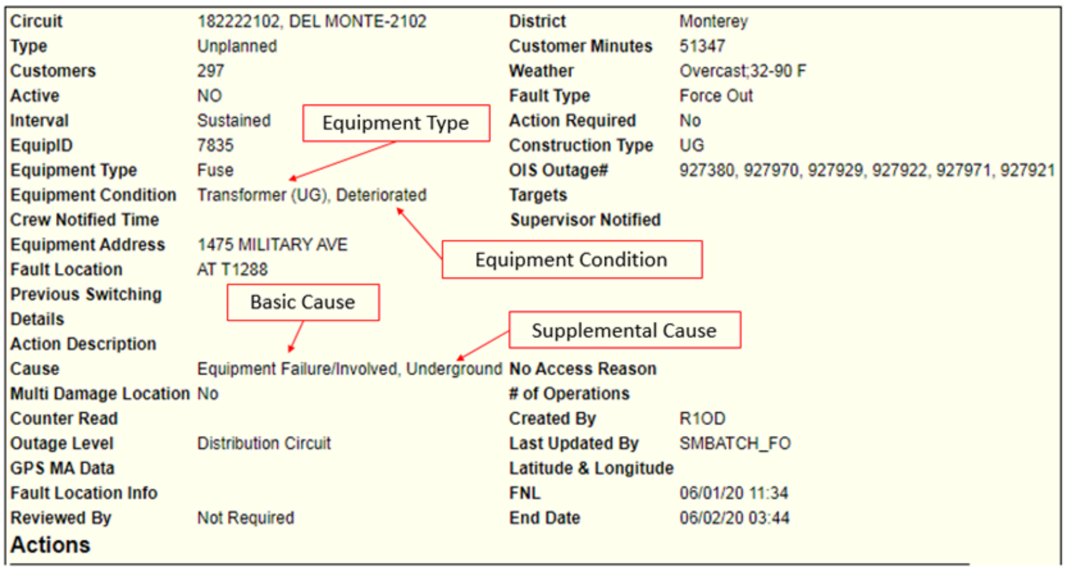
Determining whether a specific event could result in an ignition depends upon a wide variety of factors, including the nature of the event itself and prevailing environmental conditions (e.g., weather, ground moisture level, time of year). As PG&E does not have complete information to make this determination for each event, estimating overhead hardening effectiveness relies upon the following proxy, outlined below, to derive its estimates. Most distribution outages (momentary and sustained) typically involve a fault condition. Thus, for purposes of estimating overhead hardening effectiveness, it is assumed that all distribution outages could potentially result in an ignition, regardless of other prevailing conditions. This approach aligns with what has been previously stated in PG&E's 2020 WMP as well as its 2020 RAMP filing.

With the above assumption, PG&E took the following approach to estimate a general effectiveness factor for overhead hardening:

1. SMEs identified 4,336 distinct outages by using all known combinations of basic cause, supplemental cause, equipment type and equipment condition from the distribution outage database as show in Figure 3 below. Whenever an outage is reported, an operator fills in different fields that provide information about the outage, through SME evaluation, it was

decided that the combination of the four fields aforementioned provide an appropriate distinction of different outage types.

Figure 3: PG&E Distribution Outage Database Record



Circuit	182222102, DEL MONTE-2102	District	Monterey
Type	Unplanned	Customer Minutes	51347
Customers	297	Weather	Overcast;32-90 F
Active	NO	Fault Type	Force Out
Interval	Sustained	Action Required	No
EquipID	7835	Construction Type	UG
Equipment Type	Fuse	OIS Outage#	927380, 927970, 927929, 927922, 927971, 927921
Equipment Condition	Transformer (UG), Deteriorated	Targets	
Crew Notified Time		Supervisor Notified	
Equipment Address	1475 MILITARY AVE		
Fault Location	AT T1288		
Previous Switching Details			
Action Description			
Cause	Equipment Failure/Involved, Underground	No Access Reason	
Multi Damage Location	No	# of Operations	
Counter Read		Created By	R1OD
Outage Level	Distribution Circuit	Last Updated By	SMBATCH_FO
GPS MA Data		Latitude & Longitude	
Fault Location Info		FNL	06/01/20 11:34
Reviewed By	Not Required	End Date	06/02/20 03:44

Actions

2. SMEs identified whether overhead hardening would eliminate, reduce significantly, reduce moderately, reduce minimally, or will not have an effect on the likelihood of a certain type of outage occurring leading to an ignition when an asset has been hardened. From this classification the following qualitative categorization was performed:
    - All = Eliminates likelihood of a certain type of outage occurring resulting in an ignition
    - High = Reduces likelihood significantly of a certain type of outage occurring resulting in an ignition
    - Medium = Reduces likelihood moderately of a certain type of outage occurring resulting in an ignition
    - Low = Reduces likelihood minimally of a certain type of outage occurring resulting in an ignition
    - None = Will not have an effect on likelihood of a certain type of outage occurring resulting in an ignition
3. Each of qualitative categories were assigned a quantitative value, which measured the likelihood of outage reduction:
    - All = 90%
    - High = 70%
    - Medium = 40%
    - Low = 20%

- None = 0%

4. The above criteria were applied to historical outages, this resulted in likelihood of outage reduction for each outage.
5. Outages were classified by drivers, the outage drivers identified are: Animal, D-Line Equipment Failure, Human Performance, Natural Hazard, Other, Other PG&E Assets or Processes, Physical Threat, RIM, Third Party, Vegetation. The Wildfire Mitigation driver is excluded as this captures all PSPS triggered outages.
6. The final step in preparing the data was to add meteorology data that provides historical wind events times during the analyzed period 2015-2019, as well as weather signal data to allow for further analysis with meteorology experts.
7. A Pivot table is then created to aggregate Outages in HFTD that occurred during acute wind events days, this is understood to be the time where the equipment would be most stressed by the environment as well as the area where Overhead Hardening is being conducted. The aggregation is done at the outage driver level

The results from the analysis detailed in the steps above are interpreted as Overhead Hardening having an effectiveness of approximately 63% for sections where Overhead Hardening has been completed. Therefore, a section of a line that has been hardened is approximately 63% less likely to have an outage of any type. Similarly, a section of a line that has been hardened is approximately 63% less likely to have an outage of each of the drivers. Table 4 provides a summary of the results from the analysis.

Table 4: PG&E Covered Conductor Mitigation Effectiveness Estimate

Driver	Count of Incident ID	Average of Overhead Hardening Effectiveness Percentage
Animal	36	76%
D-Line Equipment Failure	179	71%
Human Performance	3	0%
Natural Hazard	285	35%
Other	256	90%
Other PG&E Assets or Processes	15	47%
Third Party	20	62%
Vegetation	204	63%
Grand Total	**998**	**63%**

SDG&E

SDG&E initially began to examine covered conductor from a personnel safety and reliability standpoint. The three-layered construction showed prospective reduction of injuries to people in the event of an energized wire-down in which the wire contacted a person and/or also might reduce the step potential to people in the vicinity. Outages that result from light momentary contacts (e.g., mylar balloons, birds, and palm fronds) also have shown the potential to be reduced. In late 2018, focus was shifted towards using covered conductor as an alternative to SDG&E's traditional overhead hardening program with the primary focus of reducing utility-caused ignitions.

SME's conducted research on the history and use of covered conductor in the industry. Additionally, the SMEs reached out to utilities on the East Coast and internationally to receive their feedback of the effectiveness and work methods for installation purposes.

In addition to other studies/tests that have been and will be performed by SCE and PG&E, as described in the Testing section, SDG&E will have a third party evaluate the likelihood and effect specific to conductors clashing at various wind speeds. Accelerated aging studies will also be performed to mimic a 40-year service life; after which, the samples will be subjected to tests designed to understand the potential for both mechanical degradation, as well as a reduction in the dielectric strength of the covering. These tests will be performed in accordance with ASTM or other industry recognized standards.

In order to quantify the risk reduction of wildfires that would be achieved by covered conductor, SDG&E evaluated 80 events that resulted in ignitions. SMEs weighed in on the likelihood that covered conductor installation would prevent an ignition for the particular type of outage depending on the severity of the incident. As seen in Table 5, the result is a reduction in ignitions from 80 to 28.4, and a resulting effectiveness estimate of 64.5%.

Table 5: SDG&E Covered Conductor Mitigation Effectiveness Estimate

Fault/Ignition Cause	Number of Ignitions	SME Effectiveness	Post-Mitigation Ignitions
Animal contact	5	90%	0.5
Balloon contact	8	90%	0.8
Vegetation contact	10	90%	1.0
Vehicle contact	14	20%	11.2
Other contact	4	10%	3.6
Other	2	10%	1.8
Equipment - All	34	80%	6.8
Unknown	3	10%	2.7

Fault/Ignition Cause	Number of Ignitions	SME Effectiveness	Post-Mitigation Ignitions
Total	**80**	**64.5%**	**28.4**

PacifiCorp

PacifiCorp has some experience with installing a spacer cable system, which primarily includes covered conductor, a structural member (messenger), and specialized attachment brackets. The company pursued this design due to historical experience with elevated outage count from trees, limbs, and incidental contact (resulting in grow in) throughout its service territory. Additionally, access conditions on some of its circuits are extremely difficult in certain times of the year, and those circuits also tend to have elevated outage rates. For the above-mentioned reasons, when siting its spacer cable pilot projects, PacifiCorp tended to focus its deployment on circuit-segments that had above average vegetation and/or animal outage rates in conjunction with difficult access.

Spacer cable systems employ an engineered weak-link system where covered conductors are in a spaced bundle configuration. The bundle is supported by a high-strength tensioned cable which has shown to be able to support the cables even when the system is under extreme stress.[9] This system is secured to poles primarily with fixed or flex tangent brackets, in which the messenger is the only connected conductor. The covered conductors are not tensioned (nor are they structural members) and instead are held together with spacers attached to a tensioned messenger and placed approximately 30-feet apart. PacifiCorp's spacer cable systems are currently installed using components rated at or above 35 kV, where the only deviation is in the covered conductor itself, whereas it uses two voltage classes; 15 kV for energized voltages of 12.47 kV and below and 35 kV for energized voltages of 20.8 kV to 34.5 kV.

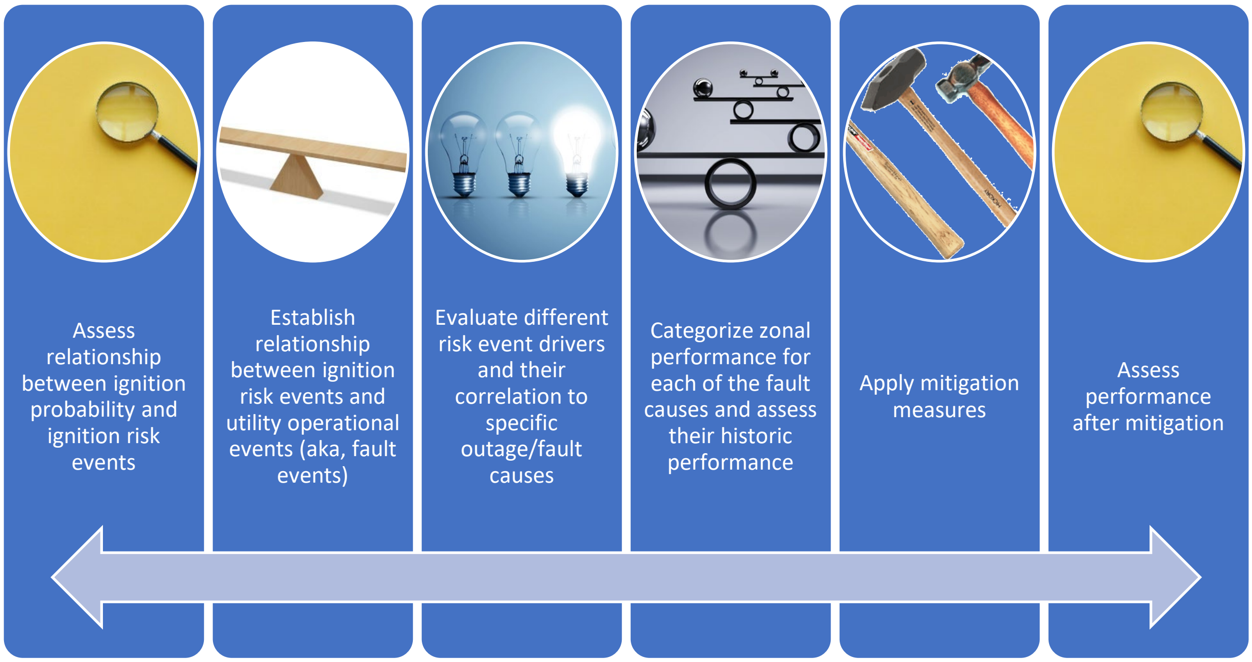
Originally contemplated as a reliability improvement tool, PacifiCorp has now moved to leveraging spacer cable as a wildfire mitigation tool; a natural progression given the similarities in risk drivers such as contract-from-object or damage from vegetation. In their original installations, reliability improvement was the driver, but because of the newness of the technology it was trialed in several different environments with differing installation approaches; the first was focused on contact-from-object/animals and subsequently two of them were focused on contact-from-object/vegetation, one in a coastal environment and another in a mountainous environment, which was followed by projects heavily targeting mitigation of contact-from-object as well as blow-in (and other incidental vegetation); the projects formed the basis for targeting covered conductor (specifically spacer cable) as a mitigation measure for ignition risk drivers.

PacifiCorp's process for evaluating ignition risk drivers, mitigation measures and effectiveness of measures (in order to long term calculate risk spend efficiency) is detailed below.

The company prepared a mapping exercise to evaluate which risks could be addressed with what alternatives, recognizing that covered conductor and a variety of other measures might all be valid approaches. As a starting point, the company evaluated its outage data to align against risk event drivers and correlating against mitigation alternatives. This process is shown graphically in Figure 4.

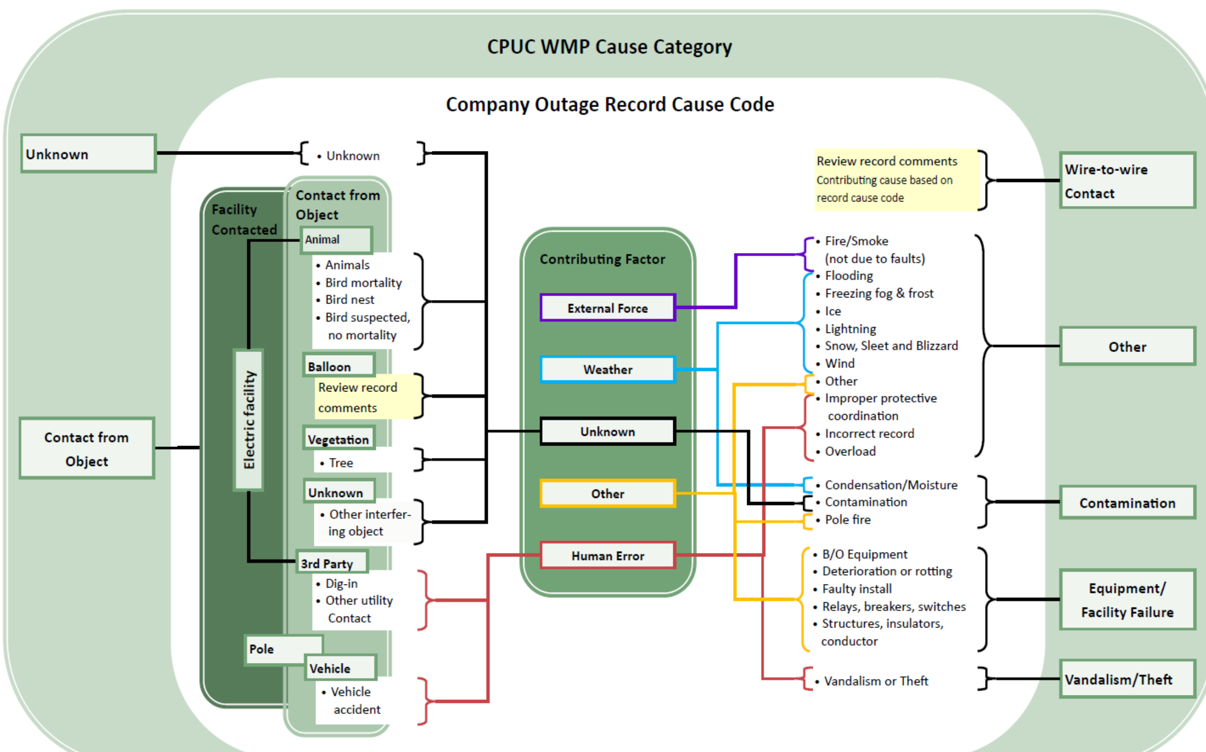
[9] Bouford, James D. "Spacer cable reduces tree caused customer interruptions." 2008 IEEE/PES Transmission and Distribution Conference and Exposition. IEEE, 2008.

Figure 4: PacifiCorp Risk Mapping Exercise



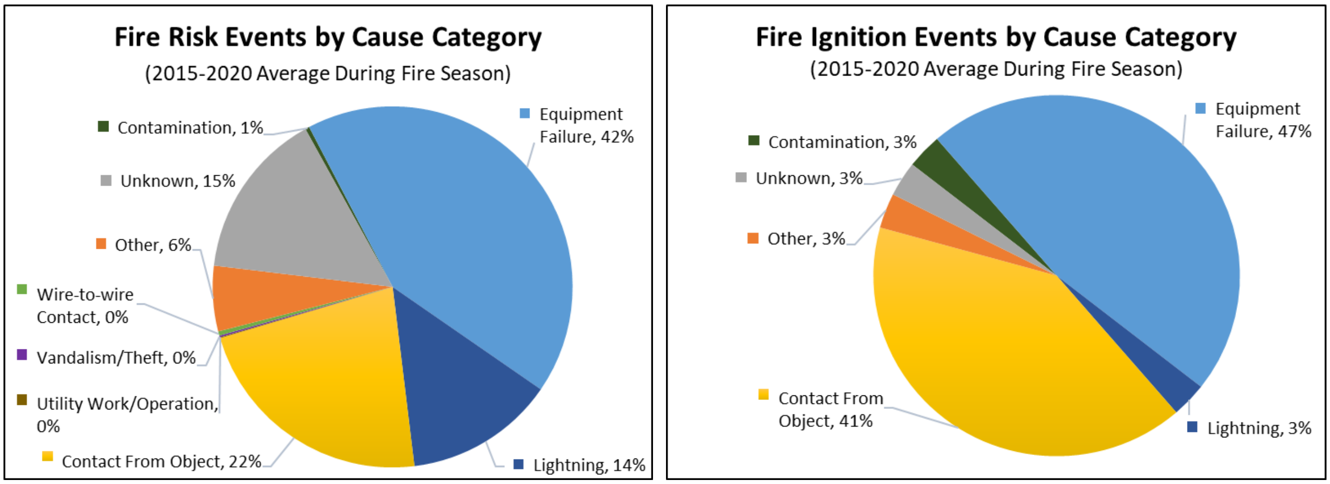
With this process, as outlined below in Figure 5, PacifiCorp evaluated outage causes (and sub-causes, as well as commented information) to establish a relationship between forced outages and risk event drivers.

Figure 5: PacifiCorp Outage Cause Evaluation



The company then determined the average percentage of fire risk events and ignition events over the 2015-2020 period as shows in Figure 6

Figure 6: PacifiCorp Fire Risk Events by Cause Category



The company then evaluated the probability (qualitatively scored and informed by the information above) of each ignition risk driver and its potential for ignition based on the season (fire and non-fire season) as shown in Figure 7. It was also segmented by transmission and distribution system, since the probabilities of each risk event driver and ignition risk were not equivalent. Qualitatively, PacifiCorp designated each cause either a low (L), medium low (ML), medium (M), medium high (MH), and high (H) by fire and non-fire season for the likelihood of the cause to result in an ignition to help establish priorities of mitigations.

Figure 7: PacifiCorp Fire Risk Events Assessment

Risk Event Driver		Non-Fire Season		Fire Season	
		Transmission	Distribution	Transmission	Distribution
Wire down event (regardless of cause)		M	M	H	H
Contact-from-object	Veg. contact	M	M	H	H
	Animal contact	L	L	L	ML
	Balloon contact	L	L	L	ML
	Vehicle contact	L	ML	M	MH
	Other contact-from-object	L	L	L	ML
Equipment / facility failure	Connector damage or failure	M	M	H	H
	Splice damage or failure	M	M	H	H
	Crossarm damage or failure	L	L	M	ML

	Insulator damage or failure	L	L	L	ML
	Lightning arrestor damage or failure	L	M	L	H
	Tap damage or failure	L	L	L	ML
	Tie wire damage or failure	L	L	L	L
	Other	L	L	L	L
Wire-to-wire contact	Wire-to-wire contact / contamination	L	L	ML	M
Contamination		L	L	L	ML
Utility work / Operation		L	L	L	ML
Vandalism / Theft		L	L	L	ML
Other		L	L	L	L
Unknown		L	L	L	L

Based on PacifiCorp's spacer cable pilot projects, the company is experiencing a 90% reduction in outage events. In order to evaluate this, PacifiCorp prepared pre-reconductor performance and contrasted it against post-reconductor performance and determined that the reduction in outages was approximately 90%. It is important to note that for these projects, since they were targeted specifically to environmental parameters that are visible (such as tree canopies or animal habitats), only the at-risk segments were reconductored (i.e., the entire zones of protection were not reconductored). The effect of this approach results in a high degree of confidence in the intended purpose of the project (against the specific risk driver). Should the measure be broadly extrapolated throughout the company's system, in the areas where these risk drivers are not prevalent their effectiveness is more problematic to evidence, since a longer duration of the countermeasure must be in place to determine that it was in fact, effective. To further explain, if an area is not prone to a specific risk driver, a longer history is required to experience a given risk event.

In the future, as the company reconductors entire zones of protection, it will have better certainty about the effectiveness of the mitigation against each ignition risk driver within that zone. For the initial projects, the scoping was directly motivated by reducing contact, primarily vegetation outage rates, and as a result the outage rates being measured are directly influenced by that decision. Even though the data is not perfect, it still provides a valuable insight into the expected reduction in risk from covered conductor. As the company constructs more projects and as time passes for outage events to accrue, PacifiCorp expects to further refine the outage rate reduction by ignition risk driver. For the ignition risk drivers that it is not able to confidently measure, PacifiCorp takes the 90% reduction in outage rate and modifies it with SME input to create estimated effectiveness values. The ignition risk drivers, the estimated reduction, and the explanation is summarized in Table 6.

Table 6: PacifiCorp Covered Conductor Mitigation Effectiveness Estimate

Ignition Risk Driver	Estimated Effectiveness Percent Reduction	Discussion
Vegetation Contact	90%	Vegetation contact is one of two primary drivers for the pilot project selection.

Ignition Risk Driver	Estimated Effectiveness Percent Reduction	Discussion
Animal Contact	90%	Animal contact is the second of two primary drivers for the pilot project selection.
Balloon Contact	99%	In general, expect contact from balloons to be mitigated.
Vehicle Contact	90%	Due to the increased strength of spacer cable systems, combined with increased resilience to wire-to-wire contact, estimate a 90% effectiveness.
Equipment Failure	90%	Much of the equipment used to construct bare overhead systems is replaced with different components. Additionally, phase conductors are not under tension. This estimated effectiveness is not incorporating downstream equipment such as transformers and protective devices.
Wire to Wire Contact	99%	Due to the forces experienced from vegetation contact, instances of wire-to-wire contact have been observed. No faults occurred.
Contamination	75%	Risk of contamination is estimated to be reduced due to systems being insulated beyond their standard NESC minimum ratings.
Vandalism/Theft	50%	In general, spacer cable has less risk of conductor theft as well as vandalism. Believe there are two areas where there could be increased risk of vandalism and theft, for example, damage from "gunshot" to the conductor covering, and theft of copper ground wiring.
Lightning	50%	Given spacer cables unique design where the messenger (neutral) is the topmost conductor, it acts as a grounded shield wire for the phase conductors. In addition, earth

Ignition Risk Driver	Estimated Effectiveness Percent Reduction	Discussion
		grounds are utilized every approximately 500 feet to further ground the system. With diligence in lightning arrester placement, estimate a 50% reduction in lightning-related faults.
Third Party	90%	Third-party including contact from joint use, boom arms, etc. should be mostly mitigated with spacer cable.

BVES

BVES has approximately 211 circuit miles of overhead conductor between 34.5 kV and 4.16 kV in its system. BVES started a covered conductor pilot program in Q2 2018 and completed it in Q3 2019 using two different types of cover conductor wires (394.5 AAAC Priority wire and 336.4 ACSR Southwire). Then BVES started the cover conductor Wildfire Mitigation Plan (WMP) late 2019 with a plan to cover 4.3 circuit miles on 34.5 kV over the next 5 years and 8.6 circuit miles on 4.16KV over the next 10 years. As of the end of Dec. 2021, BVES has covered approximately 21.1 miles between its 34 kV and 4 kV systems. BVES' average span length is approximately 150 feet and installing covered conductor on cross arms with Hendrix insulators. As part of its covered conductor program when there are spliced locations, BVES installs premade cold shrink kits (3M) and installs avian protection (raptor protection/wildlife guard).

Based on benchmarking with other utilities' estimated effectiveness against ignition risks, discussions with its covered conductor supplier, and the short amount of time that it has installed covered conductor, BVES believes that the estimate of effectiveness on ignition risk drivers in its service territory is approximately 90%. This is BVES's first initial look and as it installs more covered conductor and gathers more historical data, it will continue to assess the estimate of effectiveness. BVES presents its estimated effectiveness in Table 7.

Table 7: BVES Covered Conductor Mitigation Effectiveness Estimate

Ignition Risk Driver	Percent Reduction	Discussion (Contacts on Cover Conductor cable)
Vegetation Contact	90% +	Vegetation contact on 1, 2, 3 phase and/or neutral wire.
Animal Contact	90% +	Animal contact on 1, 2, 3 phase and/or neutral wire.

Ignition Risk Driver	Percent Reduction	Discussion (Contacts on Cover Conductor cable)
Balloon Contact	90% +	Balloon contact on 1, 2, 3 phase and/or neutral wire.
Wire down contact	90% +	Due to the following: tree/tree limb fallen on line, car hit pole , wind gust, etc.
Vehicle Contact	90% +	Vehicle Contact due to wire down on vehicle.
Wire to Wire Contact	90% +	Due to the wind gust forces causing tree/tree limb fall on line or just wire to wire contact.
Splice location contact	90% +	BVES installs Avian protection/raptor protection/wildlife guards and uses premade cold shrink kits (3M) on splice locations.
Vandalism/Theft	90% +	In BVES' service territory there is a low risk of conductor theft as well as vandalism. If vandalism occurs, Ex. damage from "gunshot" to the conductor covering installed.
Lightning Contact	90% +	During raining seasons, sometimes encounter a good amount of lightning strikes in BVES' service territory. BVES using priority covered conductor (flame resistant) cable.
Third Party	90% +	Third party including contact from joint use, boom arms, etc. should be mostly mitigated with covered conductor cable.
Flame Propagation along the covered conductor	90% +	Caused by Lightning or other.
Flame particle dripping	90% +	Caused by Lightning or other.

Liberty

To estimate the effectiveness of its Covered Conductor WMP initiative in mitigating wildfire risk, Liberty evaluated the ability of covered conductor to reduce each ignition risk driver, as seen in Table X below. Liberty employed an internal risk working group to assess the effectiveness of covered conductor and other system hardening initiatives in reducing wildfire risk. This working group consisted of SMEs across its engineering, operations, wildfire prevention and regulatory teams. The SMEs convened weekly to discuss in detail each ignition risk driver and the mitigation effectiveness of covered conductor and other system hardening initiatives. SMEs referenced Liberty's historic outage data, including the location and cause of the outage and any associated dispatch or filed notes included in its outage management database. SMEs discussed the extent to which covered conductor would reduce, eliminate, or not have an effect on the likelihood of a specific type of outage occurring and leading to an ignition. Outages were classified by the ignition risk drivers listed in the table below and an estimated mitigation effectiveness percentage was developed for each risk driver.

Table 8 explains the reasoning for the estimated effectiveness values. Liberty continues to benchmark its evaluation within the industry. As Liberty continues to collaborate and benchmark with its peer utilities, including through the Joint IOU Covered Conductor Working Group, it will revisit the estimated effectiveness metrics and revise as necessary.

Table 8: Liberty Covered Conductor Mitigation Effectiveness Estimate

Ignition Risk Driver	Covered Conductor Mitigation Estimated Effectiveness (%)	Reasoning
Animal contact	90%	• Line is potentially uninsulated at connection points, transformer taps and dead-ends (locations with higher probability of animal activity).
Vegetation contact	95%	• CC will handle most tree branches falling on it, and grow-in, but not an entire tree (fall-in).
Vehicle contact	50%	• If a car takes a pole out, there is a reasonable chance the circuit will remain in service. • A wire-down event from car-hit-pole will result in fewer faults with covered conductor .
Conductor failure	80%	• Conductor not totally fail-proof from branches (larger, heavier, falling further) or tree falls, potentially breaking poles and crossarms. Steel poles/fiberglass crossarms might mitigate some of this vs. wood.
Conductor failure - wire slap	95%	• Covered conductor largely eliminates mid-span wire-slap phase-to-phase faults
Conductor failure - wires down	80%	• See logic for vehicle contact

Ignition Risk Driver	Covered Conductor Mitigation Estimated Effectiveness (%)	Reasoning
Animal contact	90%	• Line is potentially uninsulated at connection points, transformer taps and dead-ends (locations with higher probability of animal activity).
Other - Including unknowns	75%	• Liberty suspects that many 'unknown' OMS outage cause codes are non-failure wire slap, light veg contact, lightning or animal because no damaged component can be found as a reason for protective device operation.
Weather - Snow (better defined)	90%	• Liberty's covered conductor installation typically includes new poles and crossarms due to higher conductor loads. Poles designed to meet the GO95 strength requirements.
Weather - Lightning	15%	• Messenger wire on ACS attracts lightning strikes away from conductors.
Weather - Wind	90%	• Covered conductor largely eliminates mid-span wire-slap phase-to-phase faults
Pole Fire	80%	• ACS prevents bare wire from laying on the cross-arm and burning. • Tree wire has multi-layer jacket which greatly reduces opportunity for bare wire contact with wood supporting apparatus.

Next Steps

As detailed above, the utilities estimate the effectiveness of covered conductor between approximately 60 and 90 percent. In 2022, the utilities will continue to meet on a regular basis to discuss estimated effectiveness methods, data and calculations. The utilities will learn from the benchmarking, testing, and recorded results and collaborate to improve each utilities' understanding and approach to estimate effectiveness. The utilities plan to discuss opportunities to align data and methods for greater comparability and will provide an update on these efforts in their 2023-2025 WMPs.

Recorded Effectiveness

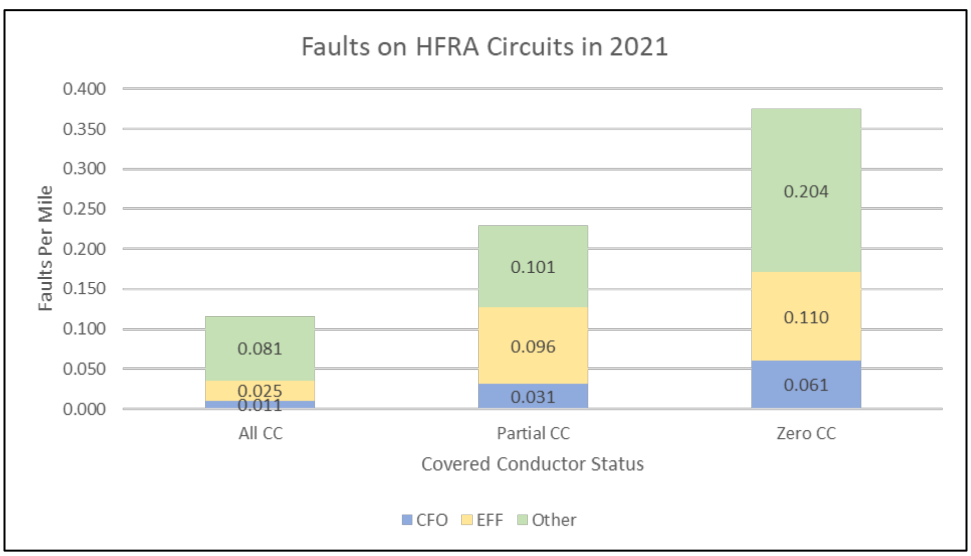
The utilities are in the early phases of covered conductor deployment and measuring its effectiveness. Though the utilities' data is limited, the early outcomes, as presented below, show covered conductor effectiveness at reducing the risk drivers that can lead to wildfires range between approximately 60 to 90 percent, which is consistent with the utilities' estimated effectiveness values, benchmarking, past testing results, and the results of the Phase 1 testing report. With the limited amount of data and the fact that the utilities have taken different approaches to measuring the effectiveness of covered conductor, in 2022, the utilities will work towards developing a common methodology (or multiple methods) all utilities can use for better comparability. The utilities also plan to continue discussions with the IEEE DRWG on methodologies to measure the effectiveness of covered conductor as part of a peer-review process. Below, the utilities describe data and analyses they have conducted regarding measuring the recorded effectiveness of covered conductor and collectively the utilities summarize future steps to improve these methods and updates to the data sets.

Covered Conductor Recorded Effectiveness

SCE

SCE is measuring the overall effectiveness of covered conductor by comparing events (primary wire downs, primary conductor caused ignitions and faults) on fully covered circuits to bare circuits in its HFRA on a per-mile basis in current years. As of November 2021, SCE's wire down and fire data does not show any events occurring on fully covered circuits. The data shows that circuits fully covered experience approximately 69% less or 31% of the faults that bare conductor do (see Figure 8).

Figure 8: SCE Faults on HFRA Circuits in 2021



As seen in Figure 8, SCE is using current (2021) data by comparing results (e.g., faults per mile) in HFRA for circuits that have been fully covered, partially covered and not covered as opposed to historical data, which may either over- or under-represent the benefits by not capturing weather variations year after year and data quality improvements in identifying and tracking risk events.

Since 2018, SCE has documented known contact-related events with covered conductor. In one instance, a tree fell on covered conductor lines, making contact with all three phases. In another case, energized covered conductor lines fell into adjacent trees after a vehicle struck a pole, as shown in Figure 9. These events did not result in faults, wires down, or ignitions because covered conductor was deployed and provide examples of effectiveness of covered conductor in the field.

Figure 9: Covered Conductor Contact with Vegetation After Car-Hit-Pole Ojai, California – July 24, 2020

PG&E

To align with the estimated effectiveness approach, in 2021, PG&E started to analyze its hardened facilities' performance with regard to recorded outages, incidents, and ignitions so that it can continue to refine its strategy and improve the scope and design of its Overhead Hardening Program. PG&E will also analyze the performance of any hardened facilities that experienced a wildfire in order to validate assumptions about the life expectancy and effectiveness of hardened facilities in various conditions.

The Overhead Hardening Program is still in its infancy which makes it difficult to have the amount of data needed to have statistical significance from this type of analysis. Initial analysis has been limited to counts of outages at the circuit segment level that compare the annual average from 2015-19 (pre-overhead hardening) to the 2020 (hardened) total count of outages where overhead hardening was completed in 2019 as shown in Table 9.

Table 9: PG&E Pre-Overhead Hardening Compared to Post Hardened Count of Outages

2015-2019 Average Outage Count	2020 Outages	Change	Percent [Ave -2020] / Ave
591	225	-366	62%

While the calculated outage reduction percentage (used as a measure of recorded effectiveness) matches the initial 62% estimated effectiveness, the results are understood to be preliminary and lack the geospatial accuracy needed for a truly recorded effectiveness.

Additionally, PG&E considered including ignitions, and incidents such as a wire down, or PSPS incidents (damage / hazard) in hardened sections to enhance the measurement of effectiveness of the Overhead Hardening Program, however the data scarcity was even greater for a meaningful analysis.

Going forward, PG&E's focus is to find ways to better capture geo location of a fault, and, if applicable, the damage and broken equipment. Industry-wide, fault location has historically been assigned to the device operated and not necessarily the actual coordinates where a fault occurs. This improvement in the quality of spatial data guarantees a more precise analysis of areas where overhead hardening has been completed.

Lastly, PG&E remains committed to explore ways to best calculate effectiveness and has established a biannual monitoring cadence with its Wildfire Governance Steering Committee to ensure continued improvement. These efforts will be shared with this working group to continue to improve methods to measure the effectiveness of system hardening initiatives.

SDG&E

SDG&E follows the same approach used to calculate the effectiveness of its Overhead Distribution Hardening, which is discussed in SDG&E's WMP in Section 4.4.2.3. SDG&E does not have sufficient data yet to draw any conclusions on the recorded effectiveness of covered conductor, as there is approximately only eighteen miles of covered conductor installed with an average age of less than one year. Across this small sample size, there have not been any faults on these covered conductor sections.

Moving forward, SDG&E will continue to track the mileage, years of service, and faults on all covered conductor circuit segments and will continue to collaborate with this working group to improve methods to measure the effectiveness of its system hardening initiatives. SDG&E's approach is to calculate the risk events per one hundred miles per year on segments that have been covered and compare the risk event rate before and after the installation of covered conductor.

PacifiCorp

As outlined above, PacifiCorp tracks risk events (forced outages) within each zone of protection (ZOP) with known conductor types and assumes homogenous performance across the ZOP; current processes do not establish specific locations where fault events occur, but are reconciled to the device that protects the ZOP. To establish the recorded effectiveness, PacifiCorp queried pre- versus post-installation performance with risk event drivers for all ZOPs having covered conductor (specifically spacer cable construction). It was important to recognize that legacy projects were focused on reliability and thus did not require reconductoring of the entire ZOP. As such, the recorded effectiveness calculations accounted for the percentage of the ZOP that wasn't reconductored. The smaller the percentage of the ZOP the less the confidence of the recorded effectiveness, while the higher the percentage of the ZOP the higher the confidence of the calculation.

Table 10 shows the performance before and after covered conductor installation, with several of the more recent projects not yet having sufficient history to calculate the effectiveness. As such, the table below summarizes PacifiCorp's experience of about 15-20 miles of the total covered conductor installed.

Table 10: Improvement Percentage for Covered Conductor/Spacer Cable Projects

Project Circuit	Install Year	Pre Install Fault Rate (per Mile)	Post Install Fault Rate (per Mile)	Improvement %	Zone Spacer Cable After (%)
4W8	2018	0.11737	0	100	35.72
4W8	2018	0.80326	1.11155	-38.38	78.82
5A15	2017	0.15403	0.09387	39.06	27.67
5A93-1	2007	0.55552	0.35134	36.75	15.92
5A93-2	2017	0.85087	0.41872	50.79	16.1
5K50	2018	0.23498	0.10819	53.96	63.42
5L82	2013	0.55291	0.14227	74.27	100
5L82	2013	0.39609	0	100	100
5L82	2013	0.13227	0	100	66.19

This data is summarized graphically below in Figure 10, where the improvement percentage is compared against the percentage of the ZOP that was reconductored. As can be seen, the higher the percentage of the ZOPs, the higher the recorded effectiveness when measured by faults (risk events) per mile.

Figure 10: Percentage of Covered Conductor (Spacer Cable) in Zone Versus Improvement Percentage

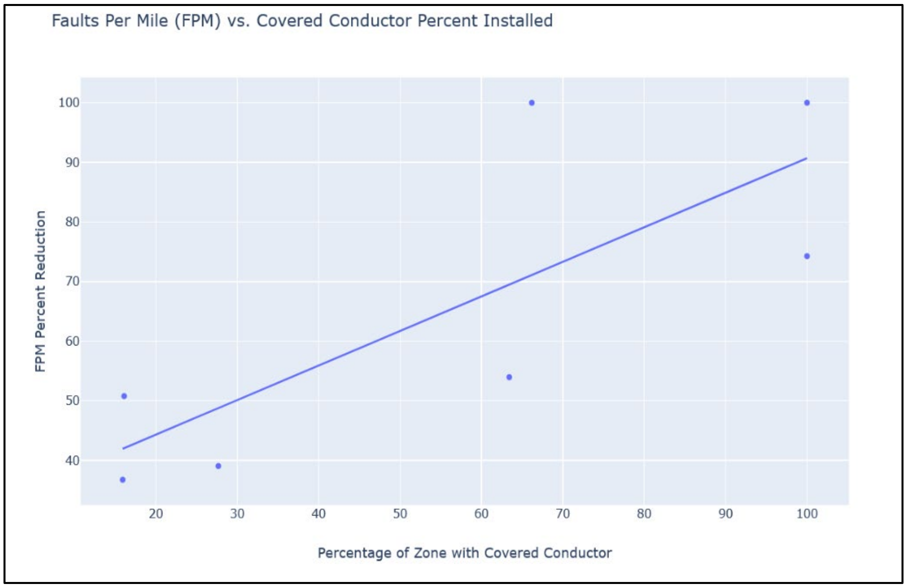
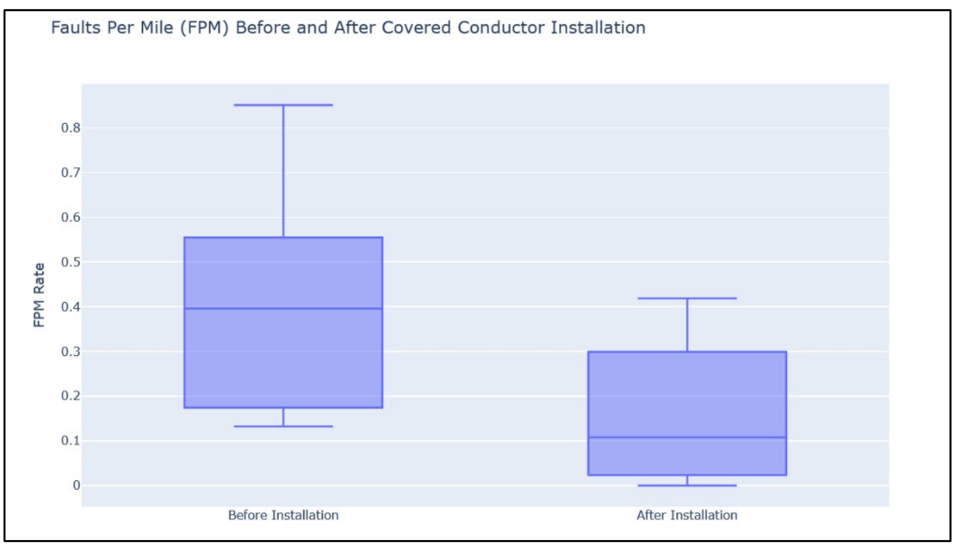


Figure 11 shows how the ZOPs performed before the mitigation was completed versus after the mitigation was completed, normalized based on the faults-per-mile recorded.

Figure 11: Comparison of Faults Per Mile Performance Before Versus After Covered Conductor (Spacer Cable) Installation



PacifiCorp has also documented known contact-related events with covered conductor. As shown in Figure 12, these events did not result in faults, wires down, or ignitions because spacer cable was deployed and provide examples of effectiveness in the field.

Figure 12: Examples of Effectiveness of Covered Conductor to Risk Events

BVES

BVES has approximately 211 circuit miles of overhead conductor between 34.5 kV and 4.16 kV in its system. BVES started a covered conductor pilot program in Q2 2018 and completed it in Q3 2019 using two different type of cover conductor wires (394.5 AAAC Priority wire and 336.4 ACSR Southwire). Then, BVES started the cover conductor WMP late 2019 with planning on covering 4.3 circuit miles on 34.5KV next 4 years and 8.6 circuit miles on 4.16KV next 10 years. As of end of Dec. 2021, BVES has covered approximately 21.1 miles between its 34 kV and 4 kV system.

In Q3 2018, BVES started a new tree-trimming contract with a new tree service contractor. BVES has been very aggressive with its vegetation manage program having up to four tree crews or more at a time to complete its three-year cycle and remediating any issue trees which has helped reduce outages from vegetation contacts.

As part of its WMP, in June 2019, BVES began replacing all explosion fuses in its service area with Trip Savers and Elf Fuses. BVES completed this project in May 2021, which eliminated the potential for ignitions from explosion fuses.

Currently, BVES has not had any outages, wire down, tree limbs and/or ignitions on the lines that have been covered. BVES is still in the early stages of its covered conductor program. As more areas are covered and as more time passes, BVES will be able to compile more recorded data to inform on the effectiveness of covered conductor. Table 11 provides a simple assessment of recorded outages since 2016 in BVES' system which shows a reduction of outages beginning in 2019.

Table 11: BVES 2016-2021 Recorded Outages Assessment

BVES, Inc.	12/10/2021
Year	# of outage
2016	163
2017	256
2018	118
2019	61
2020	84
2021	65

Liberty

Liberty's covered conductor program is relatively new, with the only significant projects being completed in 2020 and 2021. Because the program is new, data on the performance of covered conductor effectiveness will not yet demonstrate meaningful results based on the limited sample period and the wide variations in weather conditions. In addition, the covered conductor projects completed thus far represent a small percentage of each circuit and the outage data has only been evaluated on a circuit by circuit basis.

As an example, Liberty's Topaz 1261 circuit has 3.17 miles of covered conductor installed on the circuit which consists of an overall length of 55.6 miles. Table 12 shows historic 5-year forced outage data by outage risk driver for the Topaz 1261 circuit. As discussed in the Estimated Effectiveness working group section, Liberty identified significant outage risk drivers that could be mitigated with covered conductor and will use those outage risk drivers in its assessments of the effectiveness of its covered conductor projects. Liberty's forced outages on the Topaz 1261 circuit for 2021 are lower than the historic 5-year average. However, there were more forced outages in 2021 with a tree cause compared to previous years. In 2021, there were no outages recorded with wire slap as the cause, but there are only two recorded wire-slap causes in the study period. This example demonstrates that Liberty needs additional data to draw valid conclusions.

Table 12: Historic Forced Outages by Risk Driver for Topaz 1261 Circuit (2017-2021)

Outage Risk Driver	Historical Average (2017-2020)	2021
Wind/Flying Debris	2.5	1
Hardware/Equipment Failure	4	4
Vegetation	1	4
Deterioration	1	0
Wire Down	0.5	0
Animal	0.5	0
Wire Slap	0.5	0
Wildfire	0.25	0
Fire on Company Equipment	0.25	0
Total for Risk Drivers Listed	10.5	9

While Liberty's outage management system does provide five years of useful historic forced outage data by geospatial location, the following are data limitations that Liberty has identified and is working to improve:

- Only the approximate outage locations are documented by field crews. While the general area affected is valuable for evaluating performance, Liberty is working with its field crews to document location at a more specific level.
- There are limits to the way dispatchers code outages within Liberty's existing outage management system (OMS). Liberty is currently undergoing an upgrade to its OMS and is working with its operations, dispatch and engineering teams to improve the data and to identify outage metrics and risk drivers to include in the upgrade.
- The planned OMS upgrade will coincide with a budgeted GIS upgrade, closely followed by a budgeted AMI implementation. These combined implementations are expected to better capture cause documentation, geo location of faults, outage extent/duration, and protective device operation.

Next Steps

In 2022, the utilities will continue to discuss methods of measuring the effectiveness of covered conductor, document the risk events and data utilities track, and work towards developing common methods to measure the effectiveness of covered conductor for better comparability. Since each utility has different processes and technical systems related to the collection of outage data, the utilities will work towards aligning on common methods. Of particular concern is ensuring a method or methods that all utilities can employ given the complexity in interruption data and differences in, for example, outage management systems, communication technologies, business practices, and causation identification and reporting. Methods the utilities plan to discuss include, for example, measuring faults in HFRA per hundred circuit miles per year comparing results pre- and post-covered conductor installation. Other methods include, for example, measuring the number of faults experienced in the current year for circuits that have been covered and circuits that have not been covered in HFRA and other metrics to demonstrate ignition performance. This will require SME discussions and review of outage, wire-down and ignition data across the utilities. The utilities also plan to refresh its data sets and discuss any incidents, trends, anomalies, etc.

Alternative Comparison

The utilities identified an initial list of viable alternatives to covered conductor and conducted workshops with SMEs from the six utilities to assess the effectiveness of these alternatives against the same risk drivers that covered conductor is designed to mitigate. A viable alternative is a mitigation or group of mitigations that would address, to a similar or greater degree, the risk drivers that covered conductor is designed to mitigate. The utilities also included existing and a new bare conductor system as part of this assessment. The utilities used the risk drivers in Energy Safety's non-spatial data requirements (specifically, the non-repeated distribution causes and sub-cause categories in the WMP Guidelines, Table 7.1) to conduct the assessment. Below, the utilities describe the covered conductor system and alternatives that were selected for this assessment, the general assumptions that were applied, present the results of its assessment including descriptions of the factors that lead to lower or higher effectiveness, and describe the additional analyses the utilities plan to perform in 2022 to further the utilities understanding of the effectiveness of covered conductor compared to alternatives.

Covered Conductor System

A covered conductor system generally refers to installing a conductor that is covered, replacing equipment/components that are required because of the covered conductor, such as insulators, cross arms, or poles (where applicable), replacing other equipment that is determined to reduce risk, improve resiliency/reliability and/or are cost-effective, and adding other protection measures such as animal guards or avian proofing where conditions merit or are otherwise applicable in the respective environment.

In very limited situations, it may be possible to simply re-string bare conductor with covered conductor. These limited situations would require all existing poles to withstand the heavier covered conductor and where polymer insulators are already in place. Simply re-stringing covered conductor would be a rare occurrence as it is not usually possible. As such, the utilities are comparing the relative effectiveness of alternatives to a covered conductor system, as described above, in their ability to reduce the risk drivers of ignitions.

Some of the risk drivers, such as Animal Contact, cannot be fully mitigated with covered conductor by itself. For example, you may also mitigate Animal Contact on a bare wire system by installing, wider cross arms(to increase the phase spacing) and coverings on jumper wires and at device connections. This presents some challenge in estimating the effectiveness of a system since it's not simply the covered conductor itself, but rather the combined mitigations working together to mitigate any given risk driver. As such, the utilities assumed that all overhead conductor-related alternatives include animal covers except the existing bare conductor system that is essentially a "do nothing" alternative.

Alternatives

Below, the utilities describe the alternative mitigations that were compared with a covered conductor system.

Existing Bare Conductor System (status quo)

Existing systems, with enhanced maintenance activities and advanced system protection measures can be viewed as an alternative for covered conductor depending on the specific locational risk within the specified area. For purposes of this assessment, the utilities assumed a "do nothing" scenario regarding any system hardening upgrades. In the analysis below, this is labeled as Existing Bare Conductor. While the six utilities may have different existing overhead bare conductor systems in their HFRA, the utilities generally assumed existing bare conductor systems

New Bare Conductor System (like-for-like replacement)

This involves re-conductoring existing bare systems with like-for-like replacement of bare conductor, crossarms, connectors, etc. and added protection measures such as animal guards or avian proofing where conditions merit or are otherwise applicable in the respective environment. This type of system can reduce wire downs by mitigating conductor failures caused by fault current surpassing the ampacity threshold the conductor was designed for. However, this system will still be vulnerable to contact-from-object risk, wire slap, and some types of equipment failure.

Upgraded and Fire Hardened New Bare Conductor System (stronger conductor tensile strength, increased spacing, and stronger/taller steel poles)

This alternative is patterned after SDG&E's original fire hardening of its 69 kV transmission and 12 kV distribution systems located in its HFRA. SDG&E evaluated years-worth of reliability data in which one of the findings was that small wire conductor, #4 AWG and #6 AWG, was a significant driver for risk-related events. This information, coupled with the increased awareness of localized wind speeds in high risk areas, led to design changes of how these lines were constructed. The minimum size of the conductors was increased for additional tensile strength in addition to sometimes using dual steel core for support instead of single steel core. Under the previous design standards, lines were constructed to withstand working loads under stress of 56 mph wind speeds. The new design standard was able to withstand higher wind speeds, in some cases 85 mph and even up to 111 mph in specific cases. In addition to upgrading the conductor, wood poles were replaced with steel poles and increased phase spacing was used to minimize the potential of wire slap or phase-to-phase and phase-to-ground contacts.

Spacer Cable System

The spacer cable system utilizes a diamond shaped spacer to support covered conductor in a spaced bundle configuration, a high-strength messenger wire using a weak-link design concept, wherein the poles are the strongest member of the system, with the messenger the next strongest, and specialized attachment brackets that are the least strongest, such that if an impact load is experienced on phase conductors or poles, the system remains intact, but that "fails" the attachment of the bracket to the pole allowing for it to be quickly reattached. This system is secured to poles primarily with fixed or flex tangent brackets, in which the messenger is the only connected conductor. The utilities generally assumed poles would be replaced with stronger steel and/or fire-resistant poles to support this system. The covered conductors are not tensioned (nor are they structural members) and instead are held together with spacers attached to a tensioned messenger and placed approximately 30-feet apart. The high-strength messenger wire provides greater strength than a covered conductor system. The utilities also generally assumed equipment/components would be replaced similar to a covered conductor system and added protection measures such as animal guards or avian proofing where conditions merit or are otherwise applicable in the respective environment.

Aerial Bundled Cable System

An Aerial Bundled Cable (ABC) system consists of one, two, or three individual cables that are fully insulated. The cables are wrapped together and, similar to a spacer cable system, supported by a high-strength messenger with a lashing wire. Because the cables in ABC are fully insulated, ABC can withstand continuous contact-from-objects for an indefinite time period. The high-strength messenger also provides the ABC system with mechanical protection from objects falling onto the line. For purposes of the assessment, the utilities assumed the ABC would be installed using stronger structures that combined with the high-strength messenger would provide greater strength than a covered conductor system. The utilities also generally assumed equipment/components would be replaced similar to a covered conductor system and added protection measures such as animal guards or avian proofing where conditions merit or are otherwise applicable in the respective environment.

Underground System

An underground system consists of underground cable (e.g., crosslinked polyethylene cable (XLPE) installed in PVC conduit), above-ground pad-mounted equipment (e.g., transformers) or equipment in vaults, cable terminations and joints, surge arrestors and grounding electrodes. Underground cable can be direct-buried, direct-buried in conduit, or encased in concrete. For purposes of this assessment, the utilities generally assumed an undergrounded system with above-ground pad-mounted equipment and the cable/conduit encased in concrete. Undergrounding of electric infrastructure can significantly reduce wildfire risk and potentially reduce the need and frequency for PSPS outages. Additional potential benefits of undergrounding include an increase in service reliability, especially during wind events, and the reduction of the need for vegetation management work, and in general, improved public safety. An underground system can take significantly longer to complete and is more costly to construct as compared to other system hardening alternatives. An underground system can also be very complex to construct taking into account, for example, topography, geology, environmental or culture considerations, and land rights. In some instances, it is infeasible to construct.

Remote Grid

This alternative is patterned after PG&E's Remote Grid program designed to remove long feeder lines and serve customers from a Remote Grid. A "Remote Grid" is a concept for utility service using standalone, decentralized energy sources and utility infrastructure for continuous, permanent energy delivery, in lieu of traditional wires, to small loads, in remote locations, at the edges of the distribution system. As an example, in PG&E's service area there are pockets of isolated small customer loads that are currently served via long electric distribution feeders, some of which traverse HFRA and require significant annual maintenance, vegetation management, or system hardening solutions. The reduction in overhead lines as these Remote Grids are built can reduce fire ignition risk as an alternative to, or in conjunction with system hardening and other risk mitigation efforts. The utilities generally assumed in its assessment the differences between either covering a long distribution feeder line or eliminating the long distribution feeder line and installing a Remote Grid. The utilities did not include in its assessment any remaining fire risks associated with serving the small customer loads from either the covered conductor line or within the Remote Grid, i.e., only the long overhead distribution feeder line was considered in this assessment. While Remote Grids are not a general alternative to covered conductor, as the assessment below indicates, they can be effective at reducing wildfire risk for a particular long overhead distribution feeder line that serves small customer loads.

Comparison

The utilities conducted workshops over multiple days to discuss each sub-driver (from Table 7.1 of the WMP Guidelines) and assessed whether the alternatives have lower, similar or higher effectiveness than a covered conductor system. The results are shown in Table 13. A red arrow represents a lower effectiveness, an orange arrow represents similar effectiveness, and a green arrow represents a higher effectiveness.

Table 13: Mitigation Effectiveness Comparison of Alternatives to Covered Conductor

Risk Event Driver	Sub-driver	Existing Bare Conductor System	New Bare Conductor System	Upgraded and Fire Hardened New Bare Conductor System	Spacer Cable System	Aerial Bundled Cable System	Undergrounding System	Remote Grid System
Contact-from-Object	Veg. contact	↓	↓	↓	↑	↑	↑	↑
	Animal contact	↓	↓	↓	↔	↔	↑	↑
	Balloon contact	↓	↓	↓	↔	↔	↑	↑
	Vehicle contact	↓	↓	↑	↑	↑	↑	↑
	Other contact from object	↓	↓	↓	↑	↑	↑	↑
Equipment / Facility Failure (EFF)	Connector damage or failure	↓	↔	↔	↔	↔	↑	↑
	Splice damage or failure	↓	↔	↔	↔	↔	↑	↑
	Crossarm damage or failure	↓	↔	↔	↑	↑	↑	↑
	Insulator damage or failure	↓	↔	↓	↔	↑	↑	↑
	Lightning arrestor damage or failure	↔	↔	↔	↔	↔	↑	↑
	Tap damage or failure	↓	↔	↔	↔	↔	↑	↑
	Tie wire damage or failure	↓	↔	↔	↑	↑	↑	↑
	Capacitor bank damage or failure	↔	↔	↔	↔	↔	↑	↑
	Conductor damage or failure	↓	↓	↓	↑	↑	↑	↑
	Fuse damage or failure	↓	↓	↓	↔	↔	↑	↑
	Switch damage or failure	↓	↓	↓	↔	↔	↑	↑
	Pole damage or failure	↓	↔	↑	↑	↑	↑	↑
	Voltage regulator / booster damage or failure	↔	↔	↔	↔	↔	↑	↑
	Recloser damage or failure	↓	↓	↓	↔	↔	↑	↑
	Anchor / guy damage or failure	↓	↓	↓	↔	↔	↑	↑
	Sectionalizer damage or failure	↓	↓	↓	↔	↔	↑	↑
	Connection device damage or failure	↓	↔	↔	↔	↔	↑	↑
	Transformer damage or failure	↔	↔	↔	↔	↔	↔	↔
	Other	↓	↓	↓	↔	↔	↑	↑
Wire-to-wire contact	Wire-to-wire contact / contamination	↓	↓	↓	↔	↑	↑	↑
Contamination	Contamination	↓	↓	↓	↔	↑	↑	↑
Utility work / Operation	Utility work / Operation	↓	↔	↔	↔	↔	↔	↔
Vandalism / Theft - Distribution	Vandalism / Theft	↓	↓	↓	↔	↔	↔	↔
Other- Distribution	All Other - Distribution	↓	↓	↓	↔	↔	↑	↑
Unknown- Distribution	Unknown - Distribution	↓	↓	↓	↔	↔	↑	↑

The analysis shows that covered conductor has greater effectiveness than existing, new, and fire hardened overhead bare conductor systems. In some instances, a fire hardened overhead bare conductor system could provide slightly higher mitigation effectiveness. For example, for car-hit pole (vehicle contact) or other pole damage causes, a hardened overhead bare conductor system was assumed to have much stronger poles preventing occurrences of pole damage and/or wire down from a car-hit-pole scenario. In general, a spacer cable system and an ABC system provide higher effectiveness than a covered conductor system due to their strength and in the case of ABC both its strength and greater insulation properties. An underground or Remote Grid system provides the highest effectiveness, noting that the analysis of the Remote Grid System scenario was based only upon eliminating a long overhead distribution feeder line serving an isolated community and does not account for any overhead facilities beyond the long overhead distribution feeder line.

Next Steps

In 2022, the utilities plan to expand this assessment of alternatives to mitigate wildfire risk by including other technologies and mitigations such as replacing fuses, installing Remote-Controlled Automatic Reclosers/Remote-Controlled Switches (RAR/RCS), as well as newer technologies that the utilities are exploring including, for example, REFCL technologies, OPD, EFD, and DFA. Additionally, the utilities will assess how to estimate the relative percent difference of effectiveness for the alternatives.

Potential to Reduce the Need for PSPS

As part of this sub-workstream, the utilities have documented their general approach to PSPS and conducted a comparison analysis, similar to the Alternatives analysis above, by conducting workshops with SMEs from the six utilities to assess alternatives compared with covered conductor in their ability to reduce PSPS impacts. The utilities used the same alternatives as described in the section above to conduct this assessment. Below, the utilities describe their PSPS approach. Collectively, the utilities summarize the ability of a covered conductor system to reduce PSPS impacts, provide an assessment of alternatives ability to reduce PSPS impacts compared to covered conductor, and describe additional analyses the utilities plan to perform in 2022 to further the utilities' understanding of the ability of covered conductor compared to alternatives to reduce PSPS impacts.

Utilities' PSPS Approach

Below, the utilities describe their company's approach to activating a PSPS event and whether they consider raising thresholds when circuits are covered.

SCE

SCE activates PSPS largely based on two factors. The first factor used to drive PSPS decisions is the FPI, which estimates the likelihood of a spark turning into a major wildfire. FPI is calculated using forecasted wind speed, dewpoint depression, and various fuel moisture variables which are generated from SCE's customized version of the Weather Research and Forecasting (WRF) model. SCE's FPI scores range from 1 to 17, and any score at or above 12 is considered high risk. SCE reviews fire potential related products from the National Weather Service (NWS) and the GACC to confirm the wildfire threat related to PSPS. The second factor used to drive PSPS decisions is wind speed. SCE considers the NWS Wind Advisory levels (defined as 31 mph sustained wind speed and 46 mph gust wind speed) and the 99th percentile of historical wind speeds in the area to set activation thresholds. The Wind Advisory level is chosen because of the propensity for debris or vegetation to become airborne, while a circuit's 99th percentile wind speeds represent rare or extreme wind speeds that a particular circuit sees around four times per year. In 2021, SCE raised its de-energization thresholds for isolatable segments or circuits that have had covered conductor installed. The de-energization threshold for isolatable segments with covered conductor is 40 mph sustained and 58 mph gusts, which aligns with the NWS high wind warning level for windspeeds at which infrastructure damage may occur.

Once SCE's meteorologists confirm weather forecasts show an upcoming breach of FPI and circuit-specific wind speed thresholds, SCE activates its PSPS IMT and begins preparations for the upcoming event. Whether remotely due to the COVID-19 pandemic, or in-person at SCE's Emergency Operation Center, the IMT begins notifying affected parties. Notifications are sent to first responders, public safety partners, local governments, tribal governments and critical infrastructure providers approximately 72 hours prior to de-energization, followed by notifications to all other customers in scope approximately 48 hours prior to de-energization. SCE continues to provide additional notifications as well as notifications of imminent de-energization as information becomes available during the PSPS events (discussed in Section 8.2.4), develop event and circuit-specific de-energization triggers (inputs to which are discussed in Section 8.2.2) and direct resources to perform pre-patrols of all circuits in scope. Decision-making factors and protocols for PSPS de-energization are discussed in SCE's WMP Section 8.2.2.

PG&E

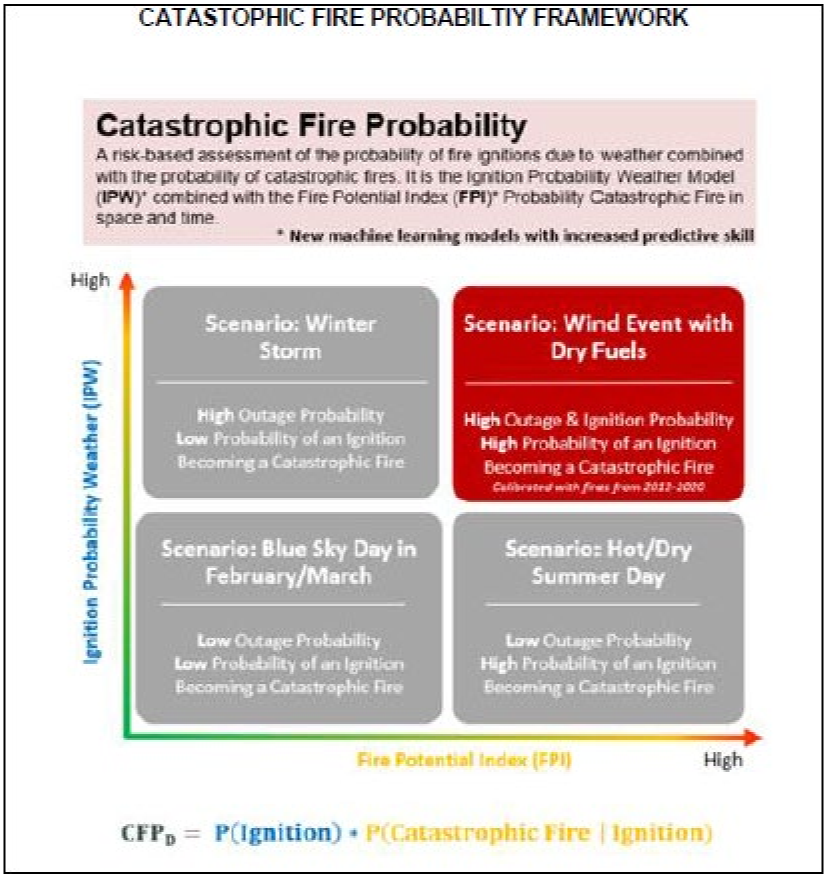
PG&E does not make specific changes in its PSPS protocols due to new improvements and mitigation initiatives, including grid hardening. The underlying models are based on historical data and not on estimating the effect of changes to system operations before they have occurred, which PG&E believes would be less accurate. However, since PG&E's PSPS models are based on historical data, new improvements and mitigation initiatives will be included in the models once the current changes are reflected in the historical data which the model incorporates over time. For example, when PG&E improves the quality of some specific assets, we expect a reduction in the chance of that asset causing an ignition. However, we do not manually input a reduction in the ignition probability in the model. Over time, the historical observed data is expected to change, and this data will feed into PG&E's models and gradually change its models' parameters.

PG&E's thresholds for PSPS are based on a risk assessment that combines the probability of utility related outages and ignitions, called the Ignition Probability Weather (IPW) model, and the probability of catastrophic fires, called the Fire Potential Index (FPI). This combination is called the Catastrophic Fire Probability (CFPD) and is given by the equation:

$$CFPD = p\ ignition * p\ catastrophic\ fire\ ignition = IPW * FPI$$

The IPW is a function of grid-performance given the weather conditions and is built using historical hourly weather data, outages, and ignitions in a machine learning model framework for localized areas. The guidance values PG&E utilizes when making a PSPS decision through the lens of this framework is a CFPD (IPW*FPI) value > 9. This value was determined by running 70 PSPS sensitivity studies from 2008 through 2020. Through this 13 year "lookback" analysis, PG&E evaluated the customer impacts through multiple dimensions (size, duration, frequency, repeat events, etc.), the days PSPS events would have occurred, as well as whether historic fires caused by utility infrastructure would have been de-energized using this analysis. The conceptual CFPD framework is presented in Figure 13.

Figure 13: PG&E Conceptual Catastrophic Fire Probability Framework



PG&E data scientists and meteorologists have taken steps to quantify the probability of outages, ignitions and catastrophic fires using both logistic regression and machine learning models. PG&E does not use wind speed thresholds on a per-circuit basis as a gauge of outage or ignition probability and therefore do not increase or decrease its wind speed thresholds where hardening has been performed. In PG&E's framework, the effects of grid-hardening and covered conductor would be handled in the IPW, which predicts the probability of utility-caused ignitions.

Overhead system hardening is expected to reduce the probability of outages and ignitions. PG&E believes that adjustments to PSPS thresholds should be considered carefully and based on robust performance data of survivability in the field during actual weather events. Covered conductor, for example, does not drive the fire ignition risk to zero. Trees can still fall into overhead lines and break covered conductor and cause an ignition. Based on aerial LiDAR, there are several million trees that have the potential to strike assets in PG&E's HFRA, which is an ignition pathway that has caused several catastrophic fires recently.

