Exhibit 1

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Exhibit 2

Overview: Diesel Exhaust & Health

CATEGORIES

Topics Health, Air Pollution, Transportation Electrification, Construction & Earthmoving Equipment, Environmental Justice, Oceangoing Vessels & Harbor Craft, Freight & Goods Movement, Trains & Railyards, Transit, VW Diesel Vehicles

Programs Exposure, Community Air Protection Program , Community Health, Zero-Emission Powertrain Certification, Alternative Diesel Fuels, In-Use Off-Road Diesel-Fueled Fleets Regulation, Study of Neighborhood Air near Petroleum Sources, School Buses

Type Information

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Background

Diesel engines emit a complex mixture of air pollutants, including both gaseous and solid material.The solid material in diesel exhaust is known as diesel particulate matter (DPM). More than 90% of DPM is less than 1 µm in diameter (about $1/70^{th}$ the diameter of a human hair), and thus is a subset of particulate matter less than 2.5 microns in diameter (PM2.5). Most PM2.5 derives from combustion, such as use of gasoline and diesel fuels by motor vehicles, burning of natural gas to generate electricity, and wood burning. PM2.5 is the size of ambient particulate matter air pollution most associated with adverse health effects of the air pollutants that have ambient air quality standards. These health effects include cardiovascular and respiratory hospitalizations, and premature death. As a California statewide average, DPM comprises about 8% of PM2.5 in outdoor air, although DPM levels vary regionally due to the non-uniform distribution of sources throughout the state.

DPM is typically composed of carbon particles (“soot”, also called black carbon, or BC) and numerous organic compounds, including over 40 known cancer-causing organic substances. Examples of these chemicals include polycyclic aromatic

hydrocarbons, benzene, formaldehyde, acetaldehyde, acrolein, and 1,3-butadiene. Diesel exhaust also contains gaseous pollutants, including volatile organic compounds and oxides of nitrogen (NO_x). NO_x emissions from diesel engines are important because they can undergo chemical reactions in the atmosphere leading to formation of PM2.5 and ozone.

Most major sources of diesel emissions, such as ships, trains, and trucks operate in and around ports, rail yards, and heavily traveled roadways. These areas are often located near highly populated areas. Because of this, elevated DPM levels are mainly an urban problem, with large numbers of people exposed to higher DPM concentrations, resulting in greater health consequences compared to rural areas. A large fraction of personal exposure to DPM occurs during travel on roadways. Although Californians spend a relatively small proportion of their time in enclosed vehicles (about 7% for adults and teenagers, and 4% for children under 12), 30 to 55% of total daily DPM exposure typically occurs during the time people spend in motor vehicles.

Diesel Particulate Matter and Health

The majority of DPM is small enough to be inhaled into the lungs. Most inhaled particles are subsequently exhaled, but some deposit on the lung surface. Although particles the size of DPM can deposit throughout the lung, the largest fraction deposits in the deepest regions of the lungs where the lung is most susceptible to injury.

In 1998, CARB identified DPM as a toxic air contaminant based on published evidence of a relationship between diesel exhaust exposure and lung cancer and other adverse health effects. In 2012, additional studies on the cancer-causing potential of diesel exhaust published since CARB's determination led the International Agency for Research on Cancer (IARC, a division of the World Health Organization) to list diesel engine exhaust as "carcinogenic to humans". This determination is based primarily on evidence from occupational studies that show a link between exposure to DPM and lung cancer induction, as well as death from lung cancer. Download the IARC report (external site).

Because it is part of PM2.5, DPM also contributes to the same non-cancer health effects as PM2.5 exposure. These effects include premature death, hospitalizations and emergency department visits for exacerbated chronic heart and lung disease, including asthma, increased respiratory symptoms, and decreased lung function in children. Several studies suggest that exposure to DPM may also facilitate development of new allergies. Those most vulnerable to non-cancer health effects are children whose lungs are still developing and the elderly who often have chronic health problems.

Estimated Health Effects of DPM in California

DPM has a significant impact on California's population. It is estimated that about 70% of total known cancer risk related to air toxics in California is attributable to DPM. Based on 2012 estimates of statewide exposure, DPM is estimated to increase statewide cancer risk by 520 cancers per million residents exposed over a lifetime. Non-cancer health effects associated with exposure to DPM (based on 2014 - 2016 air quality data) are shown in the table below.

Health Effect	**Estimated Annual Number of Cases***
Cardiopulmonary Death	730 (570 – 890)
Hospitalizations (Cardiovascular and Respiratory)	160 (20 – 290)
Emergency Room Visits for Asthma	370 (240 – 510)

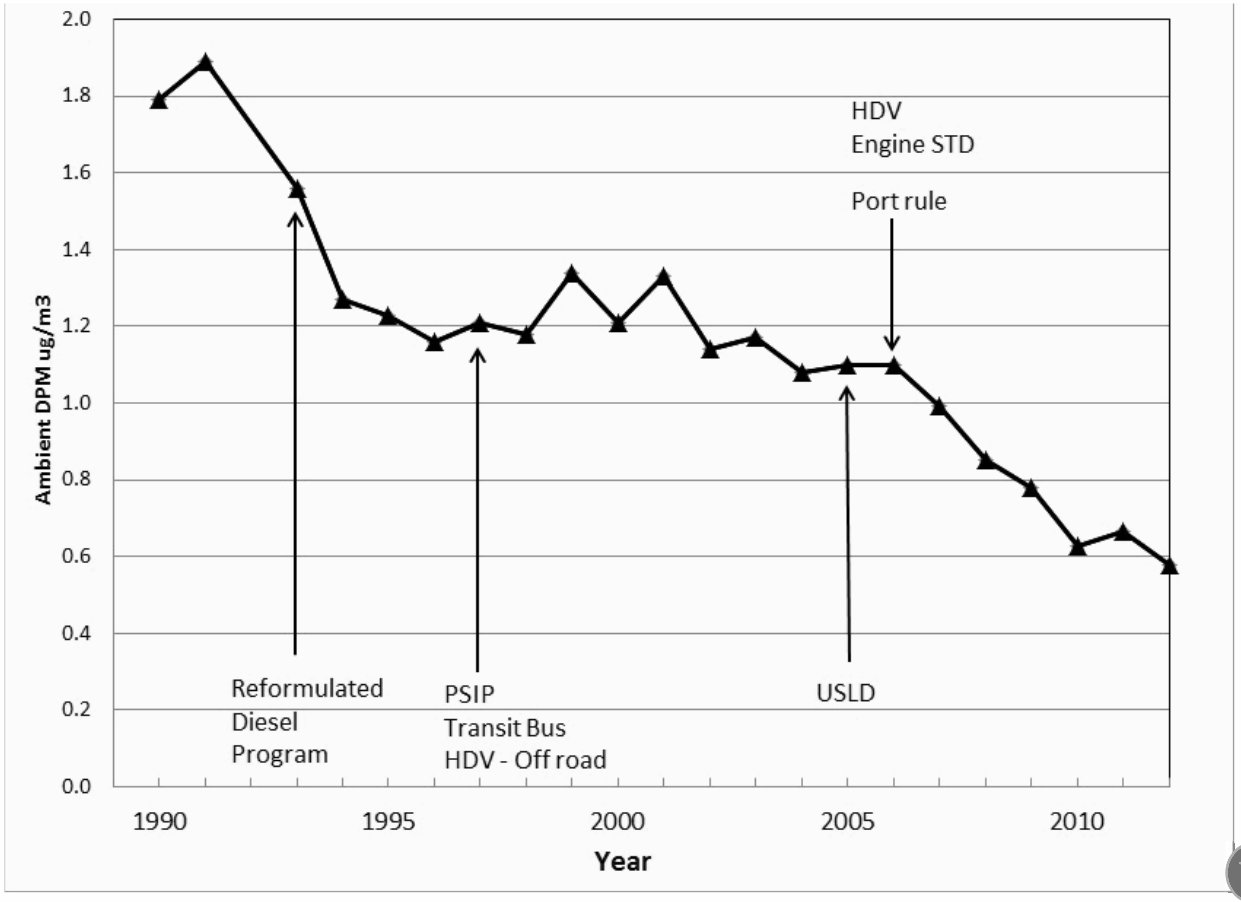
*Values in parenthesis indicate 95% confidence interval.

More Information

Trends in Outdoor Levels of DPM

The figure below shows the trend in ambient DPM. CARB regulations** of diesel engines and fuels have had a dramatic effect on DPM concentrations. Since 1990, DPM levels have decreased by 68%. The figure also shows which regulations have had the greatest impact on DPM.

DPM levels are expected to continue declining as additional controls are adopted, and the number of new technology diesel vehicles increases.


2.0
1.8
1.6
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1.2
1.0
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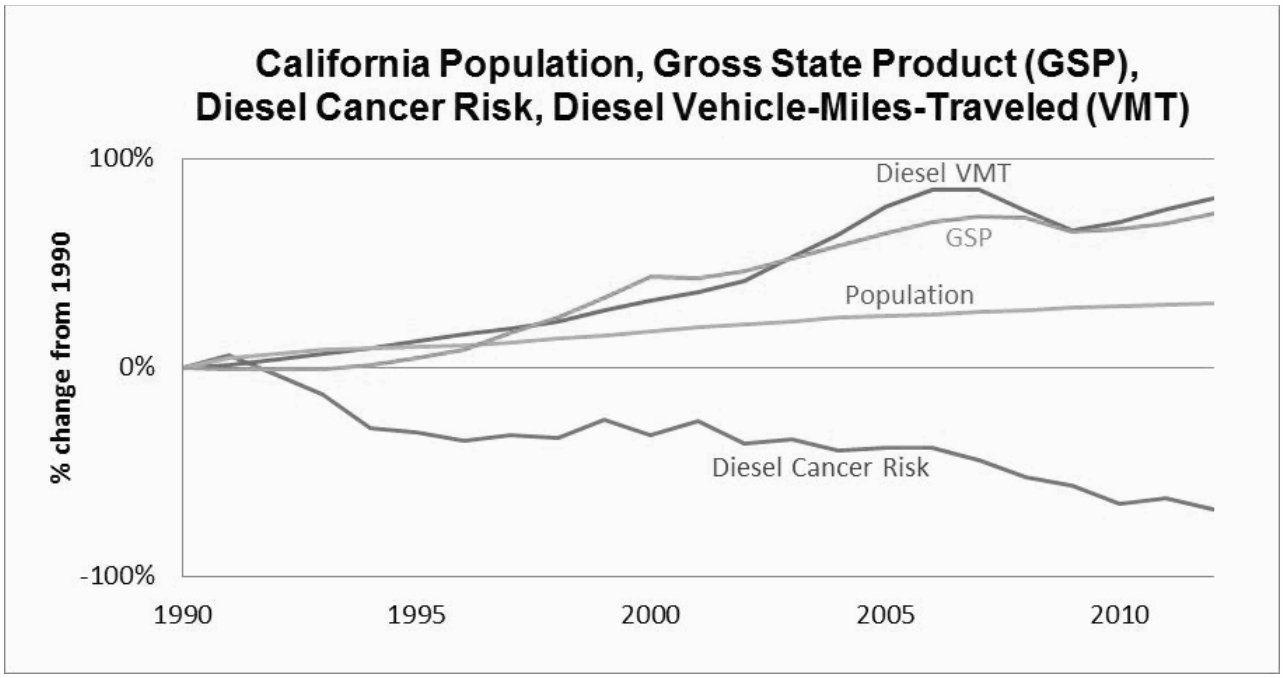
0.2
0.0
Ambient DPM ug/m3
1990
1995
2000
2005
2010
Year
HDV
Engine STD
Port rule
Reformulated
Diesel
Program
PSIP
Transit Bus
HDV - Off road
USLD