PG&E has built a PSPS model framework that can account for changes overtime based on actual performance data. The machine learning IPW framework (probability of ignitions) is flexible as PG&E does not have to consider each individual program such as covered conductor and EVM to adjust wind or PSPS thresholds on each circuit or circuit segment. Rather, the model framework addresses positive and negative changes in grid performance and reliability year-over-year as PG&E applies a time-weighted approach to weight more recent years of learned performance more heavily in the final model output. The model accounts for the performance of local grid areas hour-by-hour based on the wind speed observed at that hour and if outages or ignitions occur or not. The IPW model is 13 models trained on each year separately from 2008-2020 using hourly data and hourly outages. PG&E applies an exponential time-weighted approach to capture more rapid changes in local areas to be captured in the model (both negative - increased tree mortality, asset degradation, drought etc.; and positive – conductor and pole replacement, EVM, etc.). PG&E is in the process of updating the model with 2021 outage, ignition and historical weather data. When the model is updated, performance in 2021 will have the most model influence while 2008 will have the lowest.

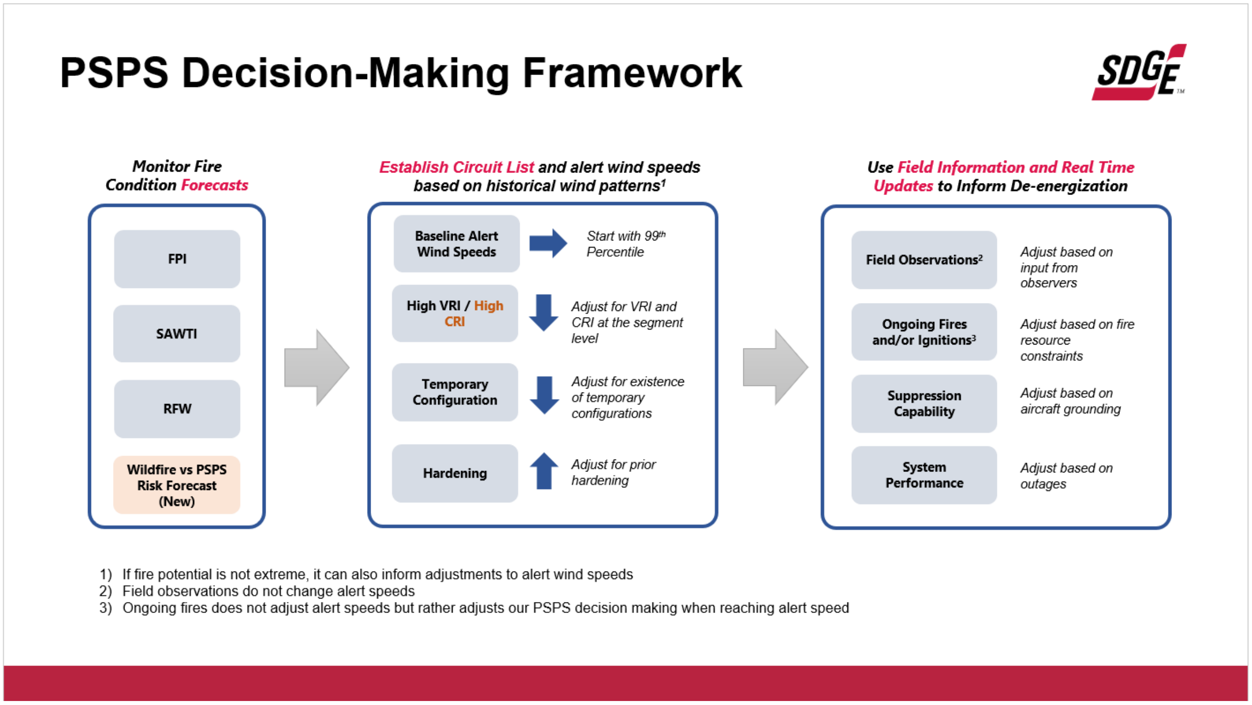
Since the IPW model accounts for changes over time and it evaluates PSPS through the risk-based assessment above, PG&E does not propose at this time adjusting its CFPD thresholds for circuits where grid-hardening has been performed. Instead, any positive effects from grid hardening, EVM, inspections, and other improvements will be trained in the Machine Learning IPW through this learned performance approach. Positive changes from any program or exogenous factors will lower the probability of outages and ignitions in these areas accordingly. In addition, if PG&E adjusts CFPD values to some circuits, it could make the fatal mistake of double counting the performance benefit achieved as changes in performance are inherently accounted for in the IPW model. PG&E welcomes feedback on its risk-based approach and ideas on how it can improve. One of the ideas PG&E is contemplating for future development of models is utilizing areas that have been hardened as a local feature of the IPW model.

SDG&E

SDG&E utilizes multiple factors to assist in the decision to de-energize. Figure 14 illustrates this PSPS decision-making framework. Some factors pertain to information in the field based on known compliance issues on the electrical system, active temporary construction/configuration of the electrical system, and a Circuit Risk Index (CRI) to identify locations in the system with a potential of having higher failure rates. Due to the dynamic nature of wildfire conditions SDG&E uses a real–time situational awareness technique to determine when to use PSPS, considering a variety of factors such as:

- Weather Condition - FPI
- Weather Condition - Red Flag Warnings
- Weather Condition - SAWTI
- Weather condition - 72-hour circuit forecast
- Vegetation conditions and Vegetation Risk Index (VRI)
- Probability of Ignition/Probability of Failure
- Field observations and flying/falling debris
- Information from first responders
- Meteorology, including 10 years of history, 99th and 95th percentile winds
- Expected duration of conditions
- Location of any existing fires
- Wildfire activity in other parts of the state affecting resource availability
- Information on temporary construction

Figure 14: SDG&E PSPS Decision-Making Framework



To-date, SDG&E has installed approximately 18 miles of covered conductor with an average age of less than one year. Therefore, SDG&E has not yet accumulated sufficient data to determine exactly how PSPS criteria will differ on circuit-segments that consist entirely of covered conductor versus bare conductor, though SDG&E does anticipate higher wind speed tolerances in these areas. In addition to real-world experience, and operations and benchmarking with other utilities, SDG&E will have a third-party evaluate the likelihood and effect specific to covered conductors clashing at various wind speeds to understand and help quantify any potential increases to wind speed tolerances on covered conductor segments.

PacifiCorp

PacifiCorp has historically leveraged multiple factors when deciding to implement a PSPS. Throughout 2021, PacifiCorp's newly established meteorology department worked to develop the capability to support real time risk assessments and forecasting and inform decision making protocols during periods of elevated risk such as PSPS assessment and activation. Situational awareness reports are generated daily which identify where fuels (dead and live vegetation) are critically dry, where and when critical fire weather conditions are expected (gusty winds and low humidity), and where and when the weather is forecast to negatively impact system performance and reliability. It is the intersection of these three factors that highlights an elevated risk to be considered for a potential PSPS event. These factors are then layered alongside real time local conditions such as real time weather measurements and field observer reports, as well as dynamic input from Public Safety Partners to characterize the local impact of a PSPS. All of these factors combined are used to determine whether to implement a PSPS.

During 2021 the following forecasted factors were considered in the decision to implement a watch:

- Comparison of forecasted wind gusts to localized history trends

- GACC-7 Day Fire Potential Outlook (High Risk with a Wind Trigger)
- Presence of any advisories such as the Fuels and Fire Behavior Advisory in effect for Northern California
- Local drought conditions
- Vapor Pressure Deficit
- Keetch-Byram Drought Index
- Presence of any Red Flag Warnings

In addition, the following real time observations were additionally included in the decision to de-energize:

- Actual wind gusts in the area
- Field observer reports
- Observer input regarding any observed precipitation (or other meteorological input)
- Measured wind speeds at utility owned weather stations
- Approximate relative humidity forecasted vs actual
- Local public safety partner input

While PacifiCorp continues to refine its methodology for determining inputs critical to making PSPS decision, however, at least for 2022, PacifiCorp does not anticipate at this time that covered conductor coverage will modify its PSPS decision-making process because PacifiCorp does not have full covered conductor coverage on any circuit or controllable sub-circuit. However, as the company increases covered conductor coverage, it will continue to assess its effectiveness, and expect it to impact its decision-making once the necessary coverage and operational history is obtained.

Liberty

In evaluating when a PSPS event should be initiated, Liberty monitors local weather conditions with its weather stations throughout its service territory and collaborates with Reax Engineering, a fire and weather scientific consultant, the National Weather Service (NWS) in Reno, Nevada, and local fire officials. The initiation of PSPS events are influenced by the following factors:

a. Red Flag Warnings: Issued by the NWS to alert of the onset, or possible onset, of critical weather or dry conditions that would lead to increases in utility-associated ignition probability and rapid rates of fire spread.
b. Low humidity levels: Potential fuels are more likely to ignite when relative humidity is low and vapor pressure deficit is high.
c. Forecast sustained winds and gusts: Fires burning under high winds can increase ember production rates and spotting distances. Winds also can transfer embers from lower fire risk areas into high risk areas, igniting spot fires and increasing wildfire potential.
d. Dry fuel conditions: Trees and other vegetation act as fuel for wildfires. Fuels with low moisture levels easily ignite and can spread rapidly.
e. Observed Energy Release Component (ERC)
f. Observed wind gusts
g. Observed Fosberg Fire Weather Index (FFWI)
h. Observed Burning Index (BI)

Liberty employs two de-energization decision trees, one for the Topaz and Muller 1296 r3 PSPS zones, and another for all other zones. In each case, the ERC, observed wind gust, and FFWI criteria are evaluated simultaneously to test whether any exceed the defined threshold. Figure 15 and Figure 16 represent the de-energization decision trees:

Figure 15: Liberty De-energization Decision Tree (Topaz and Muller 1296 r3 Zones)

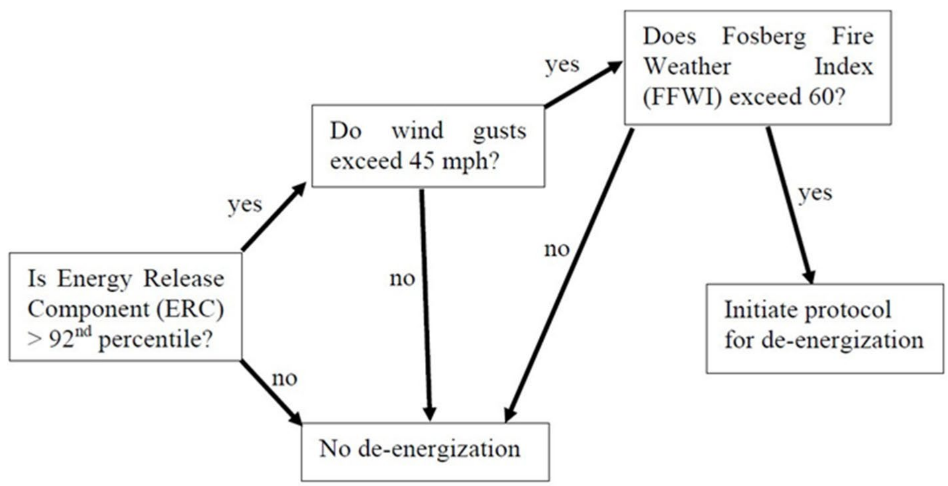
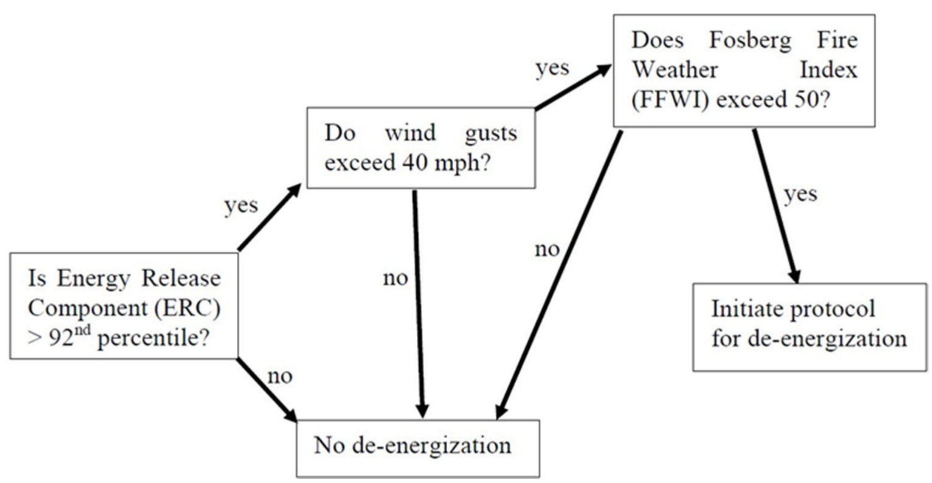


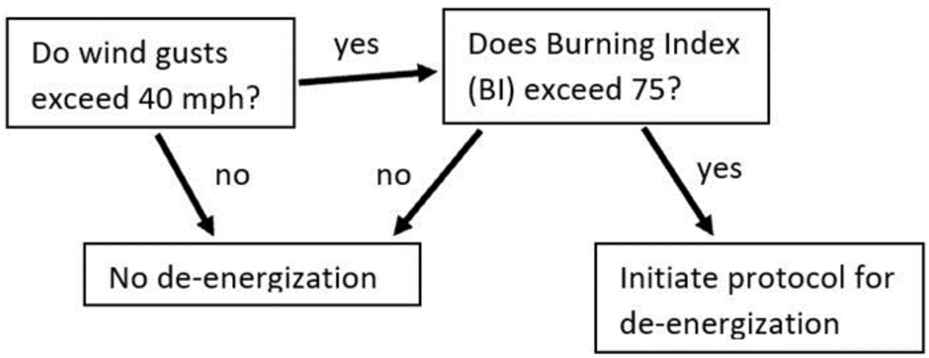
Figure 16: Liberty De-energization Decision Tree (All Other Zones)



In January 2021, Liberty's Fire and Weather Scientific consultant, Reax Engineering, formulated an enhanced version of its fire weather forecasting tool to include an additional parameter known as Burning Index (BI). BI adds an increased layer of information regarding fire potential to its already robust predictive formula. It accounts for predominant fuel type, live and dead fuel moisture, and short-term fluctuations in fire weather conditions. Use of this new formula with increased information from newly installed additional weather stations enables further granularity in the area of alternative responses to initiating a PSPS, such as managing recloser technology, de-energizing specific circuits and /or increasing patrols in specific geographic areas of concern. Liberty now utilizes both the current predictive formula and the enhanced model in order to assess improved data.

Figure 17 shows the current BI/gust de-energization formulation that is being evaluated by back testing against historical weather station observations and archived weather forecast data. The purpose of this formulation is to try to better capture "black swan" events, where extremely high winds may still have the ability to cause dangerous fire conditions even though temperatures are low and humidity levels are not critical, which can happen in the spring or fall more than the middle of the typical fire season.

Figure 17: Liberty's Current Burning Index / Gust De-energization Formulation



BVES

BVES evaluates many factors when initiating a PSPS event. However, in general, BVES will initiate a PSPS event when the NFDS fire danger forecast is high Risk (Brown, Orange or Red), and the actual sustained wind or 3-second wind gusts exceed 55 mph. In addition, BVES may initiate a PSPS if in the Utility Manager's judgement, actual conditions in the field pose a significant safety risk to the public. Individual circuits are evaluated for PSPS and may be individually de-energized to limit the area impacted by a PSPS.

Once complete overhead circuits are hardened and covered conductor is installed, BVES will consider raising the wind speed threshold for PSPS. The revised wind speed threshold for overhead structures with covered conductors is currently under evaluation. To date, BVES has never been required to activate a PSPS event.

Covered Conductor Potential to Reduce PSPS Risk

As described in the sections above, utilities generally believe that a fully-isolatable circuit-segment or zone of protection that has covered conductor can reduce PSPS impacts beyond an overhead bare conductor system. SCE, for example, increases its de-energization threshold for isolatable circuit-segments with covered conductor from 31 mph (sustained wind gusts) and 46 mph (gust) to 40 mph (sustained) and 58 mph (gust), which aligns with the National Weather Service (NWS) high-wind warning level for windspeeds at which infrastructure damage may occur. However, the rule of thumb starting point is not always 31 mph and 46 mph and instead is based on NWS high wind warning (potential asset damage). Furthermore, through back-casting analysis of 2021 PSPS events, SCE estimates that its efforts in grid hardening (largely due to covered conductor), situational awareness, and improved risk modeling (which allowed for adjustments to PSPS thresholds) helped reduce Customer Minutes of Interruption (CMI) by 43%, the number of customers de-energized by 42%, and the number of circuits de-energized by 29% from what they otherwise would have been under the same weather conditions. These data demonstrate that covered conductor provides PSPS benefits compared to overhead bare conductor systems. As the other utilities gain experience in installing more covered conductor, they plan to continue to assess raising their de-energization criteria for isolatable circuit-segments or zones of protection that are fully covered.

Alternative Comparison

The utilities conducted workshops over multiple days to discuss and assess whether the alternatives have lower, similar or higher benefits than a covered conductor system in reducing PSPS impacts. The utilities considered three PSPS benefits: 1) reduce PSPS frequency (# of de-energizations), Reduce PSPS duration (CMI), and reduce number of customers impacts by PSPS (i.e., customers in scope). The results are shown in Table 14. A red arrow represents a lower benefit, an orange arrow represents similar benefits, and a green arrow represents a higher benefit.

Table 14: PSPS Impact Benefits Comparison of Alternatives to Covered Conductor

PSPS Event Impact	Existing Bare Conductor System	New Bare Conductor System	Upgraded and Fire Hardened System	Spacer Cable System	Aerial Bundled Cable System	Undergrounding System	Remote Grid System
Reduce PSPS Frequency (# of de-energizations)	↓	↓	↔	↑	↑	↑	↑
Reduce PSPS Duration (CMI)	↓	↓	↔	↑	↑	↑	↑
Reduce Number of Customers Impacted by PSPS (customers in scope)	↓	↓	↔	↑	↑	↑	↑

The analysis shows that covered conductor has greater PSPS benefits than existing and new overhead bare conductor systems. SDG&E's upgraded and fire hardened system has shown benefits in reducing PSPS frequency, duration, and number of customers impacted. The utilities did not quantify these benefits to determine how much different are the benefits of a fire hardened bare overhead system compared to a covered conductor system and thus identified for this initial assessment a similar benefit. Similar to the assessment in the section above, a spacer cable system and an ABC system provide could provide higher benefits than a covered conductor system due to their strength and in the case of ABC both its strength and greater insulation properties. An underground or Remote Grid system provides the highest-level of benefits. Please note that the Remote Grid System scenario was based only on a long overhead distribution feeder line serving an isolated community and does not account for any overhead facilities beyond the long feeder line.

Next Steps

In 2022, the utilities plan to expand this assessment of covered conductor and alternatives in their ability to reduce PSPS impacts by including other alternative technologies and mitigations such as replacing fuses, installing RAR/RCS as well as newer technologies that the utilities are exploring including, for example, REFCL technologies, D-OPD, EFD and DFA. Additionally, the utilities will assess how to estimate the relative percent difference of the benefits for the alternatives.

Costs

The utilities have prepared an initial capital cost per circuit mile comparison of the installation of covered conductor. To construct this unit cost comparison, the utilities organized their capital costs (and/or estimates) into six cost categories. These categories include labor, material, contract, overhead, other, and financing. Labor represents internal utility resources, such as field crews, that charge directly to a project work order. Materials include conductor, poles, etc. that get installed as part of a project. Contract represents all contractors, such as field crews and planners, and consultants utilities use as part of their covered conductor programs. Overhead represents costs, such as engineers, project managers and administrative and general, that get allocated to project work orders. Other represents costs such as land fees, permit fees and costs not assignable to the other categories. Financing represents allowance for funds used during construction (AFUDC) which is the estimated cost of debt and equity funds that finance utility plant construction and is accrued as a carrying charge to work orders. These cost categories are intended to capture the total capital cost per circuit mile of covered conductor installations. For purposes of this report, the utilities obtained recorded and/or estimated costs for construction that occurred during 2021. Table 15 shows the initial covered conductor capital unit cost per circuit mile comparison across the six utilities.

Table 15: Comparison of Covered Conductor Capital Costs Per Circuit Mile

Cost Components	SCE		PG&E		SDG&E		Liberty		PacifiCorp		Bear Valley	
	Cost per Circuit Mile	%	Cost per Circuit Mile	%	Cost per Circuit Mile	%	Cost per Circuit Mile	%	Cost per Circuit Mile	%	Cost per Circuit Mile	%
Labor (Internal)	$ 8,000	1%	$ 209,000	19%	$ 182,000	13%	$ 56,000	4%	$ 2,000	0%		
Materials	$ 115,000	20%	$ 161,000	15%	$ 130,000	9%	$ 132,000	8%	$ 204,000	34%	$234,000	23%
Contractor	$ 335,000	59%	$ 470,000	43%	$ 481,000	34%	$1,167,000	75%	$ 272,000	45%	$733,000	71%
Overhead (division, corporate, etc.)	$ 96,000	17%	$ 226,000	21%	$ 418,000	29%	$ 188,000	12%	$ 62,000	10%	$38,000	4%
Other	$ 5,000	1%	$ 6,000	1%	$ 173,000	12%	$ -	0%	$ 60,000	10%	$26,000	3%
Financing Costs	$ 6,000	1%	$ 11,000	1%	$ 43,000	3%	$ 9,000	1%	$ 6,000	1%		
Total	$ 565,000	100%	$ 1,083,000	100%	$ 1,427,000	100%	$1,553,000	100%	$ 606,000	100%	$1,031,000	100%

As illustrated in Table 15, the capital cost per circuit mile ranges from approximately $565,000 to approximately $1.5 million. The capital cost per circuit mile for covered conductor varies due to multiple factors such as type of covered conductor system and components installed, terrain, access limitations, permitting, environmental requirements and restrictions, construction method (e.g., helicopter use), amount of poles/equipment replaced, degree of site clearance and vegetation management needed, and economies of scale. Below, the utilities generally describe the make-up of their covered conductor capital costs and the factors that contribute to the cost differences.

Covered Conductor Capital Costs

SCE

CC Unit Cost Make Up

The costs in SCE's WCCP incur through the main cost categories of labor, materials, contracts, overhead, and other and are captured in SAP work orders. SCE's unit costs have historically been presented as direct costs only (exclude corporate overheads and financing costs), and is the average cost of nine different regions within SCE's service area. For purposes of this report, SCE has added corporate overheads (to the overhead cost category) and financing costs to its direct unit cost for comparison with the other utilities.

SCE has two covered conductor designs that vary depending on system voltage requirements. These include 17 kV and 35 kV covered conductor designs, the former of which SCE utilizes on its 12 kV and 16 kV distribution systems, and the latter of which SCE utilizes on its 33 kV distribution systems. The primary difference between these two designs is the thickness of the inner and outer layers. For example, 35 kV covered conductor design has a thicker covering, allowing it to withstand intermittent contact at higher voltages. Additionally, SCE uses four ACSR conductor sizes (i.e., 1/0 AWG , 336.4 (18x1) AWG, 336.4 (30/7) AWG, 653.9 AWG) and three copper conductor sizes (i.e., #2 AWG, 2/0 AWG, 4/0 AWG). Circuit and customer loading requirements will determine the conductor size. SCE may also use higher strength conductors to resolve ground clearance issues in areas subject to ice. The vast majority (99%) of SCE's covered conductor installations have been with the 17 kV covered conductor design which is lower cost than the 35 kV covered conductor design.

SCE installs covered conductor in an open-crossarm configuration. In this configuration, the conductor is self-supporting and attached to insulators on crossarms at the structure. SCE's WCCP also includes the installation of FRPs, composite crossarms, wildlife covers, polymer insulators, and vibration dampers. SCE uses FRPs, which are more expensive than wood poles, when pole replacements are required to meet pole-loading criteria. SCE replaces, on average, between 10 to 12 poles per circuit mile. Composite crossarms are also used to replace traditional wood crossarms as part of the WCCP. Like composite poles, composite crossarms are also higher cost than wood crossarms. SCE also employs wildlife covers and installs them on dead-ends, terminations, equipment jumper wires, connectors, and equipment bushings. In areas below 3,000 feet in elevation or high-tension installations, SCE requires the use of vibration dampers to mitigate conductor damage due to Aeolian vibration.

SCE primarily uses contractors to construct its covered conductor projects and a mix of contract and SCE labor to design its covered conductor projects. SCE field labor and contract field labor costs are charged directly to the project work orders. SCE design resources charge a division overhead account that gets allocated to work orders because SCE planners work on multiple types of projects. Costs for design scope performed by contractors is charged directly to the covered conductor work order (contract category) because this contracted work is specific to covered conductor projects. Materials such as conductor, poles, and crossarms are charged directly to the project work order. The Overhead category includes operational resources and items centrally managed and include costs such as equipment (e.g., vehicles, tools and supplies for field work) and managerial resources that are allocated to work orders. As noted above, the Overhead category also includes corporate overheads, which includes costs for administrative and general, pension and benefits, payroll taxes, injuries and damages, and property taxes.

Cost Drivers

SCE's covered conductor projects have an estimated timeframe of 16 – 22 months from initial scoping to project completion. There are many factors that may impact the total project lifecycle and costs, including permitting and environmental requirements, easements, geography and terrain, construction resource availability, and other construction-related factors. The largest driver of the cost is typically the contract cost for which contractor rates and construction time vary across locations in SCE's HFRA. For example, regions with more difficult terrain and mountainous areas typically have higher contractor rates. Projects in these areas also typically take longer to construct and require more costly construction methods (e.g., helicopter use). Beyond challenging terrain, projects can take more time due to other factors such as permitting, weather (e.g., rain/snow conditions, Red Flag Warning (RFW) days, etc.), and environmental restrictions (e.g., nesting birds that don't allow crews to work in certain areas until the birds have fledged). There are also many other drivers that can increase costs such as local agency restrictions (e.g., only night work allowed), direct environmental costs (e.g., if biological monitors are required), vegetation (i.e., requires vegetation clearing), access constraints (i.e., requires helicopter construction and/or access road rehabilitation), customer impact (i.e., temporary generation required for a circuit), and operating restrictions (e.g., crews are pulled off work). Many of these factors can also limit flexibility and reduce productivity causing construction costs to increase. The cost per circuit mile in some regions, such as SCE's Rurals Region, is more expensive than other regions. In some instances, this cost difference can be $300,000 or more per circuit mile.

As seen in Table 15, SCE's unit cost is the lowest of the six utilities. While SCE has described many factors that affect its covered conductor costs, some of the reasons why SCE's costs may be lower than the other utilities include economies of scale with SCE installing over 1,000 circuit miles per year and its ability to bundle work for its contractors. Bundling work enables multiple projects to be completed in the same general area which minimizes mobilization and demobilization costs and increases contractor productivity. SCE has also not generally observed a steady nor large amount of vegetation management or access road rehabilitation costs across its installations. With thousands of circuit miles installed, these types of incurred costs are low when averaged across SCE's portfolio of completed installations. As noted above, SCE also only replaces, on average, 10 to 12 poles[10] per circuit mile and its WCCP is focused on covered conductor and does not include other major equipment upgrades.

PG&E

CC Unit Cost Make Up

PG&E's data set represents System Hardening projects scoped by Asset Management and approved by its Wildfire Steering Governance Committee. The covered conductor projects go through the following major phases to completion:

- Estimating and Design
- Dependency (Permitting, Land Rights and Environmental Review)
- Construction Resourcing and Contracting

[10] SCE's average number of poles per circuit mile is approximately 29. As such, 10-12 poles represents approximately 34% to 41% of the average number of poles per circuit mile.

- Construction
- Document and Close Out

A subset of these projects is “Fire Rebuild” projects. These set of System Hardening projects arise from hardening scope after a fire or other emergency events in Tier 2/3. Due to the emergency nature to rebuild assets quickly to serve the community, all the steps described above in base System Hardening are accelerated.

PG&E’s unit cost analysis is based on fully completed projects with costs-since-inception (including costs from previous years) recorded in its system of record (SAP). Based on that criteria, the data set captures 111 miles worth of projects that were completed in 2021. Construction transpired in 11 different divisions with varying terrains and conditions. 14 miles were Fire Rebuild, which typically have a lower unit cost, the remaining 96 were Base (regular) System Hardening.

Costs were organized per the six main categories agreed upon with the other utilities. The summary table blends both contract and internally resourced projects. 44 miles were constructed using external crews, categorized as Contract and 66 miles were constructed using Internal labor, categorized as Labor.

PG&E’s Overhead Hardening (covered conductor installation) scope achieves risk reduction through these foundational elements: bare primary and secondary conductor replacement with covered equivalent, pole replacements, non-exempt equipment replacement, overhead distribution line transformer replacement with transformers that have FR3 fluid, framing (composite crossarms and insulators) and animal protection, and vegetation clearing.

Cost Drivers

PG&E’s covered conductor installation costs are driven by these key contributors:

- Pole replacement – nearly 100% of the poles require replacement due to the additional weight/sag of the new covered conductor.
- PG&E incorporates numerous initiatives into a single hardening project. Non-exempt equipment and ignition component replacement impacts the cost by including the material and labor installation cost of the new equipment where it requires replacement.
- Vegetation clearing in support of the new overhead line can be a significant cost added to these projects. Both the increased height of the poles, the widened cross-arms, and the increased sag of the line can vary the cost considerably. This cost alone can add between $50,000 to $400,000 per mile depending on the terrain and the location of the line. The rural nature of much of the high-risk HFTD infrastructure drives this need.

SDG&E

CC Unit Cost Make Up

Each project goes through a six-stage gate process as follows:

Stage 1 – Project Initiation (duration ~1-3 months)

Stage 2 – Preliminary Engineering & Design (duration ~6-9 months)

Stage 3 – Final Design (duration ~3-5 months)

Stage 4 – Pre-Construction (duration ~1-2 months)

Stage 5 – Construction (duration ~3-4 months)

Stage 6 – Close Out (duration 8~-10 months)

The total duration of a project has an estimated duration of approximately 22 to 33 months.

SDG&E's covered conductor per mile unit capital costs is made up of the following six major cost categories:

1. Labor (internal) – directs costs associated with SDG&E full-time employees (FTE), including but not limited to individuals from project management, engineering, permitting, environmental, land management, and construction departments. This cost assumes approximately 25% of the electric work is completed by internal SDG&E construction crews.
2. Materials – estimated costs of material used for construction including steel poles, wire, transformers, capacitors, regulators, switches, fuses, crossarms, insulators, guy wire, anchors, hardware (nuts, bolts, and washers), signage, conduit, cable, secondary wire, ground rods, and connectors.
3. Contractor – estimated costs for construction-related services, including civil construction contractors for pole hole digging, anchor digging and substructures, and street/sidewalk repair; electrical construction for pole setting, wire stringing, electric equipment installation and removals; vegetation management where required including tree trimming or removal, and vegetation removal for poles and access paths; environmental support services including biological and cultural monitoring; traffic control; and helicopter support for pole setting, wire stringing, and removals. This cost assumes approximately 75% of the electric work is completed by contract crews.
4. Overheads – estimated costs associated with contracted services not related to construction including engineering, design, project management, scheduling, reporting, document management, GIS services, material management, constructability reviews by Qualified Electrical Worker (QEW), staging yard leases/setup/teardown/maintenance, and permitting support throughout the entire lifecycle of a project, as well as services related to program management including long term planning and risk assessment.
5. Other – estimated costs associated with indirect capital costs. These costs are estimated to be approximately 14.3% of direct capital costs that accumulate on a construction work order. This includes administrative pool accounts that are not directly charged to a specific project, including internal labor vacation, sick, legal, and other expenses.
6. Financing Costs – estimated costs associated with the collection of AFUDC when a construction work order remains active. Most SDG&E jobs are active for approximately 6 to 10 months from the time the job is issued to construction until it is fully completed and the collection of AFUDC charges stop.

Cost Drivers

Costs can vary significantly from project to project for a variety of reasons, including engineering and design, land rights, environmental, permitting, materials, and construction. Below is a description of these factors and why the costs can vary from project-to-project.

Engineering & Design: SDG&E collects LiDAR (Light Imaging Data and Ranging) survey data before the start of design and again after construction is completed. During the LiDAR data capture, other data including photos (i.e., ortho-rectified images of the poles and surrounding area, and oblique pole photos), and weather data is acquired. After collection of the raw LiDAR and Imagery data, it is processed to SDG&E's specification and includes feature coding and thinning of the LiDAR data, and selection and processing of the imagery data. The entire process for delivery to SDG&E's specification can take weeks to months depending on the size of the data capture. This LiDAR data capture is used to support the base-mapping, engineering, and design processes (Stage 1 and Stage 6).

Currently, the engineering and design of all covered conductor projects are conducted by engineering and design consultants, and their deliverables are reviewed by a separate Owner's Engineering (OE) consultant to ensure compliance with SDG&E standards and guidelines. At this time, SDG&E does not have the resources to conduct the engineering and design required at this scale of work; however, there is an assigned SDG&E full time engineering staff that provide oversight of all engineering and design consultants, including the OE. The engineering component of work relates to the structural analysis, including Power Line Systems – Computer Aided Drafting and Design (PLS-CADD) modeling, foundation calculations, or geotechnical studies. The design component includes the drafting, entering design units into SAP for material ordering and costing, and building the job packages that are sent to construction. In some cases, one consultant can perform both the engineering and design function, and in others cases an engineering consultant collaborates with a design consultant. In all cases, SDG&E's Owner's Engineer will perform both engineering and design review support. Costs from consultants can vary depending on the size and complexity of the project, and due to various other factors including environmental constraints, land constraints, permitting requirements, or scoping changes that can occur from the start of design and throughout construction. The design stage (i.e., start of design to issuance of job package to construction) typically takes anywhere from six months to two years depending on the size and complexity of the project and the challenges with acquisition of land rights, environmental release, and permitting.

SDG&E requires every pole be engineered using PLS-CADD software during two stages of the project lifecycle, the design phase and the post-construction phase. This software allows SDG&E to leverage LiDAR survey data (pre- and post-construction) and AutoCAD drawings, and to design the poles, wire, and anchors to meet General Order (GO) 95 Loading (Light and Heavy Loading) and Clearance Requirements, and to meet Known Local Wind requirements (e.g., 85 mph and in some cases 111 mph wind). SDG&E also requires its engineering and design contractors who use the PLS-CADD software to have a California-registered Professional Engineer oversee and stamp the final PLS-CADD design.

Land and Environmental**:** SDG&E requires all projects to go through a land and environmental review process at each stage of the design process. These processes are predominantly supported with the help of land management and environmental service consultants but are overseen by SDG&E representatives in each respective department. The land process includes research of SDG&E's land rights, interpretation, and may include support obtaining the proper land rights when required. Through the land rights review process, SDG&E determines the land ownership its facilities (e.g., poles, anchors, and wire) are within and get an interpretation of the limits of its land rights. The results are shared with the engineering and design team and environmental. Once the land rights are determined, environmental performs an assessment, determines the environmental impacts if any, and provides input to the design process to minimize and/or avoid environmental impacts. These land and environmental reviews can drive changes to the design and add time and cost to the project. For example, in many cases, SDG&E does not have the land rights to build the overhead covered conductor design within its existing easement, or in some cases it only has prescriptive rights. In those cases, SDG&E must amend or acquire the proper land rights, or redesign the project, if possible, to stay within the land and/or environmental constraints. If acquiring or amending land rights is required, this can take weeks to months depending on the property owner (e.g., private, BIA, State, Federal, or Municipality) and the level of change to the existing conditions.

Materials: SDG&E's philosophy with covered conductor, like SCE, is to install it in an open-crossarm configuration. In this configuration, the conductor is self-supporting and attached to insulators on crossarms at the structure. Where connections are necessary, piercing connectors are used to avoid stripping the wire and causing damage to the conductor and negating the need to wrap the connection with insulating tape. SDG&E also requires the use of vibration dampers, where necessary, to mitigate conductor damage due to Aeolian vibration. SDG&E replaces most wood poles to steel, and in some cases replaces existing steel poles if they are not adequate to support the new wire (e.g., inadequate clearance and/or mechanical loading capacity). In many cases equipment is replaced during these reconductor projects if it is older, is showing signs of failure, and/or needs to be brought up to current standards. The reason to replace wood poles with steel is due to several reasons, including the fact steel is more resilient to fires than wood and is seen as a defensive measure, steel is a man-made material and the strength and dimensions are consistent and have much smaller tolerances than wood, and because many of SDG&E's wood poles are over 50 years old. In some cases, SDG&E may also need to relocate the pole line to an area where it is more accessible to build and maintain but will require obtaining a new easement. SDG&E also replaces wood crossarms with fiberglass crossarms, insulators with polymer insulators, switches, and regulators. For transformers, SDG&E developed specific criteria for replacement. For example, where a transformer will be replaced if it is internally-fused regardless of age, if it's greater than 7 years old, if it has visual defects or damage (leaks, burns, corrosion, etc.), is less than 25 kVA, or if the transformer does not pass volt-drop-flicker calculation. SDG&E also replaces secondary wire that is either open (non-insulated) or "grey wire" (covered secondary wire where the insulation is grey in color). On most projects, there is a smaller underground job associated with the overhead work. This occurs when a pole feeds underground (e.g., a Cable or Riser Pole) and the new pole location may be too far from the existing position such that the existing cable, conduit, and terminations may not reach the new pole position. In these cases, a small job will be initiated to have the crews intercept the run of underground conduit, install a new handhole, install a new run of conduit and cable to the new pole location, and splice the cable in the new handhole to make the connection to the existing underground system.

In 2021, SDG&E experienced significant material supply chain issues, especially with covered conductor materials due to impacts from COVID-19. In the case of covered conductor, SDG&E currently sources the wire from multiple suppliers; however, the associated materials such as piercing connectors and piercing dead-ends come from one supplier out of Europe and experienced significant delays in getting orders delivered due COVID-19 and issues with US Customs paperwork. SDG&E also experienced delays receiving other material due to COVID-19 supply chain disruptions and competition for the same materials used by other utilities including transformers and other materials common to various utilities across the country. Material delays can cause construction delays or cause construction to work less efficiently, thus impacting project schedules and costs.

Construction: One of the most significant variables, and most difficult to predict, is the civil portion of construction. The civil portion of a project includes the pole hole and anchor hole digging and can vary significantly depending on several factors including accessibility (truck accessible versus non-truck accessible), soil conditions (rock versus soft soil), methods of digging (hand tools versus machine), and environmental constraints that may limit the method of digging or dictate access protocols. For example, a 0.7 miles project completed a couple of years ago was on the side of a steep mountain side and all the material, equipment (pneumatic drill and hand tools), and crews had to be flown in and out every day for months. The civil crews encountered significant rock at most locations and the spoils from the digging had to be flown out via helicopter due to the restrictions placed on construction due to environmental concerns rather than be spread-out on location. Each pole and anchor were back-filled with concrete using helicopters because of the slope of the mountain and due to the significant mechanical loading due to winter storms. In contrast to this mountain side project example, SDG&E has had other projects that are truck accessible, that do not require concrete backfill and allow it to reuse the spoils for backfill or spread out on location.

Another reason costs can vary significantly from project to project is due to the time of year and location. SDG&E often deals with elevated fire weather conditions which requires a dedicated fire watch crew to be present at each location where there is work happening that can be a fire risk. In some cases, SDG&E has multiple dedicated fire watch crews on a project as there may be multiple civil or electric crews working at different locations at the same time on the same project. Some locations are also so remote that the drive time from the staging yard to the site can take a significant amount of time out of each workday that the crew may work longer hours and/or over the weekend, including Sundays, thus increasing overtime hours for the construction crew and all other support services (e.g., traffic control, environmental monitors, etc.). In some cases, generators are used due to the remote nature of some customers and the lack of ties with other circuits in SDG&E's service area. Generators require special protection schemes, equipment, and resources to adequately plan, deploy, setup, monitor, and tear-down which increase the installation costs.

Lastly, construction costs can vary depending on the crew building the project and issues encountered during construction that were not anticipated during design. SDG&E currently uses four primary construction contractors who perform the electrical construction and typically sub-contract the civil work (e.g., pole hole and anchor digging), helicopter, traffic control and dedicated fire watch. SDG&E also uses internal electric construction teams who typically contract out the helicopter, traffic control, dedicated fire watch and civil work (pole hole and anchor digging). Based on SDG&E's experience with its traditional hardening program, 75% of the work is performed by contractors and 25% by internal crews. The costs between external and internal crews can vary depending on the work scope, location (rural versus very rural), methods of construction (e.g., truck accessible versus non-truck accessible), time of year (e.g., fire season and non-fire season and wet weather versus dry), and issues encountered during construction. Larger projects (typically 20 or more poles) that are not assigned to an internal crew are sent out to bid with the four prime construction contractors and often bundled together on the same circuit to gain economies of scale. SDG&E has determined that its ideal bid size is 100-200 poles; however, some bids have been significantly greater (e.g., approximately1,400 poles and over 60 projects) and some can be much smaller. The size of bids can change significantly depending on the location of a project, time of year, and schedule of the project. SDG&E also sees changes with pricing due to competition for construction resources with the other utilities in the state and this can drive-up costs depending on the volume of work and timing with other projects statewide.

PacifiCorp

CC Unit Cost Make Up

As included in its 2021 WMP Update Change Order filed November 1, 2021, PacifiCorp has historically broken down the costs of covered conductor into four main categories: Design, Materials, Construction, and Program Management. However, to better align with other utilities, and avoid confusion, for the purposes of this report, PacifiCorp reports the costs of covered conductor in the six main categories. These six categories are described below.

1. Labor (Internal): Internal labor charged directly to the project including project managers, project support staff, engineers, and field personnel.
2. Materials: All materials installed as part of covered conductor projects.

3. Contractor: Contracted services which are primarily design, estimating, permitting, vegetation management, and construction labor.
4. Overhead: Costs allocated to covered conductor projects such as surcharges for material handling and engineering overheads.
5. Other: Direct costs not covered in one of the other categories.
6. Financing Costs: AFUDC charges on the projects.

Cost Drivers

PacifiCorp has identified five main cost drivers for the installation of covered conductor. The cost drivers are discussed below in terms of cost increases that have been experienced, highlighting how impactful these components can be on the overall project cost.

Access: PacifiCorp includes costs for required access to facilitate project construction in covered conductor projects charged to the work order. These costs may include vegetation clearing, road construction, or other site preparation activities. These costs will typically be included in the contractor total for purposes of this cost analysis as this work is predominantly contracted. Additionally, these costs can also range significantly between projects based on the specific location and terrain where work is conducted.

Pole Replacement: PacifiCorp evaluates all poles for strength and clearance using PLS CADD. Poles are then selected for replacement for the following reasons: insufficient strength to accommodate covered conductor, insufficient minimum clearance, relocation is required, or not constructible in current state. Through 2021, the average pole replacement rate has ranged from 2 to 22 per mile leading to significant variability in the per mile job cost. Pole replacements also significantly impact labor and material costs (as described below) due to the change in scope of the project. Current cost forecasts assume 20 poles per mile will need to be replaced. Additionally, nearly all poles identified are replaced with non-wood fire resistant materials (predominantly fiberglass) at a greater cost than like-for-like replacement with wood.

Construction Labor: As included in its 2021 Change Order, PacifiCorp experienced significantly higher than anticipated labor costs in 2020 and 2021 based on regional contract rates, construction complexity/time, and overtime requirements to meet project deadlines. Current cost forecasts indicate that this increase will continue in 2022 and future years.

Materials: As included in the company's 2021 Change Order, PacifiCorp also experienced additional material costs due to the number of pole replacements. Currently, incremental pole replacements add approximately $3,500 per pole in material costs alone. Additionally, supply chain constraints in 2021 resulted in the need for expedite fees, crew re-mobilization costs, and/or use of alternate materials at higher costs.

Permitting: As included in the company's 2021 Change Order, significant cost increases have been experienced for locations requiring access into seasonal wetlands and transmission under build projects. Future projects include environmentally sensitive areas that have been in NEPA or CEQA review with high environmental review costs.

Based on the cost drivers discussed above, PacifiCorp anticipates higher costs for projects in 2022 and beyond.

BVES

CC Unit Cost Make Up

The following costs are charged to project work orders: Design, materials, construction labor and overhead cost. BVES contracts out most of the work with a BVES Field Inspector overseeing the whole project. The design consists of BVES contractor performing field visits, wind loading calculations, developing the design and assembling the material lists. BVES purchases the materials and its contractor does the construction. The overhead costs consist of BVES internal groups. The capital cost per circuit mile are based on a double circuits' area in 2021.

Cost Drivers

BVES service area is in mountainous terrain at approximately 7,000 ft elevation and consists of a 34.5 kV Delta 3-wire system and a 4.16 kV Wye ground 4-wire system. For the 34.5 kV system, 394.5 AAAC is the primary source of covered conductor and 336.4 ACSR is used as a secondary source of covered conductor. For the 4.16 kV 3-phase system, 394.5 AAAC is the primary source of covered conductor and 336.4 ACSR is used as the secondary source of covered conductor. In addition, BVES uses the 4.16 KV (2 or 1) phase system 1/0 ACSR covered conductor. When constructing covered conductor, BVES follows the CPUC's GO 95 Rule 43.1 Grade A Heavy Loading District Construction Standard (Grade A Standard). Based on the Grade A Standard, new poles are required to have a safety factor of 4.0 whereas an existing pole safety factor is 2.67. BVES and BVES's contractor are required to wind load each pole with 6lb/ft wind speed + 0.5 inches of ice. Due to the higher elevation and Grade A standard, BVES is required to replace a pole with a larger size pole to meet the required safety factor. These large poles have a much higher cost than a standard size pole. BVES replaced approximately 70% of its poles per mile of covered conductor installation. The installation and material costs of the replacement poles is one driver that has increased costs for BVES covered conductor projects.

Liberty

CC Unit Cost Make Up

Liberty's covered conductor program is relatively new and limited in scope compared to the other utilities. Liberty first piloted covered conductor projects in 2020 in select areas that already needed line upgrades because of asset age and condition, and later focused on projects that targeted short line segments in HFTD areas, had reliability issues, and were in remote areas. An average of recent covered conductor projects amounted to less than one circuit mile per project and only a total of eleven miles of covered conductor were installed over the last two years. Liberty's covered conductor work is substantially less compared to, for example, SCE's approximate 1,000 miles of covered conductor installed each year.

Liberty's covered conductor unit costs will vary depending on the terrain, number of poles replaced, type of conductor installed, project design and permitting requirements, and amount of vegetation management work required for the job order.

Liberty's covered conductor capital costs per mile is made up of the following six major cost categories:

1. Labor (internal) – Internal Labor represents Project Management, Engineering, Operations, Arborists and Line Crews dedicated to the capital job, and cost of removal.
2. Materials – Materials includes poles, crossarms, insulators, down guys, anchors, transformers, hardware, and covered conductor wire purchased through Liberty supply chain operations.
3. Contractor – Contract charges are for construction contractors and professional services to design and execute project scopes. Contract costs also include line clearance qualified tree crews needed to prune and remove trees along the covered conductor line route.

4. Overheads – Overheads are allocated to active job orders monthly based on capital spend. At Liberty, this could include indirect labor, A&G, capital overheads, fleet, and small tools allocations.
5. Other – Other is reserved for taxes applied to the job.
6. Financing Costs – Financing costs capture AFUDC accumulated costs in the covered conductor job order.

Cost Drivers

Liberty's project life cycle ranges from 18-36 months depending on project scope and permitting complexity. There are many factors that may impact the total project life cycle and costs, including permitting and environmental requirements, easements, geography and terrain, and construction resource availability. A major cost driver for Liberty is the contractor costs for construction in its service territory. Projects typically take longer to construct because of the mountainous terrain and require more costly construction methods like helicopter use, dewatering, hard rock excavation and hand digging. Other factors include permitting, weather, and environmental restrictions that will limit scheduling flexibility and reduce productivity, causing construction costs to increase.

Conductor Type: Liberty has two covered conductor designs that vary depending on project site access and terrain. These include 14.4 kV delta Aerial Spacer Cable (ACS) and tree wire solutions at this voltage level. In addition, Liberty has piloted the use of tree wire solution on its 12.5 kV grounded Wye system. Liberty selects the two different system options based on installation and maintenance considerations of the two solutions.

The ACS solution has 2 or 3 covered conductors supported by a steel messenger. The framing for ACS includes brackets that hold the messenger under tension and for the current carrying conductors at full sag, or zero tension. Installing and maintaining spacers requires a bucket truck, however, if accessibility is an issue, crews might require a Bosun Chair to access the line, adding to the costs.

The tree wire solution includes various sizes of covered wire such as a 1/0, 2/0, or 397 kcmil AAC. The ACS solution projects have installed 1/0AA wire with 1-052 AWA messenger and 1/0 AAC with 6AW messenger. Tree wire is installed with framing similar to bare conductor wire in an open-crossarm configuration for framing and installation. Tree wire is the preferred solution in areas with limited bucket truck access. Conductors are sized based on circuit load for both solutions. Wind and Ice loading are concerns in the Liberty territory, so Liberty does not utilize conductors smaller than 1/0.

Location: A vast majority of Liberty's service territory is in HFTD Tier 2 and Tier 3. In the initial phases of its covered conductor program, Liberty selected areas of its service territory based on local knowledge of the wildland/urban interface, locations of high fire threat districts, remoteness of overhead lines, and the age and condition of the infrastructure. Areas were also chosen based on their accessibility and egress options during an emergency. Most of Liberty's covered conductor projects are in Tier 2 and Tier 3 at elevations between 6,200 to 7,500 feet over rugged, rocky terrain with limited seasonal access. Projects typically utilize helicopter pole sets and crews are tasked with digging pole holes with pneumatic tools by hand versus with trucks with augers. Pole holes take days versus hours to excavate, increasing labor hours and costs.

Pole and Asset Replacements: Most of the covered conductor projects Liberty has designed and constructed have required a significant number of pole replacements per circuit mile. When replacing existing poles, Liberty uses taller and larger class poles. This is due to new loads and increased weights of the covered conductor, as well as the age of existing infrastructure. Projects include installation of poles, insulators, crossarms, anchors (rock anchors), down guys, transformers, and switches. One example is the Lily Lake covered conductor project that required 50 pole replacements for the approximately two miles of covered conductor installed. The terrain at Lily Lake is remote and characterized by massive, expansive boulder fields; making pole hole digging a very labor-intensive operation. Most of the work was conducted by hand crews and helicopters due to the remote terrain.

Economies of Scale: Compared to SCE and PG&E, that have thousands and hundreds of covered conductor circuit miles installed, Liberty has limited contract resources available during its construction period. Liberty's ratio of miles installed when compared to utilities with significantly more miles installed likely leads to higher contract costs on a per mile basis. This factor has likely contributed to Liberty's higher covered conductor cost per circuit mile.

Construction: Liberty's primary construction window is from May 1st to October 15th due to weather and TRPA (Tahoe Regional Planning Agency) dig season restrictions. The construction window also coincides with seasonal tourism, a high number of Red Flag Warning (RFW) days, and during the typical fire season that further limits construction efforts and effects costs. These restrictions also constrain resources and adds a premium on labor during construction season.

In 2021, Liberty's prime construction season was impacted by fires in Northern California. For example, the Tamarack fire in Markleeville required Liberty to utilize all internal and contract resources to respond to the fire and restore power. This was a 3- to 4-week impact where contractors working on covered conductor projects had to be re-assigned to respond to the fire. Liberty has also experienced extremely poor air quality due to area fires with Particulate Matter (PM) 2.5 > 500 ug/m^3. The poor air quality frequently interrupted construction causing increased mobilization and demobilization costs. The poor air quality impacted project schedules by approximately three to four weeks with no workdays when AQI was +500 in the Tahoe Basin. Finally, the Caldor fire forced evacuations in South Lake Tahoe, where the majority of Liberty's covered conductor projects were located further impacting construction costs.

Vegetation Management: Liberty's service territory is in a high elevation and mountainous terrain that is densely forested, averaging over one hundred trees per mile within maintenance distance of the conductor given recent 2020 LiDAR data. Vegetation management inspectors and tree crews often need to access work sites on foot while carrying tools and equipment resulting in much higher labor costs compared to typical work areas. In addition, due to the robust tree canopy in the Tahoe region, tree crew cost per circuit mile of construction has increased significantly due to SB 247 labor rate increases. Tree removals and pruning costs are unique to Liberty's service area and will increase the overall covered conductor project costs.

Next Steps

In 2022, the utilities plan to continue this sub-workstream and will further discuss and document covered conductor recorded/estimated unit costs and cost drivers as well as assemble and compare initial unit costs for alternatives. The utilities will provide an update on these efforts in their 2023-2025 WMPs.

Conclusion

This report provides descriptions of the progress of this Joint IOU effort to better understand the long-term effectiveness of covered conductor and its ability to reduce wildfire risk and PSPS impacts (and, in comparison to alternatives). The utilities have made progress on each sub-workstream and describe plans for 2022 to improve the data and analyses that have been compiled, including assessing methodologies that can be employed across all utilities to improve comparability. These efforts continue to show that covered conductor has an effectiveness between approximately 60% and 90% at reducing the drivers of wildfire risk. Additionally, the report shows covered conductor is effective at reducing the impacts of PSPS in comparison to bare conductor systems. The alternative analyses also present high-level assessments of select alternatives in comparison with covered conductor at reducing PSPS impacts. The utilities look forward to continuing these efforts in 2022 and providing an update in their 2023-2025 WMPs.

Appendix A: Covered Conductor Benchmarking Survey Results

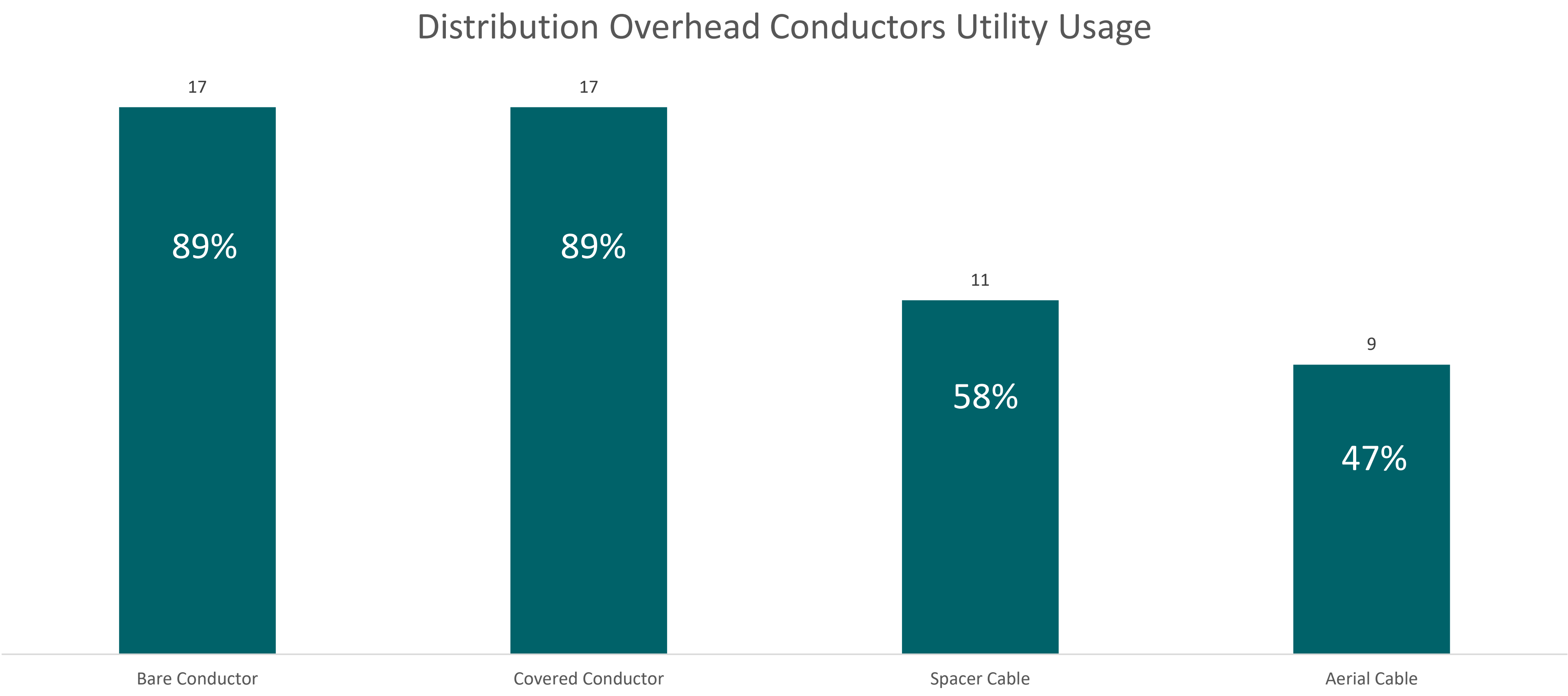
Covered Conductor Benchmarking Survey Results

Joint IOU CC Effectiveness Workstream

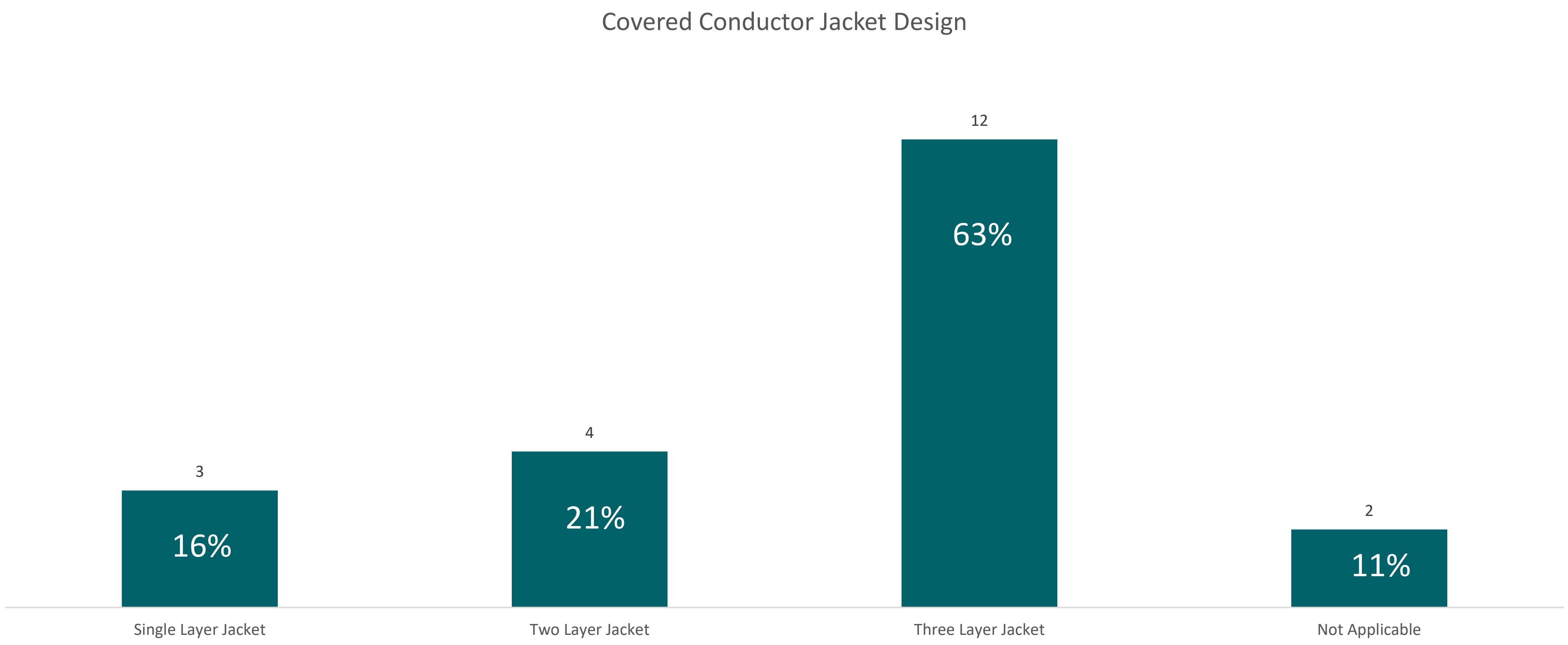
Participants

1. American Electric Power
2. Ausnet Services
3. Bear Valley Electric Service, Inc.
4. Duke Energy
5. Essential Energy
6. Eversource Energy (CT)
7. Korean Electric Power Corporation
8. Liberty
9. National Grid
10. Pacific Gas and Electric Company
11. PacifiCorp
12. Portland General
13. Powercor
14. Puget Sound Energy
15. San Diego Gas & Electric
16. Southern California Edison
17. TasNetworks
18. Tokyo Electric Power Company
19. Xcel Energy

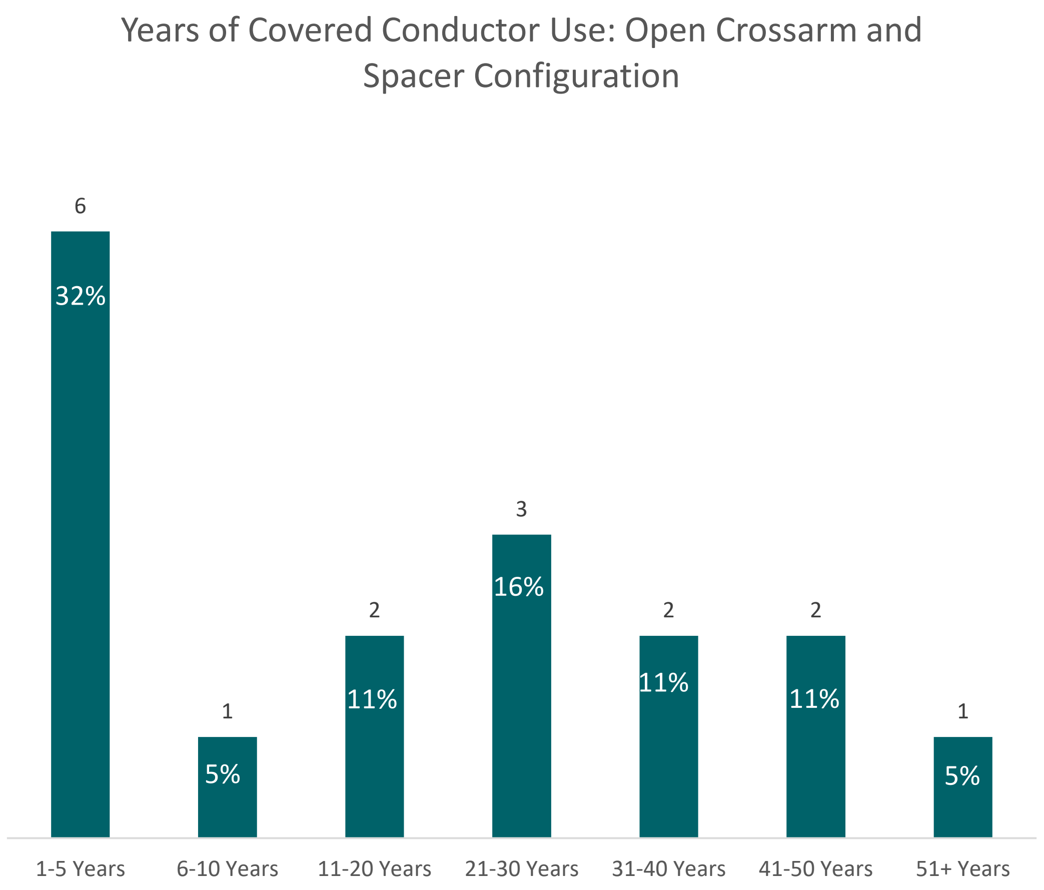
What types of overhead conductors does the utility utilize in its distribution system?

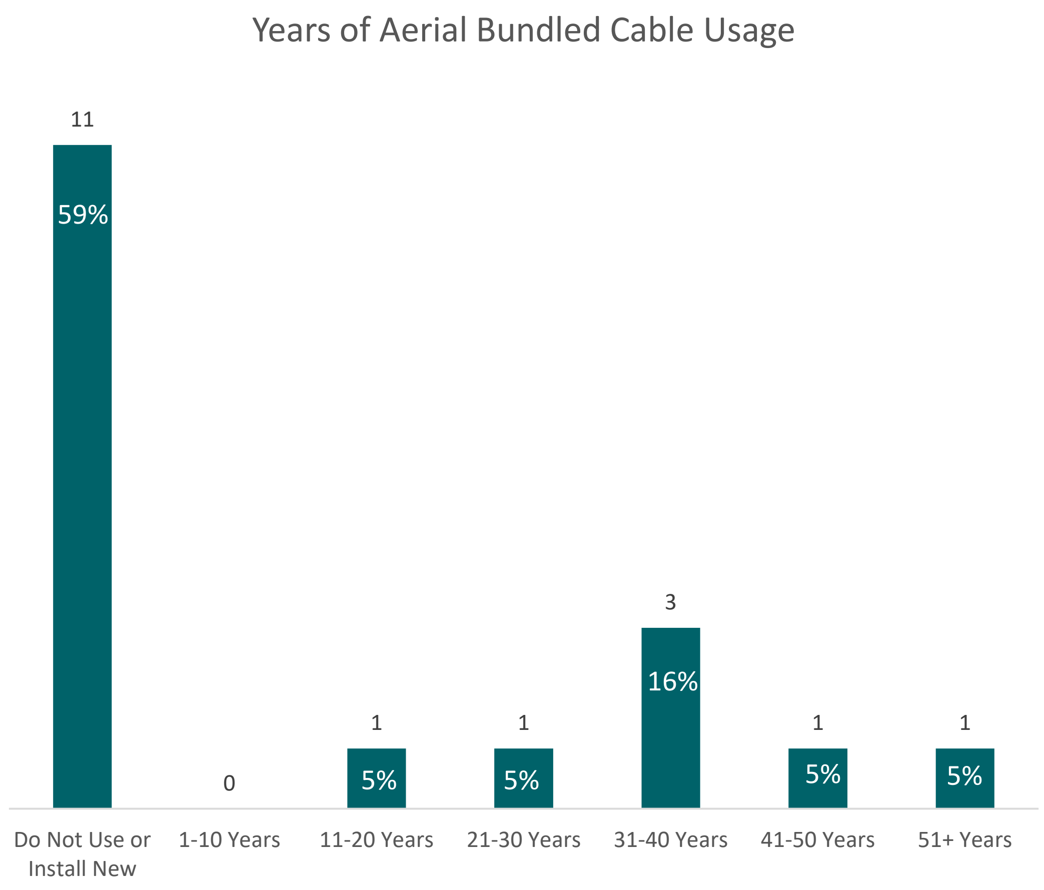


What type of covered conductor design does the utility utilize?