**Abbreviations of CARB regulations used in table: HDV Engine STD = Heavy-duty diesel truck engine standard; HDV - Off road = Heavy-duty off-road diesel engines; Port rule = Port (drayage) trucks; PSIP = Periodic self-inspection program; Transit bus = Urban transit buses; ULSD = Clean diesel fuel

The figure below shows that despite the increased number of vehicle miles traveled by diesel vehicles (VMT, red line), and despite increases in statewide population (green line) and gross state product (GSP, a measure of growth in the state's economy, light blue line), CARB's regulatory programs still led to a decline in statewide cancer risk (dark blue line).



Additional Information

- CARB's diesel programs
- CARB's diesel mobile vehicles and equipment activities

- CARB's freight transport, ports and rail programs
- California's diesel fuel program
- Other diesel-related programs
- Selected references on diesel-related health effects

Environmental Effects of Diesel Exhaust

In addition to its health effects, diesel exhaust significantly contributes to haze that reduces visibility by obscuring outdoor views and decreasing the distance over which one can distinguish features across the landscape. Researchers have reported that in the San Joaquin Valley and in southern California, diesel engines contribute to a reduction in visibility. This decrease in visibility is caused by scattering and absorption of sunlight by particles and gases present in diesel emissions.

DPM also plays an important role in climate change. A large proportion of DPM is composed of BC. Recent studies cited in the Intergovernmental Panel on Climate Change report estimate that emissions of BC are the second largest contributor to global warming, after carbon dioxide emissions. Warming occurs when BC particles absorb sunlight, convert it into infrared (heat) radiation, and emit that radiation to the surrounding air. A recent California-specific study showed that the darkening of snow and ice by BC deposition is a major factor in the rapid disappearance of the Sierra Nevada snow packs. Melting of the snow pack of the Sierra Nevada earlier in the spring is one of the contributing factors to the serious decline in California's water supply. As additional DPM controls are adopted, and the number of new technology diesel vehicles increases, BC emissions will continue to decline.

Conclusions

Although progress has been made over the past decade in reducing exposure to diesel exhaust, diesel exhaust still poses substantial risks to public health and the environment. Efforts to reduce DPM exposure through use of cleaner-burning diesel fuel, retrofitting engines with particle-trapping filters, introduction of new, advanced technologies that reduce particle emissions, and use of alternative fuels are approaches that are being explored and implemented. CARB anticipates

that newly adopted diesel exhaust control measures will reduce population exposure even further, and that as the sustainable freight program expands, population exposure to diesel exhaust pollution will decrease even further. It is estimated that emissions of DPM in 2035 will be less than half those in 2010, further reducing statewide cancer risk and non-cancer health effects.

RELATED RESOURCES

Characterizing Activity and Emissions of In-Use Commercial Harbor Craft

Sample CAP Incentives Policies and Procedures for Air Districts

South Los Angeles AB 617 Boundaries

(800) 242-4450 | helpline@arb.ca.gov
1001 I Street, Sacramento, CA 95814
P.O. Box 2815, Sacramento, CA 95812

Exhibit 3

Use of Back-up Engines for Electricity Generation During Public Safety Power Shutoff Events

CATEGORIES

Programs Emergency Backup Generators

Type Information

Disclaimer

The guidance that follows is intended to help provide an understanding of the California Air Resources Board (CARB) regulations that apply to the use of back-up engines for power during Public Safety Power Shutoff (PSPS) events. This guidance was developed in consultation with local air districts and does not alter or replace any specific requirements of applicable State or local regulations. Users should contact the air district in which the back-up reciprocating engine will be operated to ensure compliance with applicable regulatory and permitting requirements.

Background Regarding PSPS Events

Wildfires in California are occurring more often and are more destructive than ever. Fifteen of the 20 most destructive wildfires in the state's history have occurred since 2000; ten of the most destructive fires have occurred since 2015.[1] The state's fire season is now almost year round.[2] More than 25 million acres of California wildlands are classified under very high or extreme fire threat.[3] Approximately 25 percent of the state's population – 11 million people – lives in a high-risk area.[4] Within these high-risk fire areas, there are approximately 4.2 million wooden utility poles and 200,000 miles of overhead electric distribution lines.[5] These distribution networks have caused devastating wildfires, resulting in the loss of human life and billions of dollars in property damage over the past several years.

To reduce the risk of wildfires caused by electricity transmission and distribution networks – and the associated public health and safety impacts – State law and California Public Utilities Commission (CPUC) regulations require California's Investor-Owned Utilities (IOUs) to develop Wildfire Mitigation Plans (WMP).[6] The purpose of WMPs is to systematically reduce the risk of wildfires ignited by utility infrastructure over the next 10 years and beyond through a clearly articulated statewide vision to coordinate efforts, evaluate mitigation options, and assess progress.[7] Strategies in WMPs include: vegetation management (e.g. clearing vegetation growth near power lines), system hardening (e.g. installation of insulated conductors), and, as a last resort, de-energization of transmission and distribution systems (also referred to as Public Safety Power Shutoffs or PSPS events). The design of the utility system, the vegetation, terrain, and weather conditions each play a role in the utility companies' decisions to de-energize their infrastructure.