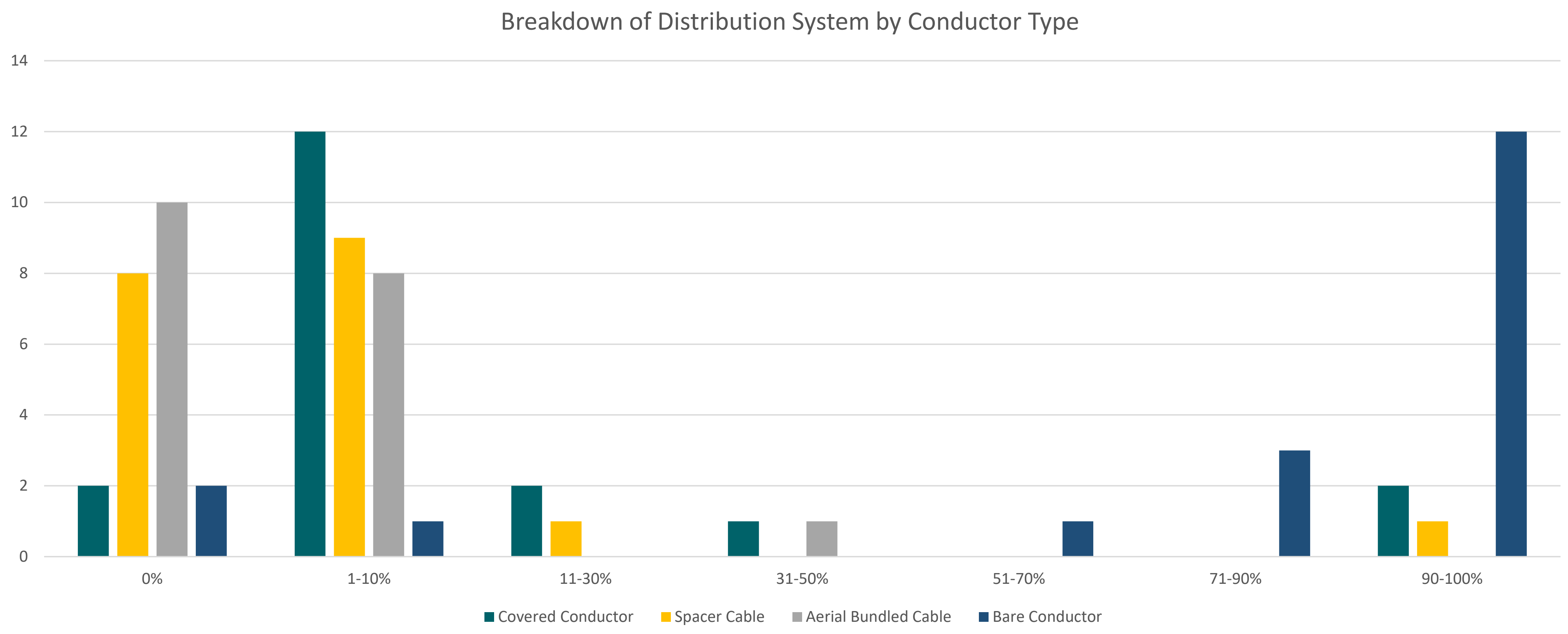


Years of Covered Conductor and Aerial Bundled Cable Usage





What percent of the primary distribution system is covered conductor vs. spacer cable vs. ABC vs. bare conductor?



Circuit Miles of Covered Conductor, Spacer Cable, and ABC Installed

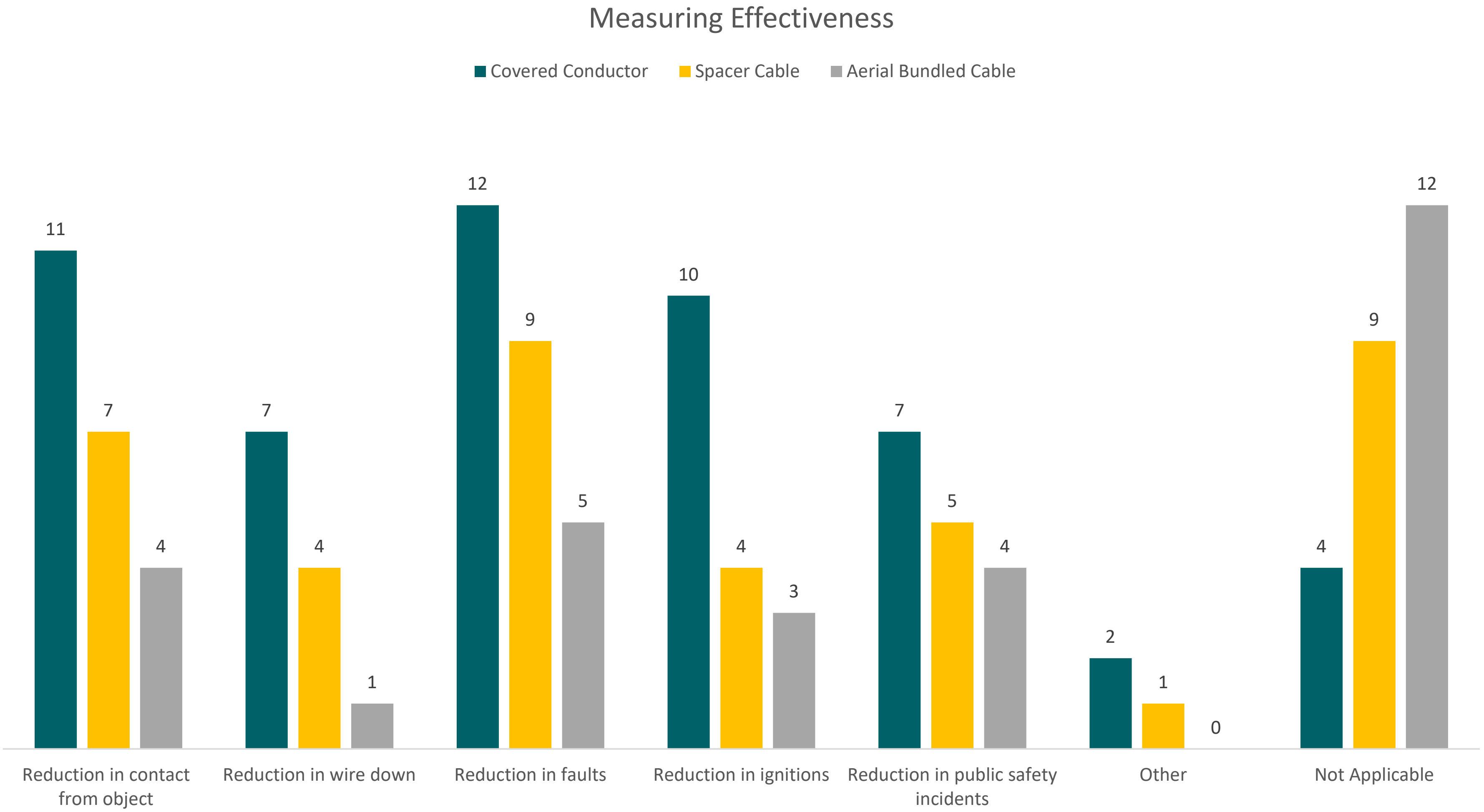
Utility	Covered Conductor Circuit Miles	Spacer Cable Circuit Miles	Aerial Bundled Cable Circuit Miles
American Electric Power	156	137	0
AusNet Services	5	25	125
Bear Valley Electric Service, Inc.	22	0	0
Duke Energy	0	0	0
Essential Energy	2,500	0	1500
Eversource Energy (CT)	8,000	520	200
Korean Electric Power Corporation[1]	120,485		
Liberty	5	2	0
National Grid	4,000	3,000	1,000
Pacific Gas and Electric Company	820	0	3
PacifiCorp	0	60	0
Portland General	243	9	0
Powercor	6	1	60
Puget Sound Energy	1,500	1	0
San Diego Gas & Electric	22	2	0
Southern California Edison	2,187	0	64
TasNetworks	2	0	10
Tokyo Electric Power Company[2]	267,190		16,156
Xcel Energy	0	50	0

1. Korean Electric Power Corporation uses Covered Conductor and Aerial Bundled Cable. Value represents total circuit miles of Covered Conductor and Aerial Bundled Cable. Circuit mile data is based on information provided from previous benchmarking
2. Tokyo Electric Power Corporation uses Covered Conductor and Spacer Cable. Value represents total circuit miles of Covered Conductor and Spacer Cable.

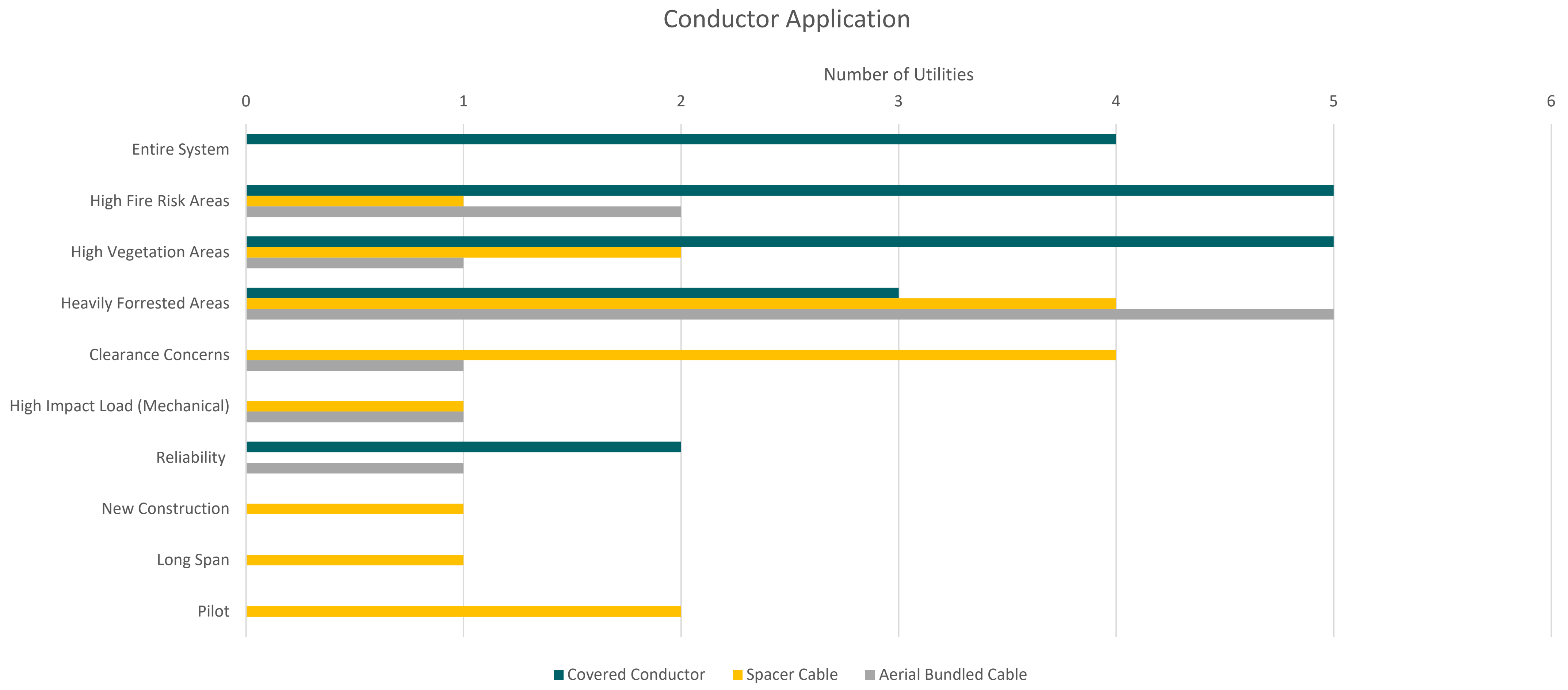
Outage and Ignition Tracking

Utility[1]	Track Outage Counts for Bare vs. CC?	Has use of CC, Spacer Cable, or ABC reduced faults?	Track ignition Counts for Bare vs. CC?	Has use of CC, Spacer Cable, or ABC reduced ignitions/ignition drivers?	If no ignition reduction, why?
American Electric Power	No	Yes	No	Yes	
AusNet Services	No	Yes	No	Yes	
Bear Valley Electric Service, Inc.	Yes	Yes	Yes	No	No prior ignitions
Duke Energy	NA	NA	NA	NA	Does not use CC
Essential Energy	Yes	Yes	Yes	Yes	
Eversource Energy (CT)	Yes	Yes	No	No	Data not tracked
Korean Electric Power Corporation	Yes	Yes	No	Yes	
Liberty	No	No	No	No	Data not tracked
National Grid	Yes	Yes	No	No	Data not tracked
Pacific Gas and Electric Company	No	Yes	No	No	Data not tracked
PacifiCorp	Yes	Yes	Yes	Yes	
Portland General	No	Yes	No	No	Data not tracked
Powercor	No	No	No	Yes	
Puget Sound Energy	No	Yes	No	No	Data not tracked
San Diego Gas & Electric	Yes	Yes	Yes	Yes	
Southern California Edison	Yes	Yes	Yes	Yes	
TasNetworks	No	Yes	Yes	Yes	
Tokyo Electric Power Company	No	Yes	No	Yes	
Xcel Energy	No	Yes	No	No	Data not tracked

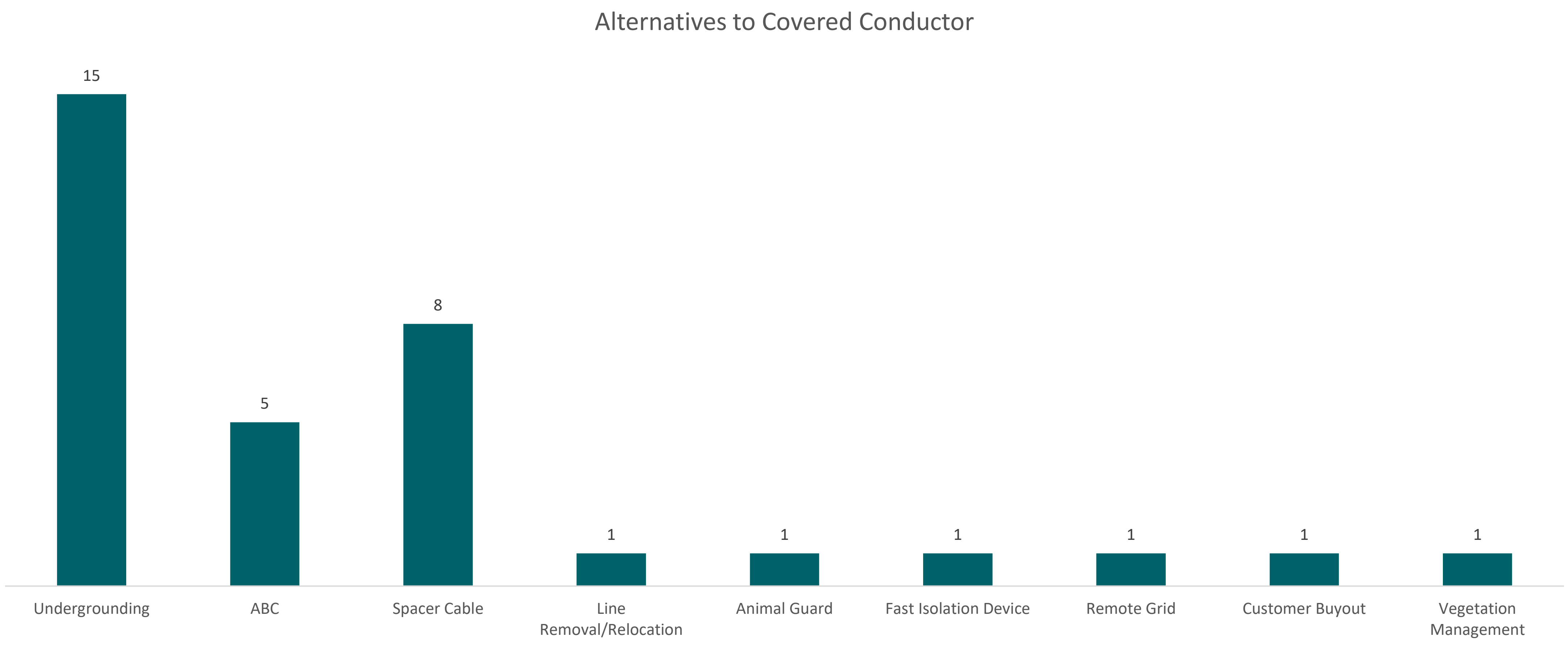
Measuring Effectiveness of Covered Conductor, Spacer Cable, and ABC



Covered Conductor, Spacer Cable, and Aerial Bundled Cable Application



Alternatives



Protection

- **Existing** fault detection methodologies
  - Overcurrent protection
    - Circuit breaker & Relay
    - Fuses
    - Reclosers
    - TripSavers
  - SCADA connected devices
  - Smart Meters
  - High voltage DC pulse with directional tracking
  - High impedance fault detection
  - Distribution automation system monitoring
  - Distance to fault algorithm

- **Potential** fault detection methodologies
  - Early Fault/Failure Detection
  - Distribution Fault Anticipation
  - Open Phase Detection
  - High impedance fault detection
  - Sensitive Ground Fault
  - Rapid Earth Fault Current Limiter
  - Downed Conductor Detection
  - LR controllers
  - Fault indicators
  - Sensing insulators
  - Zero phase voltage measurement
  - AMI meter loss of voltage detection
  - Working with vendors to develop communication aided protection to detect faulted or broken CC
  - Inspection

Patrol Protocols

- Patrol conductors after storm before energization
  - Require visual observation
  - Same as bare conductor
- Drone usage

Other Comments

Utility	Comment
SDG&E	Primarily using covered conductor, but have the option for spacer cable.
PacifiCorp	Spacer cable has been highly effective
Liberty	Piloting on a case-by-case basis, targeting highest-risk areas, based on Risk-Based Decision model.
Duke Energy	Installed covered conductor and spacer cable on our system in the past. There is a miniscule amount on our system. Our current construction standards do not call for covered or spacer cable installation for the following reasons: 1) Require additional installation procedures and maintenance compared to bare conductors. 2) Require proper Installation to prevent BIL and deterioration failures. 3) Designed to prevent intermittent vegetation contact. Should NOT be used for sustained contact of vegetation. 4) Must coincide with continual Vegetation Maintenance.
Xcel Energy	Using a strengthened neutral shield wire to protect crossarm construction from tree impacts.
TEPCO	• Use of bare wires for MV line is prohibited in Japan. For MV line, covered electric wires are basically used. • Spacer cables used when it is necessary to move the electric wire position away or change routes between utility poles. • Aerial bundled cables are used when connecting the MV line of the third route on the utility pole.
Portland General	• Developing the application strategy to mitigate wildfire in high-risk zones using these conductor types. Until now, these systems were primarily used for reliability purposes.

Appendix B: Effectiveness of Covered Conductors: Failure Mode Identification and Literature Review

Effectiveness of Covered Conductors: Failure Mode Identification and Literature Review

Effectiveness of Covered Conductors: Failure Mode Identification and Literature Review

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December 22, 2021

Doc. no. 2103590.000 - 6880

Contents

Executive Summary

Exponent, Inc. (Exponent) was jointly retained by the California investor-owned utilities (IOUs) to assess the effectiveness and reliability of covered conductors (CCs) for overhead distribution system hardening. Our investigation included a literature review, discussions with subject matter experts, a failure mode identification workshop, and a gap analysis comparing expected failure modes to currently available test and field data. Based on our investigation to date, we offer the following conclusions:

1. Covered conductors are a mature technology (in use since the 1970s) and have the potential to mitigate several safety, reliability, and wildfire risks inherent to bare conductors. This is due to the reduced vulnerability to arcing/faults afforded by the multi-layered polymeric insulating sheath material.

2. A subject matter expert workshop, composed of six California IOUs and Exponent, was conducted, and identified hazards and failure modes affecting bare conductors and CCs. Of the 10 hazards that affect bare conductors, CCs have the potential to mitigate six. Mitigated hazards include tree/vegetation contact, wind-induced contact (such as conductor slapping), third-party damage, animal-related damage, public/worker impact, and moisture.

3. The primary failure mode of bare conductors is arcing due to external contact. Laboratory studies and field experience have shown that arcing due to external contact was largely mitigated with CCs. Therefore, a corresponding reduction in ignition potential would be expected.

4. Field experience from around the world, including North America, South America, Europe, Asia, and Australia, consistently report improvements in reliability, decreases in public safety incidents, and decreases in wildfire-related events that correlate with increased conversion to CC.

5. While high-level field experience–based evidence of CC effectiveness is plentiful, relatively few lab-based studies exist that address specific failure modes or quantify risk reduction relative to bare conductors. For some failure modes, further testing is recommended to bolster industry knowledge and to enable more effective risk assessment.

6. Several CC-specific failure modes exist that require operators to consider additional personnel training, augmented installation practices, and adoption of new mitigation strategies (e.g., additional lightning arrestors, conductor washing programs, etc.).

Note that this Executive Summary does not contain all of Exponent's technical evaluations, analyses, conclusions, and recommendations. Hence, the main body of this report is at all times the controlling document.

Motivation and Scope

California investor-owned utilities (IOUs) Pacific Gas & Electric (PG&E), Southern California Edison (SCE), and San Diego Gas & Electric (SDG&E) engaged Exponent to summarize the effectiveness of CCs for hardening of overhead distribution electric lines. During the project, three additional California IOUs joined the effort: Liberty, PacifiCorp, and Bear Valley Electric Service. CCs have gained industry attention due to their potential for mitigating risks associated with public safety, reliability, and wildfire ignition. The current study was undertaken to better understand the advantages, operative failure modes, and current state of knowledge regarding CCs. The objectives of this study were to:

1. Summarize the effectiveness of CCs.
2. Summarize the implementation and design considerations of CCs.
3. Identify gaps in current testing/knowledge and practices/implementation.

To meet these objectives, we performed a comprehensive review of publicly available literature, utility-provided data, and manufacturer information. Additionally, a high-level failure mode identification workshop was conducted with input from technical subject matter experts representing the California IOUs and Exponent. The workshop output was compared against the available literature and test data to identify any gaps between the current state of knowledge and the identified failure modes.

Covered Conductor Technology

History and Motivation for Development

The term "covered conductor" refers to a variety of conductor cable designs that incorporate an external polymer sheath to protect against incidental contact with other conductors or grounded objects such as tree branches. This technology has several advantages over traditional bare conductors, and the key drivers for adoption have been to improve overall system reliability, to enhance public safety in high-population areas, to decrease required right-of-way in densely forested areas, to decrease the scope and frequency of vegetation management, and to reduce the probability of ignition from conductor heating/arcing in fire-prone areas.

Construction and Types

CCs were first adopted in the United States and Europe in the 1970s for medium-voltage distribution lines (35 kV and below) and were later implemented for high-voltage overhead lines in the 1990s [Leskinen 2004]. Early iterations had various technical challenges that led to the development of the modern CC design that will be discussed throughout this report. Modern CCs consist of an all-aluminum conductor (AAC), aluminum conductor with steel reinforcement (ACSR), or copper (CU) conductor, enclosed in a multi-layer polymer sheath. The number of layers and their composition largely depend on the specified voltage rating, as multi-layered variants have a higher impulse strength than the single-layer design and often include a semiconducting conductor shield. This report focuses on CC use in the "medium voltage" range (6–35 kV), though the technology can also be used for higher or lower voltage.

Figure 1 shows a three-layer CC design, which is commonly used for distribution-level voltages. A high-density polyethylene (HDPE) outer jacket provides strength, abrasion resistance, and weather resistance. This layer may be cross-linked to increase its high temperature strength and dimensional stability. A low-density polyethylene (LDPE) inner jacket provides dielectric strength to protect the underlying conductor and may also be cross-linked to enhance high temperature properties. Finally, a semiconducting thermoset "shield" layer is wrapped around the conductor, which equalizes the electric field around the conductor to reduce voltage stress and preserve the insulation [Wareing 2005].

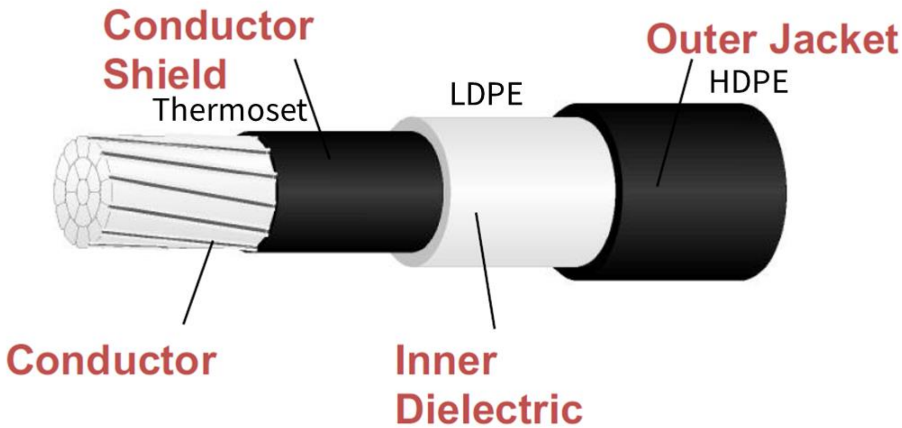

Figure 1. A schematic illustration of a three-layer CC. Diagram modified from Hendrix Aerial Cable Systems [Trager].

Overhead Configurations

One common configuration for CCs used in overhead distribution systems is the standard crossarm-mounted construction. This configuration, sometimes referred to as "tree wire," is often seen where CCs are installed on pre-existing infrastructure designed for bare conductors. This method can leverage legacy hardware, construction and maintenance practices, and pole structures if the weight, diameter, and modified tensioning are considered. Conductors are typically attached to polyethylene pin-type insulators in this configuration. A reduced crossarm structure can also be used in narrow rights-of-way. One disadvantage to this method of installation is that it requires stripping of the conductor sheath at dead-end attachments, creating a length of unprotected bare conductor. Figure 2 shows an example of tree wire construction.

Figure 2. An example of crossarm-mounted CC, or “tree wire,” construction. Photo from Hendrix Aerial Cable Systems [Trager].

CCs are also often constructed in a “spacer cable” configuration. Spacer cable takes advantage of the reduced clearance required of CCs by closely spacing adjacent conductor phases with rigid spacer hardware. This configuration is advantageous in tight corridors where right-of-way may be limited and can reduce wind-related impact on individual conductors [Trager]. No stripping of the conductor sheath is required for this installation method, resulting in a completely covered system except for tap, transformer/capacitor, surge arrester, and protective device locations. A notable feature of spacer cable is that the conductor is not self-supporting, but rather, a steel cable or “messenger cable” is used to support multiple conductors. The messenger cable can also shield the conductors somewhat from fallen branches and lightning strikes. Figure 3 shows an example of spacer cable construction.

Figure 3. An example of spacer cable CC construction. Photo from Hendrix Aerial Cable Systems [Trager].

Field Experience

Finland

Finland started adopting CCs for medium-voltage lines in the 1970s and high-voltage lines in the 1990s to increase reliability. While only 4% of the total medium-voltage network, CCs accounted for 90% of the total average medium-voltage length increase during the early 2000s [Leskinen 2004].

The annual outage rate per 100 km from Finland is shown in Figure 4 and is valid for rural areas. As the figure shows, the number of faults has steadily decreased since the 1970s to around five faults per 100 km. This likely corresponds to the increased number of CC lines in the network [Leskinen 2004].

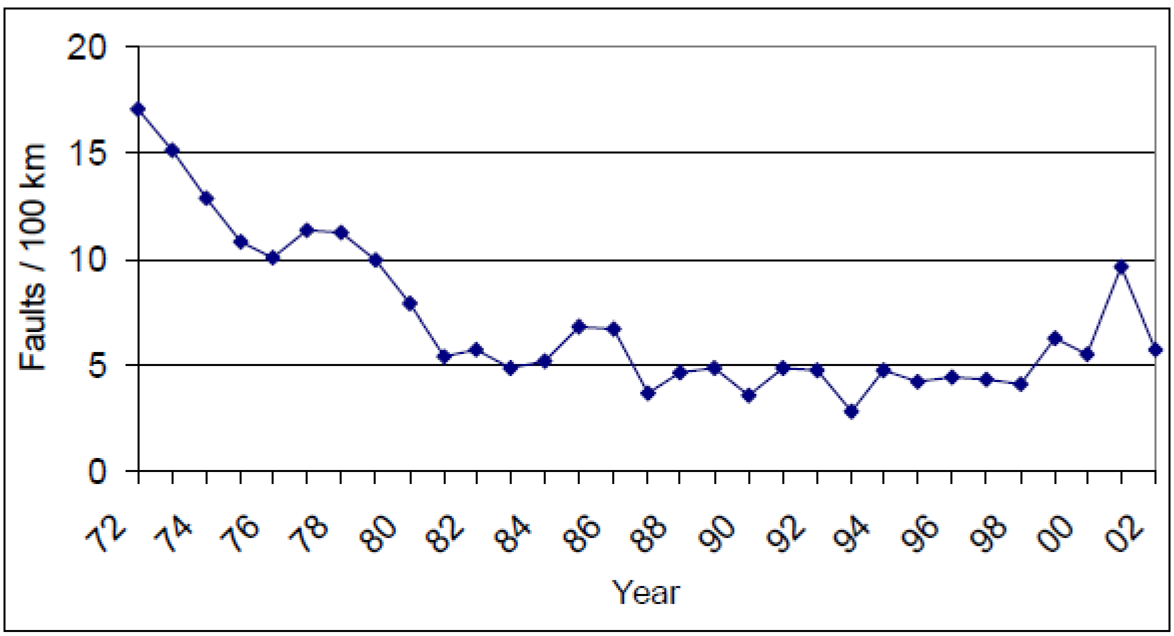

Figure 4. Annual number of faults per 100 km in rural areas of Finland from 1972 to 2002 for medium-voltage lines. Image from [Leskinen 2004].

This study also analyzed previous literature that suggested CC installation also affects the number of high-speed and delayed automatic reclosings. Based on the field data-derived empirical equations from Heine, *et. al*., as shown in Figure 5, the number of high-speed autoreclosings decreases by one third when the percentage of CC lines increases from 10% to 50% [Heine 2003, Leskinen 2004]. The number of autoreclosings is indicative of the number of faults; therefore, these data suggest that the number of faults decreased with increased use of CCs. More recent studies show that the number of permanent faults in CC lines is 20% of the number associated with bare conductor overhead lines and gives an annual fault number of one per 100 km [Leskinen 2004].

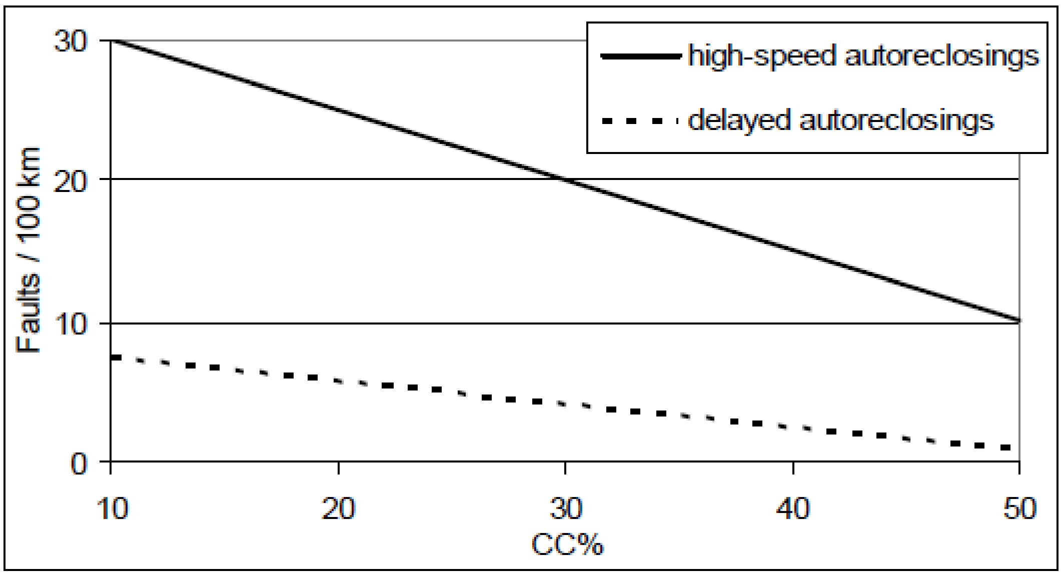

Figure 5. Fault frequency as a function of CC network share in Finland. Image from [Leskinen 2004].

Slovenia

The Slovenian utility Elektro Ljubljana began building CC lines in 1993 to improve reliability, and within ten years CC lines comprised 8% of all Slovenian medium-voltage overhead lines [Leskinen 2004]. The annual medium-voltage outage rate in rural Slovenia was between 15 and 25 per 100 km prior to the introduction of CCs. After the adoption of CC lines and other new technology such as remote-controlled load breakers and shunt circuit breakers, the annual outage rate reduced to less than two faults per 100 km. This rate is nearly double the most recent annual outage rate of Finland, as discussed in the prior section. The higher fault rate in Slovenia compared to Finland has been attributed to the higher level of lightning and a lack of standards [Leskinen 2004].

Taiwan

The Taiwan Power Company invested the equivalent of over $360 million between 1996 and 2000 to replace 11.4 kV overhead lines with 15 kV cross-linked polyethylene (XLPE) weatherproof wires (a type of CC) [Li 2010]. Figure 6 shows the impact of CC lines on the Taiwan Power Company distribution system. (The ratio of covered line length using XLPE weatherproof wire in the distribution system to the total line length of the system is given by the variable r_c.) The distribution system reliability is assessed using the system average interruption frequency index (SAIFI) and the system average interruption duration index (SAIDI). Figure 6 shows the variation of r_c, SAIFI, and SAIDI during 1985 to 2005. Installation of CC lines from 1985 to 2005 resulted in lower fault frequency and interruption duration.

As distribution systems in Taiwan are near highly populated areas, endangered-life indices (ELIs) were used for statistical data with regard to people who experience electric shocks. The following ELI values were used: the annual number of people who receive electric shocks (N_p), the annual number of people injured by electric shocks (N_{pi}), and the annual number of people electrocuted (N_{pe}). The ELI rates and r_c values from 1985 to 2005 are shown in Figure 6. As r_c increased, all ELIs decreased annually from 1995 to 2005 as more CC lines were incorporated into the distribution system.

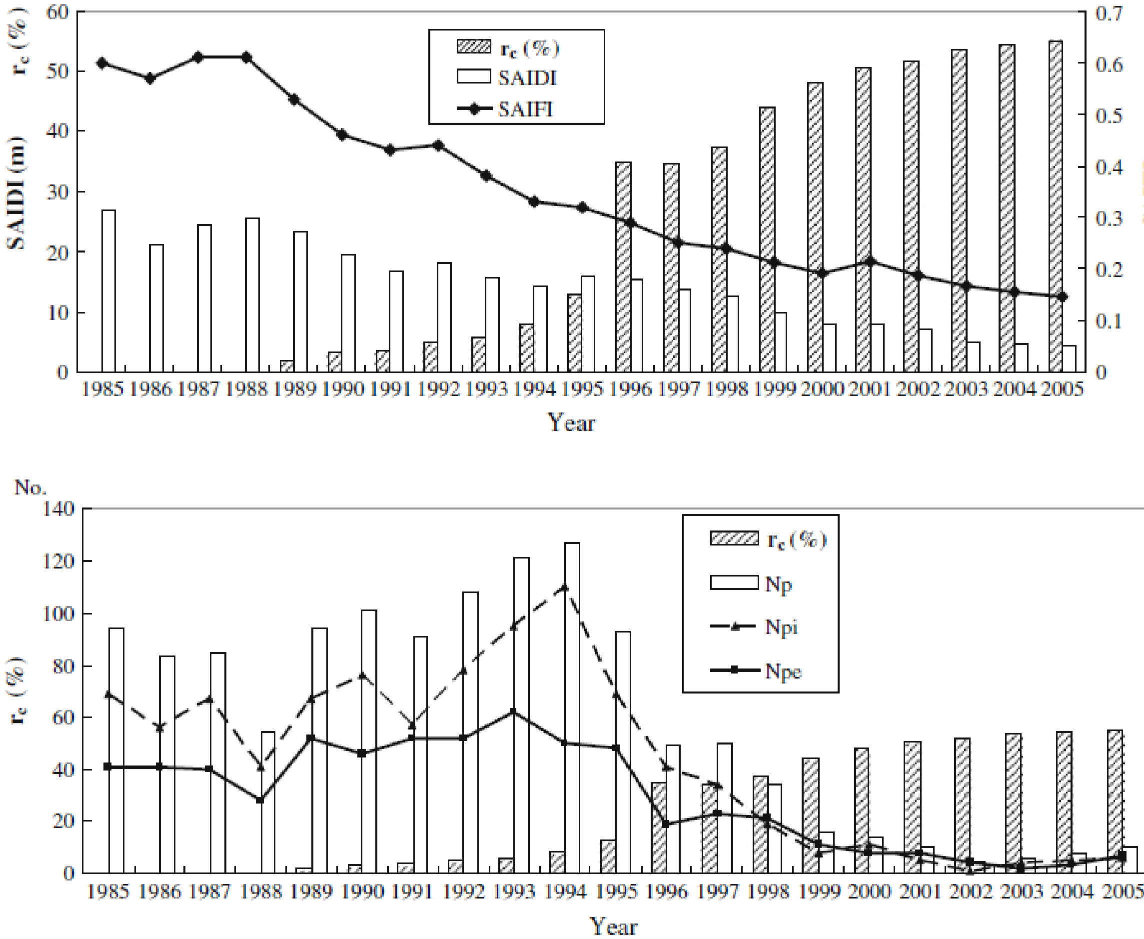

Figure 6. (Top) Taiwan Power Company results from 1985 to 2005 for the ratio of covered line length using XLPE weatherproof wire in a distribution system to the total line length of the system (r_c), system average interruption frequency index (SAIFI), and the system average interruption duration index (SAIDI). (Bottom) Taiwan Power Company results from 1985 to 2005 r_c and endangered-life indices (ELIs). The following ELI values are shown: annual number of people who receive electric shocks (N_p), annual number of people injured by electric shocks (N_{pi}), and annual number of people electrocuted (N_{pe}). Image from [Li 2010].

Australia

CCs have been used in Australia for more than 50 years, primarily motivated by wildfire risk reduction. Early CCs had limited lifetimes due to surface degradation, tracking, radio frequency (RF) emissions, and lightning damage [Wareing 2005]. In the mid-2000s, the Australian Strategic Technology Program determined that technological advancements may help solve historical issues with CCs to allow for their widespread adoption. After the Black Saturday bushfires, the Victorian Bushfires Royal Commission (VBRC) recommended the existing power lines be replaced with aerial bundled cables or other technology that reduced the risk of bushfires. The VBRC estimated a 90% reduction in the likelihood of a bushfire starting by installing CCs [SCE 2019]. Additionally, a study by the Commonwealth Scientific and Industrial Research Organization (CSIRO) found that a 98% reduction in the risk of bush fires due to CCs could be expected [SCE 2019, Electrical Connection 2021]. Although it is unclear how these specific metrics were determined, this shows high confidence by the VBRC and the CSIRO in the effectiveness of CC for wildfire mitigation.

Malaysia

The Tengag Nasional Berhad (TNB) distribution network in Malaysia includes 5,300 km of 33 kV, 22 kV, and 11 kV medium-voltage bare overhead conductor lines and 2,700 km of 33 kV and 11 kV medium-voltage aerial-bundled cables (ABC) lines [Ariffin 2012]. Malaysia has reliability challenges caused by above-average lightning activity, small-animal damage, and vegetation damage, which motivated the use of CCs to improve reliability. TNB started installing medium-voltage ABC lines in the 1990s. Early versions of ABCs had inferior fault rates and failed to deliver on the expected benefits. A redesign was undertaken to change from the single-layer copper screen with HDPE outer sheath to a double-layer copper screen. Additionally, improved construction standards were followed, and compatible accessories were used that resulted in improved performance.

TNB found that the medium-voltage bare conductor lines had a higher number of recorded failures compared with medium-voltage ABC lines from 2001 to 2007. The newly designed medium-voltage ABCs had a failure rate five times lower than that of the original medium-voltage ABCs used in the Malaysian system. In this study, a specific definition for the word “failure” was not provided.

Brazil

CEMIG, one of the four biggest power companies in Brazil, adopted spacer cables in urban areas starting in 1998 to improve reliability [Rocha 2000]. CEMIG's annual work plan was to rebuild the urban distribution system by building 1,400 km of medium-voltage lines and 2,800 km of low-voltage lines using spacer cables. CEMIG completed periodic field inspections during the first nine years of energizing the initial pilot lines. The following observations were made during the field inspections:

- Outages due to atmospheric discharges were observed where the cables had been peeled to create a metallic tie. Changes were made to how ties, polymeric rings, and polymeric anchoring clamps were installed, which resulted in improved performance.
- In areas with permanent tree contact, no signs of electrical tracking were observed.
- Minimal outages were observed in areas with vandalism (insulator breakage) and pole collisions. No outages were recorded on spacer cable lines with vandalism incidents, whereas four to five outages occurred on bare cable lines.
- Outages caused by material failures were practically eliminated.

Overall, CEMIG found a 33% reduction in the average duration and frequency of outages per customer due to the expansion of spacer cable lines [Nishimura 2001].

Failure Modes and Effectiveness

Failure Modes

A high-level failure mode identification workshop was conducted to identify operative failure modes relevant to overhead distribution systems for both bare conductors and CCs. The list of failure modes was developed during a day-long workshop with technical subject matter experts representing Exponent, PG&E, SCE, SDG&E, PacifiCorp, Liberty, and Bear Valley Electric Service. This exercise leveraged the technical knowledge from the seven different organizations and the combined experience and shared operator experiences from the six utilities. This workshop was not a full risk assessment, as other factors such as severity / consequence of an event, likelihood, and ability to detect each failure mode were outside the scope of this exercise.

The output of the failure mode workshop was a list of failure modes applicable to bare conductors and/or CCs and is presented in Table 1. The failure modes are organized into three descriptive categories: external events, human factors, and operations/maintenance. Each line item is further differentiated by the operative hazard within each category. External events primarily include hazards related to weather, vegetation, or fire. Human factors include human-induced hazards such as vehicle/equipment contact, gunshots, and Mylar balloons. The operations/maintenance category encompasses hazards related to the design, installation, and maintenance of overhead distribution lines. Within each hazard, specific scenarios that can result in failure are listed. For example, a phase-to-phase fault (failure mode) resulting from a Mylar balloon (hazard) is differentiated from a phase-to-phase fault (failure mode) resulting from a fallen tree branch (hazard). Failure modes that apply to bare conductors but are largely mitigated by using CCs are marked with a green checkmark.

Table 1. List of failure modes for bare and covered conductors.

Category	Hazard	Scenario	Bare	Covered	#	Failure Mode
External Events	Fire	External fire (wildfire)		X	1	Potential damage to sheath, reducing effectiveness
				X	2	Potential flammability of CC sheath
			X	X	3	Annealing of metal conductor due to fire exposure
External Events	Extreme heat	Extreme temperatures cause sag and clearance issues	X	✓	4	Phase-to-phase or phase-to-ground fault
External Events	UV exposure / solar exposure	Aging / exposure of conductor covering		X	5	Embrittlement and/or cracking of conductor covering
External Events	Sheath contamination	Moisture / salt contamination		X	6	Tracking/insulation failure due to moisture/salt (corona)
		Smoke during fire		X	7	Tracking/insulation failure due to smoke/ash
External Events	Ice/snow	Mechanical loading / stress on conductors	X	X	8	Excessive mechanical loading leading to conductor failure/wire down
		Unloading / dynamic shedding of ice	X	X	9	Dynamic forces leading to conductor failure and wire down
		Combined wind/ice	X	X	10	Galloping (see wind hazard)
External Events	Lightning	Atmospheric lightning	X*	X	11	Arc damage / melting of conductor, possible wire down. Short circuit duty exceeds conductor damage curve.
External Events	Animal	Animal contact		X	12	Phase-to-phase fault due to animal-damaged sheath (chewing)
				X	13	Bird dropping degradation of polymer sheath
			X	✓	14	Large bird contact of multiple conductors (phase-to-phase)

Category	Hazard	Scenario	Bare	Covered	#	Failure Mode
External Events	Moisture	Moisture/salt/ oceanic exposure	X	✓	15	Atmospheric corrosion of span leading to decreased mechanical strength or increased electrical resistance
			X	X	16	Atmospheric corrosion near hardware/dead-end leading to decreased mechanical strength or increased electrical resistance
				X	17	Freeze/thaw cycles leading to sheath damage
			X	X	18	Lack of corrosion inhibitors (on splices) leading to corrosion
				X	19	Migration of water within the sheath layer
			X	✓	20	Stress corrosion cracking of span
			X	X	21	Stress corrosion cracking near hardware/dead-end
External Events	Wind	Winds (within the natural frequency of structure)	X	X	22	Aeolian vibration-induced fatigue cracking
			X	X	23	Mechanical overload of tie wire during galloping (ice/ or lashing of spacer /messenger wires)
			X	X	24	Swinging leading to wear
			X	X	25	Vortex shedding impact / contact of adjacent conductors leading to fatigue of downstream conductors
			X	✓	26	Line slapping (intermittent conductor contact)
		Transmission / distribution line contact	X	✓	27	Differential wind-driven blowout leading to contact of distribution / transmission lines
		Pole damage		X	28	Damage due to potential for increased loading when new covered conductors replace existing bare conductors on the same poles / crossarms / guys

Category	Hazard	Scenario	Bare	Covered	#	Failure Mode
External Events	Tree damage	Tree falls, breaks conductor	X	✓	29	Conductor failure / wire down resulting in loss of service, potential for ignition (along the entire length of bare conductor or exposed section of CC)
			X	X	30	Live conductor down with no outage
		Tree branch bridges various lines (conductors do not break)	X	✓	31	Phase-to-phase fault, potential ignition
			X	X	32	Delayed fault due to long-term contact (dielectric breakdown / reduction in dielectric strength), potential phase-to-phase fault
				X	33	Abrasion of sheath
				X	34	Cracking of CC sheath
				X	35	Heating damage to sheath
				X	36	Corrosion of conductor due to compromised sheath
		Tree falls and pulls entire system to ground	X	X	37	Surrounding structure fails (broken conductor)
			X	X	38	Surrounding structure fails (conductor intact)
Human Factors	Public/worker impact	Agricultural equipment / third-party workers / under-build workers (cable/telephone)	X	✓	39	Potential for shock or electrocution
		Vehicle impact to pole / guy wire	X	✓	40	Potential for guy wire whip to create contact to conductor
			X	✓	41	Phase-to-phase contact
			X	✓	42	Phase-to-ground contact
		Gunshots	X	X	43	Conductor damage

Category	Hazard	Scenario	Bare	Covered	#	Failure Mode
Human Factors	Third-party damage	Tarps under high wind conditions	X	✓	44	Phase-to-phase contact
		Balloons	X	✓	45	Phase-to-phase contact
		Kites	X	✓	46	Phase-to-phase contact
		Palm fronds	X	✓	47	Phase-to-phase contact
Operations & Maintenance	Maintenance / Installation	Conductor damage due to incorrect hardware tool or incorrect stripping		X	48	Mechanical damage to sheath (dent/gouge)
		Poor splicing or poor connection	X	X	49	Poor contact leading to localized heating and connection failure
		Over-tensioning	X	X	50	Incorrect tensioning leading to conductor failure (due to vibration, increased stress)
		Under-tensioning	X	X	51	Increased sway leading to wear
			X	✓	52	Clearance issues due to increased sway
		Excessive angles	X	X	53	Insulator breaks off due to mechanical overload (for excessive angles). Conductor may break off or float, contacting pole.
		Broken tie wires	X	X	54	Poorly installed tie wires could break, leading to conductors separating from insulators and contacting pole.
		Improper installation	X	X	55	Bird caging—conductor strands separate

* Direct lightning strikes resulting in concentrated heating of the bare conductor and a wire down event are relatively infrequent.

Effectiveness of Covered Conductors

Failure Mode Discussion

In total, 58 unique failure mode / hazard scenario combinations were identified through the failure mode workshop. These failure modes can be categorized into three basic types:

1. Failure modes that affect both bare *and* CCs.

    Example: Aeolian vibration-induced fatigue cracking of the metal conductor (Table 1, No. 23).
2. Failure modes that affect bare conductors but are reduced or effectively eliminated by CCs.

    Example: Phase-to-phase fault due to tree branch bridging conductor phases (Table 1, No. 32).
3. Failure modes that are unique to CCs that do *not* affect bare conductors.

    Example: Lightning-induced melting of conductor sheath (Table 1, No. 12).

Failure modes that apply to bare and covered conductors

Failure modes that apply to both bare and covered conductors are well known due to historic use of bare conductors and are generally expected to be effectively managed through existing mitigations and controls. However, there are instances in which these failure modes may be *more* prevalent with CCs than with bare conductors. For instance, some wind-related phenomena such as Aeolian vibration may, in certain circumstances, be exacerbated with CCs due to their smooth surface, increased weight, and larger overall diameter [Leskinen 2004]. For similar reasons, CCs may also be more prone to ice loading than bare conductors. Ice loading may result in mechanical overload of the conductor, or increased susceptibility to galloping. A full list of failure modes that apply to both bare and covered conductors derived from the failure mode workshop is given in Table 2.

Table 2. Failure modes that affect both bare and covered conductors.

Hazard	#	Failure Mode	Potential risk relative to bare
Fire	3	Annealing of metal conductor due to fire exposure	Reduced
Ice/snow	8	Excessive mechanical loading leading to conductor failure / wire down	Increased
	9	Dynamic forces (ice shedding) leading to conductor failure and wire down	Needs study
	10	Galloping damage (see wind scenario)	Needs study
Lightning	11	Arc damage / melting of conductor, possible wire down	Increased
Moisture	16	Atmospheric corrosion near hardware/dead-end leading to decreased mechanical strength or increased electrical resistance	Comparable
	18	Lack of corrosion inhibitors (on splices) leading to corrosion	Comparable
	21	Stress corrosion cracking near hardware/dead-end	Comparable
Wind	22	Aeolian vibration induced fatigue cracking	Needs study
	23	Mechanical overload of tie wire during galloping (ice/ or lashing of spacer /messenger wires)	Needs study
	24	Swinging leading to wear	Increased
	25	Vortex shedding impact / contact of adjacent conductors leading to fatigue of downstream conductors	Needs study
Tree damage	30	Live conductor down with no outage	Increased
	32	Delayed fault due to long-term contact	Reduced
	37	Surrounding structure fails (broken conductor)	Needs study
	38	Surrounding structure fails (conductor intact)	Needs study
Third-party damage	43	Conductor damage from gunshot	Comparable
Maintenance/ installation	49	Poor contact leading to localized heating and connection failure	Comparable
	50	Incorrect tensioning leading to conductor failure (due to vibration, increased stress)	Comparable
	51	Increased sway leading to increased wear	Needs study
	53	Insulator breaks off due to mechanical overload (for excessive angles). Conductor may break off or float contacting pole.	Comparable
	54	Poorly installed tie wires could break, leading to conductors separating from insulators and contacting pole.	Comparable
	55	Bird caging—conductor strands separate	Comparable

These failure modes that can affect both bare and covered conductors are of particular importance to operators, as risk assessments may need to be updated to reflect the increased likelihood of certain events when switching to CCs. Since no studies were found that directly compared the frequency or severity of these failure modes between covered and bare conductors, the impact on mitigation and maintenance practices has not been quantified.

Despite the dearth of test data on the likelihood and severity of these failure modes for CCs relative to bare conductors, insight can be gained from a first-principles analysis of these failure modes. For example, the vulnerability to fatigue from Aeolian vibration is expected to be different for CCs for several reasons. The Aeolian vortex shedding frequency is inversely proportional to transverse wind speed, and therefore the shedding frequency will be lower for CCs because of the increase in conductor diameter due to the insulation. However, this lower cycle count could be offset by differences in the wind power input of self-damping, which define the vibration amplitude. In addition, Aeolian fatigue failure typically manifests at attachments (clamps), and it is not known whether typical CC connectors are more susceptible to the strain concentrations that lead to failure. Similarly, ice gravity loading and dynamic loads from ice and snow shedding can be expected to differ due to different conductor diameter, surface roughness, weight, and surface temperature. Additional analysis is required to better understand these failure modes.

Failure modes mitigated by covered conductors

The next group of failure modes are those that are largely mitigated by the use of covered conductors. These failure modes are the primary drivers for adoption of CCs, as they represent the risk reduction potential compared to traditional bare conductors. A total of 17 failure modes largely mitigated through the use of CC were identified through the workshop exercise, and are marked with a green checkmark in Table 1. The common theme among these failure modes is that they are created through contact with third-party objects, vegetation, or other conductors that create phase-to-ground or phase-to-phase faults. The available literature, industry testing, and field experiences from utilities around the world suggest that modern CCs can prevent arcing in the medium-voltage range over short time scales, thereby increasing system reliability and public safety, and reducing the potential for wildfire ignition. A full list of failure modes addressed by CCs derived from the failure mode workshop is given in Table 3.

Table 3. Failure modes that affect bare conductors but are largely mitigated by covered conductors.

Hazard	#	Failure Mode
Extreme heat	4	Fault due to sag/clearance issues
Animal	14	Large bird contact of multiple conductors (phase-to-phase contact)
Moisture	15	Atmospheric corrosion of span leading to decreased mechanical strength or increased electrical resistance
	20	Stress corrosion cracking of span
Wind	26	Line slapping (intermittent conductor contact)
	27	Differential wind driven blowout leading to contact of distribution / transmission lines
Tree damage	29	Conductor failure/wire down resulting in loss of service, potential for ignition (along the entire length of bare conductor or exposed section of CC)
	31	Phase-to-phase fault. Potential ignition.
Public/worker impact	39	Potential for shock or electrocution
	40	Potential for guy wire whip to create contact to conductor
	41	Phase-to-phase contact (vehicle)
	42	Phase-to-ground contact (vehicle)
Third-party damage	44	Phase-to-phase contact (tarp)
	45	Phase-to-phase contact (balloon)
	46	Phase-to-phase contact (kite)
	47	Phase-to-phase contact (palm frond)
Maintenance/ Installation	52	Clearance issues due to increased sway

As stated above, these failure modes generally consist of arcing between phases or objects. The primary and secondary effects of these failure modes have implications for system reliability, public safety, and wildfire prevention. For example, arcing between phases due to conductor slapping can create sparks, conductor melting, and/or a possible wire-down scenario. This not only creates an outage risk but also creates potential for a wildfire ignition if dry brush exists below the lines. As will be discussed, available literature indicates that CCs prevent arcing during line slap, such that sparks and melting never occur. In another example, windstorms can blow debris and vegetation into the conductors. While this may not result in a wire-down event, it can create arcing between phases, and the vegetation (e.g., palm fronds) can ignite and fall to the ground. CCs prevent arcing when vegetation is blown into the lines and, therefore, ignition cannot occur.

The extent to which existing information supports the effectiveness of CCs to address these failure modes was considered. For example, it is generally accepted that CCs largely eliminate the risk of vegetation-caused phase-to-phase faults. However, the literature and existing data were analyzed to understand the extent to which this has been proved and whether there are situations that have not been studied. Testing performed by SCE found that CCs prevented phase-to-phase and phase-to-ground faults in field tests that simulated common scenarios such as branch contact, Mylar balloon contact, and conductor slapping (simulating sustained contact) when energized at 12 kV [SCE 2019]. This is relevant and useful testing, though similar laboratory studies to further bolster these conclusions were not found in the available literature.

Most of the available literature consists of high-level observations that correlate system reliability and safety metrics to increases in CC line installation [Leskinen 2004, Li 2010, SCE 2019, Electrical Connection 2021, Ariffin 2012, Rocha 2000, Nishimura 2001]. These studies suggest that the purported benefits of CCs are effective. However, the benefits are not attributed to specific failure modes, but rather overall system reliability and safety metrics. Further, the true technical limits, i.e., to what extent, and over what time scale arcing is mitigated, still lack concrete data. Few publicly available studies were found that directly test the arcing characteristics of CCs. While the SCE testing provides systematic fault testing of CCs, one limitation of the testing performed by SCE is that it was focused on short-term incidental contact and did not test long-term effects such as a tree branch growing into conductor spans. Second, while the success of these tests at 12 kV provides useful data for many distribution-level applications, an effective steady-state breakdown voltage (upper limit) at which arcing eventually occurs was not identified.

Failure modes unique to covered conductors

Failure modes unique to CCs primarily involve damage or degradation to the insulating polymer sheath. These may not be addressed by mitigations that currently exist under asset management plans geared toward bare conductor use. Therefore, Exponent recommends to better understand these failure modes through available literature and targeted testing. When addressing CC-specific failure modes, it is important to consider that some failure modes may simply reduce the benefits of the covering (i.e., return to bare conductor risk level) while others may create a situation that has a unique and independent risk profile relative to a typical bare conductor installation. These factors will be the focus of the Covered Conductor Risks section below. As will be shown later in the report, some of these failure modes have been largely addressed by advances in technology (e.g., UV stabilizers that reduce embrittlement of conductor covering) or are unlikely to occur (e.g., animal chewing the same spot on two adjacent phases). A full list of the CC-specific failure modes derived from the failure mode workshop is given in Table 4.

Table 4. Failure modes that affect *only* covered conductors.

Hazard	#	Failure Mode
Fire	1	Potential damage to sheath, reducing effectiveness
	2	Potential flammability of CC sheath
UV exposure / solar exposure	5	Embrittlement and/or cracking of conductor covering
Contamination	6	Tracking/insulation failure due to moisture/salt (corona)
	7	Tracking/insulation failure due to smoke/ash
Animal	12	Phase-to-phase fault due to animal-damaged sheath (chewing)
	13	Bird dropping degradation of polymer sheath
Ice/snow	17	Freeze/thaw cycles leading to sheath damage
	19	Migration of water within the sheath layer
Wind	28	Damage due to potential for increased loading when new covered conductors replace existing bare conductors on the same poles / crossarms / guys
Tree damage	33	Abrasion of sheath
	34	Cracking of CC sheaths
	35	Heating damage to sheath
	36	Corrosion of conductor due to compromised sheath

Hazard	#	Failure Mode
Maintenance / installation	48	Mechanical damage to sheath (dent/gouge)

Few published studies were found that analyze specific CC-specific failure modes. However, some data have been obtained from CC manufacturers that assists in understanding the limitations of the technology. Hendrix Wire & Cable has performed several tests on the properties and durability of its CC products. These tests include tracking resistance, ultraviolet (UV) resistance, environmental stress cracking, hot creep tests, and performance of CCs in high-contamination environments [Hendrix 2019, Trager 2006]. These test results suggest that modern CC sheathing is resistant to many forms of environmental degradation. However, since these tests were designed to isolate individual variables in a controlled environment, they do not account for all possible variables in a real-world scenario. The failure modes addressed by the Hendrix testing are likely to reduce the effectiveness of covered conductors but, in most circumstances, would not result in a new, higher-risk profile.

Another consideration that is not represented in the failure mode table is the possibility of undetected wire-down events. The CC sheath provides protection from immediate phase-to-ground faults, and therefore may not trigger fault detection systems. This may lead to high-impedance faults and delay necessary field repairs. Downed bare conductors can also result in high-impedance faults, but the situation will be different for CCs since there will be reduced conductor contact with the ground. The potential for these high-impedance fault events that evade detection is the subject of current research, and new early fault detection systems are in development. Operators transitioning to covered conductors may benefit from further research into early fault detection solutions [SCE 2019, Kistler 2019]. These CC-specific failure modes will be the focus of the Covered Conductor Risks section below.

The failure modes discussed thus far are important for understanding the benefits and tradeoffs of implementing CC technology. The next sections will focus on three broad categories of system performance: reliability, public safety, and wildfire ignition. These sections are structured as such because of the available literature, much of which is not specific to individual failure modes but is broader in nature. Available knowledge in these areas from field experience and lab testing will be highlighted, as well as any deficiencies that may warrant further study.

System Reliability

Industry experience has demonstrated an improvement in system reliability when using CCs [EPRI 2014, Leskinen 2004, Li 2010, Nishimura 2001, Rocha 2000, Ariffin 2012]. The primary driver of this improvement in reliability was the decreased probability of fault events, which resulted in fewer system outages. Finland saw a steady decrease in recorded faults in rural areas in the years after 1972, which corresponded to an expansion of CC use. Finland also found that the number of automatic reclosing events decreased to one third as the percentage of CC lines increased from 10% to 50% [Leskinen 2004]. A Taiwanese study similarly found that SAIFI was reduced by approximately 75% and SAIDI was reduced by approximately 86% as the percentage of CCs was increased from 0% to ~55% [Li 2010]. The Electric Power Research Institute (EPRI) also stated that CCs have the potential to reduce tree-caused outages by 40% based on an analysis of data from Duke Energy and Xcel Energy [EPRI 2015].

Public Safety

Public safety is a driver of CC adoption in high population density areas. The Taiwan Power Company observed a ~92% decrease in the number of people experiencing an electric shock from overhead powerlines from 1994 to 2005, when CCs became nearly 60% of their total distribution network [Li 2010]. Operators in Japan observed a similar correlation between accidents and CC installation, noting a factor of 50% reduction in accidents per year from 1965 to 1984 after converting their entire 74 km 6.6 kV network to CCs [Kyushu 1997]. The National Electric Energy Testing, Research and Applications Center (NEETRAC) at Georgia Tech performed a study on the touch current characteristics of CCs vs. bare conductors [NEETRAC 2018]. Both laboratory testing and computer simulations were performed to investigate the results of human bare-hand contact on a two-mile 12 kV distribution system. These tests demonstrated that the contact current for bare conductor was as high as 7 amperes (A), while the maximum contact current for CCs was in the micro-ampere (μA) range. The increased protection against electric shock incidents is significant. However, damage to the conductor sheath or intentional stripping at hardware or dead-end connections will predictably negate or reduce these benefits.

Wildfire Ignition

Utilities in dry climates such as Australia and the western United States are subject to increased risk of wildfire ignition from powerline failures. The reduced propensity for arcing events with CCs is a distinct advantage for minimizing this risk. The Powerline Bushfire Safety Program of the Victoria, Australia, government commissioned a study that examined the fire performance of CCs in "wire down" ignition tests [Marxsen 2015]. Both covered and bare conductors were tested in "wire on ground" faults under severe fire risk conditions. The authors concluded that intact CCs effectively mitigate ignition risk, stating that "the leakage current through the outer plastic covering with the conductor lying on the ground is not sufficient to create thermal runaway so it does not create fire risk."

However, tests on damaged CCs, i.e., conductors with existing through-thickness coating loss, found that the probability of ignition for CCs can be higher than with bare conductors due to the concentration of arcing at the damage location. On flat ground with uniform dry grass coverage, the estimated probability of fire ignition for a damaged CC was 67% vs. only 37% for bare conductor [Marxsen 2015]. An important limitation of this test is that it assumes direct contact of the fuel source with the bare portion of the damaged conductor. The probability of fire would likely be much lower in areas with non-uniform vegetation cover or uneven ground, reducing the likelihood that coating holidays or stripped connection points would contact dry brush. Further, the study investigated the effects of through-thickness coating holidays but did not address the potential negative effects of partial coating loss from sources such as abrasion.

Summary of Covered Conductor Effectiveness

The prior sections outline field experience and laboratory studies that suggest a significant risk reduction with CC use. Although not all bare conductor failure modes are addressed by specific laboratory studies in controlled environments, sufficient high-level evidence exists to suggest that selected hazards affecting bare conductor are addressed by CC use. As shown in Table 5, there are six hazards that are largely mitigated by CC use, including animal, moisture, wind, tree/vegetation, public/ worker impact, and third-party damage. However, as discussed in the prior sections, this does not suggest that additional work is not required to address these hazards. In many cases, specific test scenarios may still add value to better understand CC use. Such tests scenarios are discussed in the Recommendations section of this report.

Table 5. Hazards that are largely addressed by use of covered conductors are shown in green.

	Hazard	Potential to Mitigate Failures		
		Bare Conductor	Covered Conductor	Sources
Primary Hazards	Tree/vegetation		Reduced risk of tree/veg contact-induced fault	Li 2010; Leskinen 2004; Ariffin 2012
	Wind		Reduced risk of phase-to-phase faulting from slapping or blowout	Leskinen 2004
	Third-party damage		Reduced risk of phase-to-phase faults from contact with kites, balloons, palm fronds, etc.	SCE 2019
	Animal		Reduced risk of animal contact-induced fault	Ariffin 2012
	Public/worker impact		Reduced risk of faults from worker contact or vehicle impact	Li 2010
Secondary Hazards	Moisture		Provides environmental protection except near hardware/dead-ends	
	Ice/snow			
	Fire			
	Extreme heat			
	Maintenance/ installation			
	UV exposure	N/A		
	Contamination	N/A		
	Lightning	N/A		

Comparison to Underground Cabling

The above-referenced literature and case studies demonstrate the advantages of CCs relative to bare conductors. The insulating polymer sheath mitigates several failure modes related to phase-to-phase and phase-to-ground faulting such as conductor slapping, animal contact, tree contact, and downed-conductor scenarios. While these benefits are critical to distribution system reliability and safety, there are additional hazards associated with overhead line constructions that cannot be reduced or eliminated by CCs. For example, CCs are exposed to ice/snow loading, contamination from salt, industrial pollutants, wildfire smoke, and conductor burndown from lightning strikes.

The third option typically considered for distribution system hardening is underground cabling. This method of construction has the potential to mitigate the same failure modes as CCs while also mitigating failure modes related to several other hazards, as shown in Table 6. By routing distribution lines underground, the conductors are protected from weather, fire, and other above-ground hazards that affect both bare and covered overhead conductors.

While there are benefits of underground distribution lines, there are also several economic and logistical challenges associated with their implementation. While economic considerations were largely out of scope for this work, a study conducted by SCE found that the cost per mile for undergrounding an existing overhead line ($3 million per mile) is roughly an order of magnitude more expensive than reconductoring with CCs ($430,000 per mile) [SCE 2019]. Underground conversions also may not be possible in all circumstances due to limitations of the terrain and local geology. For example, underground lines may not be practical or possible in mountainous areas or regions with high earthquake risk. Another consideration is the time required for implementation. Underground conversions are time-intensive projects, so a system hardening program based on undergrounding will take more time to realize any tangible benefits to system reliability/safety. Repairs to underground lines are more expensive and time-consuming due to access difficulties. Finally, there are environmental impacts from underground conversion that do not exist for reconductoring of existing infrastructure. These challenges are not reflected in Table 6 but require consideration in any mitigation implementation strategy.

Table 6. Mitigation potential of distribution line constructions.

	Hazard	Potential to Mitigate Failures		
		Bare Conductor	Covered Conductor	Underground
Primary Hazards	Tree/vegetation			
	Wind			
	Third-party damage			
	Animal			
	Public/worker impact			
Secondary Hazards	Moisture			
	Ice/snow			
	Fire			
	Extreme heat			
	Maintenance/installation			
	UV exposure	N/A		
	Contamination	N/A		
	Lightning	N/A		

Covered Conductor Risks

To understand all potential implications of implementing CCs, failure modes unique to CCs were assessed relative to available literature and testing information. The goal of this comparison was to understand the extent to which the identified CC-specific failure modes represent risks to operators that implement CCs. CC-specific failure modes fall into one of two categories: failure modes that may reduce the effectiveness of the insulating sheath, and failure modes that have a unique and independent risk profile relative to bare conductors (i.e., there is a potential for the risk to be higher than for bare conductors). Table 7 presents the potential consequence of the failure mode relative to bare conductors. The consequences for each failure mode were assigned based on whether the CC failure mode, should it occur, would be likely to decrease, increase, or have comparable risk relative to bare conductors, based on literature review and industry best practices. For example, contamination from salt may result in tracking on the surface of the insulation and may significantly reduce the insulating capacity of the sheath. In this scenario, the CC would have reduced effectiveness relative to a new CC but would still not exhibit a risk profile that is comparable or higher than that of a bare conductor. Complete failure of the CC insulation was considered in this analysis. For simplicity, localized (holiday) or partial failure was not considered. A detailed description of the rationale for each status can be found in the body of this section. Table 7 also lists literature sources and recommendations on whether additional testing is recommended for a given failure mode. As shown in Table 7, several effective mitigations were identified in literature for the CC-specific failure modes. However, there are still failure modes without known or proven mitigations that likely require further testing, research, and/or analysis.

Table 7. Risk of covered conductors relative to bare conductors and knowledge gaps.