Since 2013, when San Diego Gas and Electric Company first began de-energizing its lines to proactively prevent wildfires, California's IOUs have de-energized their lines on nearly 30 days, with each PSPS event lasting an average of more than 30 hours.[8] The number of people impacted by each PSPS event, to date, varies greatly, ranging from very few customers to thousands.[9] PSPS events affect primarily rural and suburban areas with a high fire risk throughout the State.[10] However, because of the design of California's electricity transmission and distribution network, PSPS events may also impact people living in highly urbanized areas remote from high-risk fire areas.

When a utility provider de-energizes its power lines, the risk of the system sparking a wildfire is greatly reduced. However, power loss has many negative impacts, especially to vulnerable populations (including residential customers that rely on reliable electric service to power life-saving medical devices), medical and emergency service providers (including hospitals, fire departments and police stations), and important public service providers (such as water agencies, gas stations and grocery stores). In order to mitigate the damage of power loss, many of these critical service providers may rely on back-up engines to replace lost grid power. Additionally, many businesses may use back-up engines to avoid catastrophic system disruptions and to minimize economic disruption that could result from prolonged power outages. This use of back-up engines may result in air quality and public health impacts, as discussed further herein.

Use of Back-up Engines to Provide Power During PSPS Events

When electric utilities de-energize their electric lines, the demand for back-up power increases. This demand for reliable back-up power has health impacts of its own. Of particular concern are health effects related to emissions from diesel back-up engines. Diesel particulate matter (DPM) has been identified as a toxic air contaminant, composed of carbon particles and numerous organic compounds, including over forty known cancer-causing organic substances. The majority of DPM is small enough to be inhaled deep into the lungs and make them more susceptible to injury. Much of the back-up power produced during PSPS events is expected to come from engines regulated by CARB and California's 35 air pollution control and air quality management districts (air districts). The following sections discuss the requirements applicable to such engines.

Requirements Applicable to Stationary Engines

Air District Permitting and Rule Requirements

Stationary back-up engines are often subject to air district requirements. These requirements vary by air district, and they may include permitting requirements, emission limits, and operational restrictions. Owners and operators of stationary back-up engines should contact the air district in which the engine would be operated to ensure that such engines are operated in accordance with applicable air district rules and requirements.

Airborne Toxic Control Measure for Stationary Compression Ignition Engines

CARB's Airborne Toxic Control Measure (ATCM) for Stationary Compression Ignition Engines[11] (Stationary Engine ATCM) establishes emission limits and operational restrictions for stationary compression-ignition engines rated at greater than 50 brake horsepower (bhp). Portable engines, as defined by the Stationary Engine ATCM, and spark-ignition engines are not subject to the requirements of the Stationary Engine ATCM.[12]

Exhibit 4

ELECTRIC RULE NO. 18 Sheet 1
SUPPLY TO SEPARATE PREMISES AND SUBMETERING OF ELECTRIC ENERGY

A. SEPARATE METERING

Separate premises, even though owned by the same customer, will not be supplied through the same meter, except as may be specifically provided for in the applicable rate schedule.

B. OTHER USES OR PREMISES

A customer shall not furnish or use electricity received from PG&E upon premises, or for purposes, other than those specified in the customer's application for service except: (T)

(N)

1. For PG&E's Operating Convenience as defined in PG&E's Rule 1, or

2. Where, pursuant to D.21-01-018, microgrids owned by public agencies[1] or third-party that primarily serves a facility operated by, or on behalf of, a public agency are permitted to supply electricity to a critical facility[2] owned or operated by, or on behalf of, a public agency on an adjacent Premises to conduct emergency and/or critical operations during a grid outage. The public agency, third-party owner of the microgrid, or the customer at the adjoining Premises is required to install a device, subject to PG&E's review and approval, that prohibits parallel operations of the service line between the Premises during normal operation. This exception is subject to the limitation of Public Utilities Code Section 218. Additionally, this exception is available until PG&E has reached the cap adopted in D.21-01-018 of ten projects that completed the interconnection process and received permission to operate in PG&E's service territory. (N)

(N)

[1] Public agencies for purposes of this exception are defined as state, county, local, and tribal agencies.

[2] For purposes of this exception, a facility is considered a critical facility if it is included in PG&E's existing critical facilities list. The critical facilities list is developed and managed by PG&E in partnership with local government, and subject to the process adopted by the CPUC in D.19-05-042 and subsequent decisions. (N)

(Continued)

Exhibit 5

ELECTRIC SCHEDULE E-CMET Sheet 1 (N)
COMMUNITY MICROGRID ENABLEMENT TARIFF (N)

1. APPLICABILITY: The Community Microgrid Enablement Tariff (CMET) schedule (Schedule CMET or this Schedule) implements, in part, on an experimental basis the Community Microgrid Enablement Program (CMEP) pursuant to Public Utilities Commission (CPUC) Decision (D.) D.20-06-017 and CPUC Resolution E-5127. This CMET governs the eligibility, engineering studies, development, and island and transitional operation of Community Microgrids, as defined herein, under the CMEP. As an experimental tariff associated with a limited CMEP, this Schedule is available, on a first-come, first-served basis, to applicants (CMET Applicants) who (i) meet the CMET Eligibility Criteria in Section C, and (ii) submit a complete CMET Application (Application). This Schedule will close to CMET Applicants on the date set forth in Section D, below. Capitalized terms specific to this tariff are defined in section N below. (N)

2. TERRITORY: This schedule applies throughout PG&E's electric service area.

3. CMET ELIGIBILITY CRITERIA: A CMET Applicant must meet all of the eligibility criteria outlined below (CMET Eligibility Criteria):

   1. Community Microgrid: The CMET Project, consistent with the framework for the CMEP approved in CPUC D.20-06-017, must meet the needs of at least one Critical Facility and at least one additional customer within the Microgrid Boundary.