Hazard	Scenario	Failure Mode	Consequence of Failure	Mitigation Notes	Selected Literature/ Testing	More Investigation Recommended
Fire	External fire	Potential damage to sheath, reducing effectiveness	Reduced effectiveness of CC	No mitigation effective against extreme temps	No testing or field experience found*	Yes
	Wildfire	Potential flammability of CC sheath	Reduced effectiveness of CC	No mitigation effective against extreme temps	SCE 2019	Yes
UV exposure / solar exposure	Aging / exposure of conductor covering	Embrittlement and/or cracking of conductor covering	Reduced effectiveness of CC	UV inhibitors commonly used to prolong polymer lifetime	Hendrix 2010; Ariffin 2012	No
Contamination	Moisture/ salt	Tracking insulation failure due moisture/salt (corona)	Reduced effectiveness of CC	Tracking and erosion issues are documented for 1-, 2-, and 3-layer CC under polluted conditions	Yousuf 2019: Cardoso 2011; Espino-Cortes 2014	No
	Smoke during fire	Tracking/insulation failure due to smoke/ash	Reduced effectiveness of CC	Tracking and erosion issues are documented for 1-, 2-, and 3-layer systems under polluted conditions	Yousuf 2019: Cardoso 2011; Espino-Cortes 2014	No
Animal	Animal contact	Phase-to-phase fault due to animal-damaged sheath (chewing)	Potentially higher consequence than bare	Redesign of coating to include a two-layer copper screen and use non-HDPE as the sheath material**	Ariffin 2012	No

Hazard	Scenario	Failure Mode	Consequence of Failure	Mitigation Notes	Selected Literature/ Testing	More Investigation Recommended
		Bird dropping degradation of polymer sheath	Reduced effectiveness of CC	Washing conductors may be effective to prevent degradation	No testing or field experience found*	Yes
Moisture	Moisture/salt/ oceanic exposure	Freeze/thaw cycles leading to sheath damage if CC is not co-extruded	Reduced effectiveness of CC	No mitigation identified in literature	No testing or field experience found*	Yes
		Migration of water within the sheath layer	Reduced effectiveness of CC	Proper installation hardware and procedures needed	No testing or field experience found*	Yes
Wind	Pole damage	Increased potential for pole damage (due to heavier conductor and larger wind area)	Potentially higher consequence than bare	Proper standards and procedures needed when retrofitting	Leskinen 2004	Yes
Tree damage	Tree falls, breaks conductor	Live conductor down with no outage	Reduced effectiveness of CC	Literature shows fewer ELIs as CC were introduced into system (see Taiwan section)	Li 2010	Yes
	Tree branch bridges various lines (conductors do not break)	Abrasion of sheath	Reduced effectiveness of CC	Literature shows CC reduced outages due to tree contact	Li 2010; Leskinen 2004; Ariffin 2012	Yes
		Cracking of CC sheaths	Reduced effectiveness of CC	Literature shows CC reduced outages due to tree contact	Li 2010; Leskinen 2004; Ariffin 2012	Yes

Hazard	**Scenario**	**Failure Mode**	**Consequence of Failure**	**Mitigation Notes**	**Selected Literature/ Testing**	**More Investigation Recommended**
		Heating damage to sheath following coating damage	Reduced effectiveness of CC	Literature shows CC reduced outages due to tree contact	Li 2010; Leskinen 2004; Ariffin 2012	Yes
		Corrosion of conductor due to compromised sheath	Reduced effectiveness of CC	Literature shows CC reduced outages due to tree contact	Li 2010; Leskinen 2004; Ariffin 2012	Yes
Maintenance / installation	Sheath damage due to incorrect hardware tool or incorrect stripping	Mechanical damage to sheath (dent/gouge)	Potentially higher consequence than bare	Proper standards and procedures needed	Rocha 2000	No

* Based on a thorough literature review. However, sources may exist that were not found through this effort.

** HDPE may be beneficial for other failure modes.

Risk Discussion

In total, 24 failure modes that are unique to CCs were assessed for their risk relative to bare conductors. The failure modes presented in Table 7 were identified through the joint IOU workshop. However, the frequency of these events (as well as consequence) was not within scope for this effort, and, as such, not all failure modes may present measurable risks to operators. Further, only a portion of these failure modes may result in an elevated risk profile relative to bare conductors, whereas others may only reduce the effectiveness of the covering. The following section discusses special cases from Table 7 in more detail.

Two fire-related failure modes were identified, including damage to, and flammability of, the sheath. In a “worst-case” scenario, if the sheath becomes damaged by fire or heat from a nearby fire, only the metallic conductor will remain. In this case, the effectiveness of CCs is greatly reduced, but no elevated risk relative to bare conductor would result. If, however, the sheath was only damaged in a localized area (versus extensive damage across the entire sheath), then a fault event could have the potential to concentrate heat and arcing in the area of the coating damage in a more severe manner than a bare conductor. In this case, a new, unique risk profile may exist beyond a simple reduction in CC effectiveness. In both cases, no mitigation, testing, or field experience was found in the literature reviewed. For this reason, further research, and possibly testing of these failure modes is recommended to determine the effect of sheath damage due to fire.

UV or solar exposure may accelerate the conductor sheath aging by causing embrittlement and/or cracking. Damage to the sheath may reduce the effectiveness of the CC. UV inhibitors are commonly incorporated in the conductor coating to prolong polymer lifetime [Hendrix 2010, Ariffin 2012].

Contamination from moisture/salt and smoke during fires was considered, as tracking could reduce the effectiveness of the insulation. Tracking of single-, dual-, and triple-layer CCs in heavily polluted areas and coastal areas is well documented in literature [Cardoso 2011, Yousuf

2019, Espino-Cortes 2014]. Similar to the fire hazard discussed above, if the insulation or sheath experiences significant tracking, then the CC effectiveness will be reduced.

Lightning may cause arc damage or melting of the CC that results in a down wire. Reports in the literature indicate CCs help to reduce the number of outages due to lightning, though the mechanism for failure prevention is unclear [Ariffin 2012, Leskinen 2004]. However, the presence of the CC insulation may create an increased risk during a lightning strike. For bare conductors during a lightning event, the electrical arc is more easily dissipated across the metallic surface. In the case of CCs, the insulation may concentrate the electrical arc at a single point during a lightning event, which may cause burndown [Lima 2016, Leal 2021]. Pinholes in the CC insulation may also result in a small reduction of the breakdown voltage. Although lightning arrestors help to mitigate this failure mode, additional testing or research could still be helpful in better understanding the effects of lightning strikes on CCs.

Animal chewing on the conductor coating may cause a localized area of damage such that arcing/heating may be concentrated during a fault. Therefore, this type of damage may present an elevated risk profile relative to bare conductors. Literature sources recommend use of a two-layer copper screen and non-HDPE as the sheath material to deter animals from chewing on the conductors. However, using non-HDPE coatings for the sheath material must be weighed against the benefits of using HDPE materials, especially in areas where animal chewing may not pose a significant risk. No further testing is recommended at this point, as this mitigation is well documented in literature [Ariffin 2012].

Moisture may result in sheath damage due to freeze/thaw cycles or water migration. In the case of water migration, sealing the ends of the conductor may help prevent damage. Few literature sources were found that addressed this specific failure mode or potential mitigation strategies. Additional research, analysis, or testing is recommended to address moisture ingress that could change the breakdown voltage potential of CCs.

Wind damage to poles due to the heavier weight of CCs and larger wind sway is potentially an increased risk compared to bare conductors. This risk can be mitigated by using proper standards and procedures, especially when retrofitting CCs onto existing structures. Additional analysis is recommended to understand potential pole damage due to CC weight.

Tree damage may result in multiple failure modes, as shown in Table 7. On a high level, field experience shows that the number of outages caused by tree contact is reduced when CCs are used [Leskinen 2004, Li 2010, Ariffin 2012, Rocha 2000]. CCs likely decrease the risk of tree-related failure modes. However, the literature studies reviewed do not detail the specific failure modes that are mitigated. Additional research and testing may be needed to determine the extent to which CCs reduce the risk of certain failure modes. Testing focused on long-term tree contact and mechanical testing of the polymer sheath is recommended.

Maintenance and installation considerations are different for CCs compared with bare conductors. Due to the CC sheath, care should be taken while installing CCs to minimize damage from incorrect hardware, stripping, or installation. Additionally, the span sag levels must be adjusted due to increased weight of CCs. Specialized training, standards, and procedures must be followed to account for the additional considerations for CC installation and maintenance. These standards and procedures should help minimize the CC risks and make them comparable to those of bare conductors. However, the additional training, standards, and procedures introduce the potential to increase the risk of CCs compared to bare conductors if not properly followed. No further testing is recommended at this time for this hazard, as long as proper procedures and standards are established for maintenance and installation.

Implementation and Design Considerations

In addition to new failure modes and risks that may be introduced by CCs, there also exist several special considerations for effective design and implementation of CC systems.

Hardware specific to CCs is recommended to ensure consistent and safe installation and reduce the risk of damaging the conductor insulation. This hardware may include insulation-piercing connectors (IPCs), spacers, tangent brackets, and messenger cable. If IPCs are not used, manual stripping of conductor insulation is required at hardware connection points. This creates a risk for local arcing/faults as well as the potential for conductor sheath damage and environmental ingress if not properly executed.

Replacement of bare conductors with equivalent CCs can potentially cause increased sag and can overload the poles, crossarms, or guys because they can increase both gravity and wind loads. The capacity of existing structures needs to be checked before reconductoring is considered. The span length for new lines is typically shorter than bare conductors due to the heavier weight of CCs. However, this can be overcome if a larger messenger wire with greater ultimate tensile strength is used [Cardoso 2011]. Span lengths of 40 meters are common for distribution systems but can be increased up to 400 meters with proper installation [Cardoso 2011].

Installation and maintenance procedures are necessary for CCs due to the special requirements listed above. Proper handling of CCs and considerations when retrofitting CCs onto existing infrastructure is needed. This includes but is not limited to minimizing the amount of coating stripped or removed, covering any exposed conductor, increasing line sag to account for the additional CC weight, and installing proper accessories for lighting arrestors, dead-end covers, composite poles, and crossarms [EPRI 2009 Crudele]. This requires additional personnel training to address unique aspects of CC care, special equipment requirements, and handling during installation and maintenance.

Recommendations

1. Line Tension Study

Several failure modes that affect both bare and covered conductors have the potential to be exacerbated with CCs relative to bare conductors. These are primarily related to the physical differences between the conductors such as diameter, weight, and surface characteristics, leading to potential differences in susceptibility to Aeolian vibrations, galloping, line sway, mechanical overload due to ice accretion, and others (Table 2). Therefore, a thorough understanding of these differences from an analytical perspective is recommended. Specifically, a study investigating the most appropriate line tension considering the size and weight of covered conductor is recommended, which would aid in mitigation of the identified failure modes.

2. Additional Arc Testing

The available literature was found to be promising and suggests that many of the identified failure modes are largely addressed by use of CCs. However, a few key scenarios have yet to be addressed. Further arc testing is recommended to investigate the effects of long-term contact with vegetation, ground, or other objects to better understand delayed high-impedance fault behavior. The effects of wet vs. dry conditions on arcing behavior also warrants further investigation.

3. Covered Conductor–Specific Failure Mode Testing

An understanding of CC-specific failure modes is critical to effective asset management. While implementing CCs will mitigate some risks associated with bare conductor use, there are new failure modes introduced through the use of CCs. The available literature focuses on the benefits of CCs and is relatively lacking with respect to these failure modes. Further research (and potentially testing) is recommended to better understand the following phenomena:

a. Sheath damage and flammability due to nearby fire
b. Tracking due to contamination from salt or smoke
c. Moisture ingress
d. CC sway behavior and the potential for pole damage

4. Early Fault Detection Research

Due to the insulation provided by CCs, a fallen intact conductor may be difficult to quickly detect with existing fault protection systems. Early fault detection schemes are a subject of current research, and additional investigation of this technology is recommended.

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Limitations

At the request of PG&E, SCE, and SDG&E, Exponent has conducted an investigation into the effectiveness of covered conductors for overhead distribution system hardening. Exponent investigated specific issues relevant to this technology, as requested by PG&E, SCE, and SDG&E. The scope of services performed during this investigation may not adequately address the needs of other users of this report, and any reuse of this report or its findings, conclusions, or recommendations presented herein is at the sole risk of the user. The opinions and comments formulated during this assessment are based on observations and information available at the time of the investigation. No guarantee or warranty as to future life or performance of any reviewed condition is expressed or implied.

The findings presented herein are made to a reasonable degree of engineering certainty. We have made every effort to accurately and completely investigate all areas of concern identified during our investigation. Exponent may supplement this report should new data become available.

Attachment I: Joint IOU Response to Action Statement-Enhanced Clearances

Joint IOU Response to Action Statement SDGE-21-04 Enhanced Clearances

Issue

SDG&E, PG&E, and SCE presented a "joint, unified" plan to the WSD on February 18, 2021. While it was apparent the three large utilities had discussed a unified approach, each utility presented differing analyses that would be performed to measure the effectiveness of enhanced clearances. WSD, now OEIS, acknowledges the complexity of this issue; any study performed assessing the effectiveness of enhanced clearances will take years of data collection and rigorous analysis.

Remedies

SDG&E, PG&E, and SCE will participate in a multi-year vegetation clearance study. The objectives of this study are to:

1. Establish uniform data collection standards
2. Create a cross-utility database of tree-caused risk events (i.e., outages and ignitions caused by vegetation contact).
3. Incorporate biotic and abiotic factors into the determination of outage and ignition risk caused by vegetation contact.
4. Assess the effectiveness of enhanced clearances

Response

The utilities have prepared a joint response to this Issue/Remedy.

SDG&E, PG&E, and SCE (jointly, investor-owned utilities or IOUs) have begun collaboration on a vegetation clearance study. This is expected to be a multi-year effort which will benchmark vegetation management practices and data collection methodologies across IOUs in order to help develop uniform data standards. Bi-weekly meetings began on September 9,2021 and eight meetings have been held to date, with attendees from the IOUs and Energy Safety at each meeting.

The IOUs are focused on addressing the required remedies of this study, which include:

- Establish uniform data collection standards
- Create a cross-utility database of tree-caused risk events (i.e., outages and ignitions caused by vegetation contact)
- Incorporate biotic and abiotic factors1 into the determination of outage and ignition risk caused by vegetation contact
- Assess the effectiveness of enhanced clearances

Initial meetings began with each utility discussing their existing data collection standards and early analysis of enhanced vegetation clearances. The IOUs discussed definitions being used and began to standardize definitions including "enhanced clearance," "inventory tree," "tree-caused risk event," and "post-trim clearance." The different types and methods of creating a cross-utility database of tree-

[1] Biotic factors include all living things (e.g., an animal or plant) that influence or affect an ecosystem and the organisms in it; abiotic factors include all nonliving conditions or things (e.g., climate or habitat) that influence or affect an ecosystem and the organisms in it.

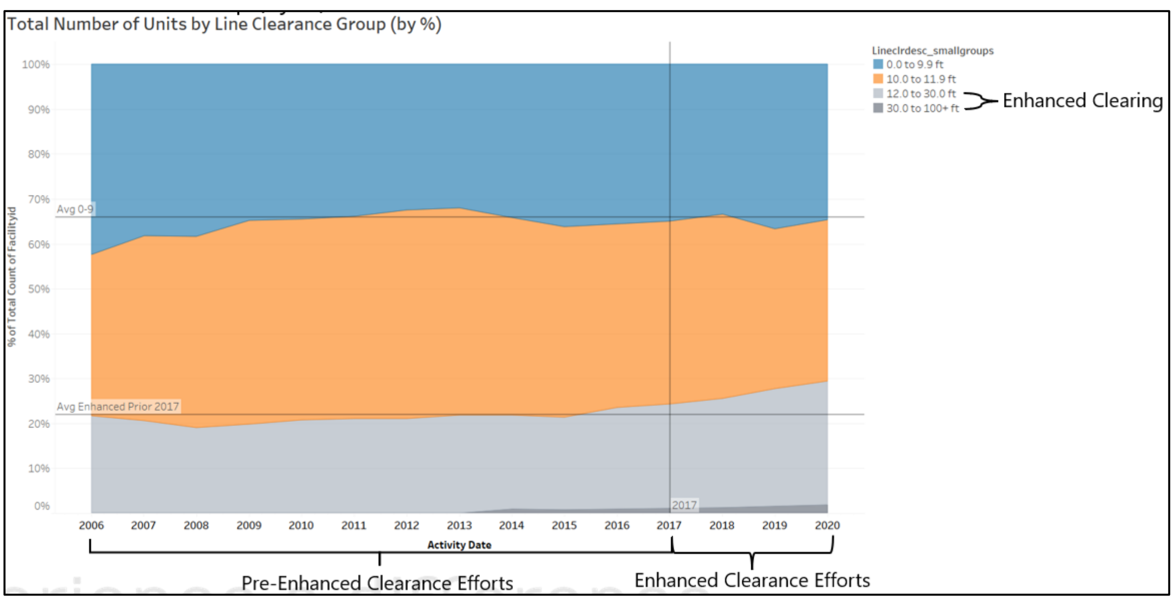
caused risk events were reviewed. There are pros and cons to the various methods discussed, with more work to be completed in the future on the format and location of this database.

The most recent meetings, which took place after the November 1, 2021 Progress Report, focused on each IOU demonstrating its current analysis around the effectiveness of enhanced clearances.

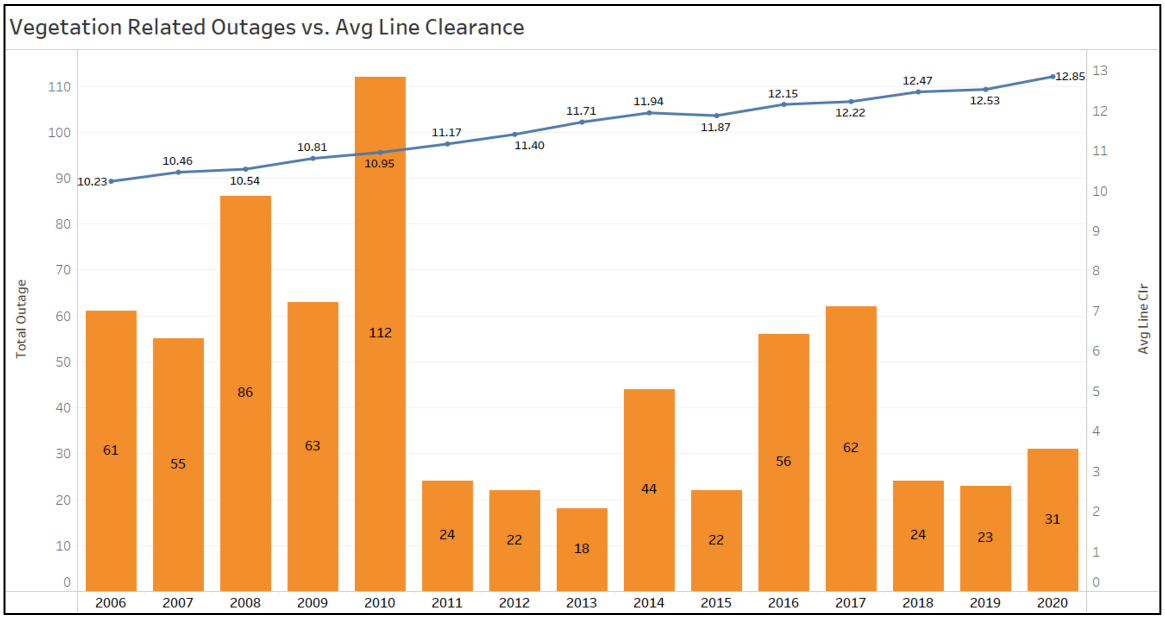
Initial analysis focus on outage/interruption events as these are precursors to ignition events. Ignition data does not have a sufficient population sample size to evaluate at this time. These initial analyses are presented below for each IOU:

SDG&E

Initial analysis performed by SDG&E studied the relationship between line clearance and vegetation related outages on the system. The outages being studied are related to unplanned forced outages, excluding instances where the line is de-energized for safety to allow crews to work in the area. The IOUs have defined enhanced clearance as trimming the vegetation at least twelve feet from the energized conductor. Enhanced clearance efforts ramped up beginning in 2017, as shown in the graph below where the percent of SDG&E's inventory trees trimmed to enhanced clearances increases to near 30%.



SDG&E sees an increase in average line clearance over time, with a related relative decrease in vegetation related outages over time. This decrease in vegetation related outages will likely lead to fewer events that could result in an ignition leading to a wildfire. Data from 2006-2016, the pre-enhanced clearance timeframe, compared to data from 2017-2020, the post-enhanced clearance timeframe, show that vegetation-related outages have decreased by thirty-eight percent since these enhanced clearance efforts began.



	Inventory Trees Inspected	Vegetation Related Outages	Outage Rate
Pre-Enhanced Clearance (2006-2016)	4,667,075	554	1.19E-04
Post-Enhanced Clearance (2017-2020)	1,863,658	137	7.35E-05
Difference			-38%

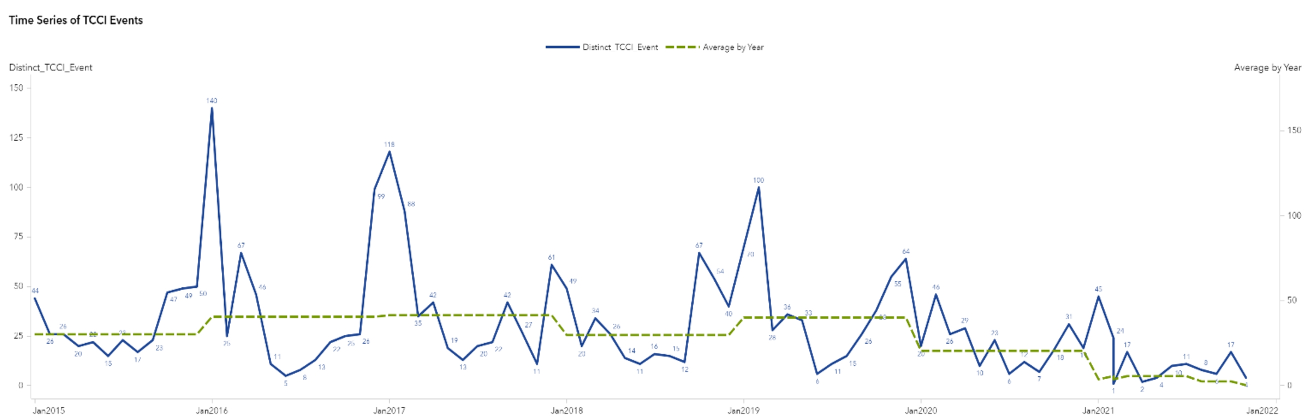
SCE

In late 2018, consistent with D.17-12-024 which amended GO 95 to increase recommended clearance distances at time of trimming in HFTDs, SCE implemented enhanced clearance programs to achieve greater trimming distances. For purposes of this analysis and considering the time to operationalize enhanced clearances to establish SCE's Grid Resiliency Clearance Distances (at least 12' clearance in HFTD and 6' in non-HFTD) across SCE's service territory, the "pre-enhanced" time frame is considered to be 2015-2019, and "post-enhanced" is focused on 2020 and future years. Outage data in the table/chart represent tree-related events (circuit interruptions) on SCE's distribution system confirmed by SCE field verification as grow-in, blow-in and fall-in events.

This data highlights a decrease in outages associated with vegetation caused events since the advent of SCE's enhanced clearances. Details about the reported events include confirmed tree-related events (Tree Caused Circuit Interruptions – TCCI's) by SCE field verification, and are categorized by Grow-In, Blow-In and Fall-In events. Approximately 100 TCCI "categories" are reduced to 6 primary categories: Grow-In, Blow-In, Fall-In, Human Caused, No Cause/Not tree related, and Uncategorized. Some events initially reported as a TCCI by SCE's outage management system could fall into categories that are not indicative of a TCCI once they are investigated and verified in the field. These include Human Caused, No

Cause/Not Tree Related, and Uncategorized (the data below does not include these categories). Legacy data was updated to new data collection standards rolled out in 2021. Complete year-to-year outage data is available from 2015 to present and complete enhanced clearance data is available from 2020 to present. This data reflects distribution related events only, as there are no transmission related events of record. Though SCE has tracked TCCIs since 2015, it has only recently made advancements in its work management system that allows SCE to associate specific outage events with the individual/specific trees in its inventory. Outage data was not associated until 2021. Through this joint study, and over the next few years, SCE expects to find more substantial evidence supporting the positive effectiveness of enhanced clearances and the reduction in tree related events. Please see the Time Series of TCCI Events figure and Average Events Pre & Post Enhanced Clearances table showing early indications that implementing enhanced clearances among other programs has decreased the number of events.

Time Series of TCCI Events

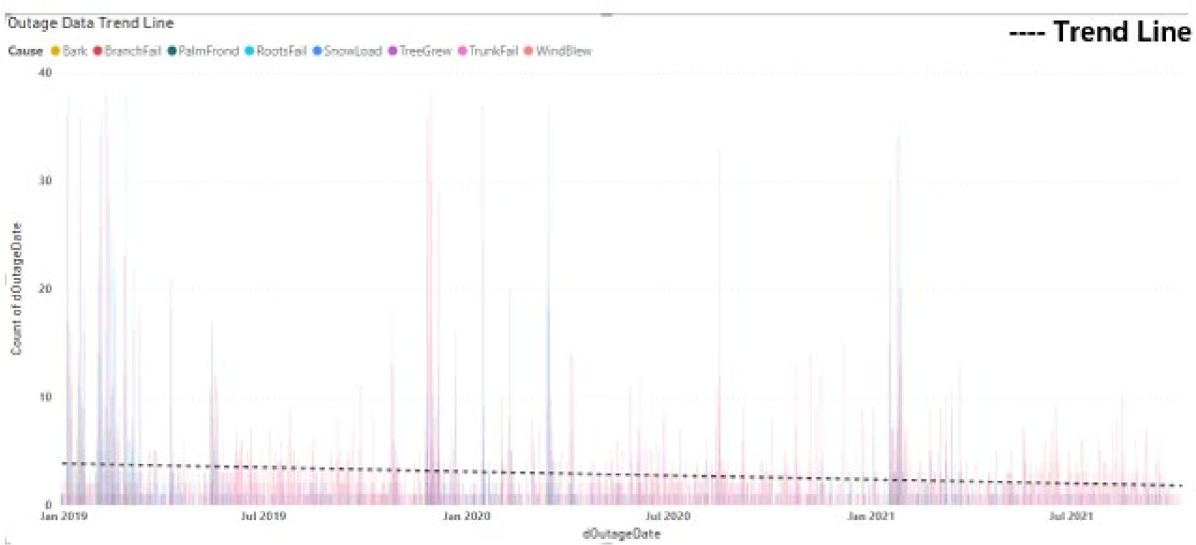


Average Events Pre & Post Enhanced Clearances

Average Events Pre and Post Enhanced Clearances	Pre-Enhanced Clearances 2015-2019 Avg TCCIs per Year	Post Enhanced Clearances 2020-2021 Avg TCCIs per Year	Difference
HFTD	148.4	61.5	-59%
Non-HFTD	289.2	136	-53%
All	437.6	197.5	-55%

PG&E

PG&E's Enhanced Vegetation Management (EVM) program began in January of 2019 and the image below illustrates the beginning of enhanced clearances toward the end of 2021, or approximately three years of data, but the outages are representative of the entire service territory. The graph shows outage data confirmed as tree-related events and the distinct causes of the outage (Bark, BranchFail, PalmFrond, RootsFail, TreeGrew, WindBlew). Trend line analysis shows a decrease over the three-year period in outage counts associated with these tree-related causes. This is for Distribution conductor only and outage counts were capped at 40 per day to remove outliers in data. (With outliers still represented, the trend analysis also shows a decrease in tree-related causes, but it is more difficult to read in this particular format.) This data is preliminary and the decreases in tree-related causes cannot be attributed solely to enhanced clearances without further examination.



Summary

The early analysis of each IOU demonstrates that after implementing enhanced clearances the number of vegetation-related outages has decreased.

The IOUs will begin 2022 by initiating a process for soliciting proposals from third-party vendors that can assist with achieving and validating the objectives of the study. Now that each utility's current methods have been reviewed and understood, the process of beginning to standardize data collection and creating a cross-utility database of tree-caused risk events will begin. As preliminary discussions lead to the analysis of vegetation events as the key metric for effectiveness, over the course of this extended study the IOUs may confirm or adjust effectiveness metrics and work towards a more uniform standard for measuring the efficacy of expanded clearances. Part of these discussions included the types of biotic and abiotic factors that can affect the risk of vegetation contact including tree genus/species, tree health, soil composition, storm conditions, Santa Ana winds, etc. The IOUs believe that biotic and abiotic factors can be extracted from existing data sets. Additionally, in partnering with their consultant, the IOUs will begin to examine whether the correlation between enhanced clearances and the lower number of tree-caused outage events may be attributable to other factors beyond clearances, such as the management of hazard trees and the installation of covered conductor. The joint study will look into whether, and to what extent, other mitigations can be effectively parsed out so as to focus in on the effects of enhanced clearances. To that end, additional data may need to be included in the joint data base (such as the presence of a covered circuit segment) to segregate causal factors.

Each IOU will collect the relevant data identified by Energy Safety for the purposes of this study.

Attachment J: Vegetation Management Inspection Findings by Vegetation Management Area (VMA) and Priority Level

Vegetation Management Inspection Findings by Vegetation Management Area (VMA) and Priority Level

	2020 Pre-Inspection Finding (unit)		2021 Pre-Inpsection Finding (unit)	
VMA	**Memo-PI**	**Routine-PI**	**Memo-PI**	**Routine-PI**
475	76	781	41	751
651	154	1,630	86	1,513
368	68	877	43	717
215	144	1,887	153	1,665
312	60	815	69	1,006
210	178	2,433	103	2,298
212	154	2,175	160	1,530
373	16	236	5	254
397	31	466	23	633
369	24	362	18	420
355	24	367	13	432
604	139	2,126	47	2,103
455	82	1,257	24	1,115
456	154	2,397	107	2,242
606	118	1,846	44	1,977
450	50	804	48	764
377	48	776	31	730
553	21	342	31	378
463	90	1,470	50	1,306
354	36	610	48	1,049
454	104	1,808	69	1,796
654	69	1,243	26	1,117
458	77	1,442	62	1,623
670	64	1,211	25	756
513	55	1,045	28	944
452	56	1,069	78	919
393	35	691	48	812
363	120	2,371	82	2,311
469	72	1,456	37	809
460	83	1,797	45	1,825
552	40	873	17	714
610	45	986	34	787
406	88	1,929	66	1,524
652	85	1,874	53	2,122
465	61	1,360	13	1,198
623	48	1,089	37	1,166

371	68	1,573	15	1,303
352	93	2,172	71	2,085
353	43	1,015	34	1,369
367	14	344	10	374
408	68	1,695	8	1,301
453	14	354	2	341
314	37	936	18	965
527	49	1,249	57	1,196
512	40	1,058	35	868
405	62	1,672	77	1,828
420	84	2,397	50	2,385
514	93	2,675	83	2,177
390	30	863	5	919
350	56	1,631	60	1,301
467	23	672	22	793
375	25	731	10	360
655	53	1,583	69	1,464
653	74	2,235	76	2,294
412	89	2,718	51	2,459
451	29	891	14	755
477	25	769	17	720
521	35	1,090	17	1,240
510	40	1,263	61	1,232
611	47	1,488	37	1,575
357	62	1,985	15	934
614	24	778	69	649
383	30	979	54	803
394	35	1,145	58	1,392
364	37	1,226	22	1,269
220	78	2,588	53	1,909
387	37	1,230	28	960
399	45	1,523	35	1,460
602	21	717	11	534
479	26	905	9	692
603	32	1,132	26	1,027
351	42	1,492	29	1,141
414	46	1,636	24	1,502
462	36	1,281	21	1,428
520	57	2,040	20	1,816
313	39	1,412	35	1,341
466	14	524	5	337

468	42	1,647	29	1,940
374	29	1,149	31	673
356	31	1,274	30	1,388
388	22	942	8	666
416	21	915	26	648
398	23	1,026	26	965
673	21	941	37	1,207
370	29	1,331	21	813
464	21	992	10	1,243
519	26	1,281	27	1,342
403	28	1,385	44	1,064
221	46	2,292	20	2,008
365	24	1,209	36	1,355
379	21	1,059	8	629
362	38	1,979	23	1,332
702	10	526	17	574
601	17	900	66	895
359	19	1,016	24	1,093
310	22	1,214	32	1,081
674	16	979	16	977
616	16	980	3	1,335
410	23	1,428	45	1,365
624	19	1,243	41	1,606
372	20	1,371	30	1,030
311	23	1,595	39	1,451
384	17	1,187	22	1,210
518	23	1,633	16	1,512
361	13	996	19	874
309	11	853	15	1,006
366	13	1,013	4	1,152
392	13	1,124	9	1,177
400	12	1,044	16	1,087
358	21	1,885	24	1,463
391	14	1,313	14	763
607	11	1,045	12	924
305	17	1,632	23	1,480
302	16	1,675	18	1,447
376	7	738	13	715
703	8	880	9	935
708	5	587	8	481
386	10	1,183	14	1,159

381	17	2,084	14	1,669
304	14	1,780	26	1,471
605	32	4,186	92	3,760
382	8	1,064	16	935
707	6	801	8	777
380	10	1,410	31	1,428
306	7	990	15	994
701	15	2,206	89	1,901
396	4	660	6	426
360	7	1,187	10	997
385	6	1,034	8	979
395	5	934	14	1,055
378	2	733	4	800
389	3	1,191	6	1,048
752		436	7	533
(blank)	4	5		2
Grand Total	**5,579**	**171,731**	**4,548**	**158,644**

Appendix 2:
SDG&E's Company Emergency and Disaster Preparedness Plan
(PUBLIC)

Company Emergency And Disaster Preparedness Plan (PUBLIC)

Document Control No. EM0001

Emergency Management

Emergency Operations | OFER | Aviation Services | Training and Exercise

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The Emergency Management director and VP Wildfire and Climate Science signatures below indicate they have reviewed, accepted, and recommend this Company Emergency and Disaster Preparedness Plan for senior executive leadership CEO approval. It is acknowledged the plan will be exercised and modified as processes or procedures change as requested by executive leadership, and or emergency management. It will also be modified as regulatory, or compliance requirements change.

[redacted] [redacted] [redacted] [redacted]

Thom Porter, EM Dir Date Brian D'Agostino, VP WCS Date

1 Introductory Material - Basic Plan

1.1 Foreword

This Company Emergency and Disaster Preparedness Plan (CEADPP) was developed for San Diego Gas & Electric, (SDG&E) in cooperation with each of its business units and in alignment with Sempra Energy Corporate Emergency Response Plan. Per CPUC GO 166 requirements, this CEADPP was developed using *FEMA's Comprehensive Preparedness Guide Volume 2.0.*, *Cal OES EOP Crosswalk*, and vetted in collaboration meetings with Orange County Governments, Cal OES San Diego OA governments, AFN-CBOs, and San Diego County Tribal Governments. The CEADPP consists of a basic plan, related attachments, hazard specific annexes, functional annexes, and appendixes for additional support information to the emergency plan.

The basic plan contains the following sections:

1.2 Letter of Approval and Promulgation

To All SDG&E Employees and Contractors:

Transmitted herewith is the Company Emergency and Disaster Preparedness Plan (CEADPP) for SDG&E. This plan supersedes any previous plan(s) promulgated for this purpose. It provides a framework for the Company to use in performing emergency functions before, during, and after an emergency incident, natural disaster, or technological incident.

This CEADPP supports the company's ability to prevent, prepare for, respond to, and recover from incidents regardless of cause, size, or complexity effectively and efficiently. This document has been formatted and updated to resemble the structural framework recommended in the Federal Emergency Management Agency's Comprehensive Preparedness Guide (CPG) and builds upon concepts establishing in the National Response Framework (NRF) and the National Incident Management System (NIMS) providing a consistent template for managing incidents of any hazard. It also meets California Public Utility Commission's General Order No. 166 standard and California Standardized Emergency Management System (SEMS Code 8607) which is meant to ensure electric utilities are prepared for emergencies, interagency collaboration, and disasters.

SDG&E's Emergency Management (EM) is responsible for the development and maintenance of this CEADPP. This plan is intended to comply with applicable Federal, State, and local statutes. It will be tested, revised, and updated as required. All recipients are requested to advise EM regarding recommendations for improvement.

This plan is hereby approved and released to all Boards, Departments and Offices of SDG&E by order of

Caroline Winn, CEO SDGE Date

1.3 Implementation

SDG&E's mission is to "Improve lives and communities by building the cleanest, safest and most reliable energy infrastructure company in America". To achieve this mission, SDG&E must engage in proactive preparedness and active response-recovery planning efforts to provide staff with the means to effectively manage any hazard that the company may encounter.

The CEADPP provides planning guidance for responding effectively to and preparation in anticipation of a risk hazard or Public Safety Power Shutdown (PSPS) incident. The CEADPP is intended to provide SDG&E personnel and other readers with the tools to meet or exceed stakeholder expectations, maintain electric & gas reliability, and safeguard the company’s brand. The severity and possible consequences of an incident cannot be predicted fully, so effective planning serves to minimize the impact on the company, its customers, stakeholders, and reputation and provide the guidance to successfully manage a non-predicted event.

This CEADPP applies to all SDG&E personnel. Every employee supporting a response must understand and appreciate their role, and those of others, for the successful execution of processes in response to an incident. To facilitate this requirement, the company will educate personnel to this plan and exercise the plan through table-top exercises and functional exercises at a minimum of a yearly basis or whenever the plan undergoes changes that will modify the response protocols.

The EM staff will determine when such training is necessary and coordinate the training and exercise functions, maintain document revision control, and coordinate any role and responsibility changes with the appropriate company departments.

The CEADPP incorporates SDG&E’s values to demonstrate its commitment to employees and customers. These values are:

Do the right thing

Champion people

Shape the future

1.4 Privacy Statement

The information in this document is classified as Internal and should be treated, stored, and maintained in accordance with the requirements outlined in the Information Security Policy. Emergency operation plans or some components are generally shared with government and community partners as the need for coordinated collaborative response needs arise. The document will be screened by the EM Director, Legal department and senior company officials as needed to determine what components should be exempted from being shared.

The CEADPP contains information that may raise personal privacy concerns, and, as a result, those portions may be exempt from mandatory disclosure under the Freedom of Information Act. As such, neither the CEADPP nor any sections thereof shall be released outside of SDG&E without prior written approval from the Director of Emergency Services or designee and the Legal Department. In addition, disclosure of information contained in the CEADPP could jeopardize the security of the company or otherwise impair its ability to carry out essential functions.

1.5 Record of Changes

In accordance with the guidelines outlined in section,8, Plan Development and Maintenance, this plan will be reviewed annually and updated every three to five years, updates will also include review of lessons learned and new or updated regulatory requirements. All change requests should be submitted to the SDG&E EM department. Major revisions will be documented below.

Date Reviewed	Reviewer Name	Revised Pages	Updated due to lesson learned or regulatory requirements Y/N	Notes
12-28-2021	[redacted]	1,5, 9, 15, 35, 46, 47	Y, CPUC GO 166 and EMAP	Name and key wording inclusion requirement to some sections
9-1-2022	[redacted]	See update appendix E this date	Org chart changes, COL approved plan update	
3-2023	[redacted]	CPUC yearly update, Conformance GO 166. See appendix E revisions this date	All reviewed with Community partners	Orange Co. Gov, Cal OES SD OA, AFN -CBOs, Tribal Gov SD

1.6 Record of Distribution

This form documents the CEADPP release to distribution entities. The receiver's identification information is listed and maintained with the release history for internal document records. This document can be released through electronic distribution systems including email or posted document management website or company mail system.

Date Released via distribution type or copies	Receiver Name	Title	Department
3-2023	Company wide	CEADPP rev 3-2023	All Departments

2 Basic Plan-Purpose, Scope, Situational Objectives and Assumptions

2.1 Purpose

This CEADPP is to ensure that SDG&E's processes and procedures are established for emergencies and disasters to minimize response times and provide for effective response and communications with the public during those emergencies and disasters.

The SDG&E CEADPP addresses emergency preparedness, crisis management, and business resumption planning to provide for the safety of employees, contractors, customers, the public and protection of property in the event of an incident affecting SDG&E employees, contractors, customers, or other stakeholders.

The purpose of the CEADPP is to provide an all-hazards strategic framework that SDG&E personnel may rely upon to respond effectively using the Incident Command System (ICS) and National Incident Management System (NIMS), (ICS-NIMS) required by federal and state SEMS mandates.

The CEADPP may be activated during business and after-hours, both with and without warning. The foundation of this plan utilizes existing company work structure and responsibilities to minimize specialized training to the plan's preparedness and response procedures. It relies on the changes to normal organizational leadership structure during an emergency activation in the CEADPP into an ICS-NIMS incident management structure to maintain chain of command and span of control principles for crisis management required in the NIMS protocols. CEADPP is compliant with the CA SEMS utility collaboration components for the 5 levels of Operational Area mutual assistance resource-response support requirements.

Utilizing the 14 NIMS management principles (Common Terminology, Chain of Command, Unity of Command, Span of Control etc.) that SDG&E has adopted, the CEADPP provides a framework by which SDG&E can respond effectively, as a company, to any threat or hazard it may face. Reliance on the guidance, processes, checklists, and other job aids found in the CEADPP will help minimize response times and provide for effective response and communications with the public and SDG&E's stakeholders during an incident.

This plan has been developed, updated, and maintained in compliance with California Public Utilities Commission (CPUC) General Order 166 as modified by Decisions (D.) 98-07-097, D.00-05-022, D.12-01-032 and D.14-05-020. Reference Section 1.4 Privacy Statement.

2.2 Scope

The CEADPP supports an all-hazards approach to incident response. As described by the Department of Homeland Security (DHS), all-hazards emergency management considers all hazards and incidents that the entity may encounter:

The EM department must be able to respond to natural and manmade hazards, homeland security-related incidents, and other emergencies that may threaten the safety and well-being of citizens and communities. An all-hazards approach to emergency preparedness encourages effective and consistent response to any condition, emergency, disaster, or catastrophe, regardless of the cause.

Examples of threats or hazards that the CEADPP may apply, include, but are not limited to:

- Wildfires*
- Cyber-attack or information security breach*
- Floods
- Supply curtailment*
- Physical security breach*
- Hazardous spills*
- Grid disruption*
- Severe weather
- Pandemic
- Gas explosion emergency
- Earthquakes
- Civil unrest*
- Other hazards that threaten the company's systems, reputation, employees, or contractors

* Can be human induced not just natural occurrence

The CEADPP, along with related standards and other company-published documentation, governs SDG&E's emergency response efforts. This plan supports and is part of the company's overall emergency response plan framework. However, SDG&E is a public utility company, not a government agency responsible for public safety-threat hazard mitigation. We adopt and follow the all-hazard plans developed through the Joint Powers Act of San Diego County and associated municipalities responsible for public safety and incorporate their risk and hazard threats plans as applicable. SDG&E responsibilities for risk and hazards fall into developing the plans and response capabilities to provide safety to the public from the risks posed by the utility electric / gas commodities, protection of our workforce and to, as efficiently and effectively as possible, maintain or restore services to the community provided by SDG&E. This is further developed in the threat / risk assessment section 2.4.

2.3 Objectives

The objectives of the CEADPP are to:

- Advance SDG&E's response capability as applicable to all hazards regardless of incident type.
- Leverage SDG&E use of the existing company operations structure and resources where applicable to maximize management effectiveness and minimize additional training requirements.
- Base the SDG&E response foundation on the NIMS and California State Emergency Management System (SEMS) emergency management principles and fundamentals.
- Utilize the EM program and plans throughout SDG&E.
- Train and document all SDG&E response members in their roles, responsibilities, and response processes in the CEADPP.
- Document SDG&E's CEADPP response practices to reflect lessons learned from activations, exercises, and industry leading practices.
- Continuous response training for personnel whenever an approved-change is made to the CEADPP.

2.4 SDG&E Threat Situation Overview

SDG&E's service territory is 4,100 square miles with approximately 1.4 million electric metered customers, 905,000 gas metered customers and servicing a population of approximately 3.7 million in San Diego County and Southern Orange County. SDG&E operates in one of the most diverse ecological service territories in the United States with micro-climates including coastal, mountains, and desert, and serves both dense metropolitan customer and remote rural communities. To further complicate providing reliable energy and gas, SDG&E service territory is located at the furthest southwest point of the United States, which limits infrastructure redundancy. As a result, SDG&E has worked to expand its local generation capacity and renewable supply.

Considering all the efforts required to be the most reliable energy company in the Unites States, SDG&E recognizes it cannot achieve that goal on its own during regional emergencies. SDG&E has developed strong relationships with local public safety partners, telecommunication companies, and other independently owned utilities via mutual assistance agreements. These relationships are in place with the recognition that no single agency or company has the capability and resources to address all disasters or major emergencies. These partnerships extend SDG&E's ability to maintain a safe, secure, and reliable source of energy for the region.

2.4.1 Risk Assessment

All Emergency Operations Plans (EOPs) are required to utilize an all-hazards approach to their response plans as there are several common components, techniques, equipment, and resources that will be deployed, irrespective of the hazard.

Most government EOP plans are centered around natural, technological, and human-caused hazards. These EOP's are designed to mitigate those hazards, limit damage to the community, and enhance public safety for those living in the path of the incident. As defined in the 2022 San Diego County Emergency Operations Plan, San Diego County (SDC) is set up as a formal Operational Area (OA) that consists of 19 jurisdictions that range in population from several thousand to over 1,000,000. In the same territory, there are also 18 different tribal nations. These combined communities create a total estimated population in San Diego County alone of over 3.3 million.

The SDC and the jurisdictional governments within San Diego County, established their legal authorities and all- hazard risks and mitigation plans, which are accounted for in this document. The risk assessment components, which inform the SDC EOP are summarized in their table-one below from the 'Multi-jurisdictional Hazard Mitigation Plan, San Diego County, California-2018 Hazard Mitigation Plan. Southern portions of Orange County falls within SDG&E's utility territory. Orange County (OC), has a current Local hazardous Mitigation Plan Dec 2021 with update revision scheduled for 2026.

Their current available draft plan has a similar list of hazards to SDC. SDG&E accepts the SDC and OC risk plans as accurate and applicable throughout its entire territory and therefore does not attempt to reproduce the same information under a company program.

Every three to five years, the SDC and OC Office of Emergency Services (OES) publishes an update of their hazard mitigation plans. For reference of the hazards please review the table summary below.

Table 1: Risks Listed in the San Diego HMP and Orange County HMP

Hazards Included in County of San Diego and Orange County Mitigation Planning	
Coastal erosion/Tsunami	Landslide
Dam Failure	Liquefaction
Drought	Nuclear Material
Earthquake	Terrorism
Floods	Wildfire/Structure Fire

2.4.1.1 SDG&E Specific Hazard Considerations

This plan recognizes that during normal operations, service failures will occur. The company's work crews, employees, management staff and leadership routinely respond to make repairs, equipment replacements, new service installations etc. which is the heart of business operations and continuity. A disaster, emergency or public safety event causes more failures over a wider area of company operations and thus causes a re-focusing of company resources or may require resource beyond those normally available. They also require additional collaboration and coordination with regulatory, government agencies, tribal partners, community partners and customer service to reduce or eliminate the issues and restore full company services.

It is not the disaster type that is critical, although there are some disaster specific elements that will need to be addressed for the safety of the public and work crews in the specific hazard annex, but the rapid restoration of the disrupted Gas and Electric services and IT systems are the core of the response.

SDG&E has established a supplemental risk analysis program. This risk analysis document is called the SDG&E Enterprise Risk Registry and is updated yearly and distributed to the VP's and Directors as risk owners and managers of the company. SDG&E's CEADPP accounts for the risks within the registry, which directly affect its operating capabilities. The CEADPP works to mitigate impacts of those risks to the company's service delivery and the responsibility it must provide those commodities to customers, businesses, government services, tribal partners, and health related services.

SDG&E 2020 Enterprise Risk Registry has identified 22 risks to the company and has ranked them from the highest to lowest assessed risk for hazards that will impact SDG&E operations. These are listed in the following table.

Table 2: SDG&E Risks Listed in Order

Enterprise Risk Registry	Hazard Specific Annex
1. Wildfires involving SDG&E equipment, including third-party attachments.	Yes
2. Dig-in on the Gas Distribution System	No
3. Employee Safety	No
4. Cyber-Security	Yes
5. Capacity restrictions or disruptions to the Natural Gas Transmission System	No
6. Electric Infrastructure Integrity	No
7. Dig-in on the Gas Transmission System	No
8. Contractor Safety	No
9. Customer and Public Safety after Meter Gas Incident	No
10.Incident related to Gas Distribution System, excluding Dig-Ins	No
11.Customer and Public Safety after contact with Electrical System	No
12.Electric Grid failure and restoration. (Blackout/failure to back start)	No
13.Sufficient supply to the Natural Gas Transmission System	No
14.Inability to recover technology and applications	No
15.Aviation Incident	No
16.Workplace Violence	No
17.Incident related to Gas Transmissions System, excluding Dig-Ins.	No
18.Consumer Privacy	No
19.Physical security of critical Electric Infrastructure	No
20.Environmental Compliance	No
21.Negative customer impacts caused by outdated Customer Information System	No
22.Massive Smart Meter outage	No

Additional Hazard Specific Annexes *	
1. Earthquake	Yes
2. Pandemic Operations Modifications	Yes
3. Wind / PSPS ConOps	Yes

* A separate hazard specific annex is utilized only if the hazard has special response, compliance, or safety procedural requirements in addition to our normal company response plans. These 5 plans require an enhanced EM response with an EOC activation with extraordinary activities. Others listed would be handled under the responsibilities of their division in the course of their day-to-day operations or can be handled by routine EOC activation. The Wildfire, and Wind / PSPS annex plans have notification / compliance response issues defined by CPUC and CalOES and must be documented procedurally. Earthquake, Pandemic, and Cyber IT annexes cross company authority lines (Sempra Energy, SoCal Gas, and SDG&E management) and require plans that incorporate safety and wide-ranging operational collaboration between the companies involved.

Each risk element in the registry is presented in a format for rapid assessment by managers and directors responsible for the risks in their respective areas. The document for each risk identifies the SDG&E Risk Owner, Risk Manager, Risk Description, Risk Update, Proposed Residual Risk Scores, Risk Bow Tie of Drivers and Triggers and Potential Consequences, and key metrics.

In the registry, the risk is scored in five areas of impact on the company and contain the previous year's score for reference:

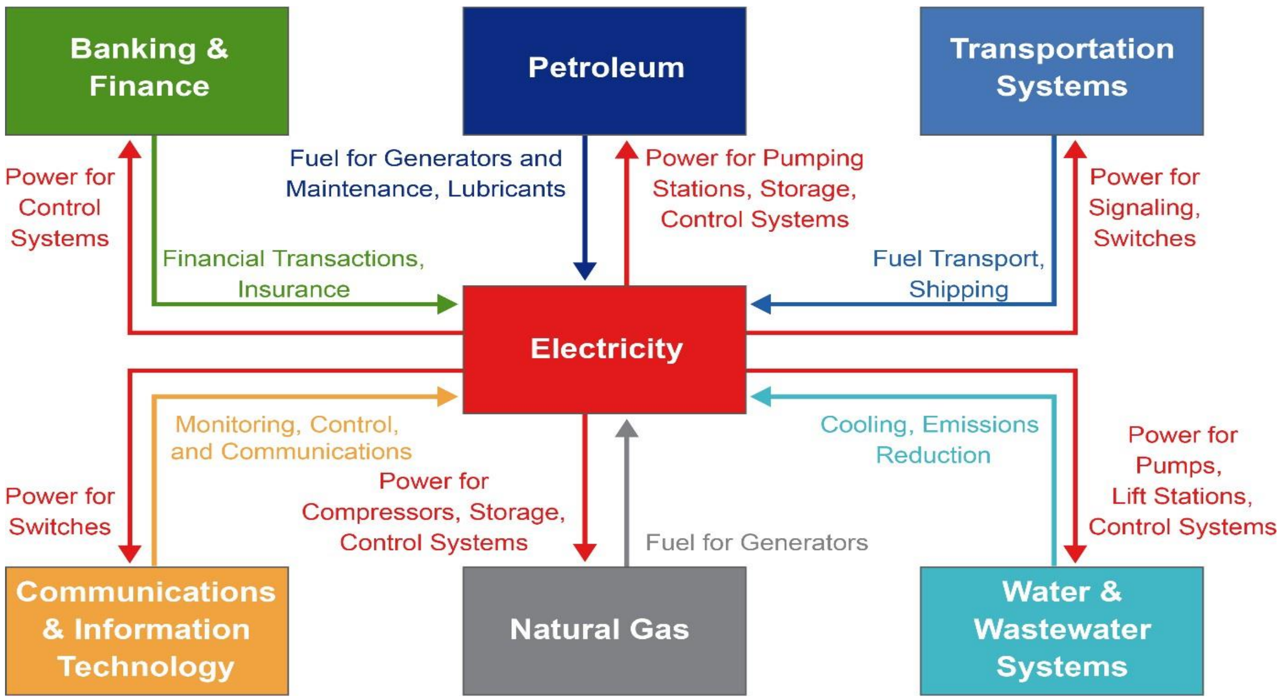
- Health, Safety, and Environmental Impact
- Operational and Reliability Impact
- Regulatory, Legal, and Compliance Impact
- Financial Impact
- Frequency

The Key Metrics component illustrates the SDG&E primary causes for that risk and how it has been managed over the previous three years. This gives the owner or manager of the risk, direction on if mitigation programs formulated for these events are being effective or not.

The Risk Registry is used throughout the company for program or financial developments of company resources and for the development of response plans.

The risk problem is compounded by their interdependencies on electrical disruption. Financial systems, transportation fuel systems, water pump systems, lighting-traffic lights, phones, internet communication systems etc. all depend on electrical power to function. SDG&E systems also have similar interdependencies as illustrated in the following figure.

Figure 1: Interdependencies on Electric Power



- **Source:** 2018: Energy Supply, Delivery, and Demand. In Impacts, Risks, and Adaptation in the United States: Fourth National Climate Assessment, Volume II U.S. Global Change Research Program, Washington, DC, USA, https://nca2018.globalchange.gov/chapter/energy

2.4.2 Capability Assessment

The EM department has direct oversight over SDG&E's Business Continuity Plans and company-wide emergency response plans. EM responsibilities have a direct impact on risks over which EM does not have direct ownership, but that directly impact SDG&E. These risks include, but are not limited to:

- Wildfires
- Catastrophic damage to gas infrastructure and transmission system
- Insufficient gas supply
- Blackouts
- Pipeline system interruptions
- Workplace violence
- IT / Cybersecurity
- Aviation incident
- Unmanned aircraft incident
- Electric Infrastructure integrity
- Physical security

EM has direct responsibility related not only to mitigation but also, where mitigation is insufficient, towards emergency response coordination where mitigation activities are insufficient from completely removing the risk. The threats and hazards that SDG&E deems most likely to occur and which are applicable to emergency preparedness activities and planning are as follows:

- Earthquake
- Wildfire
- Severe Weather, including hurricane or severe windstorm
- IT / Cyber incident
- Capacity Shortfall
- Hostile Intruder
- Internal Flooding
- Pandemic
- Physical Security Breach such as bomb, terrorist act and airplane crash

The overall purpose of emergency preparedness, including planning, is to safeguard the public, the company's employees, contractors, stakeholders, reputation, and the continuation of essential business functions.

2.4.3 Emergency Plan Implementation

To ensure SDG&E's EM has the resources and logistical support to implement the CEADPP, the EM department has been given the responsibility and authority to maintain SDG&E's Emergency Operation Center (EOC) and ICS training of all employees designated by their department supervisors to support EOC activations. Currently there are approximately 400 employees, besides the company field responders, who support emergency response within the EOC.

Government Order 166 puts the requirement upon SDG&E to have an emergency response plan and the capability to implement that plan. Therefore, SDG&E leadership has made it a priority for operational and operational support departments provide staff and logistical support to emergency events which require SDG&E CEADPP concept of operations implementation and emergency response.

2.4.4 Mitigation Overview

2.4.4.1 Hazard Mitigation and Control

The CEADPP supports an all-hazards approach to incident response. As described by the Department of Homeland Security (DHS), all-hazards emergency management considers all hazards and incidents that the entity may encounter:

> Emergency management must be able to respond to natural and manmade hazards, homeland security-related incidents, and other emergencies that may threaten the safety and well-being of citizens and communities. An all-hazards approach to emergency preparedness encourages effective and consistent response to any disaster or emergency, regardless of the cause.

The integration of plans that address the different types of incidents that may affect SDG&E service capabilities promotes a more consistent and effective response, leading to greater stakeholder satisfaction.

2.4.4.2 Hazardous Materials

SDG&E's Gas Safety Plan meets the California Public Utilities Code Section 956.6, 961, 963, and CPUC Decision 12-04-010 to meet requirements for safe and reliable operation of its gas pipeline facility. SGD&E's SP.1-SD Gas Safety Plan, and ER-1SD Gas Emergency Response Plan, which outlines all response and reporting requirements and processes followed by SDG&E.

2.5 Emergency Management and Guiding Principles

2.5.1 Vision

SDG&E advances the preparedness of all employees to respond successfully to likely threats and hazards by applying leading emergency management practices, maintaining 24/7 situational awareness through state-of-the art technology, and strengthening readiness through training and exercising "real life" scenarios. SDG&E will rely on the crisis management principles of ICS-NIMS in emergency responses where the Emergency Operations Center (EOC) is activated to level-three or above.

2.5.2 Guiding Principles

SDG&E will do the following:

- Ensure that safety, public and workforce, is SDG&E's number one priority.
- Establish and instill leading emergency management standards and practices (e.g., SEMS, NIMS, ICS).
- Ensure response plans are in place to address the highest risks that the company may face.
- Apply and expand on indices such as Fire Potential Index (FPI), predictive tools, and analytical capabilities to enhance situational awareness before and during an incident.
- Work to ensure that response to and recovery from a crisis or disaster is organized, timely, efficient, cost effective, and decisive.
- Create the foundation for an innovative, connected, and sustainable energy future in collaboration with key stakeholders.
- Treat emergency preparedness as the cornerstone on which the resiliency of the enterprise stands in the face of all hazards.
- Maintain scalable and adaptable capabilities to address simple or complex incidents.
- Actively partner with communities and stakeholders to plan, coordinate, practice, and improve preparedness for and response to incidents.
- Engage in training and exercises to test and ensure that the Company is prepared to respond to incidents.

2.6 Overall Planning Assumptions

The following assumptions apply to this plan:

- SDG&E emergency response responsibilities include the make safe, repair-restoration of electric and gas transmission and distribution services, assets, and resources of the company.
- SDG&E Gas and Electric Service Transmission-Distribution systems disruptions fall into three primary response categories:
    1. **Short-term disruption:** One to seven-day duration periods
    2. **Medium disruption:** Seven- to 30-day duration periods
    3. **Long-term disruption:** Greater than 30-days duration period.

    Note: These categories are addressed in the CEADPP for appropriate level of emergency planning, preparedness, response, and recovery activities required and company management authority responsible to resolve the situations.
- Mitigation activities conducted prior to the occurrence of a disaster result in a potential reduction in loss of life, injuries, and damage.

- SDG&E is not responsible for community first response to normal, natural, or manmade hazardous incidents impacting jurisdictions within our territory. Other governmental emergency organizations are responsible for the safety and elimination of these hazards (i.e., evacuation planning, sheltering. etc.).
- SDG&E may utilize company assets and resources to support other emergency and government agencies upon their request and with executive leadership direct approval. The company Executive Leadership Team may designate pre-approved mission assignments for rapid support as necessary.
- The CEADPP will use existing company organizational components roles and responsibilities in the response structure to involve the existing expertise, processes and assets used daily in the maintenance and repair of company assets. As the event escalates the level of coordination will move up the chain of command. If additional assets are required to support the response, utility command response will be coordinated at the activated Department Operation Centers DOC) and then at the Emergency Operations Center (EOC) as needed.
- Beyond weather, with the exceptions noted for PSPS events, the cause of the hazard is relevant only from the compliance notification and communications required to mitigate the hazard.
- Identifying the Essential Elements of Information (EEI's) in the affected area are critical to the crisis management.
- EEI's will be shared through EOC Action Planning (EAP) and Geographic Information System (GIS) documentation to keep all response personnel cognizant of safety, communications channels, incident objectives, supervisory chain of command and situational awareness.
- The SDG&E EOC will collaborate and coordinate with government EOC's to facilitate incident response and communications coordination with their Public Information Officer (PIO) as the situation requires.
- In weather related incidents, meteorological analysis will be provided for use in crisis management decisions with emphasis on its potential impact on the safety of response and recovery operations. It will also define impacts to customers and community's life sustaining issues such as excessive heat, cold, rain, lightening, water, wind, or storms etc.
- Logistical transportation issues such as road closures, damage, fuel availability, and supply chain problems, are tracked, identified, and shared with field responders via the EOC.
- Mutual assistance is requested when additional resources are needed by SDG&E and approved by the designated utility Officer in Charge (OIC). Other Utilities' may request support from SDG&E through the MA agreements signed by both parties and approved by the OIC. They will be provided as available.
- The After-Action Review (AAR) program leads the coordination of mitigation activities. These are addressed in the preparedness emergency planning phase and from After-Action Reports submitted after the incident for approval and incorporation into the appropriate planning documents.
- Supporting continuity plans and operating procedures are updated and maintained by responsible business units and departments on a yearly basis by policy of Sempra. Whenever plans or procedures are modified, applicable training by the unit responsible for carrying out the plans will be conducted focusing on the changes.
- In addition to the hazard specific annexes developed by EM, other applicable business units have developed processes, protocols, and plans to guide their specific activities, which should be aligned with EM.

2.7 Inclusive Vulnerable Community Emergency Management Practices

SDG&E is committed to providing safe and reliable energy to its customers. That promise includes taking actions to prevent wildfires and increasing infrastructure reliability. While working towards these goals, SDG&E recognizes it, and its employees are part of the communities it serves. Therefore SDG&E is proud to partner with community-based organizations to assist in providing quality of life services to "vulnerable" populations during events which may require PSPS.

SDG&E has outreach programs and councils created specifically to engage and receive input from, to community-based stakeholders and populations who fall under Cal OES's definition of Access and Function Needs (AFN) populations. In 2020 both a Wildfire Safety Council and an AFN Council were designed to engage, inform, and receive feedback from our territory stakeholders. SDG&E has also developed a wildfire outreach initiative to provide outreach events and fairs to further engage our customers and how they can better prepare for emergencies.

The following are key focus areas for SDG&E Community outreach:

- Accessible transportation
- Assistive equipment and services
- Accessible public messaging
- Restoration of essential services
- Language translation and interpretation services
- Service delivery site American Disabilities Act (ADA) compliance

2.7.1 Community Resource Centers

Community Resource Centers (CRC's) are opened during PSPS events when lines to impacted customers have been shut-off for safety reasons and the impacted customers are without power for an extended period. CPUC currently require the CRC's to be opened from 8AM to 10PM during PSPS events. The number of CRC opened is dependent on the number of communities impacted by a PSPS event. Resources typically provided at CRC's are charge stations, bottled water, blankets or hand warmers in cold weather, and information on the PSPS event, as well as disaster preparedness, mobile equipment charging stations, and other SDG&E customer programs. SDG&E has agreement for 11 fixed sites in communities and has 3 mobile trailers equipped to support this function at locations not part of the 11 fixed sites.

2.7.2 Donations and Volunteer Management Policy

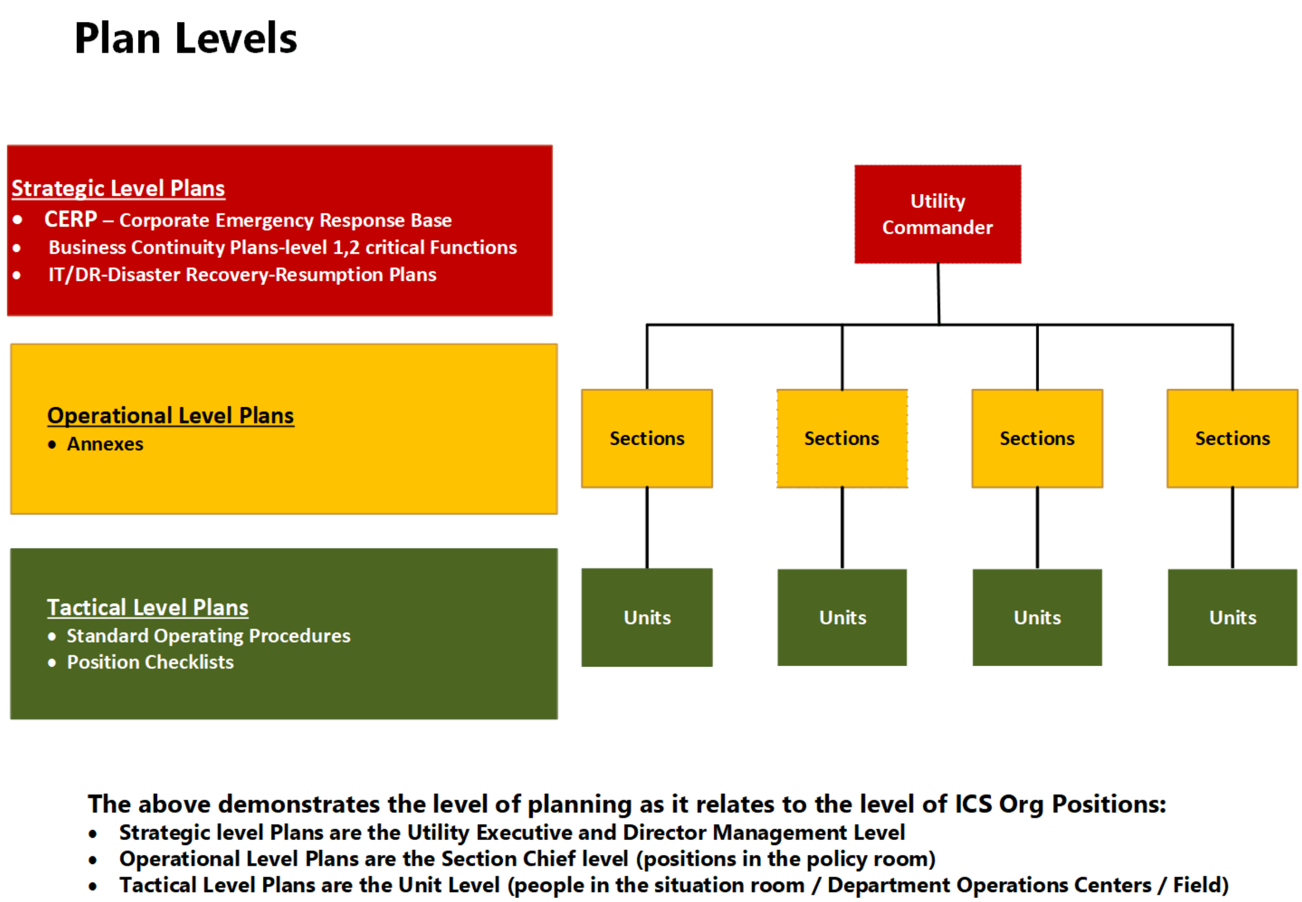
SDG&E does not accept or utilize donated goods, materials, services, personnel, financial resources, and facilities, whether solicited or unsolicited. While we do use employees who 'volunteer' and train to support our community support services, they retain their payroll status while working in the support category. Volunteering is the equivalent of re-assignment. All external donations and unsolicited volunteers described above are referred to community Non-Government Organizations for utilizations of those services.

3 Concept of Operations

This section describes SDG&E's approach to incident management or Concept of Operations (ConOps), which applies to any threat or hazard. The objective of this ConOps is to ensure that the company responds in a safe and coordinated manner, while protecting its customer service responsivities, assets, workforce, and reputation. This approach encompasses the delineation of responsibilities between the company's EOC, DOCs, and the field, and the processes, procedures, and guidelines to support incident monitoring, activation, notification, and demobilization.

There are three levels of planning within SDG&E, as illustrated below, and the CEADPP plan represents the strategic leadership overview of the response. The Operational and Tactical plans are supplemental to this plan.

Figure 2: Document Plan Levels



Pursuant to this CEADPP, the utility Officer-in-Charge, when activated, is ultimately responsible for incident management and support activities. SDG&E executive leadership will provide for a written Delegation of Authority (DOA) document to provide the designated response leader with the financial and decisional authority powers granted by the company executives on their behalf. While a Utility Field Commander or Utility Officer-in-Charge may also delegate sub-authority and actions, they cannot delegate the responsibilities outlined in this CEADPP or in their DOA. They are ultimately the responsible individual for the response activities. The EM department is responsible for coordinating EOC management activities and activation.