   2. Location: The CMET project must be located either in a Tier 2 or Tier 3 High Fire Threat District (HFTD), in an area that has been impacted by a Public Safety Power Shutoff (PSPS) event in the past, or is in an Outage Prone Area. CMET Projects located in areas that have been excluded from all reasonably anticipated potential future PSPS events due to other PSPS mitigation activities will not be eligible, regardless of whether they have previously experienced a PSPS event. (N)

(Continued)

3. CMET ELIGIBILITY CRITERIA (Cont'd.)

3. Community Microgrid Parameters: The CMET Project must include interconnected exporting energy producing resources (Project Resources) that do not exceed 20MW in aggregate within a clearly defined Microgrid in PG&E's Distribution System with a single Microgrid Islanding Point; the CMET Project must act as a single, controllable entity; the CMET Project must be able to connect to, disconnect from, and run in parallel with larger portions of the electrical grid; and the CMET Project must be capable of maintaining electrical supply and service quality when isolated to connected customers during larger grid disturbances. Project Resources must be interconnected to PG&E's Distribution System pursuant to PG&E's Wholesale Distribution Tariff (WDT) and/or Electric Rule 21 as applicable. (N)

4. Community Interest: The CMET Applicant must provide to PG&E a written letter from i) any local government or Tribe , as applicable, with jurisdiction over the area within the proposed Microgrid Boundary, or ii) Community Choice Aggregator that provides service within the proposed Microgrid Boundary to document an expression of interest in the CMET Project as part of the Application.

5. Pre-Application Report: The CMET Applicant must complete a Community Microgrid Pre-Application Report (CM Pre-Application Report) and consultation with PG&E prior to submitting a CMET Application.

6. Applicant Experience: The CMET Applicant must provide to PG&E an attestation that at least one current member of its development team has: (a) completed the development of at least one microgrid project of similar technology and capacity; or (b) begun construction of at least one other project of similar technology and capacity. The CMET Applicant must identify the entity(ies), if not the Applicant, that will be responsible for development of the CMET Project and the entity that will be the CMET Aggregator responsible for coordinated operation with PG&E pursuant to Rule 24 and an executed CMET Microgrid Operating Agreement ("CMET MOA" or "MOA"). (N)

(Continued)

ELECTRIC SCHEDULE E-CMET Sheet 3 (N)
COMMUNITY MICROGRID ENABLEMENT TARIFF (N)

4. CMET PERIOD

CMET Availability Period: The CMET shall begin on the Effective Date and shall continue thereafter until the close on December 31, 2022. At the close of the CMET, this Schedule will close to new Applications and no new CMET MOAs will be offered by PG&E. Applications submitted prior to the close will continue to be processed under this Schedule. Any MOA executed under this Schedule will continue in effect pursuant to the terms of the agreement. (N)

5. INTERCONNECTION STUDIES

1. Each Project Resource is required to be interconnected to PG&E's Distribution System under PG&E's WDT or Electric Rule 21, according to the applicability of each of those tariffs.

2. Interconnection Study: A CMET Project will require a separate application for Interconnection Study of a CMET Project's proposed Project Resources pursuant to PG&E's WDT or Electric Rule 21, as applicable for each of the Generating Facilities participating as a Project Resource.

3. Interconnection Agreement: The Interconnection Study will identify any required Interconnection Facilities, Distribution Upgrades, or Network Upgrades consistent with PG&E's WDT and Electric Rule 21, as applicable. The CMET Project is required to execute an Interconnection Agreement for each Project Resource.

4. A CMET Applicant will have up to 30 calendar days to review the Interconnection Study. The CMET Applicant, after review, will notify PG&E in writing within 5 calendar days its agreement to proceed with a Microgrid Islanding Study and pay any additional fees for this study, or its withdrawal of the Application. If the CMET Applicant fails to notify PG&E in writing within 5 calendar days after review of the Interconnection Study, the Application for the purpose of CMET Project development will be deemed withdrawn.

5. Applicant may continue with the interconnection of resources under PG&E's WDT or Rule 21 independent of a withdrawn CMET Application. (N)

(Continued)

6. MICROGRID ISLANDING STUDY (N)

1. Once it has received an agreement with the Applicant to do so, PG&E will conduct a Microgrid Islanding Study to determine i) the engineering and operational viability of the proposed CMET Project's Microgrid Boundary, ii) protection requirements to ensure faults within the microgrid can be detected when in Island Mode, iii) controls requirements to ensure power quality is maintained when in Island Mode, iv) telemetry and cybersecurity requirements, iv) and the required electrical system upgrades (Special Facilities) to establish the CMET Project Microgrid Boundary and microgrid operational controls, and v) the non-binding preliminary estimated costs and scheduled completion date for such Special Facilities, that will be required to enable the CMET Project. This Microgrid Islanding Study will include a description of operations for the CMET Project that includes a logical architecture for the associated protection, controls, communications, cybersecurity and other system components. One outcome of the Microgrid Facilities Study will be to produce a required CMET Project Special Facilities Agreement, pursuant to Electric Rule 2. Customer owned microgrid controllers and protective relays must be validated by PG&E for the interoperability with PG&E's electric distribution system. PG&E will publish a list of approved equipment and establish open and objective criteria for vendors to seek acceptance by PG&E.

2. CMET Applicant Review

   a. CMET Applicant will have up to 30 calendar days to review the Microgrid Islanding Study and sign the Special Facilities Agreement (Project SFA) and agree in writing to enter into a Microgrid Operating Agreement.

   b. If an Applicant agrees to proceed, the CMET Project will be included in the Allocated Capacity calculation under the applicable Interconnection Study.

   c. If, after review, the CMET Applicant declines to proceed with the CMET Project, the CMET Applicant will notify PG&E in writing within 5 calendar days and the Application will be deemed withdrawn. (N)

(Continued)

7. COMMUNITY MICROGRID DEVELOP-MENT AND OPERATION

CMET Project development and operation will be governed by the MOA. A CMET Project's use of PG&E's Distribution System to form a Community Microgrid requires operational coordination for public safety and overall Distribution System operation. (N)

1. Roles and Responsibilities.

   a. Distribution Provider. PG&E as utility distribution owner and operator is responsible for Distribution Service under both Blue Sky and Island Modes including the sole determination of Emergency Events.

   b. Distribution Service. PG&E will provide Distribution Service for the customers and resources within the CMET Project during Blue Sky and Island Modes pursuant to all applicable rules on file with the CPUC.

   c. Community Microgrid Aggregator (CMG Aggregator). A third-party aggregator that coordinates control of distributed resources, including Project Resources and any demand side management resources, consistent with relevant provisions of Electric Rule 2, PG&E's WDT, and Electric Rule 21 including frequency and voltage and other power quality requirements within PG&E established control parameters to enable the CMET Project to operate in Island Mode.

2. Microgrid Operating Agreement. An MOA between the CMG Aggregator and PG&E will govern CMET Project development testing and commercial operations. The MOA will include operational coordination requirements applicable to the unique characteristics of the CMET Project and general requirements consistent with relevant provisions of Electric Rule 2, Electric Rule 21, PG&E's WDT and associated interconnection agreements, Project SFA and operating protocols of the Distribution Provider to ensure operational coordination for public safety and overall system operation. The MOA is dependent upon execution of any required Interconnection Agreements and Special Facilities Agreements. (N)

(Continued)

7. COMMUNITY MICROGRID DEVELOPMENT AND OPERATION (Cont'd.)

2. Microgrid Operating Agreement. (Cont'd.) (N)

   a. Applicant and PG&E will execute a mutually agreeable MOA within 90 days of execution of the later of any applicable Interconnection or Special Facilities Agreements.

   b. If the CMET Aggregator and PG&E fail to execute a MOA within the specific time period, the Application will be considered rejected.

3. Material Modification. A Material Modification will require re-study of the changes in a new Microgrid Islanding Study.

4. PG&E reserves the right to suspend CMET Project operation, change the Microgrid Islanding Point, or other Distribution System changes required to meet its service obligations pursuant to all applicable rules on file with the CPUC.

8. CMET SERVICES AND FEES

1. PG&E Services provided under this tariff will be provided pursuant to PG&E's WDT or Electric Rule 21 as applicable, and other applicable tariffs or rules, as may be amended from time to time.

2. CMET Applicant is responsible for all applicable interconnection study fees and, subject to Section E.3, any required distributed resource interconnection distribution upgrades and service upgrades pursuant to applicable rules including NEM or D.02-03-057 as may pertain to individual Project Resources.

3. CMET Applicant is responsible for the Microgrid Pre-Application Study, Microgrid Islanding Study fees and subsequent Special Facilities costs pursuant to Electric Rule 2. Such study fees and special facilities costs may be eligible for credits to offset any applicable costs to Applicant pursuant to the CMEP. (N)

(Continued)

ELECTRIC SCHEDULE E-CMET Sheet 7 (N)
COMMUNITY MICROGRID ENABLEMENT TARIFF (N)

9. PG&E TARIFFS, PROGRAMS AND SERVICE AGREEMENTS (N)

1. PG&E Tariffs During Island and Blue Sky Modes. Billing for PG&E Bundled Customers will continue to occur under their applicable PG&E tariff provisions and rules.

2. Participation in PG&E Programs. Project Resources are eligible to provide distribution services and/or participate in demand side management programs during Blue Sky Mode consistent with applicable PG&E tariffs, programs or procurements. However, participation in PG&E programs shall not impede the ability to enable Island Mode, as determined by the Distribution provider, Island Mode, at any time during which this tariff applies to the CMET Project or the CMET MOA for the CMET Project is in effect.

3. Services Agreements. An existing power purchase agreement or other contract for energy, capacity or distribution services to PG&E, or any other counterparty, is prohibited for a CMET Project, if such PPA or other contract impedes the ability to enable Island Mode, as determined by Distribution Provider, at any time during which this tariff applies to the CMET Project or the CMET MOA for the CMET Project is in effect.

10. CAISO MARKET PARTICIPAT-ION

1. Participation in CAISO Market: Project Resources are eligible to participate in the CAISO markets consistent with applicable tariffs and the governing Interconnection Agreement for each Generating Facility during Blue Sky Mode. During Island Mode, the settlement of energy transactions associated the Project Resources will continue to occur according to applicable CAISO tariff provisions and rules, as further described in the CMET MOA.

11. METERING

CMET Project metering requirements are defined in the applicable PG&E Electric Rules including, but not limited to, 2, 15, 16, 17, 18, 21, and PG&E's WDT. (N)

(Continued)

ELECTRIC SCHEDULE E-CMET Sheet 8 (N)
COMMUNITY MICROGRID ENABLEMENT TARIFF (N)

12. TERMINATION

1. Applicant Termination: (N)

   a. Applicant may terminate the application process, including Microgrid Islanding Study, for any reason with 30 days written notice. Applicant will be responsible for any PG&E costs incurred through termination date.

   b. CMET Project development or operation may be terminated pursuant to the terms of the MOA.