SDG&E's emergency response centers on disruption of customer services and are divided along company commodity lines of services, electric and natural gas. These commodities rely on our shared services IT platforms and their support in providing these services to customers and SoCalGas affiliate company, Sempra parent corporation. IT-Cybersecurity is therefore also part of the operational emergency response. Electric and natural gas services are the main 'product' of the company and have legal, regulatory standards, that have compliance requirements with financial fines that can be applicable. Hence, disruption of these services impacts the company at many levels of public safety, notification requirements, and legal compliance. The magnitude of the service disruption is classified into three emergency response categories:

1. **Short-term disruption:** One to seven-day duration periods
2. **Medium disruption:** Seven to 30-day duration periods
3. **Long-term disruption:** Greater than 30-days duration period

Each of the commodity services have unique response, notification, regulatory, and safety requirements for employee, work crews, contractors, and public at both the state and federal levels. These considerations are incorporated into the CEADPP. There are significant differences in the response between these two commodities and the other operations centers within the company when dealing with the safety and on-scene response.
These are summarized in the bullets listed below.

Summary of commodity and supporting operation centers incident complexity:

- **3.0.1 Electric Commodity:**
    - Central switch control of circuits at Mission Control Center to de-energize electrical circuits affected.
    - Grid control stabilization.
    - Prioritization and notification of medical baseline customers.
    - Electrical Trouble Shooters (ETS) and Restoration crews dispatched to make safe, repair or replace field equipment.
    - Line down public and responder safety.
    - Line down or equipment failures which could cause fires.
- **3.0.2 Gas Commodity:**
    - Gas lines cannot be turned off remotely. Requires field crews to manually close the pipes and coordinate the response with Gas Emergency Control center.
    - Gas is a hazmat, health, fire, explosive issue for public exposure, first responder exposure, and employee exposure.
    - Requires Customer Service Field response crews dispatched to every home and business utilizing gas in the affected area to both shut-down meters and after repair to open lines and relight pilot lights.
    - Requires on scene coordination with first responders, including fire, law enforcement, and training in ICS-NIMS for proper communications, for safety, perimeter access control both traffic and pedestrian, and potential evacuation of the public in the affected area.
    - High field labor involvement.
- **3.0.3 Company Security Operations Center (CSOC-Sempra for all affiliate companies):**
    - Facility security and breaches.
    - Facility damage and protection.
- **3.0.4 Company IT Information Security (SOC):**
    - Information Breach – Personal Identifiable Information (PII) or company sensitive information.
    - Network breach or disruption affecting workflow or control.
    - Cyber or malicious software attack.

This CEADPP will primarily develop how the two commodities respond to their own unique field requirement, both in regular daily operations and in escalating incident situations. To facilitate emergency response to the incidents, the company emergency response plans will utilize the California required Standard Emergency Management System (SEMS) and Federal Government mandated and proven ICS-NIMS management response approach, adapted for critical infrastructure Utility specific needs and situation. This approach is used ubiquitously nationwide by first responders. It will also address how, when an incident affects both commodities simultaneously and requires joint field operations, we will use the ICS-NIMS utility compatible crisis management approach to achieve the priorities, policies, guidance, and incident objectives set by SDG&E executive leadership through the designated Officer-in-Charge. This is compatible with and incorporates the State legally required SEMS principles and approach which includes Operational, Regional, and State Operations centers and a designated Master Mutual Aid structure for resources.

The company's EOC is designed to support, collaborate, and coordinate with all operational groups in an emergency and acts as the focal point for outside agencies, community, governments, and tribal partners involved in the emergency to communicate with company senior executive leadership providing the intent, priorities, strategy, and guidance to our field commands.

SDG&E response plans cover no-notice commodity service disruption incidents from natural disasters or local emergencies and planned preventative-mitigation shutdown events resulting from public safety power shutdowns. They are designed to affect rapid return of services irrespective of the source or cause of the disruption. Reference the Risk Assessment section **Error! Reference source not found.** of this document.

The risk hazard may affect the scale, safety risks, or mitigation strategies required to be involved in the response, but the company's main response structure is focused on safely resolving the disruption of services. Specific hazards, threats, or risk considerations, in addition to the response concepts in this concept of operation document, are detailed in the annex section to allow leadership to incorporate the appropriate response at the time of the incident. In all emergency response situations, the following five standing primary directives are used to guide the development of the senior leaderships policies, strategies and priorities which are passed to the EOC and distributed to the Electrical Field Tactical Commands, District UFC's and DOC-E Area Commands (ACs) and the corresponding Gas Field Tactical Commands, District UFC's and DOC-G Area Commands for their use in developing the incident objectives, strategies, tactics to effectively resolve the emergency.

1. Lifesaving and safety of personnel and public.
2. Life sustaining response considerations for customers and external stakeholders.
3. Property protection including SDG&E facilities, assets and to the public.
4. Environmental protection including hazmat and contamination issues.
5. Reputation and financial stability of the company.

3.1 Incident Management Structure

This concept-of-operations is structured into four response categories, each incident is characterized by a description of the severity or complexity of its impact to the operating capability and disruptions to the commodity customer services function of the company. Categorizing a threat or hazard, using a pre-defined set of criteria, provides a more accurate assessment of the effects of an incident, and the resultant size and scale of the company response and restoration requirements.

The activation level of the EOC is determined by the authority, skills and resource coordination requirements that will be needed for the response both internally within SDG&E and by the collaboration and notification-reporting requirements with community and regulatory agencies based on that incidents' impact.

- The Government EOC is formed to coordinate, collaborate, and support community life sustaining issues, mass care and resource requirements of the first responders tactical field commands. The government EOC's are formed by the Authority Having Jurisdiction (AHJ) and the elected official or his designated, delegated authority to set the guidance, priorities, and oversight strategies for the tactical commands to follow.
- SDG&E EOC is formed under the company senior leadership authority, who also set the guidance, priorities, and oversight strategies for the tactical operations centers to follow in resolving the incident issues. A major difference is that the incident leadership is responsible to the Executive Management Team (EMT) of the company, the first AHJ that delegates the authority to an SDG&E executive to act as the utility Officer in Charge (OIC)). The OIC is sub-tiered to the Sempra Energy enterprise authority through their crisis management center (CMC), a higher-level AHJ that coordinates with SDG&E EMT when impact exceeds local capabilities.

SDG&E therefore follows two-levels of response authority, one when the impact is within the capability and capacity of SDG&E to resolve locally (OIC-EMT) and the second is when the impact is beyond SDG&E capabilities and Sempra parent corporation will become involved in the authority and decision process (SDG&E OIC EMT- Sempra CMC). Note Sempra involvement is financial-reputation-legal driven, not commodity operations level.

3.1.1 Incident Types and EOC Activation

The incident management structure is designed to expand or contract to any given level as the emergency response and recovery requires.

Note: Regular daily operations do not require activation of the EOC and is managed by the Electric, Gas commodities and the appropriate company operations centers or districts following company developed processes and protocols.

The activation of company EM, personnel and resources becomes involved, and the ICS-NIMS-SEMS crisis management structure of this plan is implemented when the event or emergency expands to require senior company leadership or executives' involvement as the incident goes beyond the normal impacts to company resources, public safety, regulatory requirements, government agencies, community or business partners or the need to acquire internal and/or external support for the incident and its responders.

The ICS-NIMS-SEMS crisis management structure of this plan is implemented when the event or emergency expands beyond normal impacts to the following:

- Company resources
- Public safety
- Regulatory requirements or government agencies
- Community or business partners
- Internal and external support for the incident and its responders

There are three primary pathways to an expanding or escalating incident, Electric, Gas, and IT-Cyber. EOC activation, response, and the scaling up of company response can be triggered by either one individually, both together or due to other risks, including IT-cyber-attack, IT systems failures, facility intentional damage, or other risks that can cause significant impact to the company operational capability or health and safety of company or public individuals. Reference the SDG&E Threat Situation Overview section 2.4.

The activation of the EOC and CEADPP will always be dependent on the scale, velocity, and potential impact of an incident or event on SDG&E and the authority and resources required to manage the situation.

In any situation where the health, safety, or property damage to the public may occur because of SDG&E assets, SDG&E has developed and will utilize its special support teams, including Air Operations support units, Fire Coordination units, Community Resource Centers, Customer Service Field units, Medical Baseline notification units etc., who are activated through the emergency plans to support the situation. SDG&E Notification Process Team rapidly and consistently provides the situation awareness to our government agencies, tribal partners, community partners, and customers.

Finally, there are defined roles and responsibility between an EOC and tactical field commands that must be maintained to be compliant with NIMS-SEMS and prevent impeding effective response, confusion in response staff or put response workforce at risk through competing directives:

- The EOC OIC, senior company leadership and executives identified in the operations policy group have sole authority to determine on behalf of the company, the operational policies, priorities, strategies, company media messaging and guidance the field commands must follow.
- Once the guidance is approved, it is the responsibility of the OIC (through the EOC) to notify and transmit that guidance to the field operational commands, District UFC's, DOC-E AC's and DOC-G AC's or appropriate affected company departments, to use in developing their tactical operational plans.
- The Tactical Field Operations under both Electric and Gas Districts and their corresponding DOC-E and DOC-G, will utilize the company guidance. They are responsible to develop the utility field command objectives, operational period, and battle rhythm, utilized in the ICS-NIMS incident management planning 'P' process to effectively manage the incident and develop the operational period Incident Action Plan (IAP) for their incidents.
- The EOC is responsible for collaboration, coordination, messaging, and approved information for release to media, government agencies and the public. While local field commands may discuss their local on-scene actions, they are not authorized to represent company policy, incident assessments or incident causes and liabilities. Such information should be referred to the EOC PIO Management staff who is responsible for

development of all talking points, to include field personnel.

- The Emergency Management Department coordinates and ensures ICS centralization throughout the company to improve consistency, continuity, and coordination of these functions.
- All personnel active in the incident must follow the NIMS-SEMS principles of Chain of Command, Unity of Effort, and Span of Control to maintain an efficient response and resolution of the incidents.

3.1.2 EOC Area of Responsibilities:

• Policy, priorities, and strategic incident or event guidance development	• Information collection and analysis for situational awareness (EEI's)	• Internal and external notifications and activations
• Support to field operations	• Customer and partner liaison	• Customer support
• PIO and media support	• Regulatory notifications and compliance	• Logistical support
• Plans and documentation support	• Financial documentation support	• Regional Coordination
• Mutual Assistance requests, verifications	• Cal OES / CPUC briefings	• Cal SOC, UOC Information coordination

Department Operations Centers (DOC) and District Field Commands:

- Responsible for the safety, resource allocation, tactical assignments, damage assessment, control-repair-restorations of gas incidents, de-energization, and re-energization processes of company assets in normal daily workforce operations and in the management of field operations in emergency events following the guidance from EOC OIC, when applicable.

3.1.3 Regular Day-to-Day Operations

SDG&E is well versed in the daily operations of service, facility security, internet-cybersecurity, local maintenance, repair, and installation of equipment. If the event does not impact the safety of the public at large, impact company service capabilities or assets, the event is considered within the normal routine response capabilities of the operating districts and workforce. The on-scene commodity supervisor or the district will become the Utility Field Commander (UFC) for that incident depending on its complexity. No activation of the EOC response structure is warranted. There is always an EM on-call duty (24/7) and monitoring set of personnel to provide support, notification and evaluate the events in case the situation escalates and requires further activation or involvement of response functions. The simplified ICS-NIMS gas and electric response structure are illustrated below and will scale-up with resource units as required to manage the incident.

- Figure 3: Typical Gas District-Local Field Response, illustrates the general basic small incident for Natural Gas (NG) field configuration.
- Figure 4: Expanding Incident Gas Field Organization, demonstrates a larger incident involving community first responders at the scene. Coordination between SDG&E response teams and the first responders is necessary utilizing an Incident Support Team with qualified ICS trained personnel to act as advisors, liaisons to support the UFC in the field.

Figure 3: Typical Gas District-Local Field Response

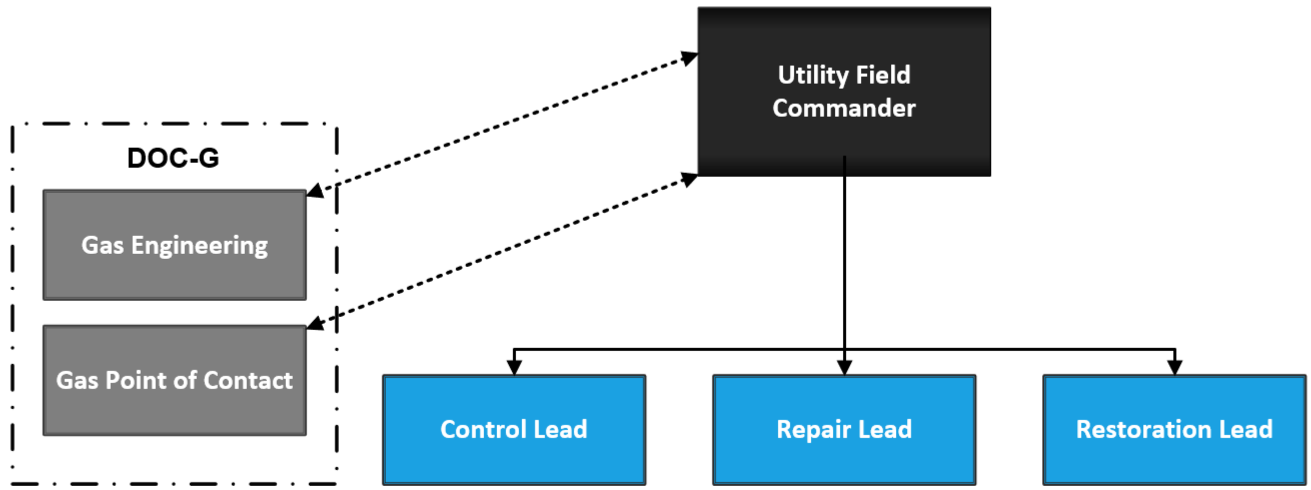
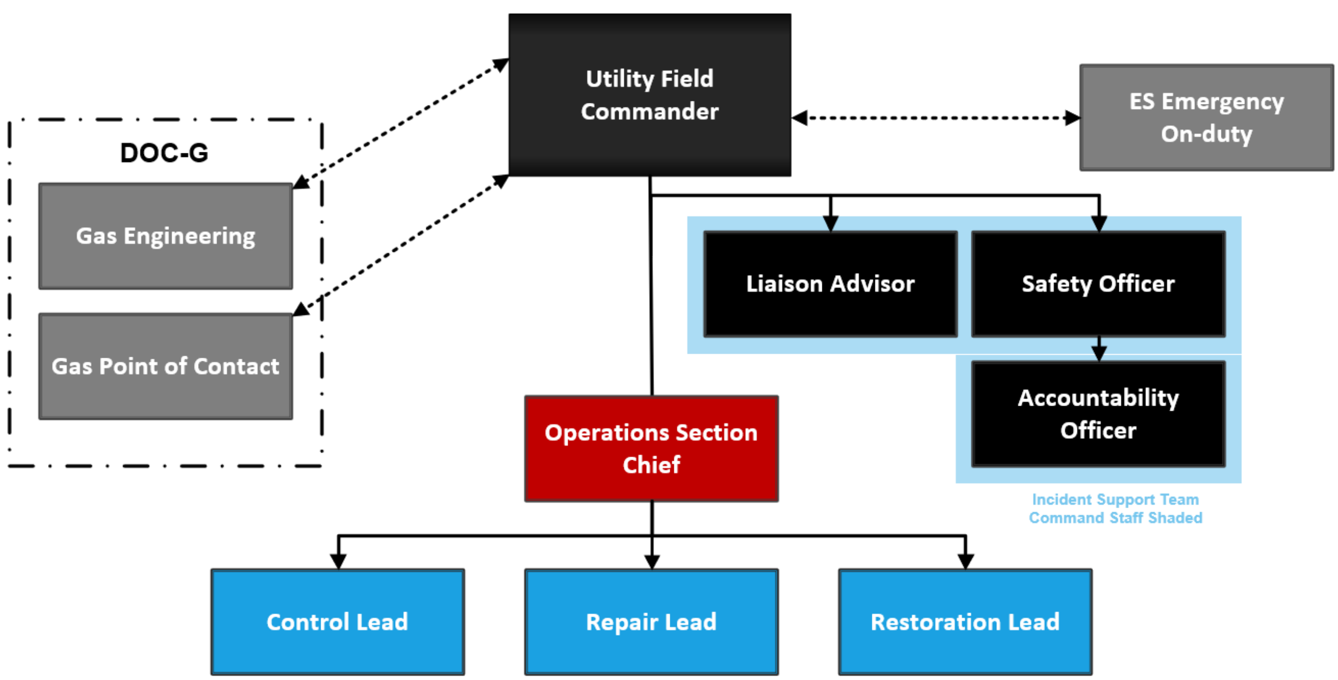


Figure 4: Expanding Incident Gas Field Organization

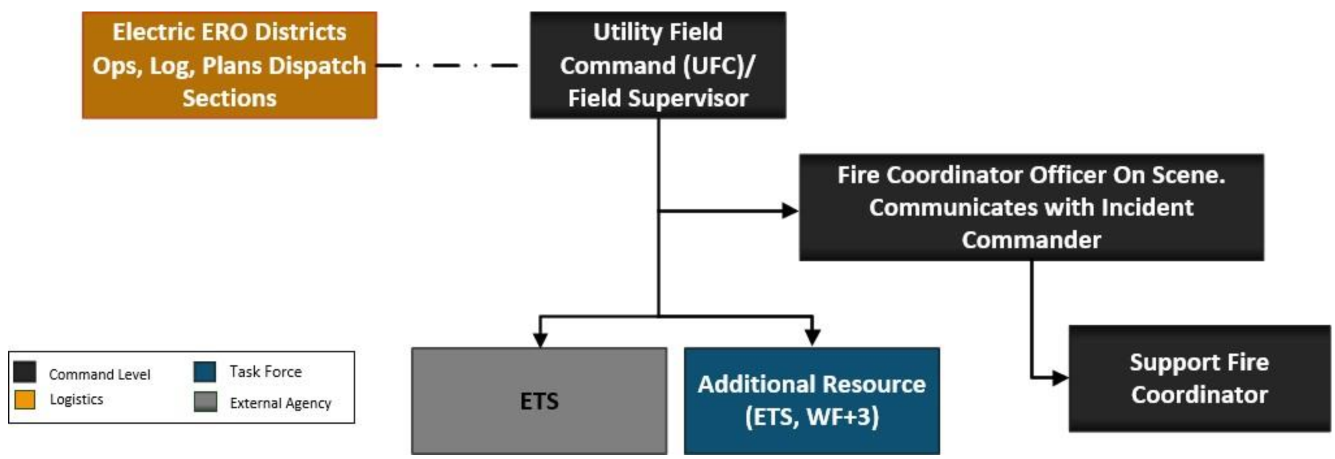


Field responses to localized electric incidents are slightly different from gas due to the different functions and hazards being mitigated. For example, electric response relies on the SDG&E Fire Coordinator function to provide the local onsite assistance like the Incident Support Team for gas events.

Figure 5 Typical Electric District-Local Field Response, shows the organizational structure for a localized field incident.

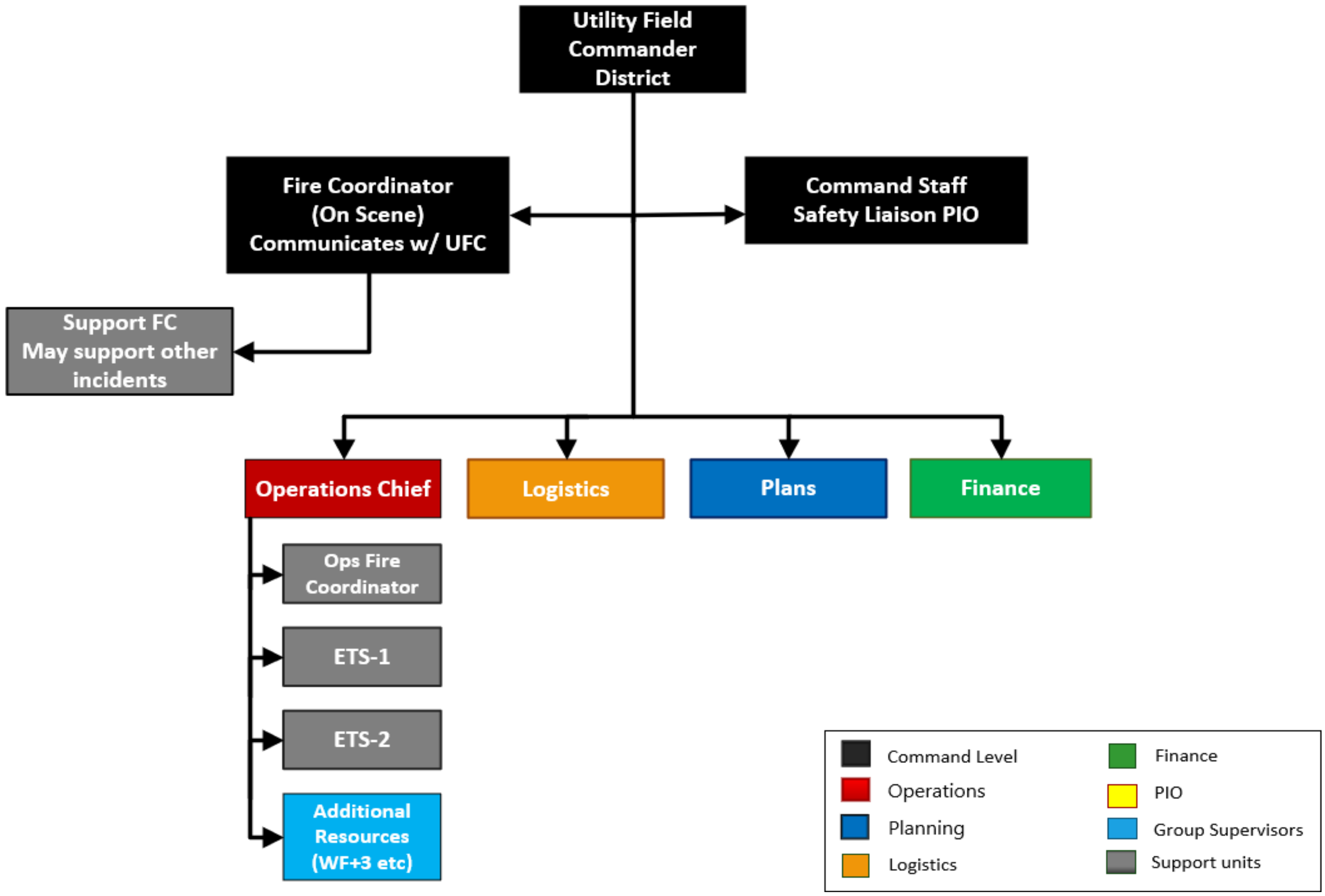
Figure 6 Expanding Incident Electric Field Command Organization, comparison demonstrates a larger incident which also requires support and coordination with first responders.

Figure 5: Typical Electric District-Local Field Response



- ETS is the Electrical Trouble Shooter resource.
- WF is the workforce and number of personnel assigned.

Figure 6: Expanding Incident Electric Field Command Organization

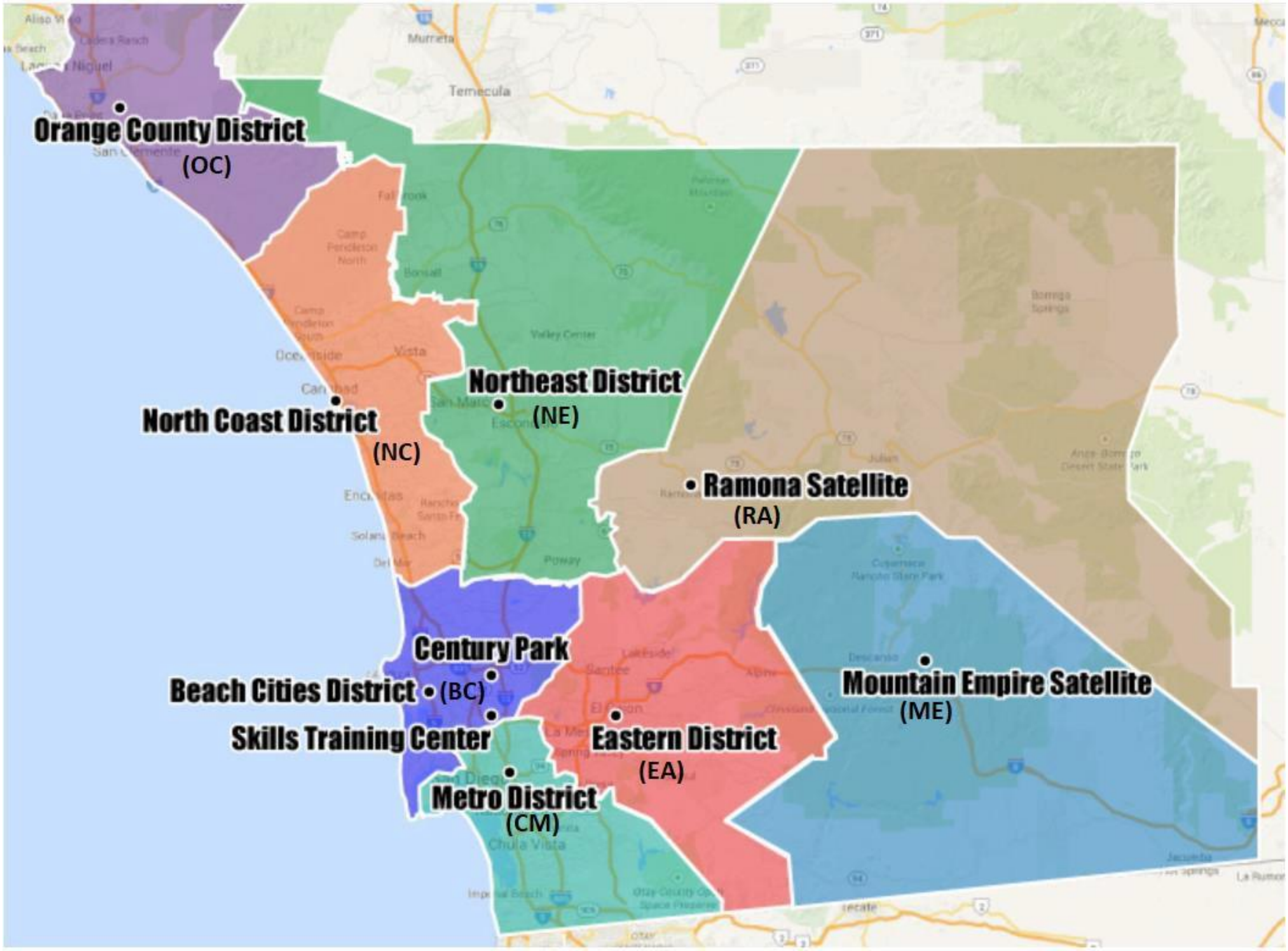


3.2 Company Commodity Services Areas of Responsibilities, Gas, Electric, IT, Security

The company commodities are divided into service districts for resources and operational control. These are illustrated below for easy reference.

> **Note**: The Gas districts do not service the Mountain Empire, Ramona, or Orange County areas as they are on either propane services or on other service providers.
>
> IT and Cyber Security services are not divided by districts either. The IT departments support SDG&E, SoCalGas and Sempra Corporate in a shared services mode.

Figure 7: SDG&E District Region Map with abbreviation labels



3.3 Incident Types and EOC Activation Levels

The criteria used to define the severity of an incident for SDG&E include hazard-specific conditions and impact conditions such as:

- Number of customers affected
- Resources deployed to address the incident
- Estimated time of restoration (ETR)
- Facilities or systems impact
- Workforce impact
- Financial impact
- The extent of media and political external interest
- Company reputational issues

The incident types and the descriptors for each are intended to be used as guidelines for preparedness and response planning. There is a difference in how we classify an incident or event type on its impact to the company and the EOC activation, staffing and authority skill-level of activation required to resolve the situation.

The incident or event is evaluated to define how significant of a disruptive impact to the company's capability to safely provide its commodity services to our customers, proper workforce environment, infrastructure-facility-resources and meet our regulatory obligations. The larger the negative impact to these functions or disruption of services, the greater the resources required to repair or restore those services. The company response may range from a simple executive notification the incident, which usually can be accommodated within a couple days by field crews, to an EOC activation level-one which is catastrophic and may need external mutual assistance and months to restore.

In other words, a type-one incident classification has the potential to exceed the SDG&E company's authority and or financial capability to resolve. As the severity of an incident increases, the financial impact to the company expands accordingly and can extend to the Sempra Enterprise stake holder where we would coordinate with the Sempra Crisis Management Center (CMC) through the SDG&E Executive Management Team (EMT) leadership decision process.

NIMS incidents are categorized by the severity of their impact on a community, human suffering, disruption of life sustaining capability, infrastructure damage that can affect community viability and financial impact that affects resiliency of people to recover from the disaster. They are classified in the *FEMA National Incident Management System Incident Complexity Guide Planning, Preparedness and Training* document Jan 2021 as five-classification types. SDG&E uses the same basic incident types, but they are modified to meet the impact of the incident on a Utility Company operational capability.

These incident types are sufficiently important to understand that they are also referenced in the ICS-NIMS training courses of ICS-300, Intermediate ICS for Expanding Incidents and ICS-400, Advanced ICS Command and General Staff-Complex Incidents for crisis management. The value of this typing is for personnel to understand that an incident can be simple or complex and the resulting skills, management authority and manpower scale up or down accordingly. SDG&E utilizes the NIMS-SEMS incident type and management scaling to configure the ICS response structure of Area Command, Utility Field Command (UFC's), Unified Commands, EMT and Sempra CMC as appropriate.

The EOC activation levels are determined by the authority, skill-level, and company resources required to effectively manage the incidents or events impacting the company. It is how the crisis management leadership group, and its staff, will expand to meet the response situation as follows:

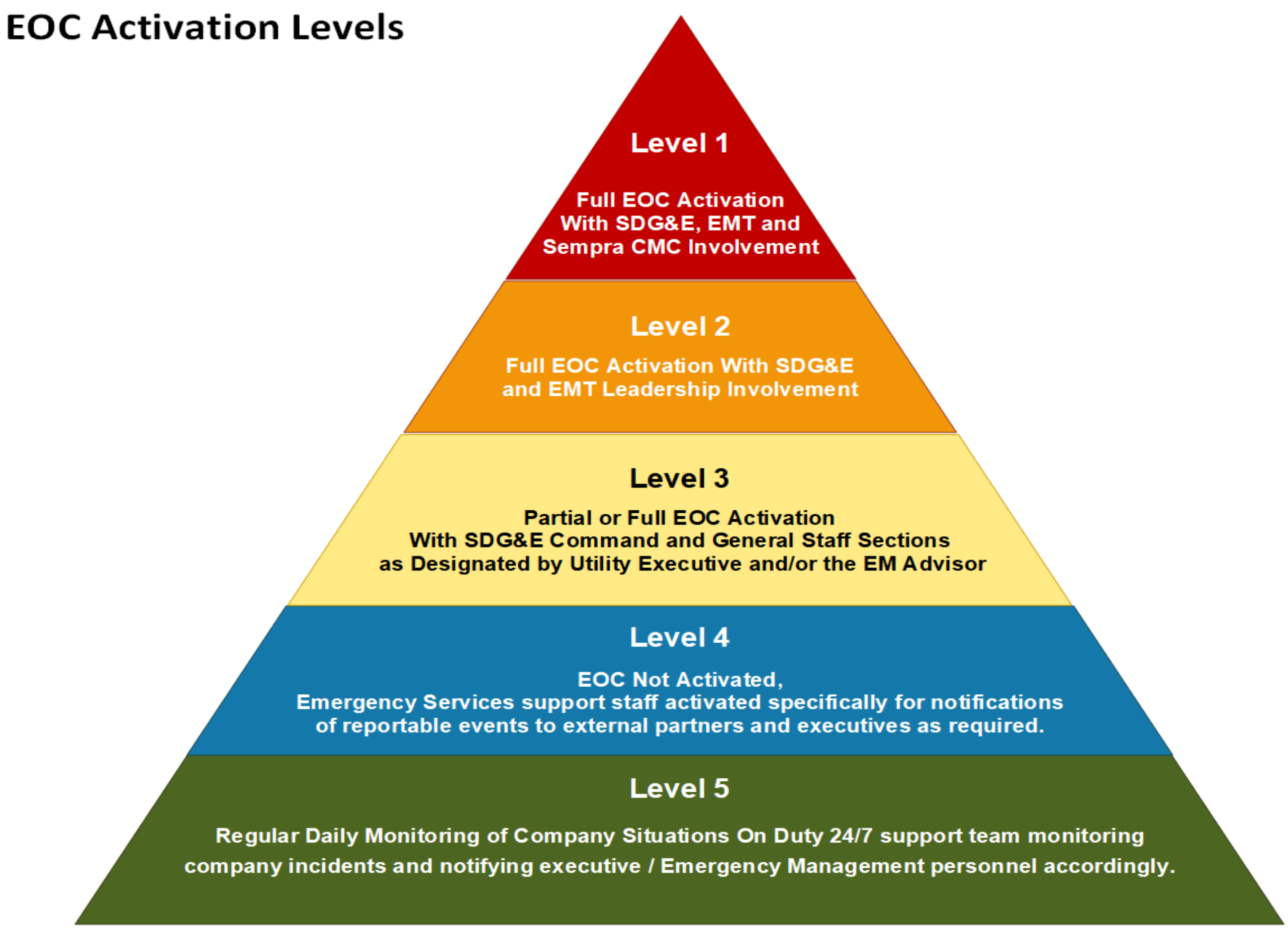
- **Executive Notification (Green, EOC not activated)** – An incident that is common and does not disrupt daily business operations. Local incident involving a relatively small number of customers, such as those managed during routine operations. Does not require activation of EOC. There is no expectation of reputational or financial exposure from this incident. First level that requires any type of Emergency Services activity.
- **Level 4: Active Monitoring, Blue, EOC activated with minimal targeted responders** – An incident or operating condition, active or transpired, that has the potential to limit the ability to meet customer demand, to cause damage to company assets, or to disrupt business processes. The number of customers affected, or systems issues to be addressed likely exceeds the ability of local resources to respond; however, it is likely that the incident can be addressed within company resources. There will be an actual or potential non-routine effect on employees. The incident may draw media and government and regulatory interest, potentially some notifications that an event has occurred, but there is no expectation of reputational damage or financial exposure.
- **Level 3: Serious, Yellow**, **Partial or Full EOC activation with the affected emergency responders and Notification Process Team** – An incident that decreases the ability to meet customer demand or carry-out critical business processes. An area-wide or higher profile incident involving a significant number of customers, affecting multiple company businesses, and/or resolution may require more resources than available within the company. The incident will draw media, regulatory and governmental interest, and questions. Reputational damage could potentially occur if the response is not addressed in an effective and timely manner. Financial exposure will be limited. EOC positions are partially staffed, fully staffed, or virtual as necessary to support affected DOC's, Electric DOC-E, Gas DOC-G, Cyber SOC, and Security CSOC as required.
- **Level 2: Severe, Orange, Full SDG&E EOC Activation including the Executive Management Team-EMT** – Incident that creates such severe impact that resources from across the company will be required to restore service or maintain operations and additional non-company resources may be required to support the recovery effort. Typically involve large numbers of customers and may result in significant customer inquiry volume. Employees' families may be affected. Facilities may be evacuated. There will be increased and on-going media attention. Government entities and regulators will want on-going reports regarding the status of company preparedness, response, and recovery conditions. There may be reputational and

financial exposure. The EOC response positions are fully staffed, or virtual, appropriate DOCs are activated, and Senior leadership (EMT) involvement could be required. Usually necessary when multiple companywide departments are or could be affected or commodity service disruptions are involved but does not meet catastrophic loss or damage to company assets criteria. It is at this level the authority and leadership experience level are elevated to implement the resource and financial commitments necessary to resolve the issues including mutual aid. The EOC staff is fully involved with its senior leadership and corresponding team staff, but the severity of the events is within the SDG&E company area of responsibility and resources to resolve.

- **Level 1: Catastrophic, Red, Full SDG&E EOC activation and Sempra executive Crisis Management Center Coordination** – An incident that is significantly disruptive to a wide range of operational and business processes both within the company and the communities it serves. Resources will be drawn from outside the region and likely from outside the state, depending on the impact to neighboring regions. May require coordination of the company's response across the service territory. There will be significant financial exposure and significant potential for reputational damage. The incident will draw national media attention and likely will involve or draw scrutiny from State and Federal agencies, regulators, and political leaders. Fully manned EOC staff for support, appropriate DOCs are activated and Senior Leadership (EMT) and potential or real involvement coordinating with Sempra CMC will be required. This will involve the most qualified experienced EOC and Senior leadership roles in the management positions and will be managing the response across the company.

The following EOC activation level diagram in this section illustrates the criteria that SDG&E will use to characterize the response management requirements.

Figure 8: EOC Activation Levels



Important: The staffing qualifications and filled EOC positions are dependent on the severity of the incident or event on company assets and capabilities. Even a Type 3 incident or event classification can create the need for a fully staffed EOC level 2 to coordinate the event. The EOC is configured when more senior leadership authority is necessary to approve appropriate company financial, resource, priority, or strategic guidance level commitments.

3.4 Disruptions of Service

The emergency response is related to the severity and magnitude of the manmade or natural disaster affecting company operations. From the company perspective, the level of response, EOC activation levels and authority to respond, is founded on the potential disruption of its commodity customer services, business functions or network communications capability or public safety mitigation, not the incident or event causing the disruption. The threat or hazard type influences the safety and velocity of the response, but it is the effect on company operations that determines the company's focus in the emergency response. There are three-levels of disruption identified for the CEADPP operational requirements. The disruption time does not mean EOC activation levels, it means the company has the capacity to resolve the issue within that time frame and may still require full authority and level-one response activation authority to resolve the situation within that time

Note: Normal work repair and restoration services that occur daily are not considered part of the company emergency response plan or activation criteria. These are handled by company departments and procedures on a regular basis as noted in section 3.1.2 Regular Day-to-Day Operations on page 19.

frame.

The disruptions in customer services are identified as:

3.4.1 Short term disruption:

- One to seven-day duration periods. (Plan Section 3.2.1.1)
- Capacity and resources usually within company and district response capability.

3.4.2 Medium disruption:

- Seven to 30-day duration periods. (Plan Section 3.2.1.3)
- Major drain on company capacity and resources, usually involving multiple district offices.

3.4.3 Long-term disruption:

- Greater than 30 days duration period. (Plan Section 3.2.1.4)
- Major financial and resource issues that may be beyond initial company response capability requiring mutual aid, California Utility Emergency Association (CUEA) program and Sempra executive involvement.

These are detailed in this CEADPP in the appropriate plan sections reference links above.

3.2.1.1 Short-Term Disruption Incidents–DOC, Level-Three or Two EOC Activation of One to Seven Days

If, on a field emergency site where first responders are present or an advisory support function is requested, a supplemental Electrical or Gas Support team may be dispatched to the site to implement ICS support coordination between the SDG&E work crews and the responders. This team is designated as an Incident Support Team (IST, Gas) or Fire Coordinators (FC, Electric) and supports the field supervisor designated as the site 'Utility Field Commander' (UFC) or the District UFC in complex events. These support teams act as advisors, liaisons, media support, command staff ICS qualified component for the field and coordinates with the first responders, so they understand the hazards the SDG&E team are repairing and when it is safely resolved. The response workforce team composition is determined by the resources necessary for the local incident requirements but will always have a leader, Utility Field Commander, appropriate liaisons and will also coordinate with the Department Operations Centers and Districts as the situation unfolds. These concepts are illustrated in a singular response Figure 3 through Figure 6 above. An expanding field operations structure and EOC, DOC, Area command are detailed in figures 9 and 10 below. EOC level Three operations structure is illustrated in Figure 15 in Appendix A.

When an incident is of sufficient scope and magnitude to affect a one-to-seven-day disruption in customer services which would require government and regulatory agency notifications and involvement, then the incident would be considered a serious impact to the company. This would warrant the stand-up of the respective DOC for Gas and or Electric Area Command. This illustrated in Figure 9. If the incident is significant enough where the EOC needs to be also activated to support the DOCs for the short duration, then SDG&E's EOC may be activated to a limited level-three or level-two to coordinate with the appropriate government agencies, community emergency partners and public. An EOC activation includes the involvement of senior company leadership authority. The EOC activation levels are described above in section 3.1.1. in greater detail.

Prior to EOC activation, the utility OIC along with the advice from the EM Advisor would determine whether an EOC level-three or level-two activation is required. The responsibilities of the EOC team are to provide the crisis management support to the OIC for internal or external coordination-collaboration, resource authorization, guidance and priorities for restoration or resolution of the crisis. The field commands implement the guidance into tactical response assignments to safely resolve the situation. The connections between the field, DOC's, EOC and executive leadership is illustrated in Figure 10: Leadership-Area Command-District Utility Field Command Model. The EOC organizational structures for SDG&E's Level-three to Level-one are in Appendix A in figures 15, 16, 17.

Figure 9: DOC Area Command-District Utility Field Command Model

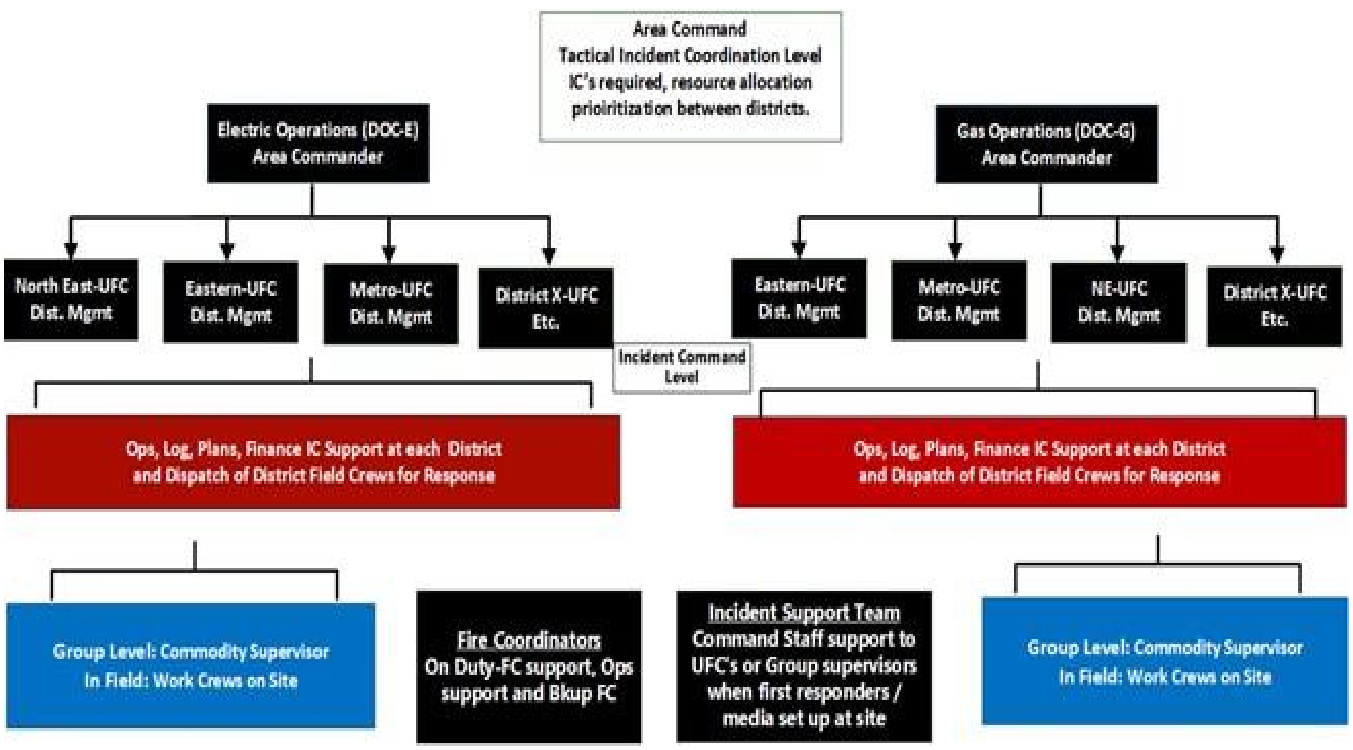
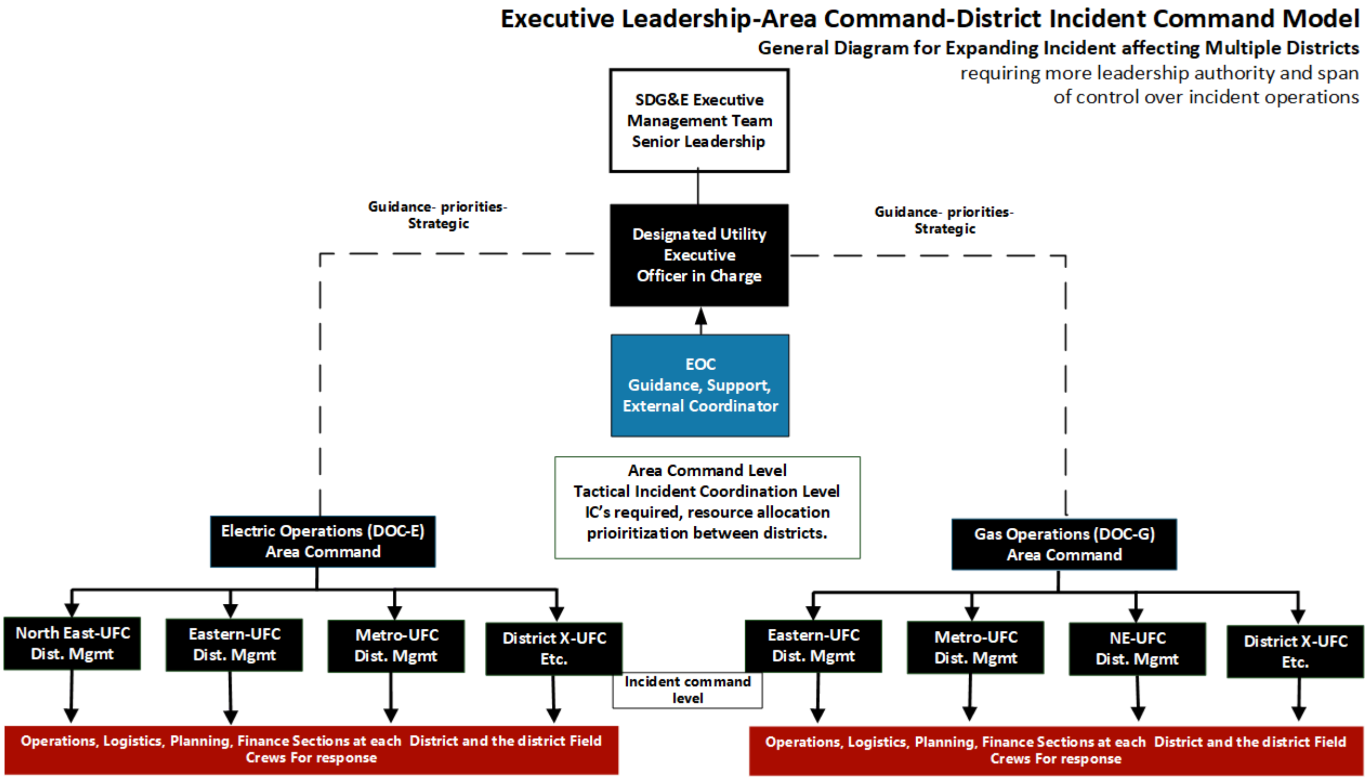


Figure 10: Leadership-Area Command-District Utility Field Command Model



Note: The supplemental field teams are for coordination with the first responders and advisors to the UFC's, not to direct SDG&E field work crews.

3.4.4 Special Case Public Safety Power Shutoff Events

A Public Safety Power Shutdown is a planned event which may occur when factors such as a Red Flag Warning, extreme FPI ratings of 14 or above, combined with high wind speeds are expected. In these cases, circuit de-energization for the safety of the affected area is activated to avoid a catastrophic fire risk from line failures. There is no actual damage yet but the potential for line failure and catastrophic fire risk is sufficient to require power mitigation preventative measures. There are major notifications and regulatory requirements around such an event, and it requires the designated executive authority (OIC) to authorize all actions since it will directly affect customers and medical support equipment in that area. This is the one situation where tactical control is shifted from the field to the executive, UFC-OIC and the executive team becomes the lead with the EOC activation level moving to two and DOC's reporting directly to them for assigned action. Refer to the Wind Event/ Public Safety Power Shutoff Concept of Operations in Annex F, for details.

3.5 EOC Level-Two Activation involvement Option

When an incident is of sufficient scope and magnitude to affect significant customer services that would require government and regulatory agency notifications, involvement, and the utility OIC, EM Advisor determine it is appropriate to activate the full EOC team for support, a level-two EOC activation would be required. An example of this type of operation would be:

- Damage or the threat of significant loss of services, short-term or medium-term that would affect public safety.
- Loss to community critical infrastructure.
- The utility OIC wants all section leads available for complexity of the incident, such as the PSPS event.

This would warrant the stand up of a level-two EOC activation to coordinate the appropriate government agencies, community emergency partners and public and includes the involvement of SDG&E senior executive leadership (EMT) authority to provide appropriate guidance and priorities as necessary. The activation levels are described in CEADPP section 3.1.1. in greater detail. The responsibilities of the EOC team are to provide the crisis management to the utility OIC for internal and external coordination-collaboration, resource authorization, guidance and priorities for restoration or resolution of the crisis. The field DOC's implement the guidance into tactical response assignments to safely resolve the situation. The following figures illustrate how SDG&E ICS-NIMS response structure scales up to full DOC Area Commands, District Utility Field Commands and the EOC full activation sections to support the incident response. An example of a level-two activation with a multiple gas district complex incident and implementation of a general Area Command-District Field Command structures for both commodities is represented Figure 9. The overall leadership-Area Command-District Command coordination / authority function is represented in Figure 10. The corresponding EOC Level-Three and two organization structure, depending on operational complexity, is illustrated in Figures 13 and 14 in Appendix A.

3.6 Medium Term–Expanding Serious-to-Severe Level-Two Incident Classification Causing Service Disruptions of 7 to 30 days

Incidents with severe impact to company service capabilities, public or company personnel safety, company financial and reputational impacts that are projected to last from seven to thirty days and events where mutual aid assistance compacts may be instituted as determined by SDG&E senior executive leadership, the EOC will be activated to a level-two or one response operations. This level is of sufficient magnitude that it involves operating in full ICS-NIMS organizational capability. The management principles of NIMS are used to expand and develop organizational structure to meet the emergency response, unity of effort, chain of command and span of control NIMS requirements. The primary change from the level-three EOC activation is the level of authority involved in SDG&E executive leadership, EMT involvement, the EOC positions active, and the number of emergency response personnel required in the crisis organizational structure. Level-two requires senior experienced leadership throughout the organizational leadership team, utility OIC with sufficient delegation of authority level to approve the financial and resource prioritizations required and will coordinate with the SDG&E EMT executive leadership on the operational guidance, priorities, strategic involvement, resource commitments, Figure 14 in Appendix A.

Note: At this point, the event or incident is estimated to still be within SDG&E's ability to resolve within its resource and financial capability and capacity. This does not mean mutual assistance can't be used. Mutual assistance may be requested to aid in expediting service recovery to customers.

The responsibilities of the EOC team are to provide the crisis management functions for the utility OIC for internal and external coordination-collaboration, resource authorization, guidance and priorities for restoration or resolution of the crisis. The field DOC's implement the guidance into tactical response assignments to safely resolve the situation.

3.7 Long Term–Catastrophic Level-One Incidents or Events Causing Service Disruption Greater than 30 days

The response organizational structures are already in place from the level-two activation. It is expanded to include not only senior level company leadership but also the inclusion of company executive leadership and Board of Directors as well and the potential for Sempra Enterprise Crisis Management Center (CMC). The EOC leadership team should be the highest skill and experienced level of qualified individuals and have a delegation of authority level to approve the financial and resource requirements that would be necessary at this classification of an incident or event. Mutual Assistance, outside assistance, and contractors would be involved and coordinated as appropriate to support the restoration of company assets and services. The same operational structure as level-two but additional personnel in each position is expanded to accommodate the workload requirements per NIMS management principles and the expansion to include the CMC, see Figure 15 in Appendix A. The responsibilities of the EOC team are to provide the crisis management functions for the utility OIC for internal and external coordination, collaboration, resource authorization, guidance and priorities for restoration or resolution of the crisis. The field commands, DOC-AC's and District UFC's implement the guidance into tactical response assignments to safely resolve the situation as illustrated in Figure 9 and Figure 10 above.

These concepts are applicable to all company emergency events beyond the primary commodity services disruption and inclusive of physical, cyber, financial, and reputational issues requiring executive company leadership and authority in the response policy decisions, priorities, and guidance roles.

This incident level could exceed SDG&E financial capabilities and thus includes Sempra Energy CMC involvement.

3.8 Internal Communications

There are two types of operational internal communications, command-directives for action and informational to assist and provide situational awareness to people performing in functional areas of the operation. Command type communications must follow the NIMS principles of Chain-of-Command, so an individual is receiving actionable direction from their supervisors only. Informational or informal communications are shared to make a person aware of things that could affect decisions or safety in a functional area. Informal communications are essential to team building and cohesiveness of operational personnel. This type of communication is shared irrespective of a person's chain of command and does not contain command-directive components. If a person has knowledge that is beneficial to the operation, sharing it is permitted at all levels. If the information is to task a person to action, it must go through the chain of command to ensure unity of effort and cohesiveness within the team. Communications on tasks and operational considerations should be documented to preserve the integrity and performance evaluations after the event. This multi-faceted approach for communication provides quick, reliable, and consistent information to all incident response personnel while ensuring that the appropriate information reaches all intended recipients.

3.9 SDG&E EOC Roles, Responsibilities, and Response Activities

3.9.1 Executive Office:

Department Name	Description
Emergency Management (EM)	The EM office coordinates SDG&E's all hazard emergency response plans and EOC activations and is the centralized coordination point for ensuring EM and ICS continuity and alignment company wide.
Electric Grid Operations (EGO)	EGO is responsible for monitoring and operating the electric transmission system (69kV and above) in a safe and reliable manner and coordinate planned and unplanned work on the system.
Electric Distribution Operations (EDO)	EDO is responsible for monitoring and operating the electric distribution system, 12kV and 4kV in a safe and reliable manner and coordinating planned and unplanned work on the system.
Customer Services (CS)	The customer service group is responsible for establishing and maintaining relationships with all assigned account major business customers as well as sending communications and notifications to all customers. This group manages customer expectations and is the conduit for communications.
Fire Science & Climate Change	The Fire Coordination group's mission is to keep employees, customers, and first responders safe through fire prevention, incident coordination, and education. Secondarily, fire coordinators serve as Subject Matter Experts (SMEs) to assess and mitigate risks associated with Operation and Maintenance (O&M) activities, capital projects, emergencies, regulatory cases, and to increase efficiency throughout SDG&E. Meteorology provides regular weather reporting and prediction consultation for SDG&E operations planning. This weather briefing provides the situational awareness for making operational decisions that support safe and reliable operations.
Wildfire Mitigation and Vegetation Management	Wildfire mitigation at SDG&E is a company-wide, inter-departmental effort involving resources and programs across utility functions. The Vice President of Electric System Operations is the wildfire risk owner and has primary responsibility for owning, executing, and auditing SDG&E's wildfire mitigation plan 2023.
SDG&E Safety Compliance	The safety department keeps employees safe while performing their duties at work and supports employees to mx a safe work environment and implement safe work practices.
External & State Legislative Affairs	The regulatory group serves as a liaison between the CPUC and SDG&E to manage relationships, communications, and compliance with CPUC regulations.
Geospatial Information's System (GIS)	GIS technology is used to study wildfire growth patterns, allowing proactive measures to be put in place before a wildfire. Using simulations generated from weather conditions, historical fire data, and vegetation data, the wildfire risk of SDG&E territory can be evaluated.
Customer Programs	Responsible for medical baseline customer data and analysis. Also responsible for coordination of SDG&E presence in Local Assistance

	Centers as requested by FEMA, County OES, American Red Cross, or any other local jurisdiction.
Business Services	Responsible for identifying and communicating to those key/major customers to include critical infrastructure customers and critical facilities. Also responsible for identifying, communicating, and managing the support services for those customers that may have access & functional needs during an emergency.
Electric Regional Operations (ERO)	ERO is responsible for field operations including conducting planned work and responding to unplanned work on the electric distribution system. They ensure compliance with the CMP, conduct distribution line patrols and repairs, provide observations in the field during extreme events, provide emergency response for power outages, staff the staging sites, and conduct line patrols for PSPS.
Kearny Mesa	Responsible for coordinating crews for maintenance of substation facilities.
Marketing and Communications	The communications group's goal is to inform and educate customers and the public while complying with regulatory communication requirements. Communications is responsible for coordinating general marketing campaigns, public education campaigns, emergency messaging, and media communications. They also participate in the EOC during activation.
Gas Operations	Gas Operations provides safe and reliable gas to customers, mx gas infrastructure, ensuring the safety of personnel and customers, and minimizing risk of fires by safely mx and operating gas infrastructure.
Cyber Security	Responsible for deterrence, prevention, and detection malicious code on Company networks and Information Systems. Also provides ongoing Information Security education, training, and outreach
Cloud and Infrastructure	Responsible maintaining the company IT cloud and server network infrastructure. Also responsible for troubleshooting and fixing software and hardware failures in coordination with responsible departments. The EOC IT Unit administers the Emergency Notification System (ENS).
Digital Workspace and Automation	Responsible for customer interface IT platforms, creating customer service IT tickets and elevating issues to major incident management teams.
Regional PA	The goal of regional public affairs is to successfully maintain relationships and communications with regional community and government entities to disseminate information before emergencies and during EOC activations as a result of an emergency.

4 Organization and Assignment of Responsibilities

4.1 SDG&E Overview

As a regulated utility providing energy-related services to customers in the San Diego area, SDG&E conducts real-time monitoring of company systems, customer service reliability, and essential company functions via multiple 24x7 operating centers. Primary among these are Emergency Operations Services, Electric Grid Operations (EGO), Electric Distribution Operations (EDO), Gas Transmission Communication Post (TCP), the Network Operations Center (NOC), the information Security Operations Center (SOC), the Call Center, Meteorology, the Fire Coordination Group, and Corporate Security.

An incident may manifest initially as a deviation from normal operations indicated by the parameters and conditions monitored by these 24/7 centers. As part of normal identification and notification processes for these conditions, these front-line centers follow procedures for notifying the Emergency Operations Services organization to initiate the CEADPP activation process. Prior to activation, the monitoring of overall situational awareness is the responsibility of the Emergency Operations Services organization in partnership and coordination with the groups listed in the section above. Once an incident has been declared, incident monitoring will be the coordinated and data analysis incorporated into the EOC situation unit. Appropriate field Incident management teams may be activated if necessary.

4.2 Field Incident Management Teams

Table 3: Field Incident Management Teams

Team Name	Responsible Area
Electric Grid Operations (EGO) and Electric Distribution Operations (EDO)	EGO transmission and the EDO distribution monitor the company's electric transmission and distribution systems and are responsible for maintaining situational awareness of electric system conditions, reliability of the equipment, and coordinating all planned and un-planned maintenance and construction activities on the SDG&E electric system infrastructure.
Gas Transmission Command Post (TCP)	The TCP monitors gas flows in the gas transmission system, using Supervisory Control and Data Acquisition (SCADA), to assess irregularities and gas transmission system conditions.
Service Dispatch	Referred to as Trouble or Station Y oversees the daily routing, workload balancing and radio communication of Customer Service Field (CSF) and Electric Distribution. Electric Troubleshooters (ETS) and Customer Service Field Technicians are dispatched during the day for routine and emergency work. As a 24/7 organization they work with many company teams and outside agencies, such as local fire and police departments, and 911, to manage emergency and unplanned work.
Network Operations Center (NOC) information Security Operations Center (SOC)	The NOC and SOC perform 24/7 monitoring of all SDG&E networks, applications and critical information technology infrastructure for operating the SDG&E electric and gas system infrastructure as well as normal business operations. These entities coordinate monitoring with the other entities discussed above and have established processes for identification of potential security-related incidents.
Customer Care Center and Corporate Communications	During or in anticipation of an incident, SDG&E's Customer Care Center representatives or social media staff may become aware of incidents through interactions with the Company's customers or the public. These entities shall provide

	ES and SDG&E leadership with updates on threats or incidents that they may become aware of during normal business operations.
Corporate Security Operations Center (CSOC)	Corporate Security performs 24/7 security monitoring of all SDG&E electric and gas facilities, and corporate offices. Corporate Security maintains a Department Operations Center, communications and coordinates with the entities discussed above, along with ES, on security-related incidents.
Fire Coordination Group	The Fire Coordination Group monitors ongoing and potential fire incidents through local fire/police radio systems and scanners.
Emergency Management	Emergency Management provides SDG&E leadership with updates on threats and incidents in the daily briefing, escalating predictions of potential incidents as needed.

4.3 Department Operations Center (DOC)

When an Event Level-three is declared, the impacted Commodity Operations Desk(s)will be opened. This position(s) is staffed by the Deputy Operations Chief. Its purpose is to help coordinate the movement of crews, equipment, and material between districts, and to provide system-wide information to various groups. It provides resource coordination and prioritization.

Alternate locations for commodity-based operations centers are designated in their individual Business Continuity Plans (BCP). Operational departments and their operation centers are designated as critical and must have no down time. Per Sempra BCP corporate policy, these units are required to test their alternate operation's center locations at least once a year. Department activations of their BCP are triggered by:

- Loss of access to primary facility.
- Cyber security incident or IT failure of critical platforms.
- Employee high absenteeism.
- At the discretion of their operational director or SDG&E Senior Vice President of Electric Operations.

4.4 Executive Notifications During Business and Non-Business Hours

Business or Non-Business Hours	Notification Types
During Normal Business Hours	Notification to EM could come from any of the monitoring entities described in Section 3.4.
During Non-Business Hours	An EM on-duty (EOD) staff member is available during non-business hours. An Emergency Incident Reporting (EIR) text paging service, e-mail, or phone call are the notification mechanisms for alerting the EOD of an actual incident or potential incident. Once alerted, the EOD will contact the notifying party, obtain information, and call the Director of EM, who will then instruct the EOD on what notifications and actions to take.

4.4.1 Executive Notification Process

This section describes the steps that the company will use to conduct an Executive Notification.

4.4.1.1 Objective

The objective of this process is to ensure that appropriate executives receive timely and adequate notice of pending or actual incidents.

4.4.1.2 Roles

The organizations and roles involved in the Executive Notification process include:

- EM
- Officer on Call (OIC on Duty)
- In-Line Director

4.4.1.3 Initiation Criteria

- The Executive Notification process may be initiated based on the following criteria, regardless of the impact on SDG&E's assets or infrastructure:
  - At the discretion of EM Director.
  - An earthquake of 4.5 or greater within SDG&E's service territory.
  - Fires that result in media attention.
  - Any building incidents at SDG&E facilities that result in evacuations or cause a potential impact on operations.
  - A hazardous spill that reaches a storm drain, is greater than 42 gallons of released hazmat, or injures employees, customers, contractors, or other stakeholders.
  - Any loss of a data center.
  - Any loss of a portion of communication system.
  - A loss of any system impacting company operations or customer service.
  - Any civil disturbance or threats of terrorism, including a cyber-attack.
  - Any injury requiring hospitalization or fatality of an employee, contractor, or member of the public.
  - A forced outage to any transmission asset leading to loss of firm load or that will likely cause the Company to shed firm load.
  - Any forced outage to a generation facility.
  - A non-momentary outage to a major distribution substation.
  - A non-momentary loss of electric service that is drawing media attention in a high-profile area or to high-profile customers.
  - Any leak or damage to gas infrastructure or facilities where media is on scene.
  - Any leak associated with evacuations or where evacuations are expected and media presence.
  - Anytime the Gas Emergency Center (GEC) is activated.
  - Where there is damage to a 4" or greater line.
  - Where there are excessive area odors; or.
  - Where asset damage has reached $50,000 or more.

4.5 Line of Succession-Continuity of Leadership

A list of qualified and designated executive personnel is kept updated on the company's Continuity of Leadership plan- 2023 for both the executive leadership and Emergency management department leadership for decision authority to act. Should a leader not be able to perform their designated function, the alternate leadership will be notified to assume that role as necessary. For example, in case of vacation, sick time, or they were not able to be notified. In addition, a company senior executive leadership and the emergency services department has an approved Continuity of Leadership (COL) plan identifying the leadership succession. This is identified in the following table 4.

Table 4: Leadership line of Succession

Order	SDGE Position Executive Authority Succession
1	CEO SDG&E
2	President & CFO SDG&E
3	COO SDG&E
4	SVP- External & Ops Support
Order	**SDG&E Emergency Management Leadership**
1	Director Emergency Management Department
2	Manager Emergency Operations Services
3	Aviation Services Manager
4	Training & Exercise Manager

4.6 Emergency Operation Centers Facility Locations

SDG&E maintains two physical EOC locations and a fully functional virtual EOC. The determination of which location is activated is based on a variety of criteria to include, but not limited to, employee safety considerations, facility safety, operational capability of the site, ability of staff to respond to the site, and which EOC type (physical or virtual) is best suited for the incident.

The primary SDG&E EOC is located at:	The alternate EOC Facility is located at:
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]

The EOC may also be constituted virtually through Microsoft Teams at the request of the OIC or Emergency Management Director authority level, see Appendix D.

5 Direction, Control and Coordination

5.1 Emergency Management Department

SDG&E's Emergency Management department is responsible for ensuring that emergency preparedness, management, and comprehensive incident response is a core business competency at SDG&E. EOS administers the company's CEADPP, coordinates emergency exercises, and reviews organizational emergency plans, as needed, to ensure compliance with company policies and governmental regulations. EOS will take the lead to do the following:

- Establish and instill leading EM standards and practices (e.g., Incident Command System), in collaboration with gas and electric operations and external partners.
- Clarify response organization roles, responsibilities, and authorities to focus field command accountability and improve decision-making.
- Ensure response plans are in place to address the highest risks.
- Bring together disparate documentation into logically organized, detailed, and accessible response plans.
- Deliver Standard Operating Procedure (SOP)-based response training.
- Manage and maintain the Emergency Operations Centers.
- The Training & Exercise Division of the EM department is responsible for development, centralization, and alignment of ICS company wide.
- Provide a variety of training and exercises to test and improve response effectiveness; and
- Apply and expand upon indices such as Fire Potential Index, predictive tools, and analytical capabilities to

enhance situational awareness before and during an incident.

5.1.1 Emergency Response Roles

Incident response is a corporate and individual responsibility. Employees have an obligation to respond to incidents as directed by SDG&E management. As a result, a significant number of employees are trained on and have been assigned response roles. During emergencies and crises, these personnel may work extended hours to support 24-hour staffing. For purposes of this document, a response role is defined as a role or task that a person performs during an incident that is under the EM supervision and/or of the EOC or utility OIC.