2. PG&E Termination: PG&E may terminate a CMET Project pursuant to the terms of the MOA.

13. CMET SPECIAL CONDITIONS

The following Special Conditions apply to PG&E's CMET:

1. CMET Suspension: Because this is an experimental tariff, PG&E may file a Tier 2 Advice Letter (AL) with the CPUC to suspend service under this Schedule. The AL will be served on the applicable CPUC service list and will be served on CMET Aggregators, CMET Applicants and any CMET Customers. The AL shall identify the portion of the CMET suspended, the reasons for the suspension, and PG&E's proposal for resolving the issue. (N)

(Continued)

ELECTRIC SCHEDULE E-CMET Sheet 9 (N)
COMMUNITY MICROGRID ENABLEMENT TARIFF (N)

14. CMET DEFINITIONS Capitalized terms in this Schedule have the meaning as defined in this Section. (N)

1. Affected System. An electric system other than the Distribution Provider's Distribution System that may be affected by a Material Modification.

2. Blue Sky Mode. The normal mode of operation when the Community Microgrid is Interconnected to and operating in parallel with the Distribution System, is not operating in Island Mode, and PG&E maintains operational coordination of the delivery of electric service.

3. CMET Applicant. The person or entity who submits an Application for a CMET Project to PG&E to apply to participate on this Schedule.

4. CMET Customer. A customer receiving PG&E distribution service within the CMET Project Microgrid Boundary.

5. CMET Project. Facilities and equipment needed to create and operate a Community Microgrid, including the generation, breakers, protective and associated equipment, improvements, and other tangible assets, contract rights, easements, rights of way, licenses and other interests or rights in real estate reasonably necessary for the construction, operation, and maintenance of the Community Microgrid subject to this CMET.

6. Community Microgrid. For the purposes of this Schedule, a Community Microgrid is defined as a microgrid with distribution system connected Project Resources that supply energy to at least one Critical Facility and at least one other customer within a Microgrid Boundary capable of Island Mode.

7. Community Microgrid Aggregator (CMG Aggregator). The entity that is providing microgrid forming service to PG&E under an executed CMET MOA pursuant to Rule 24. (N)

(Continued)

ELECTRIC SCHEDULE E-CMET Sheet 10 (N)
COMMUNITY MICROGRID ENABLEMENT TARIFF (N)

14. CMET DEFINITIONS (Cont'd.)

8. Community Microgrid Enablement Program (CMEP). PG&E program to enable community-proposed microgrids that provide enhanced resilience for critical facilities and vulnerable customer groups pursuant to D.20-06-017. (N)

9. Critical Facility. A facility that provides critical services to the surrounding community pursuant to the definition of Critical Facilities in D.19-05-042, aligned with Department of Homeland Security's Critical Infrastructure Sectors, as may be amended by the CPUC.

10. Distribution Provider. PG&E, which owns, controls, or operates facilities used for the delivery of electric energy and provides Distribution Service under this CMET.

11. Distribution Service. The transporting of electric power over and through various PG&E facilities for delivery to a Distribution Customer. The Distribution Service provided under this CMET is the distribution of capacity and energy from the Point(s) of Receipt to the Point(s) of Delivery under this CMET.

12. Distribution System. PG&E's distribution system broadly consists of the stepdown substations, the primary distribution circuits, and the secondary distribution system. The secondary distribution system consists of the line transformers that step the primary voltage down to a secondary voltage, and the secondary conductors. The provisions of this CMET applies to service on this Distribution System.

13. Effective Date. The date upon which any CPUC disposition of the CMEP Advice Letter makes that Advice Letter effective. (N)

(Continued)

ELECTRIC SCHEDULE E-CMET Sheet 11 (N)
COMMUNITY MICROGRID ENABLEMENT TARIFF (N)

14. CMET DEFINITIONS (Cont'd.)

14. Emergency Events. As determined by PG&E in its reasonable discretion, a condition or situation requiring prompt action by PG&E (a) to maintain the reliable operation of the Distribution System; (b) to prevent or limit the loss of load or generation; (c) to maintain public safety or the safety of PG&E's personnel; (d) to protect PG&E, Customer, or third-party property; or as a Scheduled Island Mode Operation as a preventative action ahead of impending weather events or natural disasters or in response to other unusual conditions. (N)

15. Generating Facility. All generators, electrical wires, equipment, and other facilities, excluding Interconnection Facilities, owned or provided by Producer for the purpose of producing electric power, including storage.

16. High Fire Threat District. An area where there is an elevated risk for power line fires igniting and spreading rapidly as identified in the CPUC Fire-Threat Map, as may be amended.

17. Interconnection Study. A study to establish the requirements for Interconnection of a Generating Facility with Distribution Provider's Distribution System or Transmission System, pursuant to WDT or Rule 21, as applicable.

18. Island Mode. A mode of operation when a Microgrid that normally operates in Grid-Connected Mode is disconnected from the Distribution System at MIP, and the Microgrid is generating or producing energy to provide electric service within the Microgrid under the operational coordination of the CMET Aggregator.

19. Material Modification is a change in Project Resources, non-Project Resources, or customer loads within the Microgrid Boundary, or other Affected Systems outside the Microgrid Boundary that has a material impact on the ability of a CMET Project to function in Island Mode. (N)

(Continued)

ELECTRIC SCHEDULE E-CMET Sheet 12 (N)
COMMUNITY MICROGRID ENABLEMENT TARIFF (N)

14. CMET DEFINITIONS (Cont'd.)

20. Microgrid. An interconnected system of loads and energy resources, including, but not limited to, distributed energy resources, energy storage, demand response tools, or other management, forecasting, and analytical tools, appropriately sized to meet customer needs, within a clearly defined electrical boundary that can act as a single, controllable entity, and can connect to, disconnect from, or run in parallel with, larger portions of the electrical grid, or can be managed and isolated to withstand larger disturbances and maintain electrical supply to connected critical infrastructure. (N)

21. Microgrid Boundary. An electrically contiguous area beyond a Microgrid Islanding Point on the Distribution System that defines a microgrid as a single controllable entity.