5.2 SDG&E Response Organization

5.2.1 Overview of Teams

SDG&E relies on its Incident Response Organization (IRO), which is comprised of key employees holding assigned roles, to respond to and manage incidents, with roles and responsibilities divided by functional area. SDG&E uses ICS as the foundation for its incident response organization and the management of its incidents. We use EOC position checklist to aid in understanding their assigned duties found in Appendix B. The Company shall have:

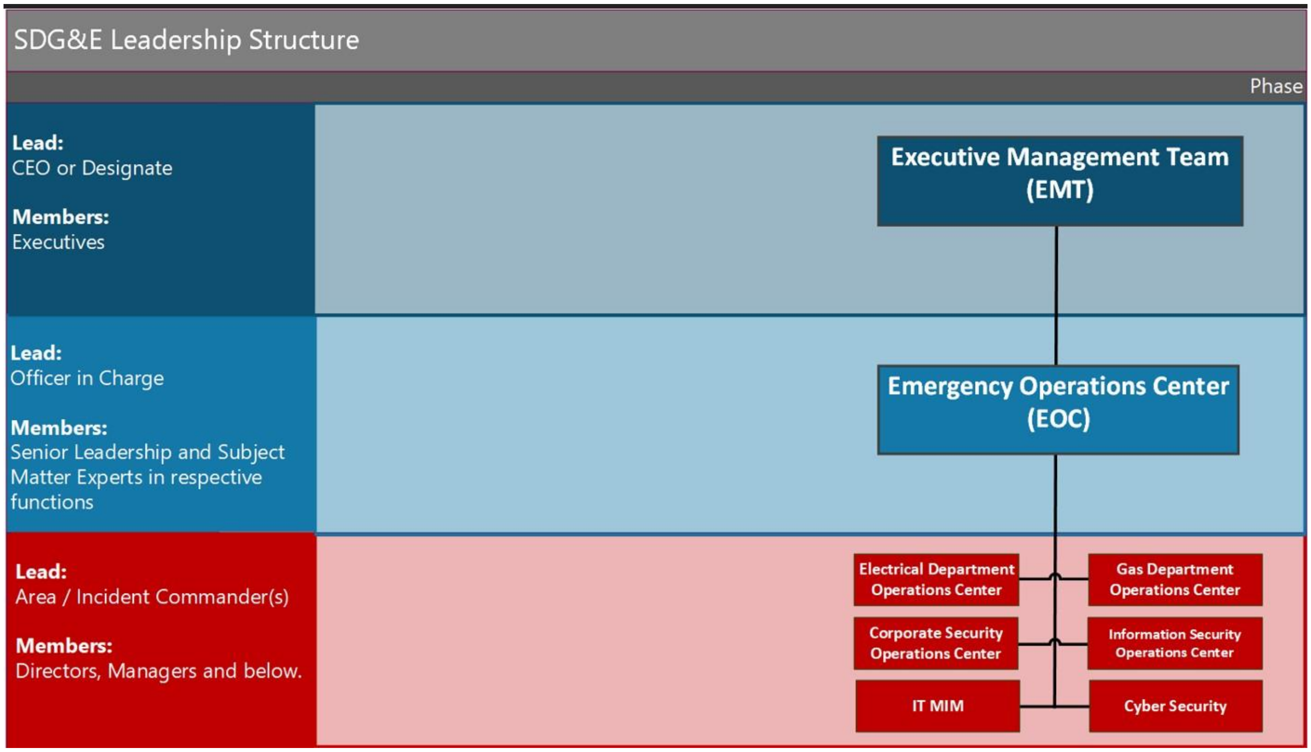
- **A Crisis Management Center (CMC)**–The Sempra-level entity that may be activated for incidents affecting multiple business groups, or where an incident is of significant scope or complexity (e.g., 2007 wildfires)and could impact Sempra financial stability, brand, or reputation and is utilized when the capability and capacity of SDG&E may not be sufficient to resolve the situation.
- **An Executive Management Team (EMT)**–Includes SDG&E senior executives who provide policy-level direction, support, and strategic leadership that focuses on SDG&E's financial, brand, and other significant corporate risks that severe/catastrophic incidents may present in the mid- to long-term but the impact to SDG&E is within capability and capacity of organization to resolve. The Officer in Charge (OIC) is considered part of this team and the point of collaboration between the EMT and the EOC.
- **A Utility Field Commander (UFC)**–Responsible for the tactical and operational response to the incident site and is led by the commodity-designated leader at the field site, group supervisor or at the district management level. Multiple UFC's may be activated during incidents that are geographically dispersed or affect multiple lines of business. These are used to resolve on scene requirements for authorized leadership presence.
- **An Incident Support Team (IST) –** An assistance team of ICS qualified members to support UFC's in the field or Districts. They provide the subject matter expertise to advise, liaison to first responder IC's, provide safety officer role and media support. The team acts in a command staff role when needed to provide the technical support.

Collectively, the teams above comprise the incident response, which is scaled up or down depending on incident size and complexity. The teams noted above are set up to promote scalability both within the teams and within the overall response structure. For example, a UFC(s) may be activated to provide on scene Utility Field Command at a gas blow out site, coordinating with local first responders, but no additional teams or even EOC involvement may be necessary if it falls into a normal work response.

The UFC would have overall management authority for both the tactical response and support functions and may call in an IST for additional expertise and support as needed. If the EOC is activated, the designated executive utility Officer in Charge (OIC) would have authority over all guidance functions, including ensuring that UFC's and Area Commanders operational activities are coordinated and would have responsibility for the tactical or operational response.

The sections that follow provide additional detail on each of these teams, with detailed roles and responsibilities on each team described in the EOC Position Guidance Documents providing checklists for each position.

Figure 11: SDG&E Leadership Structure – Overview



5.2.2 Sempra Crisis Management Center (CMC)

The CMC, which is comprised of Sempra senior executives, may be activated in the event of an incident that has the potential to or already has affected:

- Sempra's reputation,
- Financial stability,
- Presents significant corporate risks that the incident may represent a mid- to long-term disruption period.
- Alternately, the incident is of such magnitude that it may exceed the capability and capacity of SDG&E.

The CMC works with SDG&E EMT leadership to develop and approve the strategic guidance that will be utilized by the utility OIC and the financial authority to manage the resources necessary, mutual aid, CUEC, contractors etc. It is important to note that the overall tactical management of any incident and responsibility for decision making and oversight of field response operations under the rests with the UFC(s) and Area Commanders if activated. The strategic guidance they follow, as determined by the CMC and EMT, is communicated by the utility Officer-in-Charge to the field commanders. The composition of the CMC will depend on the type of incident, businesses affected, and strategic and policy needs as determined by Sempra.

5.2.3 Executive Management Team (EMT)

The EMT, which includes SDG&E senior executives, provides SDG&E:

- Focused policy-level direction guidance support.
- Strategic leadership, focusing on financial, brand, and other significant corporate risks that the incident may present in the mid- to long-term period.
- For some types and levels of emergencies, the EMT has responsibility to interface with the Crisis Management Center at Sempra.
- Determines if the situation can be resolved within the capability and capacity of SDG&E.

Important to note is the overall tactical management of any incident and responsibility for decision making and oversight of field response operations under the Incident Management Teams rests with the Utility Field Commander(s) and Area Commanders if activated. The strategic guidance they follow, as determined by the CMC and EMT, is communicated by the utility Officer-in-Charge to the field commanders. While the designated utility commander's DOA specifies their authority, the executives, which grant that authority may resend it at any time and replace or resume their own authority and responsibilities. The composition of the EMT will depend on the type of incident, businesses affected, and strategic and policy needs of the SDG&E.

5.2.4 Partial, Full or Virtual Activation of the EOC in Support of the OIC

The EOC response staff and leadership is used to support the OIC when the EOC is activated at a Level-three or higher activation event. The Command and General Staff of the EOC and any requested Subject Matter Experts (SME) will form the members of this team and convene either in the EOC or virtually as the OIC requests. This team works at the direction of and support to the OIC to develop the appropriate incident response:

- Information Collection, Situational Awareness, and Analysis from SDG&E support units.
- Documents the event situation and Significant Courses of Action approved by the OIC and SDG&E units responding to the event.
- Contacts and notifies appropriate government, regulatory agencies, community agencies and customer services as required by the type of event and SDG&E responses to protect public safety and company personnel.
- Coordinates with the appropriate SDG&E units to facilitate an effective and efficient response to the event.
- As the event expands, the OIC will call for a higher-level activation of the EOC to manage the response more effectively to the event, level-two or level-one EOC staffing and coordination activation. The EM

Advisor, usually the leader of the EM department, will assist in establishing the EOC at the appropriate activation level and brief the incoming activated EOC personnel on the current situation. The OIC / EM Advisor may also determine if it would be appropriate to require a virtual EOC activation instead of physical operations in the EOC facility. If selected, the planning section will follow the Virtual EOC Activation Procedure referenced in Appendix D,

5.2.5 Notification Group

The Notification Group, led by the Planning Section Chief, is a function within the EOC where personnel with communication responsibilities perform critical emergency information functions and crisis communications. The Notification Group's purpose is to bring together a focused set of resources that can meet the heightened demand for speed and volume in communications, with the aim of supporting SDG&E stakeholders. The Notification Group brings together – and serves as a support team for – the various functions from all internally- or externally-facing organizations or business groups that the incident may require.

The role of the Notification Group is to communicate the nature and extent of the crisis to stakeholders and the effect of the event on SDG&E's business and customers, and to provide updates on response efforts. Communicating effectively to external stakeholders, customers, regulators, elected officials, media, etc. and employees and contractors is as important as responding to the incident and ensures regulatory compliance. During an incident, the Notification Group will strive to do the following:

- Promptly acknowledge the incident with a commitment to provide stakeholders more information. Timing is appropriate to type of incident.
- Speak with one voice to provide a consistent message to all stakeholders.
- Be transparent by proactively offering a continuous stream of updated, relevant information.
- Reach all stakeholders by communicating across every possible channel; and
- Tell our story leveraging visual communications and third-party support to help tell that story.

The Notification Group organization should be scalable and may be activated, when incident scope or complexity warrant it, by the Planning Section Chief or a delegate.

The notification group can be made up of representatives from the following list:

- Public Information Office
- Liaison Officer, Regional Affairs
- Regulatory
- Legal Office
- ENS
- Customer Service
- Planning Section
- GIS
- Customer Resource Center
- AFN Unit

5.2.6 Incident Management Concepts

As noted previously, the DOC Area Command – District UFCs are responsible for the company's operational and tactical response to any type of incident. These would either be a local or field entity, run directly from the appropriate district that includes trained personnel capable of responding to incidents that are resolved within one operational period or within a few hours after resources initially arrive on scene. A full-scale district UFC response with district section chiefs would be activated for an extended complex district event along with the full EOC management support team. If multiple districts are involved, a DOC Area Command and District UFC structure would be employed to manage the incidents.

A local UFC reporting to the district may be used where:

- Only a small number of customers are affected.
- The incident duration is short.

- The incident is not complex.
- Only a small number of external entities or stakeholders are engaged; or
- Where the on-scene Utility Field Commander does not need external resource or other support.
- Local UFC's may initially manage larger and more complex incidents prior to activation of a full District incident response.

A district-wide level UFC event using its Operations, Logistics, Planning and Finance sections is utilized for complex multiple incidents requiring district-level management and oversight. This would comprise between 10 and 35 trained personnel, would typically be activated to support incident management at incidents that extend beyond one operational period. It would manage major and complex incidents requiring a significant number of resources and would typically require the development of written Incident Situation Report. Their involvement would be necessary when the incident would include one of the following:

- Have the potential to negatively affect SDG&E's brand or reputation.
- Affect a moderate to large number of customers.
- Require resources from across SDG&E or from external entities.
- Require coordination and outreach with external stakeholders.
- Are complex.
- Affect multiple sites, life threatening, or deaths are involved; or
- Are expected to last for multiple days.

A full-scale DOC Area Command structure may also be activated for planned mass-gathering type of events such as festivals, political rallies, civil unrest, state and national summits and conferences or when a complex incident involves multiple district-level responses.

5.3 Incident Management

The SDG&E operational and tactical response is managed by Utility Field Commanders, UFC's, district-level or local field supervisors, while the OIC manages the EOC, which ensures that responses across the entity are coordinated, external regulatory notifications, company media communications and provides resource and other support to the operational or tactical response. The OIC is responsible for overall guidance, priorities, policy direction and conformance to SDG&E policies. The EOC ensures information coordination and resource requests across operational or tactical response teams, while allowing each response team to retain its own authority and ability to manage the tactical response. If the utility OIC does not believe the authority should be retained by the Utility Field Commander(s), UFC's or DOC-AC's, then the utility OIC must transfer command of the affected UFC and AC to a new commander that has the appropriate qualifications for the situations. The utility OIC should consider replacing the Utility Field Commander when any of the following happen:

- The operational and tactical response is being mismanaged.
- The Utility Field Commander (UFC and AC) has created or allowed the creation of unsafe situations for the public and staff; or
- The Utility Field Commander (UFC and AC) is violating company policies.

The utility OIC should not, however, replace a Utility Field Commander because the OIC may prefer an alternative management style or disagrees with a tactical decision. SDG&E should conduct an evaluation of performance after each incident in which all key decisions are revisited and each person in a leadership role would receive feedback on performance.

Table 5: Responsibilities of Utility Field Command and Utility Officer-in-Charge

Area	Utility Field Command (UFC) DOC Area Command (AC)	Utility Officer-in-Charge (OIC)
Overall	• Sets operational incident objectives, in accordance with the corporate strategies and priorities from the OIC. • Responsible for the tactic field operations, personnel, and resources.	• Directs the corporate-level support of field incidents. • Provides overall priorities, strategic and policy guidance for activated ISTs and DOC's
Resources	• Identifies and assigns resource allocations to meet the operational objectives and in accordance with OIC leader's intent and guidance. • Approves the release of resources from the assigned incident branch.	• Makes corporate resources allocation and prioritization decisions between and among operating companies and service areas in coordination with the Deputy OIC Leader and DOC activated units.
Incident Classification	• Provides information and data to consider in incident-level classification.	• Participates in incident assessment and classification. • Approves the activation level.
Planning	• Leads, schedules, and facilitates planning meetings and status briefings for the tactical operations and develops the EOC Action Plan.	• Leads, schedules, and facilitates planning meetings and status briefings for the EOC. • Develops SDG&E-wide incident situation report, considering field DOC ISRs.
Operational Role	• Manages the operational and tactical, or field response to an incident. • Assigns resource allocations and approves IAP's.	• Monitor's incident operations to identify current or potential organization problems • Provides corporate guidance to field commands.
Communications	• Provides OIC with operational information to support communications in Incident Situation Reports.	• Develops communication strategy, determines information needs and ensures communications are provided to customers, media, and government agencies through one-voice and timely.

5.3.1 Transfer of Command

When command is transferred during an incident, UFC's, AC's or EOC Commanders, either because the incident has escalated and requires a greater level of certification or because the individual filling the position needs to be relieved due to a gap in knowledge, physical inability to continue in the response, or ineffective leadership, a formal transfer of command should take place. The steps to be taken during a transfer of command include the following:

- Face-to-face, in person or virtual briefing between incoming and outgoing individuals before command transfer.
- Consideration of re-deployment of relieved commander if relief was involuntary.
- Verbal confirmation of the transfer between commanders; and
- Announcement of the transfer to the response organization.

The essential information that the outgoing commander should cover in the briefing to the incoming commander includes an overview of the response objectives, plan for the current period and updates on the status of each key functional area of Operations, Planning, Logistics, Administration and Finance, Communications, and Safety.

5.4 Response Team Coordination

For the sake of clarity, a matrix of organizations and areas of responsibility, including functions should be included to summarize primary and supporting roles by teams. These shared general responsibilities, such as developing Incident Situation Reports, should not be neglected, and are developed in the table below. This section should also describe at a high-level the relationship between the various response teams EMT, DOC-AC and District UFC's, Field Crews.

Table 6: Team roles and Responsibilities

Responsibilities and Tasks	Field Commands (UFC's and AC's) Incident Management	Officer-in-Charge (OIC)	EOC Response	Executive Management Team
Members	District managers field supervisors DOC managers	Designated company VP's	Level-three activation command and general staff SMEs as required	Senior executives and executives
Overall Responsibility	Tactical and operational response	Policy, strategic guidance, and support to field commanders Directs EOC staff and functions	Support and coordination to OIC in level-three activation or above	Policy and strategic support and leadership
Leader	Designated UFC's or DOC AC commanders	Designated Officer in Charge	Officer in Charge	CEO or designate
ICS Equivalent	IMG-IC and or AC	EOC Director	Command planning group	Policy group
Functions	Incident operations planning logistics		OIC support in level-three operations, logistics, legal planning and analysis operations	Level-two or above EOC activation when corporate business functions or

Responsibilities and Tasks	Field Commands (UFC's and AC's) Incident Management	Officer-in-Charge (OIC)	EOC Response	Executive Management Team
	administration and finance		of affected businesses, internal and external stakeholder communications or notifications	reputation could be affected
Assigned Location	Field, incident site or DOC-E, DOC-G	Emergency Operations Center	Emergency Operations Center or Virtual EOC	CMC
Incident Situation Report Development	Tactical elements of Incident Situation Report (ISR)	Strategic incident guidance, priorities, policies, strategic resources	Incident response report and SA External information coordination, EAP	Business impact and policy guidance

Two distinctions are required for the term's strategic guidance versus the operational term strategies that will be employed on an operation.

1. **Leadership Strategic Guidance:** Refers to which **methods** are authorized for use by the field commanders in managing the tactical direction to be employed.
2. **Field strategies:** These include which of those possible authorized methods the field command has instructed its operation section to utilize in developing the TACTICS or actual actions the field crews will utilize, which defines the amount of the resources necessary to carry them out, that will be needed by the resource teams to resolve the situation within the operational period defined.

The field commander then looks at the resources available in those categories and if there is a safety issue in their affected Area of Responsibility (AOR). They see that there is a pandemic or health issue and therefore cannot use CCS and are left with the other options. If sufficient other options will resolve the issue, then they plan the tactics on how to get those folks accommodated. If there are not sufficient resources, the field commander will inform the guidance group that they need Non-Congregant Shelters (NCS) and the headquarters team will change the strategy to accommodate the situation.

SDG&E has many policy strategies to consider using during an event. The leadership policy group can authorize methods or strategies for de-energization, switch circuits, gas pinch off, shut down gas lines, grid stabilization, replacement of equipment, fire coordination, repair, and restoration etc. This group determines what methods and under what conditions they can be utilized to allow the field command to resolve the situation effectively and within the company's capability and capacity.

5.5 EOC activation Level-Three Overview

The activation of the EOC to level-three is comprised of nine functional groups, part of the Command and General Staff or other SMEs as requested by OIC, led by Section Chiefs, who represent business units that may be affected by an incident.

- The Section Chiefs are responsible to the OIC for managing their groups and providing operational and policy **support** to the field activated UFC's and DOC-AC's.
- Those reporting to Section Chiefs are responsible for obtaining and processing information and requests internally and externally.

5.6 EOC Incident Support Roles and Responsibilities

Following are brief descriptions of the SDG&E Incident Teams lead roles. For additional detail about each of these roles and the remaining roles on the SDG&E EOC level-three, read the Position Guidance Documents, located both on MS Teams files and physically located at the SDG&E Emergency Operations Center, which contain position-specific checklists. SDG&E shall have individuals assigned to these roles pre-identified and available 24-hours a day, as incidents occasionally occur without warning.

5.6.1 Utility Officer-in-Charge (OIC)

The designated executive utility Officer-in-Charge (OIC) is responsible for directing the corporate-level support of field incidents and providing overall strategic guidance for the activated UFC's and AC's. The OIC will be designated by SDG&E executive leadership, provided a Delegation of Authority document identifying their authority, identified prior to the incident and have the capability of supporting an incident from a holistic perspective. This includes support not only of the operational aspects of a response, but also planning, customer issues, media issues, administration and finance, information technology, legal, etc.

5.6.2 EM Advisor

The EM Advisor is responsible for providing the OIC with, strategic response input and Cal OES compliance guidance as requested.

5.6.3 Logistics Services Coordinator Lead

The Logistic Service Coordinator Lead is responsible for coordinating logistical and business support response activities across responding teams, providing support, where requested or required, and coordinating between Business Support staff and the OIC. This support encompasses facilities security, transportation, supplies management, and the provision of food and lodging.

5.6.4 Legal Officer Lead

The Legal Officer Lead is responsible for providing legal advice on all aspects of the incident and SDG&E's response thereto.

5.6.5 Planning Section Chief Lead

The Planning Section Chief Lead is responsible for maintaining, gathering, disseminating information on the current and forecasted situation and the status of resources assigned to the incident, including through development and oversight of the Incident Situation Report. In addition, the Planning and Analysis Strategic Lead provides subject matter advice related to emergency management, as directed, and requested by the OIC and Strategic Leads during an incident. This advice may address roles and responsibilities, processes for activation, notification, demobilization, procedures, and tools. The Strategic Lead will observe performance throughout the response to provide observations and feedback during the incident debrief and After-Active Review.

5.6.6 Gas Operations Commodity Liaison Lead

The Gas Operations Commodity Liaison Lead acts as the liaison between the EOC and the tactical Gas operations, provides support to the Gas Operations Response Team, as needed, ensures the preparation of operational plans, supports the request of resources, monitors progress, makes changes to the Incident Situation Report, and reports to the OIC.

5.6.7 Electric Operations Commodity Liaison Lead

The Electric Operations Commodity Liaison Lead acts as the liaison between the EOC and the tactical electric operations, provides support to the Electric Operations Response Team, as needed, ensures the preparation of operational plans, supports the request of resources, monitors progress, makes changes to the Incident Situation Report, and reports to the utility Officer-in-Charge.

5.6.8 Liaison Officer–External Affairs Lead

The Liaison Officer–External Affairs Strategic Lead oversees EOC External Affairs staff, manages external affairs activities, acts as a liaison between agency representatives, local municipalities, elected officials, and tribes providing accurate, timely and consistent information, and is coordination point for external partners.

5.6.9 Liaison Officer–AFN

The Liaison Officer–AFN oversees EOC AFN staff, manages the AFN support model program by coordinating with partnering Community Based Organizations and providing accurate, timely and consistent information to magnify SDG&E messages to the partner constituencies.

5.6.10 Customer Communications Lead

The Customer Communications Lead oversees the operation of applicable call centers and coordinates with EOC and Customer Care Center staff to ensure effective response to customer calls, including through the provision of Estimated Times of Restoration. In addition, the Customer Service Strategic Lead shall ensure that the Customer Service group adequately manages and responds to Key/Major Account issues that may arise during an incident.

5.6.11 Communication Strategic Lead and Public Information Officer

The role of the Communications Strategic Lead and Public Information Officer is to be the single voice of the organization(s) involved in the emergency response. The Communications Strategic Lead is responsible for interfacing and providing incident information to the public, media, internal stakeholders, other agencies, etc.

5.6.12 Safety Officer Lead

The Safety Officer Lead oversees the safety, security, and well-being of the company during a response. This position also works with the different leads to understand the different Human Resource issues the organization is dealing with and addressing them.

5.7 Information Collection, Analysis and Dissemination

This function is performed in the Planning Section to collect situational awareness information, Essential Elements of Information (EEI), Meteorology, Safety, operational documentation, and report formatting / document archiving for distribution to response operations / executive leadership.

5.8 Internal Coordination

When an emergency event occurs, the EM department is responsible for determining the level-of-emergency, activating the EOC, and notifying EOC responders. The EM department, in consultation with the OIC, will determine the appropriate levels of emergency activation, event classification levels four through one. EM notifies key departments that a major event is forecast or in progress that may significantly affect the gas and electric system. At every event level, each department has specific responsibilities that will allow the company to prepare for such an event in an organized fashion.

When an event level-three is activated, the impacted Commodity DOCs will be activated. This position(s) is staffed by on-call duty personnel and its purpose is to help coordinate the movement of crews, equipment, and material between districts, and to provide system-wide information to various groups. It provides resource coordination and prioritization.

If needed, the Customer Section Chief will coordinate with Customer Programs to ensure Customer Contact Center have adequate staffing and correct information to handle increased call volumes.

5.9 External Notification Coordination

The following notification processes and protocols are in place for incidents or events:

- Once notified of an emerging event, SDG&E will coordinate internal activities in the EOC or via the MS Teams Virtual EOC platform.
- Once criteria are met to activate the EOC beyond a monitoring stage, SDG&E will initiate an operational conference call to assess the event, determine the type and level of EOC activation. Once the EOC activation has been decided, with appropriate operational, planning, logistics, finance, customer service, and command staff available, the EOC responders will begin the incident planning process to establish operational periods, notification criteria and taskings.
- A notification group comprised of the EOC's Public Information Officer, Government Liaison, Customer Care, and Planning Section Chief will begin coordinating messaging, timing, and stages of notifications to customers, public safety partners, jurisdictions, elected officials, and critical infrastructure agencies. Notifications may be sent as phone calls, SMS texts or emails to customers. Notifications to external stakeholder points of contact are typically via email.
- Resources allocated to emergency events are approved by the utility OIC and coordinated through the UFC and AC operations section chiefs of the responding commodity. The OIC will coordinate with operational field commanders for either gas or electric to ensure restoration of power and gas follow the priorities set.
- Priorities for re-energization are hospitals, critical infrastructure, public safety, cool zones[1], and schools.

5.10 Independent Service Operators (ISO)

SDG&E deals directly with the ISO. This procedure is under the overall jurisdiction of the California Independent System Operator (CAISO). Proper and timely communication with the CAISO is required. See *ISO Operating Procedure 4610*.

5.11 EOC Activation / Deactivation Triggers

All the SDG&E EOCs are maintained and ready to activate 24/7/365. The tables below outline the activation triggers and authorities which decide which EOC type to open followed by the criteria to deactivate those functions.

Trigger Type	Trigger Description
Triggers for EOC Activation	The EOC will be activated if any of the following occur: • If there is a Red Flag Warning or Fire Potential Index (FPI) rating of 14 or higher along with forecasted strong Santa Ana winds from the National Weather Service (NWS). • Multiple business units are required to respond and the EOC activation can assist in the response coordination. • A State-of-Emergency exists, either as proclaimed by the Governor of California or County Proclamation. • Any wildfire, which may impact SDG&E critical infrastructure, levels one, two or three. • In response to any condition that requires SDG&E to perform PSPS within its service territory.

[1] Designated by County of San Diego Health and Human Services Public Health

Authority for EOC activation	The EOC may be activated by any of the following SDG&E positions: • Any Vice President who is designated to be the Officer-in-Charge during the event. • Sr. Vice President of SDG&E. • The current On Duty OIC • Director of EM in support of Emergency on Duty staff.

The EOC is deactivated on the authority / command of the OIC once the threat and activation criteria has subsided and meets their assessment of being within the normal operating parameters of SDG&E commodity services. This assessment is based on the level of threat of SDG&E's commodity assets which could affect public safety / property damage and sufficient repair of the assets to provide restoration of services to the public.

5.12 Critical Resource Programs

For field response and safety coordination, the Construction & Operations (C&O) Centers are responsible for the prioritizing the repair and restoration of service in their district, damage assessment, coordination with the Electric Distribution Emergency Operations Desk, and the management of resources and equipment necessary to restore service as quickly and safely as possible.

The C&O Manager is responsible for the repair and restoration of service within the district boundary.

The District Assessment Coordinator is responsible for the following:

- Assessment of overall damage to the district.
- Calls out primary and secondary assessors (a.k.a. field crews).
- Assigns personnel to assess damage.
- Prioritizes emergencies.
- Makes sure expectations are clear to the field crews and ensures that field crews are briefed on SAFETY: Field crews are to understand that wires down or exposed conductors are to be considered energized unless identified, isolated, tested dead, and grounded. They should be informed that downed or exposed conductors could become energized without warning in storm conditions or other emergencies. Field crews should ensure that the public does not go near downed or exposed power lines or equipment.

5.12.1 Safety Considerations

Safety of all personnel, both fields, EOC responders and contractors, is the number one priority of SDG&E. SDG&E looks to never compromise safety and takes all responsibility for safe and healthy behavior. To support this vision, the Safety Services department develops, administers, and oversees employee safety policies, standards, programs, and training. It also manages the contractor safety program.

Safety Considerations for field crews and EOC responders to prevent work related injuries include:

- Behavior based safety
- Contractor safety
- Defensive driving
- Ergonomics
- Office safety
- Equipment inspections
- Product approval
- Environmental safety
- Mental wellness

5.12.2 Restoration Priority Guidelines:

Restoration priority guidelines include consideration of the following:

- Emergencies - Life Threatening.
- Special Cases - As defined by Operations Manager.
- Primary Electric Outages - Generally, set assessment and restoration priorities so that service is restored first to critical and essential customers so that the largest number of customers receive service in the shortest amount of time.
- Non-Primary Electric Outages - Emergency Agencies standing by and equipment damage not related to primary outages.
- Transformer Outages.
- Single-No-Light outages.

5.12.3 Damage Assessment

System-wide damage assessment at the onset of the emergency is extremely important and the information can be difficult to collect. A network software application called Oracle Utilities Network Management System is being utilized to assist with this process and to provide estimated restoration times. The District Assessment Coordinator is responsible to immediately assign resources to the damage assessment process. Personnel may include, but not limited to; Electric Troubleshooter, Working Foremen, Linemen, Construction Supervisor, Project Coordinators, and Planners.

Once the assessment is completed, the assessment is updated on either the Oracle Utilities Network Management System or the Service Order Routing Technology (SORT) application. The updated information is passed to the Oracle Storm Management application within the Oracle Utilities Network Management System and focal Point. The purpose of utilizing these two systems is intended to provide data on current and completed backlog to the Distribution Electric Emergency Operations Desk so that assessment of damage system-wide can be accomplished and staffing levels can be adjusted accordingly.

There is a PSPS specific program called EPOCH used for collecting damage assessments directly from the field. Once the submittals from the field are reviewed and approved, the EPOCH collected data connects SPARC, which then creates a repair ticket which is then submitted and managed through Oracle.

5.12.4 Mutual Assistance:

The energy industry has a strong track record of maintaining high levels of service and reliability. At times, however, events such as earthquakes, firestorms, hurricanes, and other natural disasters occur that cause significant and widespread damage to the electric grid and / or natural gas infrastructure that creates widespread power outages to the end user These events could also cause significant damage to the gas transmission and distribution systems creating the potential for unsafe operating conditions (i.e., over pressurization), gas leaks, and large-scale outages. Following these events, gas and electric utilities must respond safely, swiftly, and efficiently to restore service to its affected customers. Restoring power after a major incident is a complex and difficult task. A speedy restoration requires significant logistical expertise, skilled line workers and assessors and specialized equipment on a large scale. During such events, utilities turn to mutual assistance and the mutual assistance network for the added resources to help speed restoration.

Mutual assistance is an essential part of the energy industry's contingency planning and restoration process. utility companies impacted by a major outage event are able, under Mutual Assistance, to increase the size of their workforce by 'borrowing' restoration workers form other companies. When called up, a company will send skilled restoration workers along with specialized equipment, oversight management and support personnel to assist the restoration efforts of a fellow electric/gas service company.

As part of the mutual assistance plan, the Electric Distribution Electric Emergency Operations Desk Manager, GERC or EOC Company OIC will:

- Notify Emergency Operations Services that mutual assistance is being considered and request that informal inquiries to other utilities be made.
- Determine resource needs from discussions with the districts, the outage forecast data, the storm forecast and resource shortages; and
- Hold discussions with the Vice President of Electric System Operations, the Senior Vice President of Electric Operations, the Directors of Electric Operations, the Director of Design and Construction Management, the Manager of Emergency Operation Services, and the Director of EM on the need for mutual assistance and obtain approval to request.
- Upon approval the Mutual Assistance Plan is activated.
- Conditions triggering these discussions include, but are not limited to:
  - Nearing ten percent of SDG&E's electric customers being out of service at any one time.
  - When forecasted restoration time exceeds 24 hours, discussion for mutual assistance is initiated and decisions are documented.
  - Storm Impact intensity is forecasted to last another 48 hours.
  - All SDG&E crew resources have been or will be committed.
  - All local contract crews have been or will be committed.

6 Communications

Internal and external communications are a key part of any response to an emergency. However, they are separate but equally important efforts. Internal communications are targeted at ensuring a comprehensive and coordinated response. External communications are to ensure our customers, community partners, and public safety remain fully informed of our effort to respond and resolve any hazard affecting SDG&E. Internal communications are essential for emergency coordination across departments and command levels.

6.1 Internal Communications

When an emergency event occurs, which requires a company coordinated response, the EM department is responsible for assisting executive leadership in determining the level of emergency, activating the EOC, and notifying executives, relevant directors, managers, and EOC responders. Internal communications between operational department management and field personnel have specific procedures will allow the Company to prepare for such an event in an organized fashion.

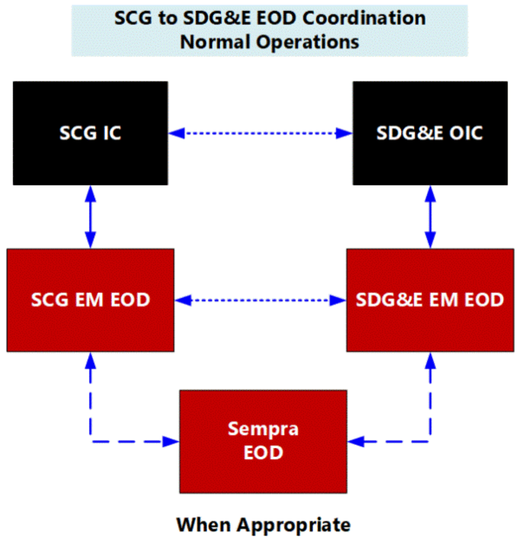
In the event of an EOC activation due to an unpredicted major emergency, a full EOC responder workforce will be notified via SWN and email system. Details for the company-wide communication procedures and auxiliary communication procedures are detailed and referenced in Annex A Crisis Communications and Emergency Communications Tools Plans.

6.2 Affiliate Communications

6.2.1 SoCalGas

SDG&E and SoCalGas (SCG) maintain 24/7 communications capability to ensure coordination of gas emergencies whenever they occur. The communications between SDG&E and SCG are through our organizations 24/7 Emergency on Duty (EOD) call desk and our EOC's when activated. Our District gas engineers also utilize the EOD system when field emergencies arise. This is represented in the diagram below.

Figure 12: Standard Emergency Coordination SCG-SDG&E



6.2.2 Sempra Corporation Coordination

When an event is considered sufficient for SDG&E EOC to be activated to a level-one status, coordination with the parent company Sempra is also activated. The Sempra designated employee on call is notified and will coordinate with the CMC to link it with SDG&E OIC and senior executive leadership.

6.2.3 Joint intercompany Communications Coordination

When an emergency is of such magnitude and is affecting all three corporations (SDG&E, SoCalGas, Sempra) such as in an IT-Cybersecurity situation or catastrophic disasters, communications have been established to link our EOC's and executive leadership together. This provides for immediate situational awareness and joint strategic planning to occur simultaneously. This general approach also allows for single voice corporate messaging to avoid media and public confusion over the corporate response. See Figure 13 below. The inclusion of an executive unified command function, as necessary for an IT-Cybersecurity event, is also illustrated in figure 14 to ensure situational awareness to our senior executive leadership and effective response coordination of the companies.

Figure 13: Intercompany Coordination in IT-Cyber Event-One Voice Messaging

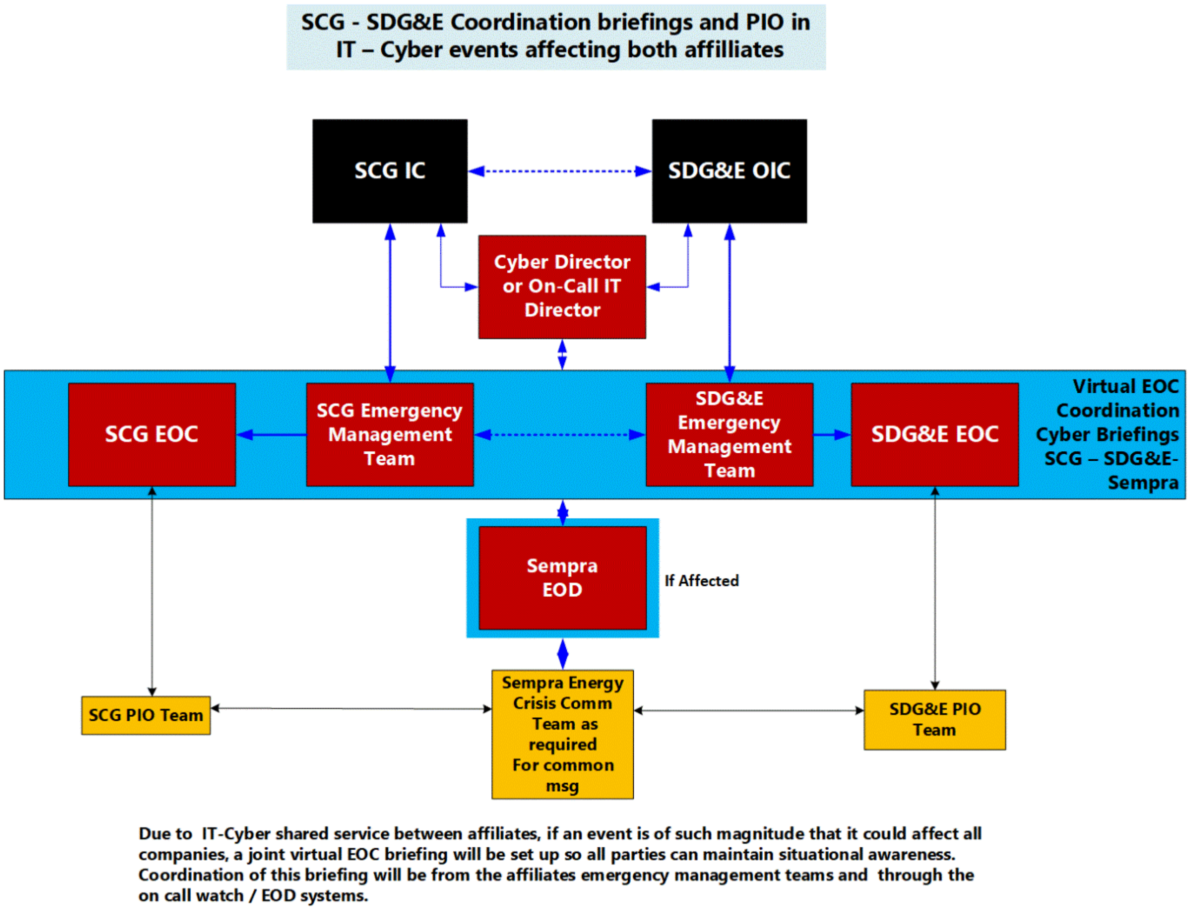
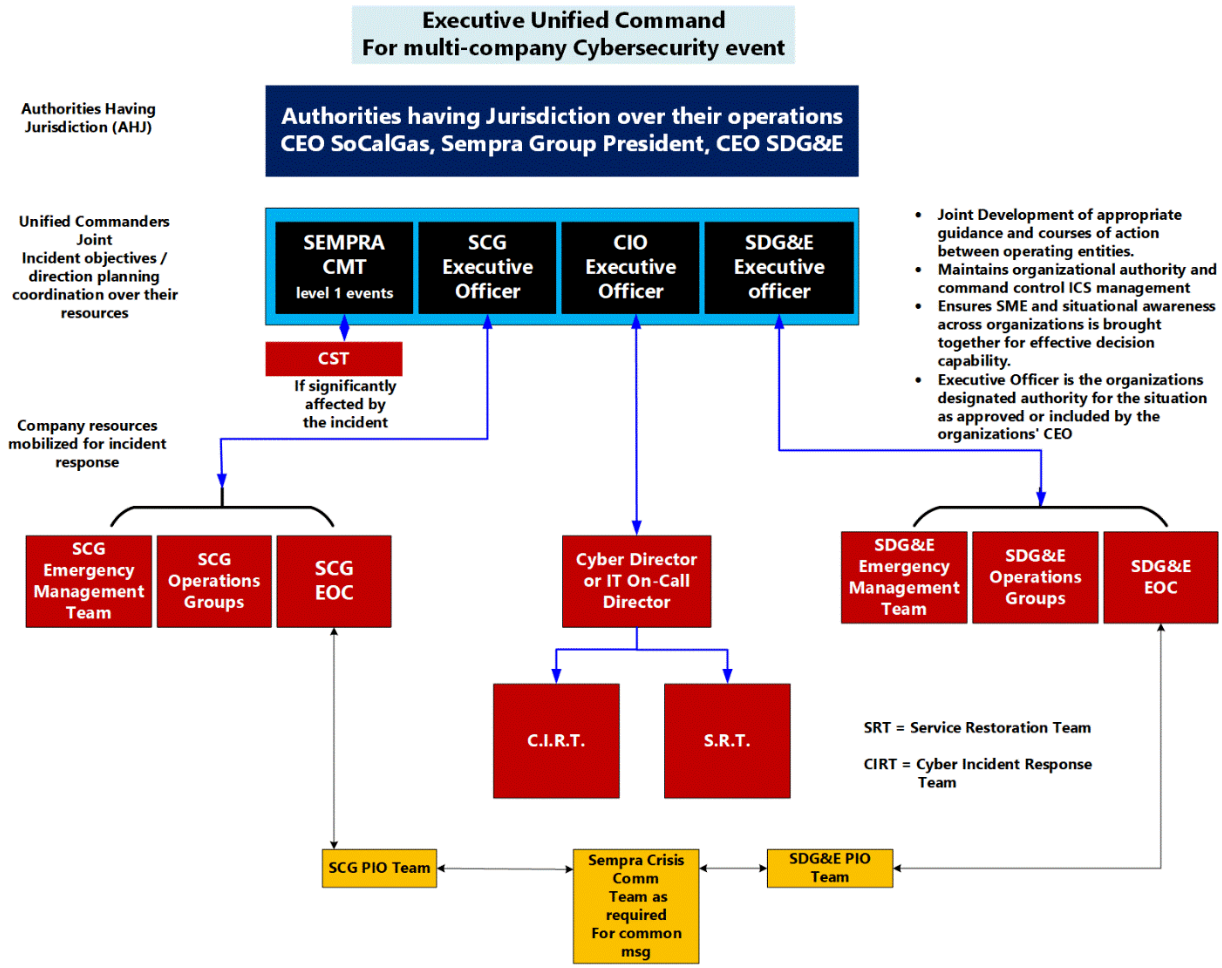


Figure 14: IT-Cybersecurity Event Unified Command Coordination of Sempra Companies



6.3 External Communications

External communications are driven by both specific event and regulatory requirements. Public communications are coordinated and led by the Marketing and Communication department. They are considered the source for the "one-voice" communications which may come from SDG&E to customers, media, and our external partners. Coordination for external communications requires multiple departments and EOC positions from utility operations, these departments which man multiple EOC positions include:

- Customer Service
- Customer Care
- Regional Public Affairs
- EM
- Customer Programs
- Business Services
- Asset Management
- Electric Engineering
- Utility Operations

All must be coordinated to ensure external public stakeholders are properly informed of SDG&E efforts in emergency response.

6.3.1 Agency Listing

- California Energy Commission (CEC) – (916) 654-4287
- California Public Utilities Commission (CPUC) – (415) 703-1366
- State Office of Emergency Services (OES) Warning Center – (916) 845-8911
- California Utilities Emergency Association (CUEA) Executive Director – (916) 845-8518
- County Office of Emergency Services, San Diego – (858) 688-9970
- County of Orange Emergency Operations – (714) 628-7055

6.4 Customer Communications – Marketing/Communications, Customer Care Center

The Customer Care Center starts to obtain emergency damage data during the Event Level-three alert and continues through the completion of the emergency. During Events Level-two or one, the Customer Contact Center will dispatch a representative to the Electric Distribution Emergency Operations Desk to coordinate outage data for the Customer Care Center.

SDG&E understands the important role the media plays in helping us communicate with our customers and the community. To ensure the most accurate presentation of information, media comments are limited to designated spokespersons or members of the media relations team. SDG&E has several communications tools to expedite the delivery of emergency information to media and customers. These tools contain both primary normal communications tools and alternate means of communications (see Annex A for details) and include:

- **Emergency Radio Ads:** SDG&E has contacted 24 local radio stations to obtain their turn-around time commitment to place emergency ads, which range from one-hour to 24 hours depending on the station and day-of-week. Additionally, the stations are prepared to provide news coverage as the situation may merit.
- **Media Advisories:** Media Communications will issue media advisories as appropriate and post situation updates on SDG&E's news center and social media channels that include Twitter, Facebook, and Instagram. Additionally, when appropriate, proactive calls will be made to local print publications, broadcast television and radio stations to provide situation updates.
- **Website outage information:** An outage website, which can be accessed through www.SDGE.com, provides information about active electrical outages. Another relevant emergency information can be accessed through www.SDGEnews.com. The information communities affected contains details such as communities affected, outage cause, number of customers affected and estimated restoration times. Similar information can be found on SDG&E’s phone app.

In addition, the Media Communications team monitors the 24-hour media hotline where the media can obtain more information and updated information.

6.5 Reporting Procedures:

6.5.1 During Normal Business Hours:

Notification to EM could come from a Company Utility OIC, Operations, a District Director or their designee, Corporate Communications, the Customer Care Centers or First Responder Agencies.

The on-duty EM employee is responsible for obtaining accurate internal information and then contacting each of the organizational emergency contacts on the agency listing. The on-duty EM employee is responsible for providing follow-up information at a reasonable frequency throughout the event to those agencies on the agency listing. Developing a record from the initial contact and each subsequent contact is necessary.

6.4.2 During Non-Business Hours:

EM has a rotational employee that stands one-week on duty shifts. An EM on-duty telephone number, text page, and e-mail provides the notification mechanism for alerting the EM team. The on-duty EM will contact the notifying party within 30-minutes, obtain information and call the Manager of Emergency Operations Services, who will instruct the EM on-call on what notifications and actions to take.

The on-duty EM employee is responsible for obtaining accurate internal information and then contacting the organizational emergency contacts on the agency listing as appropriate. The exception is the CPUC who is contacted by SDG&E's Claims Department when reporting criteria is met. An EM employee is responsible for providing follow-up information at a reasonable frequency throughout the event to the appropriate agencies on the agency listing. Developing a record from the initial contact and each subsequent contact is necessary.

6.6 External Partners

Guidelines have been developed for the EM Department for reporting major electric and gas outage information for purposes of regulatory compliance and supporting proactive communication links. Local and State Agencies or SDG&E may initiate outreach. Using Standard Emergency Management System (SEMS) and familiarity with local agencies organizational structure, SDG&E coordinates emergency response activities with local agencies as the incident requires.

Communication with local emergency management agencies is coordinated through the EM department. These agencies are updated on emergency events and progress of restoration through EOC liaisons and/or EM's Emergency On Duty (EOD) representatives.

6.7 Media Partners

The Media Communications team is responsible for providing timely and accurate information to the news media and employees. Information is disseminated through traditional news outlets, social media outlets and internal communication platforms. SDG&E uses a "OneVoice" communications strategy for all internal/external stakeholders to ensure consistent messaging.

6.8 Customers Notifications

During emergencies direct customers communications using email, phone and SMS texts are implemented using an emergency notification system (ENS) which sends approved messages to customers using available contacts systems. The Customer Care Center starts to obtain emergency damage data during the Event Level-three alert and continues through the completion of the emergency. During Events Level-two or one, the Customer Care Center will dispatch a representative to the Electric Distribution Emergency Operations Desk to coordinate outage data for the Care Center.

In preparation of PSPS events SDG&E performs advanced customer outreach using the ENS system. For Medical Baseline Customers (MBL) who aren't contact confirmed using the ENS, phone calls are made by Customer Care Center representatives, then for remaining customers not reached via phone, Customer Service Field representatives are dispatched to their door to inform them in-person or they leave notifications on their door to notify them of an upcoming PSPS event.

6.9 Employees

Per SDG&E Natural Disaster or Major Emergency Procedures the following sections detail employee responsibilities and district responsibilities within SDG&E.

6.9.1 Employee and Facility Emergency Action Plans

Every facility within SDG&E must have an Emergency Action Plan (EAP). The primary goal of these EAP's is to ensure the safety of all employees during a workplace emergency. The plans should be followed whenever possible; however, they do not replace the use of common sense by an individual employee.

Each EAP has a designated Emergency Response Team (ERT) which is comprised of trained employees who assist the appointed Building Leader in responding to a workplace emergency. The ERT may elect to train employees to be able to render first aid, CPR, AED, or implement firefighting measures. The ERTs members are a Building Leader, Floor Leader(s), Assistant Floor Leader(s), and other employees trained to respond in an emergency, however any employee may be assigned responsibilities during an emergency.

6.9.2 Employee Responsibilities

- Employees with specific emergency assignments report to their assigned locations and perform duties as indicated:
  - In local instructions, or pre-assigned emergency duties.
  - In written emergency instructions not a part of the Formal Communications program.
  - If the GEC, EOC or Docs are activated, employees trained as responders may be requested to report to these locations. Employees will be notified through the call out lists created by these entities with information regarding when and where to report. Employees will be notified via cell phone or landline, pager, or text message.

6.9.3 Employee Actions with No Specific Emergency Assignment

On or Off Hours	Employee Actions
During scheduled working hours:	• SDG&E CSF and Gas Distribution employees follow instructions of a supervisor, police, or fire personnel, etc. • Employees in the field make the job safe and report to their regular operating district, if possible; otherwise, to the nearest functional operating district or headquarters location. • Non-field employees should follow instructions of a supervisor, police, or fire personnel, etc.
During non-working hours:	If the disaster has occurred elsewhere and has caused no damage in the vicinity of the employee's location, turn on a radio or television set to receive general instructions. Employees await instructions from the company or call the Employee Emergency Information Hotline number, listed below for further reporting information. Unless otherwise informed, employees report to work at their next regular working time.

6.9.3.1 General Disaster with Significant Damage in Employee District

If the disaster is general, has caused significant damage in the employee's assigned district as determined from observation or radio and television reports, the employee will:

- First, make sure their family is safe.
- Follow emergency procedures and instructions specific to their department, if any.
- Contact their supervisor to report their status, availability to stay at work or come to work, and their contact information.
- Call the Employee Emergency Information Hotline, listed below for periodic updates on the crisis. If phones are down, employees may try their company website and radio or television news for additional information.
- Unless otherwise informed, employees report to work at their next regular working time.
- EM department maintains an Emergency Reporting Instructions (ERI) wallet card which is distributed to all employees. This card outlines the emergency reporting responsibilities of employees, supervisors, managers, and directors.

6.9.4 Major Emergency Employee Information

Employees may call the following number to verify status of company operations following a major emergency.

- SDG&E Human Resources will be responsible for recording emergency incident information messages on the employee hotline [redacted].

6.10 Communications Equipment Testing

Annex A contains SDG&E's Communications Plan, and addresses the systems and equipment utilized by SDG&E for response and alternative communications which assists in continuity of operations and preparedness. The EOC (primary and alternate) communications systems are tested monthly by the IT department to ensure they are fully operational. In addition to the monthly tests, SDG&E will also conduct a test of the communications systems annually. SDG&E's EOC activates on a regular basis (5 to 10 times annually) for various situations. However, if SDG&E activates the EOC at a level 2 or higher during the twelve-month period, the activation will be considered as compliance to the yearly test in lieu of a running a separate test. During EOC activations, the communication systems are used to communicate to company personnel, regulatory, government, and public. Any discrepancies or system failures during tests or activations are documented and repaired. This also meets the regulatory requirements of GO166 which states: "The utility shall conduct an exercise annually using the procedures set forth in the utility's emergency and disaster preparedness plan. If the utility uses the plan during the twelve-month period in responding to an event or major outage, the utility is not required to conduct an exercise for that period."

7 Administration and Finance

This section describes the administrative protocols including documentation, after-action reporting, cost-recovery, and resource financial management.

7.3 After Action Review Program

SDG&E's After-Action Review (AAR) program involves conducting a comprehensive review with key stakeholders after tabletop exercises, EOC activations, and field incidents, where there are opportunities for continuous quality assurance and quality improvement. Findings and lessons learned from the AAR process are documented, communicated, assessed, and referenced to reduce the risk of reoccurrence. The following actions summarize the AAR programmatic response following an incident:

- Facilitating a comprehensive incident de-brief with key stakeholders, both internal and external, where appropriate.
- Documenting and storing lessons learned and/or findings in a shared and approved repository, made available to employees, as appropriate.
- Assigning findings and/or lessons learned to the responsible department(s), where accountability and timelines are then established.
- Incorporating and or considering lessons learned gleaned from this process in designing and developing EOC-related skills training and exercises.

7.4 EOC Document Management

During EOC activations the Planning Section, as an extension of the EM department, is responsible for coordination of event documentation, including EOC event files.

- The Documentation Unit (Doc Unit) establishes, monitors and managers documents created during an event.
- The Situation Status Unit (Sit Stat Unit) monitors the overall event a makes sure to record decisions made during the event.

Following each event, the Doc Unit Lead coordinates with the Sit Stat Unit to make sure event files are compiled and archived. For reference the timeline of saving documents and communications refer to the table below.

Depending on the event, such as PSPS, there is potential for cost-recoverability. The cost-analysis goes into the rate-case review. In every event, the Finance office assigns a specific Incident Order (IO) code so every accountable people-hour or equipment cost can be assigned to the specific event.

7.4.1 Vital Record Retention:

Sempra Energy Records Management BU Master Schedule June 12, 2019.PDF guides the retention of records for the enterprise. The pertinent records retention policy for disaster / regulatory compliance of the EM operations and plans are:

Table 6: Record Retention Timeline

Record Type	Retention time in years
CA Utility Regulatory records	Indefinite
CA Utility Regulatory records	Active + 6, active means as long as it is in effect
Government Relations	6
Customer Relations	3
Gov Compliance and Reporting SEC	Indefinite
Gov Compliance and Reporting general	6
Formal Orders and Decisions Regulatory	Indefinite
Business Continuity and Disaster Records	Active +3
Administrative Records	3

7.5 Financial Accounting

The SDG&E Finance and Accounting department lays out company policy for approval and commitment procedures, general ledger entry transactions, and revenue management approval. This department provides guidance on shared assets, services and sundry actives and billing. Finance and Accounting administers and provides training for the Systems, Applications & Products (SAP) system which is the company wide financial accounting tool. This department is ultimately for planning and justifying the budgets for every SDG&E department.

The Finance and Accounting department supports the EOC Administrative / Financial section which is responsible for maintaining the cost impact (claims, damages, resources) of an activated emergency operation within the company. This unit follows all approved financial accounting policies / plans of SDG&E as referenced in the financial plan for the company. These costs are distinguished and made available to Senior leadership for their visibility and decision capability during a disaster.

8 Plan Development and Maintenance

This general plan has been adjusted for changes made since the last submittal and incorporates the requirements of CPUC Decisions D.98-07-097, D.00-05-022, and D.12-01-032 as well as the latest CPUC reporting guidelines of November 1, 2012, CPSD Memorandum. Procedural manuals are updated as required to conform to this general plan.

8.3 Plan Maintenance

The plan will be reviewed annually by the EM department and updated to meet changes in regulatory requirements and recommendations resulting from training, exercises, and After-Action Reports. Every three-years EM will do a full document review and invite stakeholders companywide to provide input. EM update and track the changes annually. The changes will be recorded in the Record of Changes section of this plan.

Following the three-year review, the plan will be re-submitted to SDG&E leadership for approval following the SDG&E 'SOP_Document_Approval_Maintenance-Final' plan.

The plan will then be shared with each department for reference.

8.4 Plan Evaluation

Annual reviews are performed in Q1 of each year. The annual review will be based on outcomes from exercises to testing multi-hazard events as well as actual emergency events. These exercises simulate the need to activate the EOC. The exercises will focus on operational objectives set by leadership. The overall objectives are to improve coordination and communication during an event. Exercises will include drills, workshops, and discussion-based events such as a tabletop exercise. Based on the foundations built in the less complex events, functional exercises will be performed to test all processes and procedures used responding to those events. Annually the scenarios will change dependent on the current hazard environment, regulatory requirements, and leadership intent.

Based on the compiled after-action feedback process from the exercises and real-world events, the review will verify if the current plan still meets regulatory requirements and or operational needs. Updates to the plan will be based on the compiled reports over the three cycle and submitted to leadership for approval and internal distribution.

Annual presentations reviewing our CEADPP are done with our external stakeholders. It allows them an opportunity to provide input and feedback. Their input is recorded and considered for the three-year document review. The plan and its review are done to meet California's Assembly Bill1650.

8.5 Training and Exercise

The EM department is responsible for programing the training and exercises for the EOC responders and the operational departments. SDG&E EM coordinates safe, effective, and risk-based emergency preparedness to prepare for, respond to, and recover from all threats and hazards safely and efficiently. The EM department sustains quality assurance and improvement processes through strategic planning, training, and simulation exercises targeting both EOC responders and operational departments.

Following each exercise and real-life event, a lessons-learned meeting takes place with event responders to generate the After-Action Report (AAR). This report summarizes what worked well and what needs improvement to the plan and is conducted with each active participant. AARs are then presented to leadership with identified action items to assist in determining responsibility, accountability, and completion dates for plan revision. The improvement items are then incorporated into existing procedures, accounted for in the overall SDG&E Emergency Response Plan and appropriate resulting training. Action items requiring incorporation to the CEADPP will be part of the annual review in Q1.

9 Authorities and References

Authorities for compliance rest with the California Public Utility Commission (CPUC) and the Federal Energy Regulatory Commission (FERC).

The CPUC regulates privately owned electric, natural gas, telecommunications, water, railroad, rail transit, and passenger transportation companies, in addition to authorizing video franchises. The CPUC's five Governor-appointed Commissioners, as well as our staff, are dedicated to ensuring that consumers have safe, reliable utility service at reasonable rates, protecting against fraud, and promoting the health of California's economy.

The Federal Energy Regulatory Commission, or FERC, is an independent agency that regulates the interstate transmission of natural gas, oil, and electricity. FERC also regulates natural gas and hydropower projects.

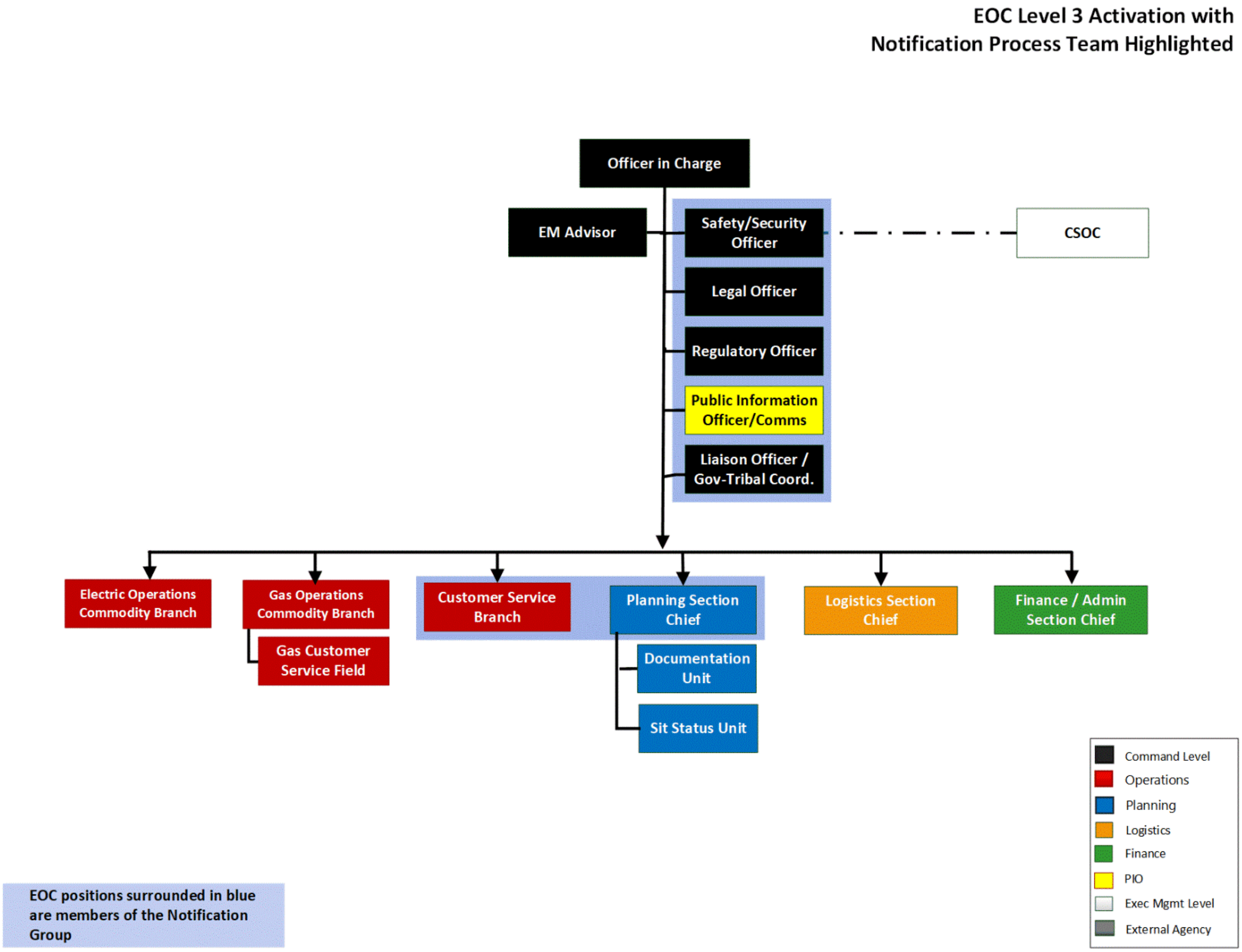
Online Resources	• SDG&E Weather Awareness System: http://www.sdgeweather.com/ • NWS San Diego: http://forecast.weather.gov/MapClick.php?lat=32.80437037169639&lon=-117.13430639012711#.WByySvkrLRY • Santa Ana Wildfire Threat Index: https://fsapps.nwcg.gov/psp/sawti • NOAA Storm Prediction Center's Fire Weather Forecast: https://www.spc.noaa.gov/misc/about.html#FireWx • Cal OES 2019 PSPS Guide
Public Utility Code	• California Public Utility Commission: General Order 166 – Standards for Operation, Reliability and Safety During Emergencies and Disasters • NERC Reliability Standards: COM – 001 – 3, EOP-004-4, 005 -3, 006-3,008-2,010-1,011-1
Corporate and Company Policy or Charter	• Sempra Corporate Emergency Response Plan, Sept 2022 • SDG&E: Gas Emergency Response Plan. ER-1SD 2023 • SDG&E 2020 Electric Emergency Load Curtailment Plan - 2022 • SDG&E Fire Preparedness Transmission Restrictions TMC1320a • SDG&E Crisis Communications Plan • EOC Communications Failover Plan 11-2022

10 List of Appendix

Title:
EOC Levels of Emergency
Matrix of Responsibilities
Acronyms and Definitions
Virtual EOC Executive Summary

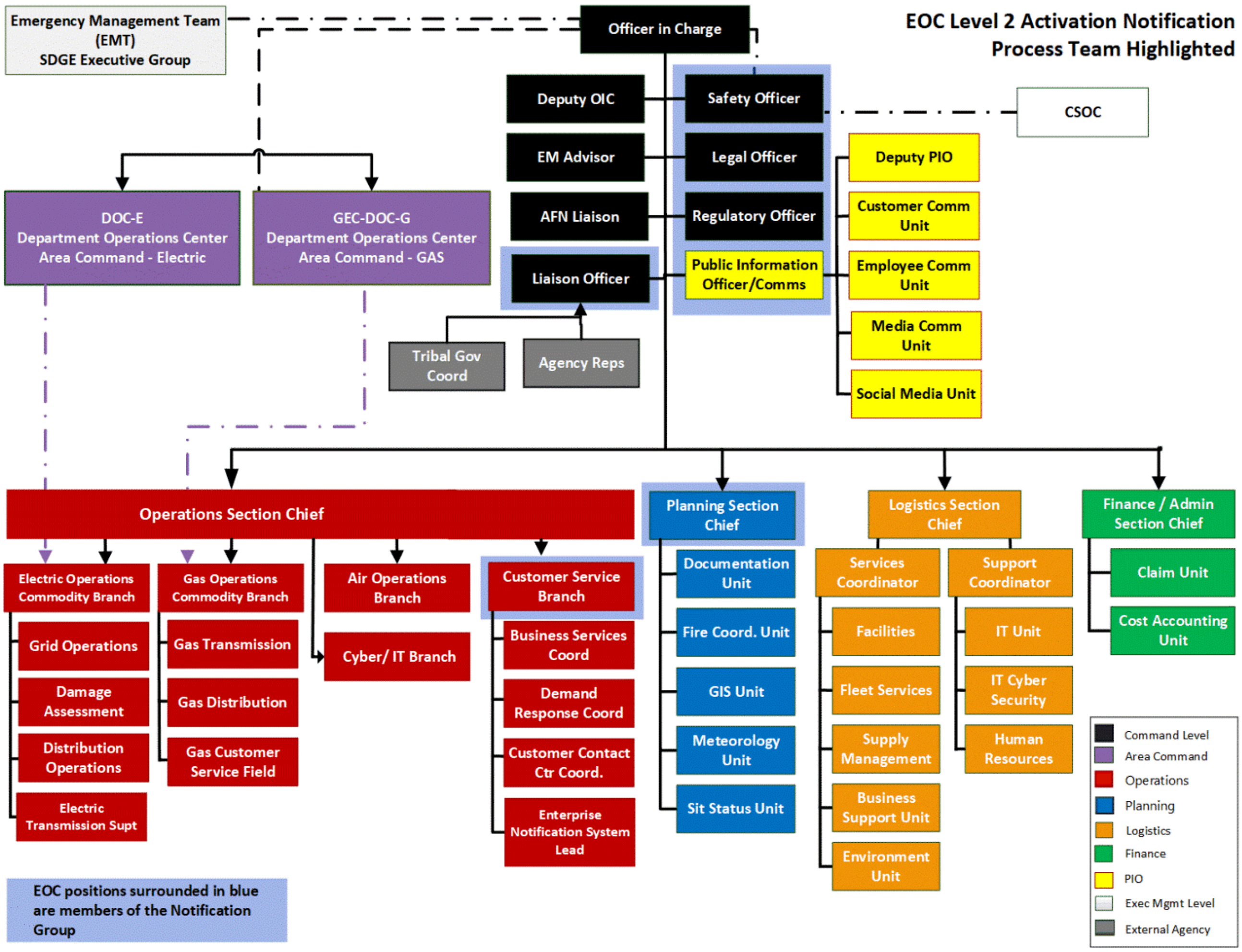
Appendix A EOC Levels of Emergency

Figure 15: EOC Level 3 Activation with Notification Team Highlighted



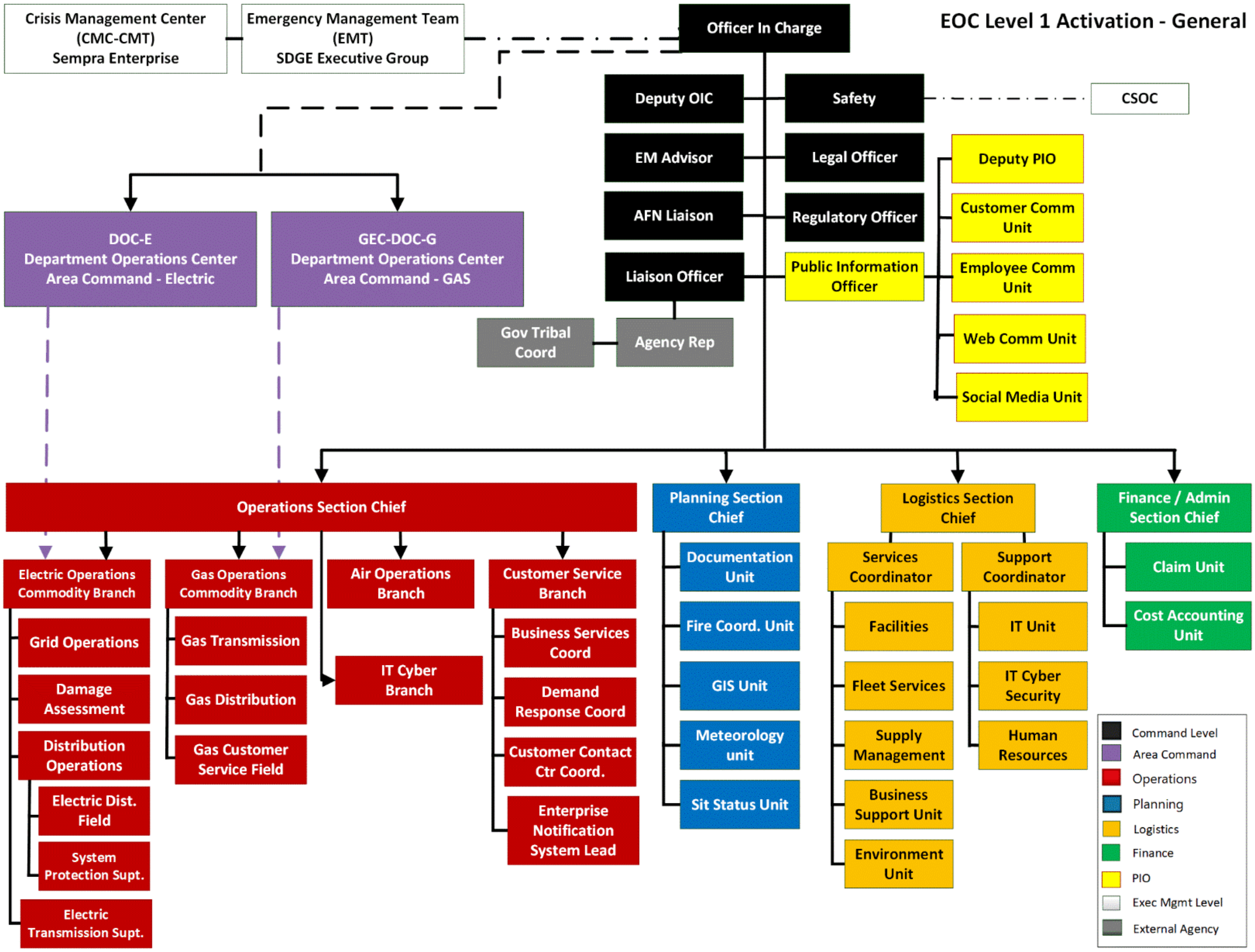
- This EOC minimum configuration is used in a situation involving external regulatory notification requirements, public, government or media involvement.
- Notifications is an intensive operation, and the team components identified in this figure illustrate this process.

Figure 16: EOC Level Two Activation with Notification Team Highlighted



EOC Level-two functional diagram for coordination of support requests from the field and internal and internal notification.

Figure 17: EOC Level-one activation illustrating the inclusion of Sempra enterprise CMC functions.



Appendix B Matrix of Responsibilities

Matrix of SDGE EOC Workforce Roles and Responsibilities

Appendix C Acronyms and Definitions

Acronym	Definition
AAR	After Actions Report
AC	Area Command
AFN	Access and Functional Needs
AOR	Area of Responsibility
BCP	Business Continuity Plans
C&O	SDG&E Construction and Operations Centers, also called Districts
Cal OES	California Office of Emergency Services
CEADPP	Corporate Emergency and Disaster Preparedness Plan
CIRT	Cyber Incident Response Team
CMC	Sempra Enterprise Crisis Management Center
ConOps	Concept of Operations
CPG	Federal Emergency Management Agency's Comprehensive Preparedness Guide
CPUC	California Public Utilities Commission
CRC	Community Resource Centers
CS	Customer Service
CSF	Customer Service Field
DCC	SDG&E's Distribution Control Center, distribution control only
DHS	Department of Homeland Security
DOC	Department Operations Center
DOC-E	Department Operations Center - Electric
DOC-G	Department Operations Center - Gas
EAP	Emergency Action Plan

EDO	SDG&E Electric Distribution Operations Department
EEI	Essential Elements of Information
EGO	SDG&E Electric Grid Operations Department
EMT	Executive Management Team
ENS	Emergency Notification System
EOC	Emergency Operations Center
EOD	Emergency on Duty
EOP	Emergency Operations Plans
ERO	SDG&E Electric Regional Operations Department
ETR	Estimated time of restoration
ETS	SDG&E Electric Troubleshooter
FERC	Federal Energy Regulatory Commission
FPI	Fire Protection Index
FSCA	Fire Science and Climate Adaptation
GCC	SDG&E's Transmission Grid Control Center, transmission control only
GEC	SDG&E Gas Emergency Center
GIS	Geographic Information System
EAP	Emergency Action Plan
HFTD	High Fire Threat Districts
IC	**Incident Commander:** The person, Fire / Law Enforcement first responder, who has the overall responsibility for all aspects of the incident. They are responsible for the operational mitigation of the incident, the logistical support needs, any financial issues involved, safety of incident personnel, public information, and planning functions for extended incidents. They can and should delegate authority for performing certain activities to other qualified personnel as the incident grows.
ICP	**Incident Command Post:** The primary place the IC and other key incident personnel will be located. It should be accessible, located near or adjacent to the incident, but not necessarily within the incident, and large enough to accommodate the associated activity.
ICS	**Incident Command System:** Basic principles of ICS include establishing positive command and control of the incident by identifying an IC or group of Unified Commanders in a multiple jurisdiction incident, identifying an ICP for single point of contact, and establishing a central ordering point for all additional resources and/or supplies. Emphasis in ICS is on managing span of control for supervision of incident personnel and providing a platform for inter-functional and interagency cooperation.
SOC	Information Security Operations Center

IST	**Incident Support Team:** SDG&E Emergency Operations Center responders is led by the Utility Officer-in-Charge.
LEPC	*Local Emergency Planning Committees*
MIMT	**Cyber–Major Incident Management team**
Major Incident	Emergency incidents that result in major damage, that are unusually complex, and/or require multiple crews to respond and are declared as such by the first responder, on-duty supervisor, or other company official in the proper chain of authority.
MMI	Modified Mercalli Index
NG	Natural Gas
NIMS	National Incident Management System
NOC	Network Operations Center
NRF	National Response Framework
NWS	National Weather Service
OA	**Operational Area**
OES	**Office of Emergency Services**
OIC	Designated utility **Officer in Charge:** leadership with authority over all support functions
OSS	SDG&E Grid Control Operations Shift Supervisor
PII	Personal Identifiable Information
PIO	Public Information Officer
POC	Point of Contact
PPE	Personal Protective Equipment
PSPS	Planned Safety Power Shutoff
RFW	Red Flag Warning
SAWTI	Santa Ana Wildfire Threat Index
SCM	Substation Construction and Maintenance Section of SDG&E's Kearny Maintenance and Operations Department
SDC	San Diego County
SEMS	California State Emergency Management System
SME	Subject Matter Expert

SONGS	San Onofre Nuclear Generating Station
SOP	SDG&E Standard Operating Procedure
SORT	Service Order Routing Technology
SPM	System Protection Maintenance Section of SDG&E's Kearny Maintenance and Operations Department
TCM	Transmission Construction and Maintenance Section of SDG&E's Kearny Maintenance and Operations Department
TST	SDG&E Electric Distribution Operations Technical Support Team
UC	**Unified Command:** When multiple jurisdictions are involved, a Unified Command can be formed to manage the incident. Each respective agency can have an IC within the Unified Command. It is critical that members of the Unified Command be co-located and that the Unified Command speaks with one voice in overall incident management. Generally, the agency with the greatest responsibility for the incident will serve as the primary IC.
UFC	Utility Field Commander
WF-4	Working Foreman 4-man crew
VRI	Vegetation Risk Index

Appendix D Virtual EOC Executive Summary

By direction of the OIC or EM Director, instead of standing up the physical EOC, SDG&E has the capability using Microsoft TEAMS, to stand up a virtual EOC with all the functioning components of the physical EOC. Video conferencing, file sharing, notifications etc. functions within the physical EOC are carried out remotely from the facility. This is summarized in the PDF Virtual EOC doc link provided.

Appendix E Plan Updates

- Revisions to CEADPP 3-2023.pdf

11 Functional Annexes

Annexes are documents which will be updated as required to meet operational response needs and may not meet the three-year cycle update process prescribed for the overall Company Emergency Response Plan (CEADPP). These documents can be referenced and pulled into the CEADPP for guidance when the functional or hazard specific event requires. They are considered separate but connected documents.

Annex A Crisis Communications and Emergency Communications Tools Plans

The Crisis Communications Plan focuses on communications with external partners and the public. It is intended to coordinate internal resources and the Notification Group to ensure the "one voice" communication tone is consistent between all external stakeholders, customers, elected leaders, regulatory, and public safety partners. This plan is managed by the Marketing and Communication department.

SDG&E has three support plans to assist leadership and EM staff as to the resource capabilities, normal and alternate communication systems, and utilization procedures.

EOC-Communications Failover plan.PDF

Leadership Communications capabilities 9-08-2021.PDF

SDGE Satellite Phone Protocols.PDF

Crisis Communications Plan 2020.PDF

Annex B Mutual Assistance Plan

The Electric Distribution, Electric Emergency Operations Desk Manager, GEC, or Emergency Operations Center Company Utility Commander will do the following:

- Notify Emergency Operations Services that mutual assistance is being considered and request that informal inquiries to other utilities be made.
- Determine resource needs from discussions with the districts, the outage forecast data, the storm forecast and resource shortages.
- Hold discussions with the Vice President of Electric System Operations, the Senior Vice President of Electric Operations, the Directors of Electric Operations, the Director of Design and Construction Management, the Manager of Emergency Operation Services, and the Director of EM on the need for mutual assistance and obtain approval to request.

Conditions triggering these discussions include, but are not limited to the following:

- Nearing ten percent of SDG&E's electric customers being out of service at any one time.
- When forecasted restoration time exceeds 24-hours, discussion for mutual assistance is initiated and decisions are documented.
- Storm Impact intensity is forecasted to last another 48-hours.
- All SDG&E crew resources have been or will be committed.
- All local contract crews have been or will be committed.

SDG&E has four Mutual Assistance Agreements. They are with:

- California Utility Emergency Agency (CUEA)
- Edison Electric Institute (EEI)
- American Gas Association (AGA)
- Western Regional Mutual Assistance Group (WRMAG)

Annex C Gas Emergency Response Plan

This emergency response plan, along with referenced documents and procedures, outlines how San Diego Gas and Electric prepares for, responds to, and recovers from gas related emergencies. This plan incorporates and complies with the emergency response requirements found in Public Utilities Code 961 (b), (c), and (d)(1-10) as well as the emergency response procedures required by 49 CFR 192.615.

- Gas Emergency Response Plan-ER1SD.pdf 2023

Annex D Electric Emergency Operations Plan

The Electric Grid Operations EOP provides an overview of the subset of documents that constitute SDG&E's

EGO EOP to operate and maintain a reliable transmission system during emergency and critical conditions.

- EOP1000 EGO.pdf
- TMC1310 ICS_Electric Transmission Monitoring and control.pdf
- TMC1320a_EFF-2021-1013.pdf
- TMC1004_EFF-2021-1013.pdf
- 2022 Electric Load Curtailment Plan.pdf

Annex E Continuity of Leadership

- Executive Continuity of Leadership Plan Final May 2022.pdf

12 Hazards, Threats, or Incident Specific Annexes

The hazard specific annexes are updated as required to meet both operational and regulatory requirements to assist executive leadership in their response coordination. These documents are also considered separate but connected documents which are designed to complement the CEADPP.

Annex F Earthquake

The earthquake annex includes information from the following references:

- SDGE Earthquake Annex Plan 4-2023.pdf
- EOP1000 EGO.pdf
- SoCal Catastrophic Earthquake Response Plan-FEMA FUOU 2022.pdf
- 2023 SDG&E Gas Safety Plan_Final.pdf

Annex G Public Safety Power Shutoff

The Wind Event Annex includes information from the following references:

- Wind Event_PSPSCONOP_CPUC_2023 Rev 2.pdf
- CALOES PSPS Standard Operating Guide 2020.pdf

Annex H Cyber/IT Event

The Cyber Annex includes the information from the following references:

- IRF1100 Cyber Security Response Procedure.pdf
- EM-Cyber-IT Concept of Operations.pdf
- Exec-EM-IT_Cyber-Coord Plan rev 12 01-14-2023.pdf

Annex I Wildfire Event

- SDG&E Wildfire Mitigation Plan 2023-2025.pdf
- Wildfire Annex rev 3-10-2023.pdf

Annex J Pandemic Event

The Pandemic Annex the information from the following references:

- Pandemic Plan

Appendix 3:
SDG&E’s 2023 Crisis Communications Plan
(PUBLIC)

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San Diego Gas & Electric®

2023
Crisis Communications Plan
(PUBLIC)

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Contents

Appendix

Introduction

This communications plan has been developed to outline responsibilities for communicating to customers, media and employees during an emergency involving SDG&E, including those which prompt the activation of SDG&E's Emergency Operations Center.

Because the utility covers such a large geographic area and has employees in many different departments interacting and communicating with SDG&E's various stakeholders including the media, customers, community-based organizations and elected officials, it is essential that the sharing of information and communications are coordinated to ensure "OneVoice" incident messaging and overall consistency.

Responding swiftly in an emergency is critical to managing the situation effectively. Often, the first few hours of an incident determine success or failure with crisis management. SDG&E responds to gas and electric emergencies as an important part of its normal business practices. Each operational area has emergency procedures that are specifically written for these types of incidents. These emergency response procedures are thoroughly practiced, and the personnel involved are well trained to respond to and resolve routine gas and electric emergencies.

Separate crisis communication plans have been developed for natural gas incidents and electric incidents.

The approach and messaging included in this plan is reviewed on an annual basis and subject to consultation with the Legal team and senior executives before execution.

Identifying an Incident, Crisis or Disaster

Emergencies can begin as an incident and quickly escalate and create a larger threat that could have impacts on gas and electric system integrity, employee safety, customer confidence, shareholder consequences and/or trigger significant media attention. At SDG&E, emergencies that escalate and create a larger threat are considered a crisis or disaster. A crisis or disaster can occur by the escalation of a single emergency or a series of emergencies.

For the purposes of this plan, an incident, crisis and disaster are defined as follows:

<u>Incident</u>

An incident is defined as a situation that needs to be monitored and dealt with by a limited, targeted group of individuals. An incident can be an emergency that is as simple and short-lived as a circuit outage affecting 1,000 customers and is restored the same day. It could also be an emergency that is as complex and lengthy as a storm involving multiple outages that take more than one day to restore. The key is that the impact of an incident can be effectively dealt with by a limited group of employees who have the necessary knowledge and experience, and no specialized decision-making or communications are required.

Within SDG&E, an incident generally is considered to be an unplanned event that involves an electrical outage affecting numerous customers; damage to natural gas facilities that has or could result in injuries to employees and/or customers, including a broken pipe with escaping natural gas (called a "broken and blowing").

An incident, if it continues for an extended amount of time and/or stretches the company's resources and ability to respond, usually is considered a crisis or an emergency depending on the type and extent of the damages. However, any incident, if it is not managed or communicated appropriately, could evolve into a crisis.

Crisis
A crisis is defined as an incident that has received or has the potential to generate unusual focus from the media or government/regulatory agencies and/or negatively impact the company, requiring specialized decision–making and communication capabilities. A threat of terrorism or a gunman at a company site are potential examples of a crisis. A Crisis Management Team (CMT) and applicable procedures for formation of the team have been developed by Emergency Operations Services to provide the specialized decision-making and communication capabilities required during a crisis.

A crisis may include workplace violence that results in injury or death of an employee or customer, a violent act in the community that results in injury or death of an employee, kidnapping of a company executive, serious ethics or legal violations by an executive, employee or group of employees, death of a customer or employee or significant property damage from company operations or damage to company facilities such as explosion or fire caused by leaking gas. A crisis could also include rolling blackouts because of the significant impacts to company operations and the unusual focus from media requiring specialized decision–making and communication capabilities. The January 2008 mudslide in La Jolla that damaged homes and utility equipment was a crisis that generated national media interest. (Note: The fact that the damage was the result of a natural landslide not company operations and the damage to company facilities was moderate made this a crisis by definition not an emergency.)

Disaster
A disaster is defined as a dramatic event or confluence of events that severely impacts business operations in multiple ways typically for, but not necessarily, more than one day. The Emergency Operations Center (EOC) and its applicable procedures have been developed to respond to a disaster. The EOC is managed by Emergency Operations Services.

A disaster could include an earthquake, widespread fire affecting SDG&E facilities and/or mass acreage, a cyber-security breach or an act of terrorism affecting SDG&E infrastructure, or other natural disaster that affects a significant number of customers and facilities, or widespread system outage not caused by natural disaster affecting a significant number of customers, The September 8, 2011 Pacific Southwest Event (system-wide blackout) is example of a widespread outage emergency that severely impacted business operations and customers.

While the triggering events vary by emergency, media coverage – or potential media coverage – is a common element of all major situations. At SDG&E, "emergency operations procedures" have been put in place to ensure the response to and recovery from a crisis or disaster is organized, timely, efficient, cost-effective and decisive.

When an emergency incident escalates into a crisis or disaster, there is a need for an organized response with specific procedures and designated personnel. This organized response provides the required specialized decision-making and communication capabilities and the additional resources needed to efficiently respond to and recover from an event.

This plan addresses only the media and employee communication aspects of these events.

Plan Objective

The objective of this plan is to manage communications effectively so that customers, the media, employees and others who may be affected by the event are kept informed. By being open, transparent and consistent in our communications, we will have a better chance of avoiding unnecessary questions and concerns that could help to create a crisis.

Responsibilities

SDG&E has a well-defined process for managing an incident. Typically, distribution or transmission field personnel take the on-site lead and communicate via a text message or a direct call to the Dispatch Department. Claims department personnel go to the scene to assess potential liability and management will be informed. If the incident is deemed to be a crisis, the CMT will be activated after consultation with the officer on-call and the Emergency Management Director. If the incident is deemed to be a major event or disaster, the entire EOC will be activated.

Communications personnel and the Joint Information Center, or Public Information Officer (PIO) section, of the EOC, is responsible for developing and obtaining approval for the company's key messages, coordinating the company's response to the media, identifying the appropriate company spokesperson, and communicating to employees.

The PIO section takes the lead for communicating to customers directly or on a mass scale, and on the digital media communication strategy, including social media. Human Resources and Employee Communications (within the PIO Section) share responsibility for communicating to employees including determining key messages for situations that directly impact employees and/or company facilities.

Key Communications Tactics

In any crisis or disaster, following are the key tactics in developing an emergency communications strategy:

- Complete a thorough damage/situation/injuries assessment.
- Appoint a lead point person for both crisis management and crisis communications.
- Determine executive availability and identify media spokespeople at both the executive and management levels.
    - Determine the appropriate spokespeople for different events (e.g., media briefings, media updates, one-on-one interviews).
- Develop a communications response strategy.
- Create a strategy and action plan for communicating with the customers, media and employees throughout the crisis.
- Develop key talking points, including core message themes that potentially can be carried forward throughout the crisis. Include facts that reflect the status of the crisis and the company's response, as well as proactive steps taken by the company.
- Consult with Legal and the Executive Incident Commander, as well other relevant internal departments, to approve messaging.
- Determine most effective media channel(s) (i.e., radio (particularly KOGO), TV, newspapers and/or social media) given the nature of the situation.
- Develop news releases/media statements and employee updates (via e-mail, employee hotline, company intranet, digiboards, and/or voicemail) as necessary.
- Use of social media to help broaden communications reach. If media briefings are necessary, activate media check list which includes identifying a suitable briefing room or area clear of the incident area and procure necessary A/V equipment; arranging escorts for media within the building, to and from the media briefings;

coordinating with facilities and security on guest parking and access.

- Monitor ongoing media coverage and respond/adjust messaging as appropriate.
- Schedule regular updates for the crisis management team/EOC to share feedback from the media and other key stakeholders; discuss next steps in communications.
- Develop a PIO Section staffing schedule immediately for any crisis expected to require 24/7 response for the duration of the EOC activation.

Communications Triggers & Resulting Communications

Communications has identified five stages of an emergency event. These include:

- Phase 1: Monitoring evolving situation
- Phase 2: Crisis in progress
- Phase 3: Disaster in progress
- Phase 4: Wrap up
- Phase 5: Conclusion; return to business as usual

Following are the event triggers, information sources and resulting communications for each phase:

Phase 1: Monitor evolving situation

Event/Triggers:

- Notification of situation or media attention on key situation begins
    - Examples: Fire starts in service territory, employee arrest or allegations made against employee, facility or operations disruption, extreme weather warnings, etc.
- CMT/EOC/CMC not activated

Information Sources:

- EM Advisor
- Planning Section Chief
- Safety
- Human Resources
- Legal
- Executive Incident Commander at the EOC), and potentially
- Other appropriate Executive(s)
- Corporate Security
- Public Information Officer
- Customer Service Section Chief
- Liaison Officer
- Electric or Gas Commodity Chief, if warranted

Resulting Communications:

- No communications at this point
- Monitor situation (Fact finding to determine if communications needed)

Phase 2: Crisis in progress

Event/Triggers:

- Significant media attention on issue with little or no impact on employees, operations or facilities
    - Examples: widespread fires not affecting our systems, significant negative regulatory ruling or lawsuit, ethics violation (could involve employees)
- Impact on employees or facilities/equipment/system impact with little to no media attention

    - Examples: employee charged with significant crime, employee evacuations (numerous homes or facilities), police action involving SDG&E facilities (bomb, terrorist), employee shooting, pandemic affecting employees. Employee death(s) (excluding natural causes)
- EOC/CMC not activated
- Crisis Management Team activated

Information Sources:
- EM Advisor
- Planning Section Chief
- Safety
- Human Resources
- Legal
- Executive Incident Commander at the EOC and potentially other appropriate Executive(s)
- Corporate Security
- Public Information Officer
- Customer Service Section Chief
- Liaison Officer
- Electric or Gas Commodity Chief, if warranted

Resulting Communications:
- Public Information Officer:
    - Develop media talking points
    - Consider communicating on social media channels, if warranted
    - Consider updates on SDG&E NewsCenter
- Employee Communications:
    - Draft and issue initial employee communication typically via SDG&E Now, Sempra Now or Sempra News article (posted to PowerUp/SempraNet), facility digiboards or no employee communication

<u>Phase 3: Disaster in progress</u>

Event/Triggers:
- Significant media attention on issue
- Significant Customer attention on issue
- Significant facilities/equipment/system impact
- **EOC activated**
    - Examples: Major system disruption, potential for widespread fires (Red Flag Warning), widespread fires, earthquake or other major natural disasters, cyber-security incident.

Information Sources:
- EM Advisor
- Planning Section Chief
- Safety
- Human Resources
- Legal
- Executive Incident Commander at the EO and potentially other appropriate Executive(s)
- Corporate Security
- Public Information Officer
- Customer Service Section Chief
- Liaison Officer

- Electric or Gas Commodity Chief, if warranted

Resulting Communications:

- Joint Information Center, or PIO Section, develops communications strategy
- Communications:
    - Draft/update media talking points
    - Develop customer notifications messaging
    - Consider drafting news release
    - Ongoing updates on SDG&E NewsCenter
    - Consider holding news conference
    - Proactively call/email reporters/TV and radio stations
    - Respond to media inquiries
    - Communicate on appropriate social media channels
    - Consider video
- Initial employee communications:
    - SDG&E Now or Sempra Now to all or targeted management.
    - Include situation update report, links for more information, company response (HR response, media talking points/statement – if appropriate)
- Second employee communications:
    - Employee Emergency Hotline message (Human Resources is responsible for drafting and recording this message)
    - SDG&E Emergency Update or Sempra Emergency Update with overview of situation and when/what types of information will be communicated in the future (i.e., how this event impacts employees and their work, or the company and its services resulting from the event)
- Additional employee communications:
    - Digiboard (if appropriate) summary
    - PowerUp or SempraNet site to house all future information if the event is big enough, including links to government and media sources
    - Sempra News article (to post on PowerUp/SempraNet)
    - Secure photographer and videographer for b-roll/photo

Phase 4: Wrap up

Event/Triggers:

- Incident wrapping up
- Begin to return to business as usual

Information Sources:

- EM Advisor
- Planning Section Chief
- Safety
- Human Resources
- Legal
- Executive Incident Commander at the EOC and potentially other appropriate Executive(s)
- Corporate Security
- Public Information Officer
- Customer Service Section Chief
- Liaison Officer
- Electric or Gas Commodity Chief, if warranted

Resulting Communications:

- Communications:
  - Draft final wrap up talking points
  - Draft final news release recapping event
  - Draft final SDG&E NewsCenter update
  - Complete media interviews
  - Consider holding news conference to close event
  - Final communication on appropriate social media channels
- Employee Communications:
  - Wrap up employee communication via SDG&E Emergency Update, Sempra Emergency Update, Sempra News article, or intranet post (PowerUp or SempraNet)
  - Potential Executive communication to employees (via email or hard copy)
  - Potential employee video
  - Post updates on digiboards

Phase 5: Conclusion; return to business as usual (revert to Phase 0)

Event/Triggers:

- Incident ends
- Back to business as usual

Information Sources *(some or all of the positions below may contribute depending on response scaling)*

- EM Advisor
- Planning Section Chief
- Safety
- Human Resources
- Legal
- Executive Incident Commander at the EOC and potentially other appropriate Executive(s)
- Corporate Security
- Public Information Officer
- Customer Service Section Chief
- Liaison Officer
- Electric or Gas Commodity Chief, if warranted

Resulting Communications:

- No communications

Staffing

PIO Section responders are on call to respond to company emergencies. Each member of the team would fill communications roles on the CMT or in the EOC/JIC if activated.

In the event of a large scale, sustained emergency, SDG&E and Southern California Gas Company have a mutual agreement to provide personnel support as needed during a sustained emergency.

Company Media Spokespeople

In the immediate aftermath of a crisis affecting SDG&E, in accordance with the Corporate and SDG&E Media Policy, no employee should speak directly to the media without first getting clearance from the Public Information Officer (PIO). The PIO will consult with members of SDG&E’s and/or corporate crisis management team to determine the appropriate spokesperson, the strategy and timing for responding to the media, as well as the content of any company response.

Media should be referred directly to SDG&E’s media hotline, 877-866-2066.

Key management personnel may be called upon by PIO and the crisis management team to act as corporate spokespeople with the media. Anyone serving as a media spokesperson should have received professional media training in advance. Media Relations, within Corporate Communications, is responsible for coordinating professional media training for key personnel.

See appendix for Media Spokesperson guidelines.

Appendix

Crisis Communication Management:

Every incident is unique. However, there are certain key principles of which you must be aware in the event of a crisis. These principles underlie the successful management and containment of most corporate crises. They include the following:

- *Define the real problem and determine strategy accordingly.*

  Make certain that the core problem is being addressed. Once this problem has been defined, we can determine the objectives of the crisis management process and the strategy necessary to drive this process.

- *Manage both the internal and external flow of information.*

  Companies often focus on managing the external flow of information in a crisis. However, it is equally important to manage the internal flow of information. This involves keeping internal audiences informed and providing them with the facts.

- *Assume the situation will escalate and get worse.*

  Understand that the situation is going to get worse. Be careful not to be overly optimistic or make categorical public statements early in a crisis.

- *Understand the media interest in your story.*

  Although the media is the prime driver of most crises, no company should rely on the media to deliver its message. Reporters tend to delight in the crisis environment in a way that is not helpful to a company and its executives.

- *Remember all your stakeholders.*

  During a crisis, companies often overlook direct communications to affected stakeholders. SDG&E should employ the best technology at its disposal to communicate effectively with all its stakeholders.

- *Measure results.*

  It is imperative for SDG&E to measure continually the effectiveness of its crisis management tactics to assess the overall effectiveness of its management strategy. Monitoring customer engagements, reaching out to key customers or officials, local and state agencies, community-based organizations, and analyzing media coverage can quickly generate useful data regarding the public perception of a crisis within 48 hours of its unfolding.

Evaluating the Situation:

What at first may seem to be a simple and controlled situation can easily become media fodder if it is not handled properly. And sometimes when a situation is handled to the best of our abilities, the media may still seize upon it if it's a "slow" news day. Take the following steps to evaluate the seriousness of a situation in the eyes of the media:

1) Source of information

- Have you personally been notified of this situation on an individual basis? (Internal situation affecting a small number of people)
- Were you alerted by SDG&E (Internal situation affecting a large number of people)
- Has the public notified you of this situation? (External situation affecting a small or large number of people)
- Has the media notified you of this situation? (External situation affecting a large number of people)
    - Were you alerted by local agencies? (External situation affecting a small or large number of people)

2) Parties impacted

- Employees
- Families of employees
- Sempra Shareholders
- SDG&E Business partners
- Customers
- Public at-large
- Public Safety Partners
- Law enforcement

3) Surrounding events

- Has this situation happened before? How recently and what was the outcome?
- Are there any other events that might have a bearing on this situation?
- Has a third party verified SDG&E credibility, training, certification, safety, etc., related to this situation? (i.e., the CPUC, CalOES, OSHA, etc.)

4) Outside interest

- Is the situation a private or public incident?
- Is a third party involved in or have access to information about the incident?
- Is it important for others (employees, customers, etc.) to know?

5) Media interest

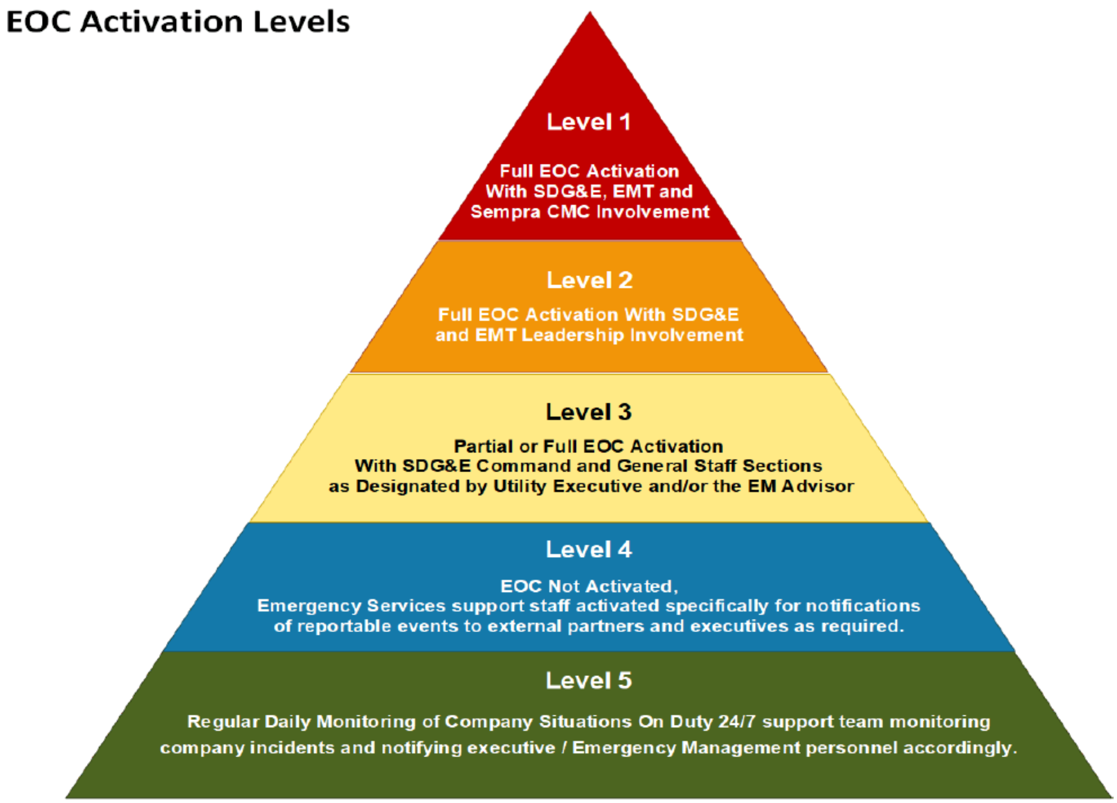
- Based on these factors, is it likely that media will be interested?
- What else is going on in the city/state/nation/world? Could this situation attract readers/viewers?
- Is the situation already being reported on/have reporters already called?

Situation Level – EOC Activation Levels:

Based on the answers to the previous questions, the situation can be labeled as one of the following. These also correspond with the five Emergency Operations Center Activation Levels (Figure 1) as outlined in the 2021 Company Emergency and Disaster Preparedness Plan (CEADPP):

LEVEL	COMMUNICATION CHARACTERISTICS
1-2 SEVERE TO CATASTROPHIC	• Media have immediate and urgent need for information about the crisis. CEO/COO or other designated Executive may need to provide opening statement of empathy/caring
	• One or more groups or individuals express anger or outrage
	• Broadcast and print media appear on-site for live coverage and allegations of criminality or threat to public safety; active opposition to SDG&E, financial impact; and or the threat of the filing of serious criminal charges; major disruption to Company operations, include cyber-security incident
3 SERIOUS	• Crisis causes growing attention from local and regional media
	• Media contacts SDG&E about the crisis
	• In addition to the media, stakeholders and community partners are present at site
	• Affected and potentially affected parties threaten to talk to the media
4 ACTIVE MONITORING	• Crisis situation may/may not have occurred; the situation is attracting slow, but steady media coverage.
	• External stakeholders (e.g., Local, CalOES, CPUC or Federal regulators) receive media inquiries.
	• The public at large is aware of the situation/event but is attracting very little attention and no widespread impact
5 DAILY MONITORING	• Crisis attracts little or no attention
	• Limited impact, comment and public disclosure
	• Public and/or media are virtually unaware of issue(s)

Figure 1. Emergency Operations Center (EOC) Activation Levels.



Hour One of incident:

STEP 1 - Determination of Crisis Communications

1) What are the facts of the incident?
2) What data/research can we use to discuss/communicate this incident?
3) Are there any extenuating circumstances we should be aware of?
4) What action, if any, are the other parties involved planning to take?
5) Who will be affected by this incident?
6) What is the magnitude of the incident?
7) Has the media already picked up the story? If so, what is being reported?
8) Are there any professional symposia/outside speaking engagements, internal meetings, or other events being held that might need to be postponed or that would require some change in content?
9) What other holes are there in our information that need to be filled?
10) Is any part of this situation confidential or affect customer privacy?
11) What key points should be included in the general statement to be prepared?
12) Will SDG&E need to collaborate with any outside authorities/agencies on our communications?

Parties Impacted:

In response to a crisis, SDG&E may need to communicate with some or all of the following parties. Specific audiences – and the order in which each is contacted – will vary according to the situation. However, it is important to remember the various constituencies with which SDG&E works and ensure each group is notified.

- **Notify employees.** Maintaining employee morale (and production) is often critical during a crisis. Employees can also serve as important ambassadors with a company's external constituencies. It's important, therefore, that employees be kept informed of company positions during a crisis with clear and accurate information. If possible, notify employees before public disclosure of any crisis development. It's better that an employee hears about a problem from the Company rather than from a (possibly biased) news report. As a company's front-line ambassadors, they need to be informed immediately about the crisis and of all developments.

- **Brief customer care center (CCC) specialists.** Customers who hear about a situation involving SDG&E will most likely utilize the customer service number in an attempt to find out additional information. CCC specialists should be briefed as quickly as possible and provided with appropriate message points in order to answer customers.

- **Notify customers.** A problem with our trucks, operations or infrastructure will mean a problem for our customers. Keep them informed of all relevant developments that impact their service through the dissemination of accurate and timely information. As a general rule, the company should attempt to limit direct contact to affected customers only (consider direct or regional announcements).

- **Contact your officials**. This is important when the support of local and state officials can be critical.

- **Contact the appropriate government agencies.** These contacts are especially important in cases involving safety. Many response decisions will, in fact, be made jointly with these authorities.

- **Work with Sempra Executive Team, Corporate Communications and Investor Relations to reach out to shareholders and board members. In collaboration with Sempra,** carefully craft messages for the financial audience to ensure that questions are addressed, and confidence in SDG&E performance is maintained.

- **Contact and brief third-party spokespeople.** Outside spokespersons such as a safety consultant or public relations firm could be retained, briefed and media-trained in advance so they can respond quickly and effectively when needed.

- **Brief the media.** How a company handles media inquiries affects the way news about that company is reported. In addition, journalists such as editorial writers, columnists and other influential reporters can strongly influence public opinion. A company should strive for honesty and fairness in its dealings with the press.

- **Contact industry influencers.** Support of the industry or notification to them about an issue that might affect them is critical.

Field Incident Response Guidelines
Identify examples of a field incident that would require this amount of coordination and communication short of EOC activation (field vehicle in traffic accident with customer injuries and resulting traffic issues, attack on an employee by a customer, major outage

in downtown San Diego with system damage, operations incident leading to high call center volume, broken and blowing gas line causing evacuations).

The Public Information Officer may first learn of an incident from the Field Dispatch Department, the Customer Care Center, EOC staff or from Field Operations Leadership. .

When an incident occurs in the field, field personnel normally are the first to be informed and the first responders from SDG&E. As soon as possible, the Utility Field Commander at the scene completes an initial assessment of the situation and the Field Dispatch Department or Emergency Operations Services personnel are notified. A larger distribution list is then contacted, including the Media On-Duty or Public information Officer.

Media may be on the scene and reporting the incident even before SDG&E representatives arrive because the media monitor police and fire department scanners so they know immediately when police or fire personnel are called out.

Many incidents reported through the Field Dispatch Department are routine investigations that show there is no SDG&E involvement or are unlikely to attract media attention. If the incident appears to involve significant damages or injuries and might attract the media or if media is already present at the scene, the Media On-Duty or designated media representative will take the lead in developing strategy and talking points for responding to the media.

If the incident attracts major media coverage and there is media on-scene, at the request of the SDG&E Utility Field Commander, an SDG&E media representative will go to the scene to respond to media who are covering the incident "live" and will coordinate with the Public Information Officer to determine the plan for responding to the media, develop and obtain approval of the messages, respond to media inquiries that come in by phone and, if the incident goes on long enough, arrange for backup coverage.

Upon arrival on scene, the SDG&E media representative will check into the SDG&E Incident Command Post and report to the Utility Field Commander.

- Check media outlets to see how the incident is being reported.
  - Scan social media, the online editions of local major media and the Union Tribune San Diego and other local papers and blogs. This often provides a gauge of how the incident will be covered throughout its duration.

- Develop and obtain approval for talking points.
  - Based on information obtained, the field media representative will develop the response to the media, in coordination with the PIO, who will obtain approvals, from Legal, and the On-Duty Utility Incident Commander (Executive).)
  - Under no circumstances should the field media representative speculate on what may or may not have happened.
  - Update and distribute talking points as new information becomes available.

- Provide management, Customer Care Center and CMT/EOC responders with approved messages and media interest if appropriate.

- Determine if it is appropriate to share incident information on social media.
  - If the incident is getting major media attention or has affected a significant number of customers, it is appropriate to provide updates via

Twitter.

- Determine if it is appropriate to draft an employee communication about the incident.

Communications Team Roster *(Updated April 1, 2023)*

Name	Phone	Email
[redacted] (PIO)	[redacted]	[redacted]
[redacted] (PIO)	[redacted]	[redacted]
[redacted] (Media Representative)	[redacted]	[redacted]
[redacted] (Media Representative)	[redacted]	[redacted]
[redacted] (Spanish Media Representative)	[redacted]	[redacted]
[redacted] (Media Representative)	[redacted]	[redacted]
[redacted] (Media Representative)	[redacted]	[redacted]
[redacted] (Admin)	[redacted]	[redacted]

Media Spokesperson Guidelines
For anyone who is called upon to be a corporate media spokesperson, as pre-approved by Public Information Officer, the following guidelines apply:

- Stick closely to company message points. Don't speculate or stray into other issues outside your expertise. Don't respond to hypothetical questions.

- Never say "No comment." Saying so makes you appear guilty or evasive.

- Always try to frame answers in positive terms, rather than negatives or double- negatives.

- If you don't know or are not sure, say so. Don't guess at an answer.

- Always be truthful and empathetic. This doesn't mean that you have to relay everything you know, but it does mean that the information you provide should be, to the best of your knowledge, truthful and accurate.

- In any situation requiring intervention by police, fire or other state or federal emergency services personnel, *these officials should take the lead with the media*. The crisis management team/Incident Command Team will be coordinating with these agencies and the company will provide comment to the media at the appropriate time.

- When discussing an incident with the media, it is important not to speculate about who's at fault, as this often becomes central to any investigation and future litigation.

- Be aware that anything you say can and should be considered on the record, regardless of what reporters promise you. Unless authorized by the Public Information Officer to speak on background, don't do so.
- Stay professional and be calm when dealing with reporters. Don't get combative or argumentative; however, it is OK to firmly correct misstatements of facts or inaccurate assumptions by reporters. Deliver your talking points and the basic facts of the situation. Maintain control of the interview.
- In any serious situation, avoid humor in your interchanges with the media. Instead, focus on demonstrating concern and empathy for the situation.
- Don't comment on others' speculation relayed to you by reporters. If you haven't directly heard or read what others have said, then you cannot verify that it is accurate and you shouldn't comment.

General Company Facts (boilerplate)

SDG&E is an innovative San Diego-based energy company that provides clean, safe and reliable energy to better the lives of the people it serves in San Diego and southern Orange counties. The company is committed to creating a sustainable future by providing its electricity from renewable sources; modernizing natural gas pipelines; accelerating the adoption of electric vehicles; supporting numerous non-profit partners; and, investing in innovative technologies to ensure the reliable operation of the region's infrastructure for generations to come. SDG&E is a subsidiary of Sempra (NYSE: SRE). For more information, visit SDGEnews.com or connect with SDG&E on Twitter (@SDGE), Instagram (@SDGE) and Facebook.

Crisis Communication Plan Updates

The plan is reviewed annually by the Marketing and Communications department and updated as needed to meet changes in regulatory requirements and recommendations resulting from training, exercises, and After-Action Reports. Any changes are recorded in the Record of Changes table below.

Date Reviewed	Reviewer Name	Revised Pages	Updated due to lesson learned or regulatory requirements (Y/N)	Notes
6/17/2021	[redacted]	15, 16	N	Updated team members on the roster and updated phone numbers and email addresses
1/21/2022	[redacted]	15, 16	N	Updated team members on the roster and updated phone numbers and email addresses. Additional JIC specifications.
4/21/2022	[redacted]	3-6, 8-12,14-15, 17-22	N	Changed operational and position definitions, communications methods and tactics, Situation and EOC Activation Levels and information sources
2/20/2023	[redacted]	15	N	Updated Comms Team Roster and contact information
4/19/2023	[redacted]	15	N	Updated Comms Team Roster contact information and boilerplate messaging.

PIO Section Checklist
ACTIVATION LEVEL: 2 and above

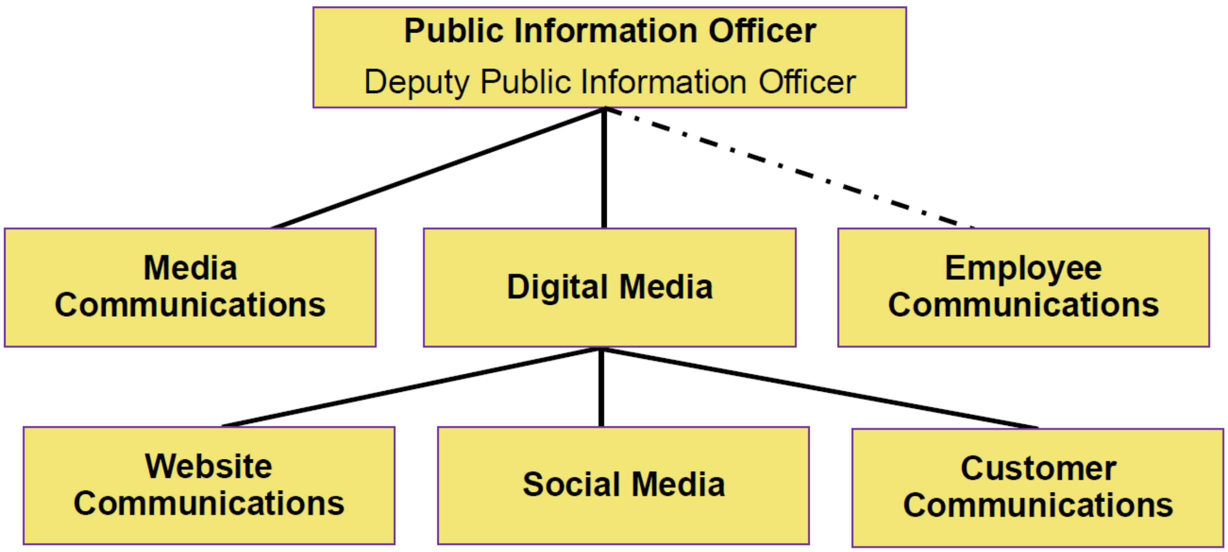
Public Information Officer (PIO) Responsibilities:
Position Summary: The role of the Public Information Officer (PIO) is to provide OneVoice talking points for the Utility Commander of the organization(s) involved in the emergency response. The PIO is responsible for interfacing and providing incident information to be used for the public, media, internal stakeholders, other agencies, etc. ▪ Reports to the Utility Commander. ▪ Assume responsibility for safety, security and staffing needs of communications section during an emergency incident. Coordinate or maintain communications with PIOs for key agencies (CAL FIRE/San Diego County Fire Authority and local governments) as needed. ▪ Support the Utility Commander to address Media, Social Media, Customer Communications emergency response activities, including developing and updating talking points, addressing misinformation and coordinate with the Social Media Unit to track media and social media responses. ▪ Provide management, guidance and oversight of EOC Communications section. ▪ Utilize the internal communications staff to facilitate Communications activities. ▪ Communicate activities to other Section Chiefs. ▪ Top Priorities: Develop the overall response communications strategy. Make sure the information provided about SDG&E's system and employees is <u>accurate and has gone through the appropriate approval process</u>.

Section A: Getting Started		
1.	Check ins - Upon arrival, check in with the Utility Commander and with the on-duty communications section responders.	
2.	Check in with Section Chiefs - *Incident Start-up:* Identify Critical Media, Social Media, Employee Communications, and Customer Communications issues in working with other Section Chiefs, time permitting. <u>Note</u>: Information will also be obtained in the operational briefing which is typically within 30 to 45 minutes after EOC activation and/or start of operational period. *Shift Relief:* Check in with the current Public Information Officer to obtain briefing.	
3.	Microsoft Teams Channels – Log in to Microsoft Teams with company account. ▪ Ensure access to the SDG&E EOC and EOC PIO Teams channels and appropriate folders ▪ Ensure each representative in the PIO section is able to sign in and obtain access to appropriate channels and folders	
4.	Meet with the PIO Section Coordinators - Provide an update based on operational briefing information. ▪ <u>Level 2 Activation:</u> Report to EOC: PIO, Social Media Coordinator and Media Communications Coordinator. Can scale up or down at of PIO. ▪ <u>Level 3 Activation:</u> Report to EOC: PIO, Social Media Coordinator, Media Communications Coordinator, Customer Communications Coordinator. Can scale up or down at discretion of PIO. ▪ <u>Level 4 Activation:</u> Report to EOC: PIO, Social Media Coordinator, (Media Communications Coordinator, Customer Communications Coordinator, Web Lead). Can scale up or down at discretion of PIO.	

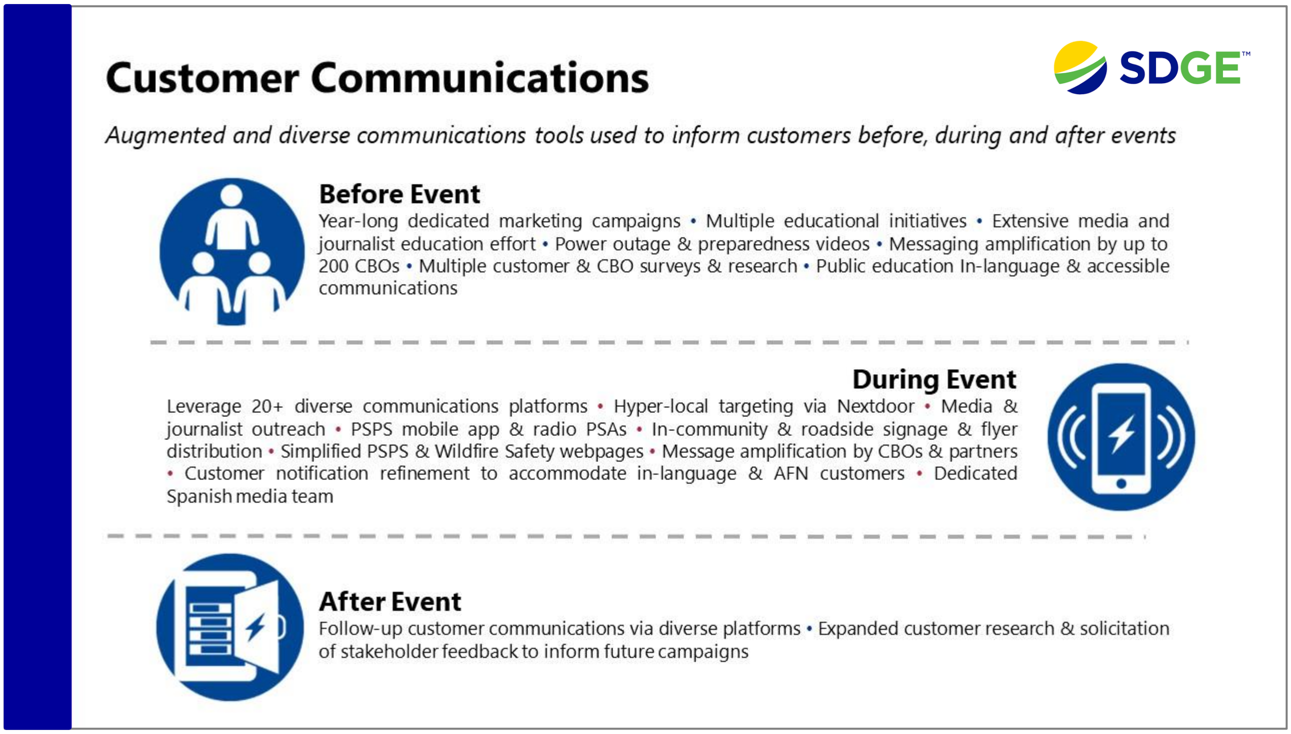
a)	Position Coverage – Ensure all positions needed in the PIO Section are staffed according to needs of the incident. Coordinate with Communication Section Position Leads to create a staffing schedule and make any necessary adjustments.	
b)	Current Information – Confer with the other EOC Section Chiefs whom you will need to interact with to prepare for EOC operational briefings and as needed during the operational period	
Section B: Operational Period Briefing		
c)	Utility Commander guidance and direction - Conduct assessments regarding needs based on direction from Utility Commander. • Review the Utility Commander Briefing Checklist. Refer to Section D for additional assessment and Situation Report guidelines. • Consult with Social Media Coordinator to obtain update on social media strategy for the incident • Consult with other Section Chiefs as needed.	
Section C: Assessment, Control and Mitigation		
d)	Type of Assessment - Determine the type of assessment needed as defined by Utility Commander and identify potential support requirements. Gather assessment information on Communications Section issues. Considerations: • What kind of emergency (i.e., natural disaster, major weather event, power outage, gas leak, cyber or physical attack)? • Determine which type of communication platforms and media outlets would be most effective to communicate incident information to customers. • Prioritize media audience: o Radio (San Diego's Emergency Broadcast System is KOGO-AM 600) o TV o Newspaper/Online News Sources o Social Media (Twitter, Nextdoor, Facebook groups, bloggers etc.)	
e)	Identify and Resolve Issues • Get system status from the appropriate Section Chief as to any outages. For electric outages, included circuit, location, cause, number of customers, estimated restoration time and any other available info that would be of interest to leadership/media and EOC personnel. • If a PSPS incident, distinguish between PSPS related outages and non-PSPS related outages and manage communications accordingly.	
f)	Additional Considerations • Approve all media communications, including but not limited to, media statements, advisories/news releases/talking points & other content as needed. • Ensure review and approval by the Legal Section Chief and Utility Commander. • Provide approved talking points to Communications Section: Social Media Coordinator, Media Coordinator, Customer Communications Coordinator and Web Coordinator. • Provide approved talking points to appropriate Section Chiefs for further dissemination. • Keep Communications' decision log and hand off to PIO relief. • Manage news conference(s), when required. • Monitor recovery effort, prepare for "second day" follow-up & ensure staffing as needed in coordination with Communications Section Unit Leads. • Lead "lessons learned" debriefing process post-EOC activation.	

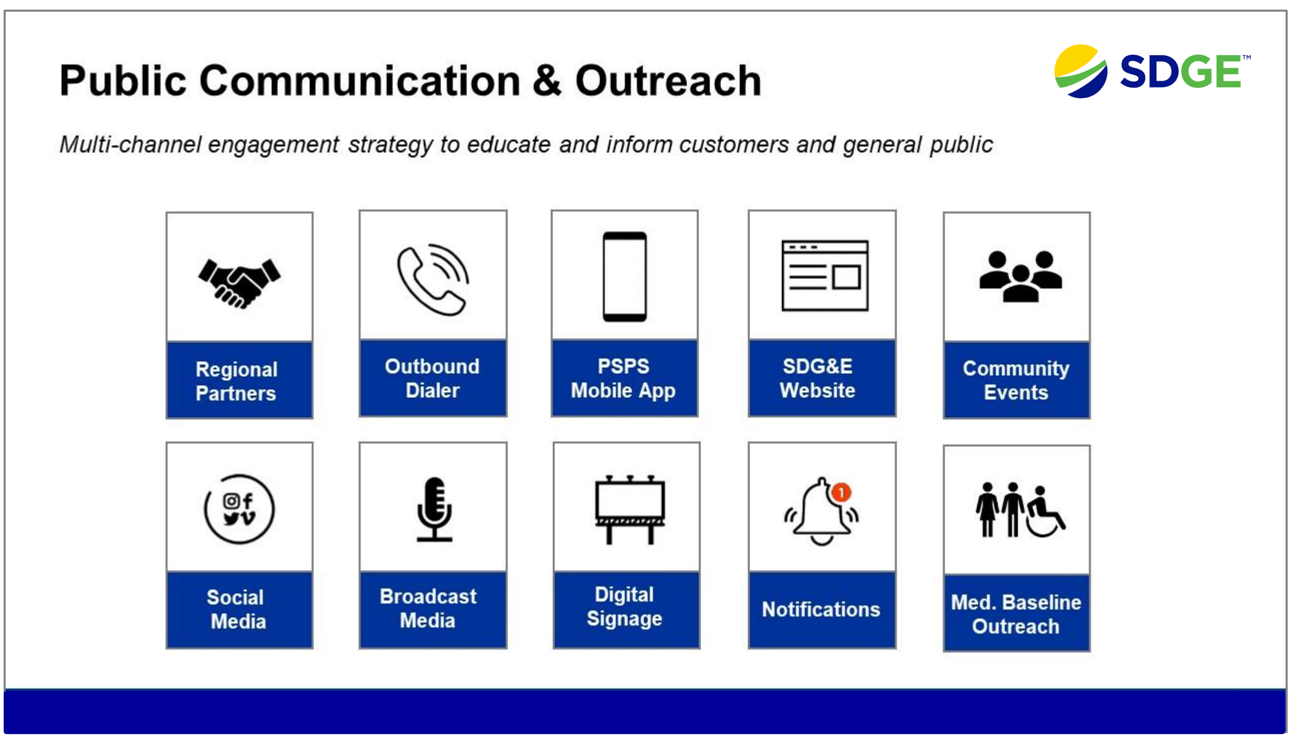
g)	Document Assessments – Provide necessary updates for the EOC Incident Action Plan.	
h)	Follow up on and/or delegate out tasks in response to ad hoc requests that may be requested by Utility Commander or other Section Chiefs during the course of an event. Be prepared to report on status during the EOC Operational Briefing.	
i)	Monitor Situation Updates	
Section D: Periodic Updates		
j)	Incident Action Plan - Review the Incident Action Plan for the current operational period Ensure the Incident Action Plan include updates, new issues, and long-range issues (12 hours or longer). Coordinate with Communication Section Coordinators and prepare for the operational briefing to include updates on *incidents, bulletins, issues or concerns.*	
k)	Significant Events – Based on assessments, identify significant events and ensure those are recorded in the Incident Action plan for the operational period.	
l)	Operational Period Briefings - Participate in Operational Period Briefings. Update talking points accordingly and distribute.	
m)	Post Operational Period Briefing - Brief and communicate to the Communications Section on Operational Briefings.	
n)	Update and post status report in Teams as necessary.	
Section E: Ongoing Recovery/Restoration Processes		
o)	Action Plans - Continue to communicate and track Communications Section action plan progress, including Social Media.	
p)	Executing Plans - Ensure Communications Section Coordinators are identifying action items, developing and executing action plans. Manage updating appropriate logs and boards.	
q)	Issue Resolution - Resolve issues impacting Communications Section action plans.	
r)	EOC Activities and Information - Relay requests for assistance to/from other Sections and provide pertinent information to other Section Chiefs.	
s)	Shift Management - Ensure PIO shift coverage. Ensure Communications Section Coordinators have identified shift coverage as well. (Refer to the Shift Management Template)	
Section F: Resources		
t)	Contact Phone Numbers for EOC Staff	
u)	Satellite Phone Directory – List of all satellite phones at both SDG&E and SCG.	
v)	Shift Schedule Example – Example of ES SL Shift Schedule management.	
w)	Utility Commander Guidance Document	

Joint Information Center /PIO Section Organization



Customer Communications & Outreach





Appendix 4:
Mutual Assistance Agreement Among Members of the California Utilities Emergency Association (CUEA)

MUTUAL ASSISTANCE AGREEMENT
(Electric and Natural Gas)

AMONG

MEMBERS OF THE
CALIFORNIA UTILITIES EMERGENCY
ASSOCIATION

TABLE OF CONTENTS

0. DEFINITIONS

As used herein, unless otherwise indicated, the following terms are defined as set forth below.

0.1 Activation: The initiation of the Assistance and administrative process of this Agreement including: request for Assistance, assessing and communicating the scope of assistance request, assessing and communicating the resources available for Assistance, activation procedures, mutual assistance coordination, and other processes and procedures supporting the Mobilization of Assistance resources.

0.2 Assistance: Includes all arrangements and preparation for and the actual mobilization of personnel, material, equipment, supplies and/or tools or any other form of aid or assistance, including all related costs and expenses as set forth in this Agreement, provided by an Assisting Party to a Requesting Party, from the time of the official authorization by the Requesting Party and including the return and demobilization by an Assisting Party of its personnel and equipment, also as set forth in this Agreement.

0.3 Deactivation: The termination of the Assistance and administrative process including: notification of Deactivation, Demobilization planning, identification of applicable costs, processes and procedures supporting Demobilization of resources, provide for invoicing, audit, critique information, and closure of the Assistance.

0.4 Demobilization: The actual returning of all Assistance resources to the Assisting Party's normal base.

0.5 Emergency: Any unplanned event that, in the reasonable opinion of the Party to this Agreement, could result, or has resulted, in (a) a hazard to the public, to employees of any Party, or to the environment; (b) material loss to property; or (c) a detrimental effect on the reliability of any Party's electric or natural gas system. The Emergency may be confined to the utility infrastructure or may include community-wide damage and emergency response. An Emergency may be a natural or human caused event.

0.6 Mobilization: The actual collecting, assigning, preparing and transporting of all Assistance resources.

0.7 Mutual Assistance Liaison: The person(s) designated by the Requesting Party, and Assisting Party, to coordinate all administrative requirements of the Agreement.

0.8 Natural Gas or Gas: The term "natural gas" as used in this Agreement shall include all commercially available forms of natural gas including Synthetic Natural Gas.

0.9 Operations Liaison: As described in Section 3.18, the person or persons designated by the Requesting Party to provide direct contact, communications and coordination at the operations level for Assisting Party's crews and resources at the location of the assistance. This may include but is not limited to: contact and communications for assisting crews, safety information processes and procedures, ensuring coordination of lodging and meals, addressing issues of Equipment requirements, materials requirements, and other logistical issues necessary to ensure safe effective working conditions.

0.10 Qualified: The training, education and experience of employees completing an apprenticeship or other industry / trade training requirements consistent with Federal Bureau of Apprenticeships and Training, Department of Transportation Pipeline Safety Regulations, or other recognized training authority or regulation. Training and qualification standards and are the responsibility of the Requesting Party to evaluate, in advance, the acceptable level of qualification for trade employees (i.e. lineman, electrician, fitter, etc.).

0.11 Work Stoppages: Any labor disputes, labor union disagreements, strikes, or any circumstance creating a shortage of qualified labor for a company during a non-emergency situation.

MUTUAL ASSISTANCE AGREEMENT
(Electric and Natural Gas)

1. PARTIES

This Mutual Assistance Agreement (hereinafter referred to as "Agreement") is made and entered into effective September 15, 2005. Each Party is, and at all times it remains a Party, shall be a member in good standing of the California Utilities Emergency Association. Each of the parties that has executed this Agreement may hereinafter be referred to individually as "Party" and collectively as "Parties." The Parties to this Agreement are listed in Attachment "A" hereto.

2. RECITALS

This Agreement is made with reference to the following facts, among others:

2.1 Certain of the Parties to this Agreement entered into a prior agreement ("Prior Agreement") dated December 16, 1994 to provide one another with mutual assistance. This Prior Agreement set forth procedures governing the requesting and providing of assistance in the restoration of electric and/or natural gas service. It is the intention of the Parties that this new Agreement, when signed by the Parties shall be effective for requesting or providing Assistance for the restoration of electric service following natural or man-made Emergencies which may occur on or after the date on which each of the Parties involved in the requesting or providing of Assistance signed this Agreement. Upon execution of this Agreement the Prior Agreement shall terminate, except that any rights or obligations which arose under the Prior Agreement shall remain unaffected by this new Agreement. Upon satisfaction of any such rights or obligations, the Prior Agreement shall be of no further validity or effect.

2.2 Being a Party to this Agreement does not by itself assure any Party that Assistance will be provided if, when or as requested. Each Party reserves the sole right to respond or not to respond to requests for Assistance on a case-by-case basis. By signing this Agreement, each Party thereby agrees that any Assistance which is received or given upon the request of a Party to this Agreement shall be subject to each and every one of the terms and conditions of this Agreement.

2.3 The Parties own, operate and maintain electric and/or natural gas utility facilities and are engaged in the production, acquisition, transmission, and / or distribution of electricity or natural gas.

2.4 Each of the Parties operates and maintains their respective facilities within accepted industry practices and employs skilled and Qualified personnel to operate, repair and maintain such facilities according to such industry practices.

2.5 It is in the mutual interest of the Parties to be prepared to provide for Emergency repair and restoration to such services, systems and facilities on a reciprocal basis. The purpose of this new Agreement is to provide the procedures under which one Party may request and receive assistance from another Party. This new Agreement is also designed to allow a new Party to join in the Agreement by signing a copy of this Agreement following the giving of notice to the existing Parties pursuant to Section 6.3 of this Agreement.

2.6 Assistance for labor shortages due to Work Stoppages are beyond the scope of this Agreement.

NOW, THEREFORE, in consideration of the mutual covenants and agreements contained herein, the Parties have mutually agreed effective on the date set forth on the signature page hereof and agree further as follows:

3. SCOPE OF ASSISTANCE

3.1 In the event of an Emergency affecting the electrical generation, electrical or natural gas transmission, distribution, and/or related facilities owned or controlled by a Party, such Party ("Requesting Party") may request another Party ("Assisting Party") to provide Assistance. The Assisting Party shall, in its sole discretion, determine if it shall provide such Assistance. If the Assisting Party determines to provide Assistance, such Assistance shall be provided in accordance with the terms and conditions of this Agreement.

3.2 Requests for Assistance may be made either verbally or in writing by the Authorized Representative of the Requesting Party and shall be directed to the Authorized Representative of the Assisting Party. Authorized Representatives of the Parties are identified in Attachment "B" hereto and shall be updated upon any change in such Authorized Representative. Upon acceptance of a request for Assistance either verbally or in writing, the Assisting Party shall respond with reasonable dispatch to the request in accordance with information and instructions supplied by the Requesting Party. All requests for Assistance shall follow the procedures described in Attachment "D". The Requesting Party shall also follow the procedures set forth in Attachment "E" for Deactivation of Assistance.

3.3 The Requesting Party shall provide the Assisting Party with a description of the work needed to address the Emergency, with the most urgent needs for Assistance addressed first. If the request is not based on a lack of resources, such information must be stated in the request. The Assisting Party shall use its reasonable efforts to schedule the Assistance in accordance with the Requesting Party's request. However, the Assisting Party reserves the right to recall any and all personnel, material, Equipment, supplies, and/or tools at any time that the Assisting Party determines necessary for its own operations. Any Requesting Party for whom an Operator Qualification (OQ) Program and/or Drug and Alcohol Program under 49 CFR Parts 192 and 199 respectively, is required should pre-screen the other Parties to this Agreement to determine which Parties have compatible regulatory agency accepted programs and may therefore be contacted for assistance. Parties to this agreement agree to make their programs and related records available for review to assist in the pre-screening.

3.4 The Requesting Party will provide the name and contact information for the person(s) designated as the Mutual Assistance Liaison(s), the Operations Liaison(s) described in Section 3.18, and person(s) to be designated as supervisory personnel to accompany the crews and Equipment. The Assisting Party will provide the name(s) and contact information for the person(s) designated to be the Mutual Assistance Liaison and the Operations Liaison(s).

3.5 All Reasonable Costs and Expenses associated with the furnishing of Assistance shall be the responsibility of the Requesting Party and deemed to have commenced when the Requesting Party officially authorizes the Assisting Party to proceed with Mobilization of the personnel and Equipment necessary to furnish Assistance, and shall be deemed to have terminated after Demobilization when the transportation of Assisting Party personnel and Equipment returns to the work headquarters, individual district office, or home (to which such personnel are assigned for personnel returning at other than regular working hours) is completed.

For the purposes of this Agreement, a Requesting Party shall be deemed to have authorized the Assisting Party to proceed with Mobilization when the Requesting Party signs and submits a formal request to the Assisting Party, in a form substantially similar to that included as Attachment “F”. If written information cannot be furnished, a verbal confirmation will be acceptable, with a written confirmation to follow within 24 hours.

The Parties hereto agree that costs arising out of inquiries as to the availability of personnel, material, Equipment, supplies and/or tools or any other matter made by one party to another prior to the Requesting Party authorizing the Assisting Party to proceed with Mobilization, as set forth in this Section 3.5, will not be charged to the potentially Requesting Party.

3.6 For purposes of this Agreement, the term "Reasonable Costs or Expenses" shall be defined to mean those costs, expenses, charges, or outlays paid or incurred by an Assisting Party in any approved phase of rendering Assistance to a Requesting Party pursuant to the provisions of this Agreement. Reasonable Costs or Expenses shall be deemed to include those costs and/or expenses that are appropriate and not excessive; under the circumstances prevailing at the time the cost or expense is paid or incurred. Reasonable Costs or Expenses may include, but are not limited to, direct operating expenses such as wages, materials and supplies, transportation, fuel, utilities, housing or shelter, food, communications, and reasonable incidental expenses, as well as indirect expenses and overhead costs such as payroll additives, taxes, insurance, depreciation, and administrative and general expenses. Notwithstanding the above, any such Reasonable Costs or Expenses shall continue to be subject to the provisions of Section 5 of this Agreement regarding Audit and Arbitration.

3.7 The Assisting Party and Requesting Party shall mutually agree upon and make all arrangements for the preparation and actual Mobilization of personnel, material, Equipment, supplies and/or tools to the Requesting Party's work area and the return (i.e. Demobilization) of such personnel, material, Equipment, supplies and/or tools to the Assisting Party's work area. The Requesting Party shall be responsible for all Reasonable Costs or Expenses incurred by the Assisting Party for Mobilization and/or Demobilization, notwithstanding any early termination of such assistance by the Requesting Party.

3.8 Unless otherwise agreed upon in writing, the Requesting Party shall be responsible for providing food and lodging for the personnel of the Assisting Party from the time of their arrival at the designated location to the time of their departure. The food and housing provided shall be subject to the approval of the supervisory personnel of the Assisting Party.

3.9 If requested by the Assisting Party, the Requesting Party, at its own cost, shall make or cause to be made all reasonable repairs to the Assisting Party's Equipment, necessary to maintain such Equipment safe and operational, while the Equipment is in transit or being used in providing Assistance. However, the Requesting Party shall not be liable for cost of repair required by the gross negligence, bad faith or willful acts or misconduct of the Assisting Party.

3.10 Unless otherwise agreed the Requesting Party shall provide fuels and other supplies needed for operation of the Assisting Party's vehicles and Equipment being used in providing Assistance.

3.11 Unless otherwise agreed to by the Parties, the Requesting Party shall provide field communications Equipment and instructions for the Assisting Party's use. The Assisting Party shall exercise due care in use of the Equipment and return the Equipment to the Requesting Party at the time of departure in like condition; provided, however, if repairs are necessary the Requesting Party will be financially responsible unless such repairs are necessitated by the gross negligence, bad faith or willful acts or misconduct of the Assisting Party.

3.12 Employees of the Assisting Party shall at all times continue to be employees of the Assisting Party, and such employees shall at no time and for no purpose be deemed to be employees of the Requesting Party.

3.13 Wages, hours and other terms and conditions of employment applicable to personnel provided by the Assisting Party, shall continue to be those of the Assisting Party.

3.14 If the Assisting Party provides a crew or crews, it shall assign supervisory personnel as deemed necessary by the Assisting Party, who shall be directly in charge of the crew or crews providing Assistance.

3.15 All time sheets, Equipment and work records pertaining to personnel, material, vehicles, Equipment, supplies and/or tools provided by the Assisting Party shall be kept by the Assisting Party for invoicing and auditing purposes as provided in this Agreement.

3.16 No Party shall be deemed the employee, agent, representative, partner or the co-venturer of another Party or the other Parties in the performance of activities undertaken pursuant to this Agreement.

3.17 The Parties shall, in good faith, attempt to resolve any differences in work rules and other requirements affecting the performance of the Parties' obligations pursuant to this Agreement.

3.18 The Requesting Party and Assisting Party shall each provide an Operations Liaison to assist with operations, personnel and crew safety. These individuals shall be the link between the Parties and keep the crews apprised of safety, operational, and communication issues.

3.19 All work performed by the Parties under this Agreement shall conform to all applicable Laws and Good Utility Practices.

3.20 All workers performing work under this Agreement shall follow their own employer's established safety and other operation rules. Each Party will use its best reasonable effort to respect the safety and work practices of the other Party, and will at all times cooperate in the interest of the safety of both Parties. Where it is not possible for both Parties to safely and independently follow their own safety and work practices, field personnel will discuss and mutually agree upon the safety and work practices for both Parties for the particular work at issue

4. PAYMENT

4.1 The Requesting Party shall reimburse the Assisting Party for all Reasonable Costs and Expenses that are appropriate and not excessive, under the circumstances prevailing at the time the cost or expense is paid or incurred by the Assisting Party as a result of furnishing Assistance. Such costs and expenses shall include, but not be limited to, the following:

(a) Employees' wages and salaries for paid time spent in Requesting Party's service area and paid time during travel to and from such service area, plus the Assisting Party's standard payroll additives to cover all employee benefits and allowances for vacation, sick leave, holiday pay, retirement benefits, all payroll taxes, workers' compensation, employer's liability insurance, administrative and general expenses, and other benefits imposed by applicable law or regulation.

(b) Employee travel and living expenses (meals, lodging, and reasonable incidentals).

(c) Cost of Equipment, materials, supplies and tools at daily or hourly rate, including their normally applied overhead costs inclusive of taxes, insurance, depreciation, and administrative expenses. Cost to replace or repair Equipment, materials, supplies, and tools (hereinafter collectively referred to as the "Equipment", which are expended, used, damaged, or stolen while the Equipment is being used in providing Assistance; provided, however, the Requesting Party's financial obligation under this Section 4.1 (c): (i) shall not apply to any damage or loss resulting from the gross negligence, bad faith or willful misconduct of the Assisting Party, and (ii) shall only apply in excess of, and not contribute with, any valid and collectible property insurance which applies to such damage or loss.

(d) Cost of vehicles provided by Assisting Party for performing Assistance at daily or hourly rate, including normally applied overhead costs inclusive of taxes, insurance, depreciation, and administrative expenses. Cost to repair or replace vehicles which are damaged or stolen while the vehicles are used in providing

Assistance; provided, however, that Requesting Party's financial obligation under this Section 4.1 (d): (i) shall not apply to any damage or loss resulting from the gross negligence, bad faith or willful misconduct of the Assisting Party, and (ii) shall only apply in excess of, and not contribute with, any valid and collectible first-party physical damage insurance which applies to such loss.

(e) Administrative and general costs which are properly allocable to the Assistance to the extent such costs are not chargeable pursuant to the foregoing subsections.

(f) Overtime costs incurred by the Assisting Party in their service territory as a result of Assistance provided to the Requesting Party.

4.2 Unless otherwise mutually agreed to, the Assisting Party shall invoice the Requesting Party at the address designated on Attachment "B" for all Reasonable Costs and Expenses of the Assisting Party in one invoice. If the Assistance extends beyond a thirty (30) day period, invoicing can occur monthly unless otherwise agreed upon in writing. The Assisting Party shall provide the invoice in substantially the form set forth in Attachment "G".

4.3 The Requesting Party shall pay such invoice in full within sixty (60) days of receipt of the invoice, and shall send payment to the Assisting Party at the address listed in Attachment "B" unless otherwise agreed to in writing.

4.4 Delinquent payment of invoices shall accrue interest at a rate of twelve percent (12%) per year prorated by days until such invoices are paid in full.

5. AUDIT AND ARBITRATION

5.1 A Requesting Party has the right to designate its own qualified employee representative(s) or its contracted representative(s) with a management/accounting firm who shall have the right to audit and to examine any cost, payment, settlement, or supporting documentation relating to any invoice submitted to the Requesting Party pursuant to this Agreement.

5.2 A request for audit shall not affect the obligation of the Requesting Party to pay amounts due as required herein. Any such audit(s) shall be undertaken by the Requesting Party or its representative(s) upon notice to the Assisting Party at reasonable times in conformance with generally accepted auditing standards. The Assisting Party agrees to reasonably cooperate with any such audit(s).

5.3 This right to audit shall extend for a period of two (2) years following the receipt by Requesting Party invoices for all Reasonable Costs and Expenses. The Assisting Party agrees to retain all necessary records/documentation for the said two-year period, and the entire length of this audit, in accordance with its normal business procedures.

5.4 The Assisting Party shall be notified by the Requesting Party, in writing, of any exception taken as a result of the audit. In the event of a disagreement between the Requesting Party and the Assisting Party over audit exceptions, the Parties agree to use good faith efforts to resolve their differences through negotiation.

5.5 If ninety (90) days or more have passed since the notice of audit exception was received by the Assisting Party, and the Parties have failed to resolve their differences, the Parties agree to submit any unresolved dispute to binding arbitration before an impartial member of an unaffiliated management/accounting firm. Arbitration shall be governed by the laws of the State of California. Each Party to an arbitration will bear its own costs, and the expenses of the arbitrator shall be shared equally by the Parties to the dispute.

6. TERM AND TERMINATION

6.1 This Agreement shall be effective on the date of execution by at least two Parties hereto and shall continue in effect indefinitely, except as otherwise provided herein. Any Party may withdraw its participation at any time after the effective date with thirty (30) days prior written notice to all other Parties.

6.2 As of the effective date of any withdrawal, the withdrawing Party shall have no further rights or obligations under this Agreement except the right to collect money owed to such Party, the obligation to pay amounts due to other Parties, and the rights and obligations pursuant to Section 5 and Section 7 of this Agreement.

6.3 Notwithstanding Section 12, additional parties may be added to the Agreement, without amendment, provided that thirty 30 days notice is given to all Parties and that any new Party agrees to be bound by the terms and conditions of this Agreement by executing a copy of the same which shall be deemed an original and constitute the same agreement executed by the Parties. The addition or withdrawal of any Party to this Agreement shall not change the status of the Agreement among the remaining Parties.

7. LIABILITY

7.1 Except as otherwise specifically provided by Section 4.1 and Section 7.2 herein, to the extent permitted by law and without restricting the immunities of any Party, the Requesting Party shall defend, indemnify and hold harmless the Assisting Party, its directors, officers, agents, employees, successors and assigns from and against any and all liability, damages, losses, claims, demands actions, causes of action, and costs including reasonable attorneys’ fees and expenses, resulting from the death or injury to any person or damage to any property, which results from the furnishing of Assistance by the Assisting Party, unless such death or injury to person, or damage to property, is caused by the gross negligence or willful misconduct of the Assisting Party.

7.2 Each Party shall bear the total cost of discharging all liability arising during the performance of Assistance by one Party to the other (including costs and expenses for reasonable attorneys' fees and other costs of defending, settling, or otherwise administering claims) which results from workers' compensation claims or employers' liability claims brought by its own employees. Each Party agrees to waive, on it own behalf, and on behalf of its insurers, any subrogation rights for benefits or compensation paid to such Party's employees for such claims.

7.3 In the event any claim or demand is made, or suit or action is filed, against the Assisting Party, alleging liability for which the Requesting Party shall indemnify and hold harmless the Assisting Party, Assisting Party shall notify the Requesting Party thereof, and the Requesting Party, at its sole cost and expense, shall settle, compromise or defend the same in such manner as it, in its sole discretion, deems necessary or prudent. However, Requesting Party shall consult with Assisting Party during the pendency of all such claims or demands, and shall advise Assisting Party of Requesting Party’s intent to settle any such claim or demand. The Party requesting indemnification should notify the other Party in writing of that request.

7.4 The Equipment which the Assisting Party shall provide to the Requesting Party pursuant to Section 3 above, is accepted by the Requesting Party in an “as is” condition, and the Assisting Party makes no representations or warranties as to the condition, suitability for use, freedom from defect or otherwise of such Equipment. Requesting Party shall utilize the Equipment at its own risk. Requesting Party shall, at its sole cost and expense, defend, indemnify and hold harmless Assisting Party, its directors, officers, agents, employees, successors and assigns, from and against any and all liability, damages, losses, claims, demands, actions, causes of action, and costs including reasonable attorneys' fees and expenses, resulting from the death or injury to any person or damage to any property, arising out of the utilization of the Equipment by or for the Requesting Party, or its employees, agents, or representatives, unless such death, injury, or damage is caused by the gross negligence, bad faith or willful misconduct of the Assisting Party.

7.5 No Party shall be liable to another Party for any incidental, indirect, or consequential damages, including, but not limited to, under-utilization of labor and facilities, loss of revenue or anticipated profits, or claims of customers arising out of supplying electric or natural gas service, resulting from performance or nonperformance of the obligations under this Agreement.

7.6 Nothing in Section 7, Liability, or elsewhere in this Agreement, shall be construed to make the Requesting Party liable to the Assisting Party for any liability for death, injury, or property damage arising out of the ownership, use, or maintenance of any watercraft (over 17 feet in length) or aircraft which is supplied by or provided by the Assisting Party. It shall be the responsibility of the Assisting Party to carry liability and hull insurance on such aircraft and watercraft as it sees fit. Also, during periods of operation of watercraft (over 17 feet in length) or aircraft in a situation covered by this Agreement, the Party which is the owner/lessee of such aircraft or watercraft shall use its best efforts to have the other Parties to this Agreement named as additional insures on such liability coverage.

8. GOVERNING LAW

This Agreement shall be interpreted, governed and construed by and under the laws of the State of California as if executed and to be performed wholly within the State of California.

9. AUTHORIZED REPRESENTATIVE

The Parties shall, within thirty 30 days following execution of this Agreement, appoint Authorized Representatives and Alternate Authorized Representatives, and exchange all such information as provided in Attachment "B". Such information shall be updated by each Party prior to January 1st of each year that this Agreement remains in effect, or within 30 days of any change in Authorized Representative or Alternate Representative.

The Authorized Representatives or the Alternate Authorized Representatives shall have the authority to request and provide Assistance.

10. ASSIGNMENT OF AGREEMENT

No Party may assign this Agreement, or any interest herein, to a third party, without the written consent of the other Parties.

11. WAIVERS OF AGREEMENT

Failure of a Party to enforce any provision of this Agreement, or to require performance by the other Parties of any of the provisions hereof, shall not be construed to waive such provision, nor to affect the validity of this Agreement or any part thereof, or the right of such Parties to thereafter enforce each and every provision. This Agreement may not be altered or amended, except by a written document signed by all Parties.

12. ENTIRE AGREEMENT

This Agreement and the Exhibits referenced in or attached to this Agreement constitute the entire agreement between the Parties concerning the subject matter of the Agreement. It supersedes and takes the place of all conversations the Parties may have had, or documents the Parties may have exchanged, with regard to the subject matter, including the Prior Agreement.

13. AMENDMENT

No changes to this Agreement other than the addition of new Parties shall be effective unless such changes are made by an amendment in writing, signed by each of the Parties hereto. A new Party may be added to this Agreement upon the giving of 30 days notice to the existing Parties and upon the new Party's signing a copy of this Agreement as in effect upon the date the new Party agrees to be bound by each and every one of the Agreement's terms and conditions.

14. NOTICES

All communications between the Parties relating to the provisions of this Agreement shall be addressed to the Authorized Representatives of the Parties, or in their absence, to the Alternate Authorized Representative as identified in Attachment "B". Communications shall be in writing, and shall be deemed given if made or sent by e-mail with confirmation of receipt by reply email, confirmed fax, personal delivery, or registered or certified mail postage prepaid. Each Party reserves the right to change the names of those individuals identified in Attachment "B" applicable to that Party, and shall notify each of the other Parties of such change in writing. All Parties shall keep the California Utilities Emergency Association informed of the information contained in Attachment "B" and reply to all reasonable requests of such association for information regarding the administration of this Agreement.

15. GENERAL AUTHORITY

Each Party hereby represents and warrants to the other Parties that as of the date this Agreement is executed by the Parties: (i) the execution, delivery and performance of this Agreement have been duly authorized by all necessary action on its part and it has duly and validly executed and delivered this Agreement; (ii) the execution, delivery and performance of this Agreement does not violate its charter, by-laws or any law or regulation by which it is bound or governed, and (iii) this Agreement constitutes a legal, valid and binding obligation of such Party enforceable against it in accordance with the terms hereof, except to the extent such enforceability may be limited by bankruptcy, insolvency, reorganization of creditors' rights generally and by general equitable principles.

16. ATTACHMENTS

The following attachments to this Agreement are incorporated herein by this reference:

Attachment A Parties to the Agreement;

Attachment B Names and Address of Authorized Representative(s)/Invoicing;

Attachment C Custodianship of Agreement;

Attachment D Procedures for Requesting and Providing Assistance;

Attachment E Procedures for Deactivation of Assistance;

Attachment F Request for Assistance Letter;

Attachment G Invoice.

SIGNATURE CLAUSE

This Agreement may be executed in any number of counterparts, each of which shall be an original, but all of which together shall constitute one and the same agreement.

IN WITNESS WHEREOF, the Parties have caused this Agreement to be executed by their respective duly authorized officers as of the dates set forth below.

Company Name: San Diego Gas and Electric

Name of Officer: Scott Crider

Signature of Officer: Scott Crider

Title of Officer: Vice President - Customer Services

Date Executed: November 15, 2017

Company Name: Southern California Gas Company

Name of Officer: Gillian Wright

Signature of Officer: Gillian A Wright

Title of Officer: Vice President – Customer Services

Date Executed: November 16, 2017

ATTACHMENT A
March 2017

Parties to the Mutual Assistance Agreement
(Electric and Natural Gas)
Among Members of the California Utilities Emergency Association

- **Alameda Municipal Power (2011)**
  Jim Breuner Breuner@alamedamp.com
  Cellular Phone: 510-715-9821

- **Alpine Natural Gas (2007)**
  Mike Lamond mike@alpinenaturalgas.com
  Cellular Phone: 209-304-3206

- **Anaheim Public Utilities Department (2007)**
  Dennis Schmidt dschmidt@anaheim.net
  Cellular Phone: 714-493-7171

- **Anza Electric Cooperative, Inc (2013)**
  Brian Baharie brianb@anzaelectric.org
  Cellular Phone: 951-240-0555

- **Azusa Light & Water (2009)**
  Federico Langit Jr. flangit@ci.azusa.ca.us
  Cellular Phone: 626-812-5213

- **Bear Valley Electric Service (2012)**
  Paul Marconi paul.marconi@bves.com
  Cellular Phone: 909-202-9539

- **Burbank Water and Power (2010)**
  Cesar Ancheta cancheta@burbankca.gov
  Cellular Phone: 909-762-9291

- **Colton Public Utilities (2011)**
  Tim Lunt tlunt@ci.colton.ca.us
  Cellular Phone: 909-772-7877

- **Glendale Water and Power (2011)**
  Ramon Abueg rabueg@glendaleca.gov
  Cellular Phone: 818-262-7496

- **City of Healdsburg Electric Department (2011)**
  Todd Woolman twoolman@ci.healdsburg.ca.us
  Cellular Phone: 707-480-6485

- **Imperial Irrigation District (2012)**
  Gary Hatfield gdhatfield@iid.com
  Cellular Phone: 760-427-0744

- **Lassen Municipal Utility District (2011)**
  Brian Beem bbeem@lmud.org
  Cellular Phone: 530-249-6249

- **Lathrop Irrigation District (2013)**
  Glenn Reddick gmr5252@aol.com
  Cellular Phone: 916-712-2054

- **Liberty Energy (2011)**
  Randy Kelly randy.kelly@libertyutilities.com
  Cellular Phone: 775-636-3034

- **City of Lodi (2011)**
  C.J. Berry cberry@lodi.gov
  Cellular Phone: 916-549-4879

- **City of Lompoc (2010)**
  Tikan Singh t_singh@ci.lompoc.ca.us
  Cellular Phone: 805-315-7090

- **City of Long Beach (2010)**
  Stephen Bateman steve.bateman@longbeach.gov
  Cellular Phone: 310-892-5728

- **Los Angeles Department of Water and Power (2011)**
  Daniel Barnes daniel.barnes@ladwp.com
  Cellular Phone: 760-920-1288

- **Modesto Irrigation District (2011)**
  Ed Franciosa edf@mid.org
  Cellular Phone: 209-404-6847

- **City of Moreno Valley Electric Utility (2013)**
  Jeannette Olko: jeannetteo@moval.org
  Cellular Phone: 909-709-8676

- **Northern California Power Agency (2015)**
  Randy Howard: randy.howard@ncpa.com
  Cellular Phone: 916-878-0854

- **Pacific Gas & Electric Company (2012)**
  Evermary Hickey emhp@pge.com
  Cellular Phone: 415-271-8072

- **Pacific Power, a division of PacifiCorp (2010)**
  Debbie Guerra debbie.guerra@pacificorp.com
  Cellular Phone: 503-819-5449

- **City of Palo Alto (2010)**
  Dean Batchelor dean.batchelor@cityofpaloalto.org
  Cellular Phone: 650-444-6204

- **Pasadena Water and Power: Power Delivery (2009)**
  Jeff Barber jbarber@cityofpasadena.net
  Cellular Phone: 626-354-1450

- **Pittsburg Power Company dba Island Energy (2012)**
  Peter Guadagni pguadagni@ci.pittsburg.ca.us
  Cellular Phone: 925-726-9277

- **Plumas-Sierra Rural Electric Cooperative (2011)**
  Jason Harston jharston@psrec.coop
  Cellular Phone: 530-249-4605

- **Rancho Cucamonga Municipal Utility (2013)**
  Fred Lyn fred.lyn@cityofrc.us
  Cellular Phone: 909-243-2747

- **City of Redding – Redding Electric Utility (2009)**
  Dan Beans dbeans@reupower.com
  Cellular Phone: 530-410-3859

- **City of Riverside (2012)**
  Ron Cox rcox@riversideca.gov
  Cellular Phone: 951-237-0443

- **City of Roseville – Roseville Electric (2010)**
  Jason Grace jgrace@roseville.ca.us
  Cellular Phone: 916-532-9272

- **Sacramento Municipal Utility District (2011)**
  Jeff Briggs jeff.briggs@smud.org
  Cellular Phone: 209-996-8186

- **San Diego Gas & Electric Company (2011)**
  Danny Zaragoza dzaragoza@semprautilities.com
  Cellular Phone: 619-654-9525

- **San Francisco Public Utilities Commission (2011)**
  Mary Ellen Carroll mcarroll@sfwater.org
  Cellular Phone: 415-204-7873

- **City of Shasta Lake (2011)**
  Tom Miller Tom.miller@ci.shasta-lake.ca.us
  Cellular Phone: 530-917-9711

- **Silicon Valley Power, Electric Utility of City of Santa Clara (2011)**
  Kevin Kolnowski Kkolnowski@svpower.com
  Cellular Phone: 408-615-6686

- **Southern California Edison Company (2011)**
  Nancy Sacre sacrenm@sce.com
  Cellular Phone: 626-315-0680

- **Southern California Gas Company (2013)**
  Paul Smith psmith1@semprautilities.com
  Cellular Phone: 310-499-3441

- **Southwest Gas Company (2011)**
  Sam Grandlienard sam.grandlienard@swgas.com
  Cellular Phone: 760-953-9181
  Ed Estanislao Edgardo.estanisloa@swgas.com
  Cellular Phone: 702-498-2830

- **Truckee-Donner Public Utility District (2011)**
  Jim Wilson jimwilson@tdpud.org
  Cellular Phone: 530-448-3016

- **Turlock Irrigation District**
  Ron Duncan rgduncan@tid.org
  Cellular Phone: 209-541-7578

- **City of Ukiah (2011)**
  Tim Santo tsanto@cityofukiah.com
  Cellular Phone: 707-272-0350

- **Vernon Public Utilities (2013)**
  Todd Dusenberry tdusenberry@ci.vernon.ca.us
  Cellular Phone: 323-807-4261

- **Western Area Power Administration (2011)**
  Matt Monroe Monroe@wapa.gov
  Cellular Phone: 916-353-4633

ATTACHMENT B

Names and Address of Authorized Representative(s)/ Billing

Date ______________________
Name of Utility ______________________
Mailing Address ______________________
____

Individuals to Call for Emergency Assistance:

AUTHORIZED REPRESENTATIVE:

Name			
Title		Address	
E-Mail		Pager No.	
Day Phone		Night Phone	
FAX		Cellular	

ALTERNATE AUTHORIZED REPRESENTATIVE(S):

Name			
Title		Address	
E-Mail		Pager No.	
Day Phone		Night Phone	
FAX		Cellular	
Name			
Title		Address	
E-Mail		Pager No.	
Day Phone		Night Phone	
FAX		Cellular	

DISPATCH CENTER WITH 24-HOUR TELEPHONE ANSWERING:

Name			
Title			
Address			
Phone		Fax	

BILLING/PAYMENT ADDRESS:

Department of Utility ______________________
Billing/Payment Address ______________________
____
Telephone No. ______________________
Fax/Email

Information provided to 2016
CUEA Custodian:

ATTACHMENT C

Custodianship of Agreement

Responsibilities of the California Utilities Emergency Association's Mutual Assistance Agreement (Electric) Custodian are:

A. Request all Parties provide an annual update of the Authorized Representative and Alternate Authorized Representative, as identified in Attachment "B", no later than December 15 of each year.

B. Distribute annual update of Attachment "B" no later than January 15 of each year.

C. Coordinate and facilitate meetings of the parties to the Agreement, as necessary, to include an after action review of recent mutual assistance activations and document changes requested by any party to the Agreement. An annual meeting will also be held to review general mutual assistance issues.

D. Assist and guide utilities interested in becoming a party to the Agreement by providing a copy of the existing Agreement for their review and signature.

E. Facilitate any necessary reviews of the Agreement.

ATTACHMENT D

Procedures for Requesting and Providing Assistance

A. The Requesting Party shall include the following information, as available in its request for Assistance:

A.1 A brief description of the Emergency creating the need for the Assistance;
A.2 A general description of the damage sustained by the Requesting Party, including the part of the electrical or natural gas system, e.g., generation, transmission, substation, or distribution, affected by the Emergency;
A.3 The number and type of personnel, Equipment, materials and supplies needed;
A.4 A reasonable estimate of the length of time that the Assistance will be needed;
A.5 The name of individuals employed by the Requesting Party who will coordinate the Assistance;
A.6 A specific time and place for the designated representative of the Requesting Party to meet the personnel and Equipment being provided by the Assisting Party;
A.7 Type of fuel available (gasoline, propane or diesel) to operate Equipment;
A.8 Availability of food and lodging for personnel provided by the Assisting Party; and
A.9 Current weather conditions and weather forecast for the following twenty-four hours or longer.

B. The Assisting Party, in response to a request for Assistance, shall provide the following information, as available, to the Requesting Party:

B.1 The name(s) of designated representative(s) to be available to coordinate Assistance;
B.2 The number and type of crews and Equipment available to be furnished;
B.3 Materials available to be furnished;
B.4 An estimate of the length of time that personnel and Equipment will be available;
B.5 The name of the person(s) to be designated as supervisory personnel to accompany the crews and Equipment; and
B.6 When and where Assistance will be provided, giving consideration to the request set forth in section A.6. above.

ATTACHMENT E

Procedures for Deactivation of Assistance

A. The Requesting Party shall, as appropriate, include the following in their Deactivation:

- A.1 Number of crews returning and, if not all crews are returning, expected return date of remaining crews.
- A.2 Notification to the Assisting Party of the time crews will be departing.
- A.3 Information on whether crews have been rested prior to their release or status of crew rest periods.
- A.4 Current weather and travel conditions along with suggested routing for the Assisting Party's return.

B. The Assisting Party shall, as appropriate, include the following in their Deactivation:

- B.1 Return of any Equipment, material, or supplies, provided by the Requesting Party.
- B.2 Provide any information that may be of value to the Requesting Party in their critique of response efforts.
- B.3 Estimation as to when invoice will be available.
- B.4 Invoice to include detail under headings such as labor charges (including hours) by normal time and overtime, payroll taxes, overheads, material, vehicle costs, fuel costs, Equipment rental, telephone charges, administrative costs, employee expenses, and any other significant costs incurred.
- B.5 Retention of documentation as specified in Section 5.3 of the Mutual Assistance Agreement.
- B.6 Confirmation that all information pertaining to the building, modification, or other corrective actions taken by the Assisting Party have been appropriately communicated to the Requesting Party.

ATTACHMENT F

Letter Requesting Assistance

Date

Assisting Party Name

Assisting Party Address

In recognition of the personnel, material, Equipment, supplies and/or tools being sent to us by [name of Assisting Party] in response to a request for mutual assistance made by [Requesting Party] on [date of request], we agree to be bound by the principles noted in the California Utilities Emergency Association Mutual Assistance Agreement (Electric and Natural Gas).

(Brief Statement of Assistance Required)

[Requesting Party Name]

[Authorized Representative of Requesting Party].

<u>[Signature of Authorized Representative of Requesting Party]</u>

ATTACHMENT G

SUPPLEMENTAL INVOICE INFORMATION

Sections 4 and 5 of this Mutual Assistance Agreement provide for the accumulation of costs incurred by the Assisting Party to be billed to the Requesting Party for Assistance provided. Each utility company has their own accounts receivable or other business enterprise system that generates their billing invoices. Generally these invoices do not provide for a breakdown of costs that delineate labor hours, transportation costs, or other expenses incurred in travel to and from the Assistance, or the subsequent repair of equipment that may be necessary.

This attachment provides guidelines, format and explanations of the types of cost breakdown, and supportive information and documentation that are important to accompany the invoice for providing of mutual assistance. It is intended to provide sufficient information to the Requesting Party at the time of invoice to minimize an exchange of detail information requests that may delay the payment of the invoice.

This information in no way eliminates the requesting Party's ability to audit the information or request additional cost detail or documentation.

Supplemental Invoice Information is a recommendation and not a requirement.

The form is available electronically from the Agreement Custodian.

CUEA MUTUAL ASSISTANCE AGREEMENT
(ELECTRIC – NATURAL GAS)
SUPPLEMENTAL INVOICE INFORMATION

This supplemental invoice information detail is submitted pursuant to Sections 4.0 and 5.0 of the CUEA, Mutual Assistance Agreement for Electric and Natural Gas, for assistance provided. *(RP = Requesting Party, AP = Assisting Party)*

AP Invoice Date: ____________ RP Purchase Order # *1* ____________

AP Invoice #: ____________ RP Reference or W/O# *2* ____________

Bill To: *3* (Requesting Party) ____________ Remit To: *4* (Assisting Party) ____________

Address: ____________ Address: ____________

Phone: ____________ Phone: ____________

Attention: *5* ____________ Attention: *6* ____________

Name or Description of Event: ____________

Location of Assistance or Event: ____________

Assistance / Billing Period: From: *7* ____________ To: *8* ____________

Date Assistance Accepted: Date Demobilization Complete:

LABOR 1: *Employee Wages and Salary while at RP Service Area 9*

Labor: Straight Time, Overtime and Premiums:	*Hours*	Wages	*Additives*	***LABOR 1 Subtotal:***	

LABOR 2: *Employee Wages and Salary while traveling to and from RP Service Area 10*

Labor: Straight Time, Overtime and Premiums:	*Hours*	Wages	*Additives*	***LABOR 2 Subtotal:***	

LABOR 3: *Employee Wages and Salary of service and support personnel not traveling to RP Service Area 11*

Labor: Straight Time, Overtime and Premiums:	*Hours*	Wages	*Additives*	***LABOR 3 Subtotal:***	

LABOR 4: *Overtime Wages and Salary Incurred in AP Service Area as a Result of Assistance 12*

Labor: Overtime and Premiums:	*Hours*	Wages	*Additives*	***LABOR 4 Subtotal:***	

LABOR TOTAL ***TOTAL Wages, Salaries and Payroll Additives:*** ____________

MATERIALS: *Cost of materials, supplies, tools, and repair or replacement of non-fleet equipment used in assistance 13*

MATERIALS TOTAL ***TOTAL Materials, Equipment, etc. and Additives:*** ____________

TRANSPORTATION: *Cost of vehicles and equipment including parts and repairs and Additives (No Wages)*

Fleet Costs: *(Hourly or Use Charge for vehicles and equipment and Additives) 14* ____________

Repair Costs: *(Cost of repair or replacement of vehicles and equipment, excluding labor) 15* ____________

TRANSPORTATION TOTAL ***TOTAL Vehicles, Equipment, etc. and Additives:*** ____________

EXPENSE: *Cost of transporting employees and equipment, to and from RP's Service area, and living expenses not provided by RP.*

Transportation Expense: *Cost to transport vehicles and equipment (fleet) to and from RP Service Area 16* ____________

Travel Expense: *Cost to transport personnel, airfare etc., (non-fleet equip/tools) to and from RP Service Area 17* ____________

Living Expense: *Cost of meals, lodging and incidentals not provided by RP or incurred during travel 18*

Meals: ____________ *Lodging:* ____________ *Incidentals:* ____________ ____________

EXPENSE TOTAL ***TOTAL Transportation, Travel and Living and Additives:*** ____________

ADMINISTRATIVE & GENERAL COSTS: *Cost properly allocable to the Assistance and not charged in above sections 19*

ADMINISTRATIVE & GENERAL TOTAL

TOTAL Administrative & General: ____________

All costs and expenses of Assisting Company are summarized in this Invoice.

Pay This Amount: ____________

(A Form W-9, Request for Taxpayer Identification Number and Certification, has been included with this invoice.) ***20***

Instructions and Explanations

This information provides a breakdown of costs incurred in the providing of assistance, and is intended to provide sufficient details to allow Requesting Party to expedite payment by minimizing requests for detailed information. This detailed breakdown, and supportive documentation, should supplement the remittance invoice normally generated by the utility's business enterprise or accounts receivable systems.

Reference Section Explanations: (Numbers correspond to sections on preceding supplemental invoice page(s).)
(Information in parentheses and italics are references to the related section of the CUEA MAA)

1 If Requesting Company has designated a Purchase Order to be used for this remittance, provide the PO number in this space.

2 If Requesting Company has designated a Work Order or Tracking number to be used for this remittance, provide the number here.

3 This "Bill To" address is designated by the Requesting Party and may be the same as the Billing / Payment Address as it appears on the Assisting Company's "Attachment B" of the Agreement. *(Sec. 4.2)*

4 This "Remittance Address" is the address specified on the Assisting Company's Primary Invoice.

5 The person identified in Billing / Payment section of Requesting Party's "Attachment B", or Authorized Representative, or the Requesting Party's designated Mutual Assistance Coordinator.

6 The person identified in Billing / Payment section of Requesting Party's "Attachment B", or Authorized Representative, or the Assisting Party's designated Mutual Assistance Coordinator.

7 The date the assistance was agreed to commence. *(Sec. 3.2)*

8 The date the assistance demobilization is complete. *(Sec. 3.7) (Note: subsequent repair or replacement costs incurred by the AP may be realized and billed past this date, as noticed by the AP to the RP in writing.)*

9 Labor 1: This total includes all hourly wages, including straight time, overtime, premium pay and payroll additives that are the normal payroll of the Assisting Party. This is for <u>time worked in the Requesting Party's service area</u>, and does NOT include time or pay for travel to, or from, the Requesting Party's service area. Labor 1 total includes all employees, management and supervision, that physically traveled to the Requesting Party's service area. (The numbers are reported as totals for Hours, Wages, and Additives (premiums and additives reported in same total). Supportive information such as time sheets, or spreadsheets, that break down the totals reported, is strongly recommended.) *(Sec. 4.1(a))*

10 Labor 2: This total includes all hourly wages, including straight time, overtime, premium pay and payroll additives that are the normal payroll of the Assisting Party. This is for <u>time or pay for travel to, or from, the Requesting Party's service area</u>, and does NOT include time worked in RP's service area. Labor 2 total includes all employees, management and supervision, that physically traveled to the Requesting Party's service area. (The numbers are reported as totals for Hours, Wages, and

Additives (premiums and additives reported in same total). Supportive information such as time sheets, or spreadsheets, that break down the totals reported, is strongly recommended.) *(Sec. 4.1(b))*

11 Labor 3: This total includes all hourly wages, including straight time, overtime, premium pay and payroll additives that are the normal payroll of the Assisting Party. This is for time or pay for employees, management, or supervision that is directly attributed to the assistance, but did NOT travel to the Requesting Party's service area. Labor 3 total may include support services in the Assisting party's own service area such as warehouse, fleet, Assistance Liaisons, administrative and coordination personnel. (The numbers are reported as totals for Hours, Wages, and Additives (premiums and additives reported in same total). (Supportive information such as time sheets, or spreadsheets, that break down the totals reported, is strongly recommended.) *(Sec. 4.1)*

12 Labor 4: This total includes only overtime pay and additives that are incurred by the Assisting Party for emergency response in the Assisting Party's service area, that is directly attributable to the providing of assistance. This total requires detailed support information and explanation provided to the Requesting Party prior to the inclusion of costs for assistance. *(Sec. 4.1 (f))*

13 Materials: This total includes all non-fleet equipment, tools and supplies, provided by Assisting Party's warehouse or other supplier that was used, consumed, or has normally applied overhead costs or depreciation, as outlined in the agreement. *(Sec. 4.1 (c))*

14 Transportation: This total includes the hourly or use charge of vehicles and equipment, and normally applies overheads and additives, for all vehicles and equipment used in the providing of assistance. These are direct *"Fleet"* costs excluding labor, which is included in Labor totals. *(Sec. 4.1 (d))*

15 Transportation: This total includes cost of repair or replacement of vehicles or equipment used in the providing of assistance, by AP, dealer service, or contracted repairs, including all normally applies overheads and additives. These are direct *"Fleet"* costs excluding labor, which is included in Labor totals. *(Sec. 4.1 (d))*

16 Transportation Expense: This total includes only the incurred costs of transporting, by contractor or entity other than the AP or RP, the fleet vehicles and equipment to RP's service area, and return to AP's home base. (Supportive information such as contract carrier's invoice or trip tickets is recommended.)

17 Travel Expense: These include all costs incurred by AP for the transportation of personnel to and from the RP's service area. These include airfare, cab fare, rental vehicles, or any other transportation not provided by the RP. It also included the transportation or shipping costs of non-fleet tools or equipment to and from the RP's service area. *(Sec. 4.1)*

18 Living Expense: This includes all meals, lodging, and incidentals incurred during travel to and from RP's service area. It includes any of these costs incurred while working in the RP's service area that were not provided by the RP. *(Sec. 4.1(b))*

19 Administrative and General Costs: This includes all costs that are allocable to the Assistance, to the extent that they are not included in all the foregoing costs identified in this invoice. *(Sec. 4.1(e))*

20 Form W-9, Tax Identification and Certification: This standard tax form should be completed and accompany this form, unless such information has been previously transmitted to the Requesting Company.

Appendix 5:
Western Region Mutual Assistance Agreement for Electric and Natural Gas Utilities

WESTERN REGION

MUTUAL ASSISTANCE AGREEMENT

For

ELECTRIC AND NATURAL GAS UTILITIES

Effective: 11/14/2003

TABLE OF CONTENTS

WESTERN REGION MUTUAL ASSISTANCE AGREEMENT (Electric and Natural Gas)

DEFINITIONS

The following are definitions of terms as used in this agreement:

Activation: The initiation of the Assistance and administrative process of the agreement including: request for Assistance, assessing and communicating the scope of assistance request, assessing and communicating the resources available for Assistance, activation procedures, mutual assistance coordination, and other processes and procedures supporting the Mobilization of Assistance resources.

Deactivation: The termination of the Assistance and administrative process including: notification of Deactivation, Demobilization planning, identification of applicable costs, processes and procedures supporting Demobilization of resources, provide for billing, audit, critique information, and closure of the Assistance.

Demobilization: The actual returning of all Assistance resources to the Assisting Party's normal base.

Emergency: A sudden unplanned disruption of essential systems and infrastructure creating a potential for public safety, severe economic loss, or other socio-economic hardships resulting from the loss of the utility service. The emergency may be confined to the utility infrastructure or may include community-wide damage and emergency response. Emergencies may be natural disasters or human caused events.

Mobilization: The actual collecting, assigning, preparing and transporting of all Assistance resources.

Mutual Assistance Coordinator: The person(s) designated by the Requesting Party, and Assisting Party, to coordinate all administrative requirements of the Agreement.

Natural Gas: Term gas or natural gas referred to in this document include all commercially available forms of natural gas including Synthetic Natural Gas.

Operations Liaison: The person or persons designated by the Requesting Party to provide direct contact, communications and coordination at the operations level for Assisting crews and resources at the location of the assistance. This may include but is not limited to: contact and communications for assisting crews, safety information processes and procedures, ensuring coordination of lodging and meals, addressing issues of equipment requirements, materials requirements, and other logistical issues necessary to ensure safe effective working conditions. .

Qualified: The training, education and experience of employees completing an apprenticeship or other industry / trade training requirements consistent with Federal Bureau of Apprenticeships and Training, Department of Transportation Pipeline Safety Regulations, or other recognized training authority or regulation. Training and qualification standards vary by state or province and are the responsibility of the Requesting Party to evaluate, in advance, the acceptable level of qualification for trade employees (i.e. lineman, electrician, fitter, etc.).

Work Stoppages: Any labor disputes, labor union disagreements, strikes, or any circumstance creating a shortage of qualified labor for a company during a non-emergency situation.

WESTERN REGION MUTUAL ASSISTANCE AGREEMENT (Electric and Natural Gas)

1.0 PARTIES

1.1. This Mutual Assistance Agreement (hereinafter referred to as "Agreement") is made and entered into effective November 14, 2003. The Parties to this Agreement are listed in Attachment A of this document. Each of the parties that have executed this Agreement may hereinafter be referred to individually as "Party" and collectively as "Parties."

1.2. Being a Party to this Agreement does not by itself assure any Party that Assistance will be provided if, when, or as requested. Each Party reserves the sole right to respond or not to respond to requests for Assistance on a case-by-case basis. By signing this Agreement, each Party thereby agrees that any Assistance, which is received or given upon the request of a Party to this Agreement, shall be subject to each and every one of the terms and conditions of this Agreement.

2.0 RECITALS

This Agreement is made with reference to the following facts, among others:

2.1. Whereas, the Parties own operate and maintain utility facilities and are engaged in the production, acquisition, transmission, and/or distribution of electricity or natural gas, and

2.2. Whereas, each of the Parties operates and maintains their respective facilities within accepted industry practices and employs skilled and qualified personnel to operate, repair and maintain such facilities according to such industry practices, and

2.3. Whereas, it is in the mutual interest of the Parties to be prepared to provide for emergency repair and restoration to such services, systems and facilities on a reciprocal basis. The purpose of this Agreement is to provide the procedures under which one Party may request and receive assistance from another Party. This Agreement is also designed to allow a new Party to join in the Agreement by signing a copy of this Agreement and the giving of notice to the existing Parties pursuant to Section 6.3 of this Agreement, and

2.4. Whereas, assistance requests for Work Stoppages are beyond the scope of this Agreement.

2.5. Whereas, for purposes of this Agreement, "Assistance" shall be defined as: All preparation and arrangements by the Assisting Party for Activation, Mobilization, Deactivation and Demobilization, of personnel, material, vehicles, equipment, supplies and/or tools or any other requested form of aid or assistance, starting at the time of the authorization by the Requesting Party, as set forth in this Agreement.

THEREFORE THE PARTIES HEREBY AGREE AS FOLLOWS:

3.0 SCOPE OF ASSISTANCE

3.1. In the event of an Emergency affecting the generation, transmission, distribution, services, and/or related facilities owned or controlled by a Party, such Party ("Requesting Party") may request another Party or Parties ("Assisting Part"to provide Assistance. The Assisting Party shall, in its sole discretion, determine if it shall provide such Assistance, including the extent and limitations of that Assistance. If the Assisting Party determines to provide Assistance, such Assistance shall be provided in accordance with the terms and conditions of this Agreement.

3.2. Requests for Assistance may be made either verbally or in writing by the Authorized Representative, as defined in Section 9 and identified in Attachment B, of the Requesting Party and shall be directed to the Authorized Representative of the Assisting Party. Upon acceptance of a request for Assistance, either verbally or in writing, the Assisting Party shall respond with reasonable dispatch to the request in accordance with information and instructions supplied by the Requesting Party. All requests for Assistance shall follow the procedures described by Section 3.0 and in Attachment C.

3.3. The Requesting Party shall provide the Assisting Party with a description of the work needed to address the emergency, with the most urgent needs for Assistance addressed first. The Assisting Party shall use its reasonable efforts to schedule the Assistance in accordance with the Requesting Party's request. However, the Assisting Party reserves the right to recall any and all personnel, material, equipment, supplies, and/or tools at any time that the Assisting Party determines necessary for its own operations. Any Requesting Party for whom an Operator Qualification (OQ) Program is required should pre-screen the other Parties to this Agreement to determine which Parties have compatible regulatory agency accepted programs and may therefore be contacted for assistance.

3.4. The Requesting Party will provide the name and contact information for the person(s) designated as the Mutual Assistance Coordinator(s), the Operations Liaison(s), and person(s) to be designated as supervisory personnel to accompany the crews and equipment. The Assisting Party will provide the name(s) and contact information for the person(s) designated to be the Mutual Assistance Coordinator(s).

3.5. All costs associated with the furnishing of Assistance shall be the responsibility of the Requesting Party and deemed to have commenced when the Requesting Party officially authorizes the Assisting Party to proceed with Mobilization of the personnel and equipment necessary to furnish Assistance, and shall be deemed to have terminated when the transportation of Assisting Party personnel and equipment returns to the work headquarters, individual district office, or home (to which such personnel are assigned for personnel returning at other than regular working hours) and Demobilization is completed.

3.6. For the purposes of this Agreement, a Requesting Party shall be deemed to have authorized the Assisting Party to proceed with Mobilization when the Requesting Party signs and submits a formal request to the Assisting Party, in a form substantially similar to that shown in Attachment C-1. If written information cannot be furnished, a verbal confirmation will be acceptable, with a written confirmation to follow within 24 hours.

3.7. The Parties hereto agree that costs arising out of inquiries as to the availability of personnel, material, equipment, supplies and/or tools or any other matter made by one party to another prior to the Requesting Party authorizing the Assisting Party to proceed with Mobilization will not be charged to the potentially Requesting Party.

3.8. The Requesting Party agrees to repayment of "reasonable costs or expenses," as further described in Section 4.0 of this Agreement, and any such reasonable costs or expenses shall continue to be subject to the provisions of Section 5.0 of this Agreement regarding Audit and Arbitration.

3.9. The Assisting Party and Requesting Party shall mutually agree upon and make all arrangements for the preparation and actual Mobilization of personnel, material, vehicles, equipment, supplies and/or tools to the Requesting Party's work area and the return (i.e. Demobilization) of such personnel, material, vehicles, equipment, supplies and/or tools to the Assisting Party's work area (See Attachments C and D). The Requesting Party shall be responsible for all reasonable costs and expenses incurred by the Assisting Party for Mobilization and/or Demobilization, notwithstanding any early termination of such assistance by the Requesting Party.

3.10. Unless otherwise agreed upon, the Requesting Party shall be responsible for providing food and lodging for the personnel of the Assisting Party from the time of their arrival at the designated location to the time of their departure. The food and housing provided shall be subject to the approval of the supervisory personnel of the Assisting Party.

3.11. If requested by the Assisting Party, the Requesting Party, at its own cost, shall make or cause to be made all reasonable repairs to the Assisting Party's vehicles and equipment, necessary to maintain such equipment safe and operational, while the equipment is in transit or being used in providing Assistance. However, the Requesting Party shall not be liable for cost of repair required by the gross negligence or willful acts of the Assisting Party, or if the vehicles or equipment was not issued by the Assisting Party in safe and operational condition.

3.12. Unless otherwise agreed the Requesting Party shall provide fuels and other supplies needed for operation of the Assisting Party's vehicles and equipment being used in providing Assistance.

3.13. Unless otherwise agreed to by the Parties, the Requesting Party shall provide field communications equipment and instructions for the Assisting Party's use. The Assisting Party shall exercise due care in use of the equipment and return the equipment to the Requesting Party at the time of departure in like condition, provided that if repairs are necessary the Requesting Party will be financially responsible unless such repairs are necessitated by the gross negligence or willful acts of the Assisting Party.

3.14. Employees of the Assisting Party shall at all times continue to be employees of the Assisting Party, and such employees shall at no time and for no purpose be deemed to be employees of the Requesting Party.

3.15. Wages, hours and other terms and conditions of employment applicable to personnel provided by the Assisting Party, shall continue to be those of the Assisting Party.

3.16. If the Assisting Party provides a crew or crews, it shall assign supervisory personnel as deemed necessary by the Assisting Party, who shall be directly in charge of the crew or crews providing Assistance.

3.17. All time sheets, equipment and work records pertaining to personnel, material, vehicles, equipment, supplies and/or tools provided by the Assisting Party shall be kept by the Assisting Party for billing and auditing purposes as provided in this Agreement.

3.18. No Party shall be deemed the employee, agent, representative, partner or the co-venturer of another Party or the other Parties in the performance of activities undertaken pursuant to this Agreement.

3.19. The Parties shall, in good faith, attempt to resolve any differences in work rules and other requirements affecting the performance of the Parties' obligations pursuant to this Agreement.

3.20. The Requesting party shall provide the Assisting Party with an Operations Liaison (See Attachment C, A.5) to assist with operations, personnel and crew safety. This person(s) shall provide the Assisting Party's crews an operational and safety orientation, pertaining to work practices and safety requirements of the Requesting Party's system, prior to Assisting Party commencing work, and continue to be the link between the Parties and keep the crews apprised of safety, operational, and communication issues.

3.21. The Requesting party shall initiate the Deactivation of Assistance by notification to the Assisting Party within 24 hours of deactivation schedule or as soon as is reasonably practicable. Requesting and Assisting Parties will follow the Procedures for Deactivation of Assistance outlined in Attachment D.

4.0 PAYMENT

4.1. The Requesting Party shall reimburse the Assisting Party for all "reasonable costs and expenses" that are appropriate and not excessive, under the circumstances prevailing at the time the cost or expense is paid or incurred by the Assisting Party as a result of furnishing Assistance. Such "reasonable costs or expenses" shall include, but not be limited to, the following:

a) Employees' wages and salaries for paid time spent in Requesting Party's service area and paid time during travel to and from such service area, plus the Assisting Party's standard payroll additives to cover all employee benefits and allowances for vacation, sick leave, holiday pay, retirement benefits, all payroll taxes, workers' compensation, employer's liability insurance, administrative and general expenses, and other benefits imposed by applicable law, regulation, or contract pursuant to Section 3.15.

b) Employees' travel and living expenses such as transportation, fuel, utilities, housing or shelter, food, communications, and reasonable incidental expenses directly attributable to the Assistance.

c) Cost of equipment, materials, supplies and tools at daily or hourly rate including their normally applied overhead costs inclusive of taxes, insurance, depreciation, and administrative expenses. Cost to maintain, fuel, replace or repair equipment, materials, supplies, and tools (hereinafter collectively referred to as the "Equipment"), which are expended, used, damaged, or stolen while the Equipment is being used in providing Assistance; provided, however, the Requesting Party's financial obligation under this Section (4.1. c): (i) shall not apply to any damage or loss resulting from the gross negligence or willful misconduct of the Assisting Party, and (ii) shall only apply in excess of, and not contribute with, any valid and collectible property insurance which applies to such damage or loss.

d) Cost of vehicles provided by Assisting Party for performing assistance at daily or hourly rate including normally applied overhead costs inclusive of taxes, insurance, depreciation, and administrative expenses. Cost to maintain, fuel, and repair vehicles, or replace vehicles which are damaged or stolen while the vehicles are used in providing Assistance; provided, however, that Requesting Party's financial obligation under this Section (4.1.d):(i) shall not apply to any damage or loss resulting from the gross negligence or willful misconduct of the Assisting Party, and (ii) shall only apply in excess of, and not contribute with, any valid and collectible first-party physical damage insurance which applies to such loss.

e) Administrative and general costs, including the costs associated with the Assisting Party's administrative field coordination personnel, which are properly allocable to the Assistance to the extent such costs are not chargeable pursuant to the foregoing subsections.

f) Overtime costs incurred by the Assisting Party in their service territory as a direct result of assistance provided to the Requesting Party.

4.2. Unless otherwise mutually agreed to, the Assisting Party shall bill the Requesting Party at the address designated on Attachment "B" for all costs and expenses of the Assisting Party in one invoice with itemization or supporting documentation of charges. If the assistance extends beyond a 30-day period, billing can occur monthly unless otherwise agreed upon.

4.3. The Requesting Party shall pay such bill in full, not withstanding the rights of Audit and Arbitration in Section 5.0, within thirty 30 days of receipt of the bill, or a remittance period agreed to by both parties, and shall send payment to the Assisting Party at the address listed in Attachment "B".

4.4. Delinquent payment of bills shall accrue interest at a rate equal to the incremental cost of debt replacement for the Assisting Party, not to exceed the legal rate permitted by the Governing Law (Section 8.0) of Assisting Party, and as identified at the time of billing, prorated by days, until such bills are paid. This rate shall be identified on the bill submitted by the Assisting Party.

5.0 <u>AUDIT AND ARBITRATION</u>

5.1. A Requesting Party has the right to designate its own qualified employee representative(s) or its contracted representative(s) with a management or accounting firm who shall have the right to audit and to examine any cost, payment, settlement, or supporting documentation relating to any bill submitted to the Requesting Party pursuant to this Agreement.

5.2. A request for audit shall not affect the obligation of the Requesting Party to pay bills as required herein. The Requesting Party or its representative(s) shall undertake any such audit(s) upon notice to the Assisting Party at reasonable times and in conformance with generally accepted auditing standards (GAAS). The Assisting Party agrees to conform to generally accepted accounting principles (GAAP) and to reasonably cooperate with any such audit(s).

5.3. This right to audit shall extend for a period of two (2) years following the receipt by Requesting Party of billings for all costs and expenses. The Assisting Party agrees to retain all necessary records/documentation for the said two-year period, and the entire length of this audit, in accordance with its normal business procedures.

5.4. The Assisting Party shall be notified by the Requesting Party, in writing, of any exception taken as a result of the audit. In the event of a disagreement between the Requesting Party and the Assisting Party over audit exceptions, the Parties agree to use good faith efforts to resolve their differences through negotiation.

5.5. If ninety (90) days or more have passed since the notice of audit exception was received by the Assisting Party, and the Parties have failed to resolve their differences, the Parties agree to submit any unresolved dispute to binding arbitration before an impartial member of an unaffiliated management or accounting firm. Governing Law for arbitration is pursuant to Section 8 of this Agreement. Each Party to arbitration will bear its own costs, and the expenses of the arbitrator shall be shared equally by the Parties to the dispute.

6.0 TERM AND TERMINATION

6.1. This Agreement shall be effective on the date of execution by at least two of the Parties hereto and shall continue in effect indefinitely, except as otherwise provided herein. Any Party may withdraw its participation at any time after the effective date with 30 days prior written notice to all other Parties.

6.2. As of the effective date of any withdrawal, the withdrawing Party shall have no further rights or obligations under this Agreement except the right to collect money owed to such Party, the obligation to pay amounts due to other Parties, and the rights and obligations pursuant to Section 5.0 and Section 7.0 of this Agreement.

6.3. Notwithstanding Section 12.0, additional parties may be added to the Agreement, without amendment of the Agreement, provided that notice is given to existing signatories who may contest inclusion of new signatories within 30 days of such notice, and that any new signatories agree to be bound by the terms and conditions of this Agreement by executing a copy of the same which shall be deemed an original and constitute the same agreement executed by the existing signatories. The addition or withdrawal of any party to this Agreement shall not change the status of the Agreement among the remaining Parties.

7.0 LIABILITY

7.1. Except as otherwise specifically provided by Section 4.1 and Section 7.2 herein, to the extent permitted by law and without restricting the immunities of any Party, the Requesting Party shall defend, indemnify and hold harmless the Assisting Party, its directors, officers, agents, employees, successors and assigns from and against any and all liability, damages, losses, claims, demands actions, causes of action, and costs including reasonable attorneys' fees and expenses, resulting from the death or injury to any person or damage to any property, which results from the furnishing of Assistance by the Assisting Party, unless such death or injury to person, or damage to property, is caused by the gross negligence or willful misconduct of the Assisting Party.

7.2. Each Party shall bear the total cost of discharging all liability arising during the performance of Assistance by one Party to the other (including costs and expenses for attorneys' fees and other costs of defending, settling, or otherwise administering claims) which result from workers' compensation claims or employers' liability claims brought by its own employees. Each Party agrees to waive, on its own behalf, and on behalf of its insurers, any subrogation rights for benefits or compensation paid to such Party's employees for such claims.

7.3. In the event any claim or demand is made, or suit or action is filed, against the Assisting Party, alleging liability for which the Requesting Party shall indemnify and hold harmless the Assisting Party, Assisting Party shall promptly notify the Requesting Party thereof, and the Requesting Party, at its sole cost and expense, shall settle, compromise or defend the same in such manner as it, in its sole discretion, deems necessary or prudent. However, Requesting Party shall consult with Assisting Party during the pendency of all such claims or demands, and shall advise Assisting Party of Requesting Party's intent to settle any such claim or demand. The party requesting indemnification should notify the other party in writing of that request.

7.4. The vehicles or equipment, which the Assisting Party shall provide to the Requesting Party pursuant to Section 3 above, shall not, to the actual knowledge of Assisting Party, be provided in unsafe operating condition, as represented by manufacturer standards and industry practices. Except as provided in the immediately preceding sentence, the Assisting Party makes no representations or warranties as to the condition, suitability for use, freedom from defect or otherwise of such vehicles or equipment. Requesting Party shall utilize the vehicles or equipment at its own risk. Requesting Party shall, at its sole cost and expense, defend, indemnify and hold harmless Assisting Party, its directors, officers, agents, employees, successors and assigns, from and against any and all liability, damages, losses, claims, demands, actions, causes of action, and costs including reasonable attorneys' fees and expenses, resulting from the death or injury to any person or damage to any property, arising out of the utilization of the equipment by or for the Requesting Party, or its employees, agents, or representatives, unless such death, injury, or damage is caused by the gross negligence or willful misconduct of the Assisting Party.

7.5. No Party shall be liable to another Party for any incidental, indirect, or consequential damages, including, but not limited to, under-utilization of labor and facilities, loss of revenue or anticipated profits, or claims of customers arising out of supplying electric or natural gas service, resulting from performance or nonperformance of the obligations under this Agreement.

7.6. Nothing in Section 7.0, or elsewhere in this Agreement, shall be construed to make the Requesting Party liable to the Assisting Party for any liability for death, injury, or property damage arising out of the ownership, use, or maintenance of any aircraft or watercraft (over 17 feet in length) which is supplied by or provided by the Assisting Party. It shall be the responsibility of the Assisting Party to carry liability and hull insurance on such aircraft and watercraft as it sees fit. Also, during periods of operation of aircraft or watercraft (over 17 feet in length) in a situation covered by this Agreement, the Party, which is the owner/lessee of such aircraft or watercraft, shall use its best efforts to have the other

Parties to this Agreement named as additional insured's on such liability coverage.

8.0 GOVERNING LAW

8.1. All disputes, contests or arbitration of this Agreement, for assistance provided or requested, shall be interpreted, governed and construed by the choice of law state or province as specified by the Assisting Party in Attachment B.

9.0 AUTHORIZED REPRESENTATIVE

9.1. The Parties shall, within 30 days following execution of this Agreement, appoint Authorized Representative and Alternate Authorized Representative(s), and exchange all such information as provided in Attachment "B". Such information shall be updated by each Party prior to January 1st of each year that this Agreement remains in effect. The Authorized Representatives or the Alternate Authorized Representatives shall have the authority to request and commit to the providing of Assistance.

10.0 CUSTODIANSHIP OF AGREEMENT

10.1. The custodial responsibilities of this Agreement, as outlined in Attachment E, may be assigned to one of the Parties to this Agreement, which assignment shall be subject to acceptance by such Party, or may be assigned to a third party, in either case by vote of the participating Parties starting within 30 days after the initiation of this Agreement, and then by January 31st of each year.

11.0 ASSIGNMENT OF AGREEMENT

11.1. No Party may assign this Agreement, or any interest herein, to a third party, without the written consent of the other Parties.

12.0 WAIVERS OF AGREEMENT

12.1. Failure of a Party to enforce any provision of this Agreement, or to require performance by the other Parties of any of the provisions hereof, shall not be construed to waive such provision, nor to affect the validity of this Agreement or any part thereof, or the right of such Parties to thereafter enforce each and every provision.

13.0 ENTIRE AGREEMENT

13.1. This Agreement is the entire agreement between the Parties concerning the subject matter of the Agreement. It supercedes and takes the place of all conversations the Parties may have had, or documents the

Parties may have exchanged, with regard to the subject matter. The recitals to this agreement are hereby incorporated herein.

14.0 AMENDMENT

14.1. No changes to this Agreement other than the addition of new Parties shall be effective unless such changes are made by an amendment in writing, signed by each of the Parties hereto. A new Party may be added to this Agreement upon the giving of 30 days notice to the existing Parties and upon the new Party's signing a copy of this Agreement as in effect upon the date the new Party agrees to be bound by each and every one of the Agreement's terms and conditions.

15.0 NOTICES

15.1. All communications between the Parties relating to the provisions of this Agreement shall be addressed to the Authorized Representative of the Parties, or in their absence, to the Alternate Authorized Representative(s) as identified in Attachment "B". Communications shall be in writing, and shall be deemed given if made or sent by e-mail with electronic confirmed delivery, confirmed fax, personal delivery, or registered or certified mail postage prepaid. Each Party reserves the right to change the names of those individuals identified in Attachment "B" applicable to that Party, and shall notify each of the other Parties of such change in writing as described above. All Parties shall keep the Custodian of the Agreement informed of the information contained in Attachment "B" and reply to all reasonable requests of such association for information regarding the administration of this Agreement.

16.0 ATTACHMENTS

Attachment "A" (Parties to this Agreement)
Attachment "B" (Names and Addresses of Authorized Representative(s) /Billing)
Attachment "C" (Activation of Western Regional Mutual Assistance Agreement)
Attachment "C-1" (Sample Written Request for Assistance)
Attachment "D" (Deactivation Under Western Regional Mutual Assistance Agreement)
Attachment "E" (Custodianship of Western Regional Mutual Assistance Agreement)
Attachments to this Agreement are incorporated herein by this reference.

17.0 SIGNATURE CLAUSE

17.1. This Agreement may be executed in any number of counterparts, each of which shall be an original, but all of which together shall constitute one and the same agreement.

17.2. IN WITNESS WHEREOF, the Parties have caused this Agreement to be executed by their respective duly authorized officers as of the dates set forth below.

Company Name: San Diego Gas & Electric Company

Signature of Officer:

Title of Officer: Vice President - Electric Distribution Operations

Date Executed: March 31, 2016

Print Officer Name: John Sowers

Appendix 6:
Edison Electric Institute Mutual Assistance Agreement

EEI | Edison Electric INSTITUTE

Edison Electric Institute
Mutual Assistance Agreement

Edison Electric Institute ("EEI") member companies have established and implemented an effective system whereby member companies may receive and provide assistance in the form of personnel and equipment to aid in restoring and/or maintaining electric utility service when such service has been disrupted by acts of the elements, equipment malfunctions, accidents, sabotage, or any other occurrence for which emergency assistance is deemed to be necessary or advisable ("Emergency Assistance"). This Mutual Assistance Agreement sets forth the terms and conditions to which the undersigned EEI member company ("Participating Company") agrees to be bound on all occasions that it requests and receives ("Requesting Company") or provides ("Responding Company") Emergency Assistance from or to another Participating Company who has also signed the EEI Mutual Assistance Agreement; provided, however, that if a Requesting Company and one or more Responding Companies are parties to another mutual assistance agreement at the time of the Emergency Assistance is requested, such other mutual assistance agreement shall govern the Emergency Assistance among those Participating Companies.

In consideration of the foregoing, the Participating Company hereby agrees as follows:

1. When providing Emergency Assistance to or receiving Emergency Assistance from another Participating Company, the Participating Company will adhere to the written principles developed by EEI members to govern Emergency Assistance arrangements among member companies ("EEI Principles"), that are in effect as of the date of a specific request for Emergency Assistance, unless otherwise agreed to in writing by each Participating Company.

2. With respect to each Emergency Assistance event, Requesting Companies agree that they will reimburse Responding Companies for all costs and expenses incurred by Responding Companies in providing Emergency Assistance as provided under the EEI Principles, unless otherwise agreed to in writing by each Participating Company; provided, however, that Responding Companies must maintain auditable records in a manner consistent with the EEI Principles.

3. During each Emergency Assistance event, the conduct of the Requesting Companies and the Responding Companies shall be subject to the liability and indemnification provisions set forth in the EEI Principles.

4. A Participating Company may withdraw from this Agreement at any time. In such an event, the company should provide written notice to EEI's Vice President of Energy Delivery or his/her designee.

5. EEI's Director of Business Continuity and Operations or his/her designee who shall maintain a list of each Mutual Assistance Agreement Participating Company Signatory which shall be posted in the Restore Power Workroom as https://eeirestorepower.groupsite.com/page/mutual-assistance-agreement .

San Diego Gas & Electric
Company Name

Katherine M. Speirs
Signature

Officer Name: Katherine Speirs
Title: Vice President – Electric System Operations
Date: December 11, 2018

EEI | Edison Electric INSTITUTE

SUGGESTED GOVERNING PRINCIPLES COVERING EMERGENCY ASSISTANCE ARRANGEMENTS BETWEEN EDISON ELECTRIC INSTITUTE MEMBER COMPANIES

Electric companies have occasion to call upon other companies for emergency assistance in the form of personnel or equipment to aid in maintaining or restoring electric utility service when such service has been disrupted by acts of the elements, equipment malfunctions, accidents, sabotage or any other occurrences where the parties deem emergency assistance to be necessary or advisable. While it is acknowledged that a company is not under any obligation to furnish such emergency assistance, experience indicates that companies are willing to furnish such assistance when personnel or equipment are available.

In the absence of a continuing formal contract between a company requesting emergency assistance ("Requesting Company") and a company willing to furnish such assistance ("Responding Company"), the following principles are suggested as the basis for a contract governing emergency assistance to be established at the time such assistance is requested:

1. The emergency assistance period shall commence when personnel and/or equipment expenses are initially incurred by the Responding Company in response to the Requesting Company's needs. (This would include any request for the Responding Company to prepare its employees and/or equipment for transport to the Requesting Company's location but to await further instructions before departing). The emergency assistance period shall terminate when such employees and/or equipment have returned to the Responding Company, and shall include any mandated DOT rest time resulting from the assistance provided and reasonable time required to prepare the equipment for return to normal activities (e.g. cleaning off trucks, restocking minor materials, etc.).

2. To the extent possible, the companies should reach a mutual understanding and agreement in advance on the anticipated length – in general – of the emergency assistance period. For extended assistance periods, the companies should agree on the process for replacing or providing extra rest for the Responding Company's employees. It is understood and agreed that if; in the Responding Company's judgment such action becomes necessary the decision to terminate the assistance and recall employees, contractors, and equipment lies solely with the Responding Company. The Requesting Company will take the necessary action to return such employees, contractors, and equipment promptly.

3. Employees of Responding Company shall at all times during the emergency assistance period continue to be employees of Responding Company and shall not be deemed employees of Requesting Company for any purpose. Responding Company shall be an independent Contractor of Requesting Company and wages, hours and other terms and conditions of employment of Responding Company shall remain applicable to its employees during the emergency assistance period.

4. Responding Company shall make available upon request supervision in addition to crew leads. All instructions for work to be done by Responding Company's crews shall be given by

Requesting Company to Responding Company's supervision; or, when Responding Company's crews are to work in widely separate areas, to such of Responding Company's crew lead as may be designated for the purpose by Responding Company's supervision.

5. Unless otherwise agreed by the companies, Requesting Company shall be responsible for supplying and/or coordinating support functions such as lodging, meals, materials, etc. As an exception to this, the Responding Company shall normally be responsible for arranging lodging and meals en route to the Requesting Company and for the return trip home. The cost for these in transit expenses will be covered by the Requesting Company.

6. Responding Company's safety rules shall apply to all work done by their employees. Unless mutually agreed otherwise, the Requesting Company's switching and tagging rules should be followed to ensure consistent and safe operation. Any questions or concerns arising about any safety rules and/or procedures should be brought to the proper level of management for prompt resolution between management of the Requesting and Responding Companies.

7. All time sheets and work records pertaining to Responding Company's employees furnishing emergency assistance shall be kept by Responding Company.

8. Requesting Company shall indicate to Responding Company the type and size of trucks and other equipment desired as well as the number of job function of employees requested but the extent to which Responding Company makes available such equipment and employees shall be at responding Company's sole discretion.

9. Requesting Company shall reimburse Responding Company for all costs and expenses incurred by Responding Company as a result of furnishing emergency assistance. Responding Company shall furnish documentation of expenses to Requesting Company. Such costs and expenses shall include, but not be limited to, the following:

    a. Employees' wages and salaries for paid time spent in Requesting Company's service area and paid time during travel to and from such service area, plus Responding Company's standard payable additives to cover all employee benefits and allowances for vacation, sick leave and holiday pay and social and retirement benefits, all payroll taxes, workmen's compensation, employer's liability insurance and other contingencies and benefits imposed by applicable law or regulation.

    b. Employee travel and living expenses (meals, lodging and reasonable incidentals).
    c. Replacement cost of materials and supplies expended or furnished.

    d. Repair or replacement cost of equipment damaged or lost.

    e. Charges, at rates internally used by Responding Company, for the use of transportation equipment and other equipment requested.

    f. Administrative and general costs, which are properly allocable to the emergency assistance to the extent such costs, are not chargeable pursuant to the foregoing subsections.

10. Requesting Company shall pay all costs and expenses of Responding Company within sixty days after receiving a final invoice therefor.

11. Requesting Company shall indemnify, hold harmless and defend the Responding Company from and against any and all liability for loss, damage, cost or expense which Responding Company may incur by reason of bodily injury, including death, to any person or persons or by reason of damage to or destruction of any property, including the loss of use thereof, which result from furnishing emergency assistance and whether or not due in whole or in part to any act, omission, or negligence of Responding Company except to the extent that such death or injury to person, or damage to property, is caused by the willful or wanton misconduct and / or gross negligence of the Responding Company. Where payments are made by the Responding Company under a workmen's compensation or disability benefits law or any similar law for bodily injury or death resulting from furnishing emergency assistance, Requesting Company shall reimburse the Responding Company for such payments, except to the extent that such bodily injury or death is caused by the willful or wanton misconduct and / or gross negligence of the Responding Company.

12. In the event any claim or demand is made or suit or action is filed against Responding Company alleging liability for which Requesting Company shall indemnify and hold harmless Responding Company under paragraph (11) above, Responding Company shall promptly notify Requesting Company thereof, and Requesting Company, at its sole cost and expense, shall settle, compromise or defend the same in such manner as it in its sole discretion deems necessary or prudent. Responding Company shall cooperate with Requesting Company's reasonable efforts to investigate, defend and settle the claim or lawsuit.

13. Non-affected companies should consider the release of contractors during restoration activities. The non-affected company shall supply the requesting companies with contact information of the contactors (this may be simply supplying the contractors name). The contractors will negotiate directly with requesting companies.

Date	Description
October 2014	Sections 4, 5, and 10
September 2005	Sections 11 and 12