22. Microgrid Islanding Point (MIP). The point on PG&E's distribution System that establishes the microgrid interface consistent with applicable standards including IEEE 1547-2018 and IEEE 519.

23. Microgrid Island Study. An engineering study conducted by the Distribution Provider to determine the required modifications to the Distribution Provider's Distribution Facilities, including the cost and scheduled completion date for such modifications, that will be required to provide the requested Microgrid Boundary and island operation capable of maintaining voltage, frequency and power quality within PG&E control parameters in accordance with Rule 2.

24. Microgrid Operating Agreement. An agreement between the PG&E and CMG Aggregator that governs CMET Project development and testing, and commercial operations to ensure safety and service quality in compliance with applicable rules. (N)

(Continued)

ELECTRIC SCHEDULE E-CMET Sheet 13 (N)
COMMUNITY MICROGRID ENABLEMENT TARIFF (N)

14. CMET DEFINITIONS (Cont'd.)

25. Microgrid Pre-Application Study. A preliminary study of a proposed Community Microgrid and consultation for the purpose of enabling an Applicant to develop an effective CMET Application. (N)

26. Outage Prone Area. Areas served by the top 1% Worst Performing Circuits excluding Major Event Days as shown in PG&E's Annual Electric Reliability Report, in either the AIDI or AIFI category, in either of the last 2 years.

27. PG&E Bundled Customer. A customer receiving full retail electric service from PG&E under an applicable retail tariff.

28. Project Special Facilities Agreement (Project SFA). A Special Facilities Agreement for the CMET Project Service Facilities upgrades necessary to enable Blue Sky and Island Mode operations.

29. Project Resource. Electric generation and storage technology used to form a microgrid that are interconnected to the Distribution System pursuant to PG&E's WDT or Electric Rule 21 within the Community Microgrid Project Microgrid Boundary that complies with the emissions standards adopted by the State Air Resources Board pursuant to the distributed generation certification program requirements of Section 94203 of Title 17 of the California Code of Regulations, or any successor regulation.

30. Scheduled Island Mode Operation. A Microgrid operating in Island Mode that is scheduled and coordinated between the CMG Aggregator and PG&E. (N)

(Continued)

ELECTRIC SCHEDULE E-CMET Sheet 14 (N)
COMMUNITY MICROGRID ENABLEMENT TARIFF (N)

14. CMET DEFINITIONS (Cont'd.)

31. Service Facilities. PG&E's Service Facilities shall consist of (a) primary or secondary underground or overhead service conductors, (b) poles to support overhead service conductors, (c) service transformers, (d) PG&E-owned metering equipment, and (e) other PG&E-owned service-related equipment that extend from PG&E's Distribution Facilities to the Customer's Service Delivery Point as defined in PG&E's Electric Rule 16. (N)

32. Special Facilities Agreement. Special facilities will be installed under the terms and conditions of a contract in the form on file with the Commission, pursuant to Electric Rule 2.

33. Unscheduled Island Mode Operation. A Microgrid operating in Island Mode that is not scheduled or coordinated between the CMG Aggregator and PG&E in response to an unplanned event on the Distribution System. (N)

(Continued)

Exhibit 6

Microgrid Incentive Program

Incentive Program (MIP) approved earlier this year by the California Public Utilities Commission (CPUC). The program is intended to fund clean energy microgrids to support the critical needs of vulnerable populations impacted by grid outages.

Please find information and the schedule for the workshops below. To register, click on the link provided below or in the email invitation you may have received. If you would like to present on a topic at one or more workshops, please contact us via the information provided below. A detailed agenda will be finalized prior to each workshop and will be provided in advance to registered attendees.

Background

On January 21, 2021, the CPUC issued Decision D.21-01-018, which among other items, approved $200 million statewide for a new Microgrid Incentive Program intended to fund clean energy microgrids to support the critical needs of vulnerable populations impacted by a grid outage. The decision was issued in Track 2 of the Rulemaking 19-09-009, the Order Instituting Rulemaking Regarding Microgrids Pursuant to Senate Bill 1339 and Resiliency Strategies, September 12, 2019. For more information on this proceeding, visit **www.cpuc.ca.gov/resiliencyandmicrogrids**.

Stakeholder workshop purpose

Session Name

Meeting 1: Laying the Foundation

What should guide the development of the MIP? How do we most effectively engage communities and target the MIP?

Agenda Items and Description

Objectives and Goals

- Identify the overarching objectives established in the Staff Proposal and Track 2 Decision.

Guiding Principles

- What data regarding project costs, performance, etc. should be required to be made available to the CPUC, the Joint IOUs or the general public?

Date and Time

July 7, 2021, 1 p.m. – 5 p.m. PT*

WORKSHOP 1 - LAYING THE FOUNDATION (PDF, 264 KB)

Session Name

Meeting 2: Program Design

Exhibit 7

Clean Air Plans; 2008 8-Hour Ozone Nonattainment Area Requirements; San Joaquin Valley, California

A Rule by the Environmental Protection Agency on 03/25/2019

DOCUMENT DETAILS

Printed version:
PDF (https://www.govinfo.gov/content/pkg/FR-2019-03-25/pdf/2019-05159.pdf)

Publication Date:
03/25/2019 (/documents/2019/03/25)

Agency:
Environmental Protection Agency (https://www.federalregister.gov/agencies/environmental-protection-agency)

Dates:
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40 CFR 52

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FRL-9990-13-Region 9

Document Number:
2019-05159

Exhibit 8

PACIFIC GAS AND ELECTRIC COMPANY

2021 WILDFIRE MITIGATION PLAN REPORT

RULEMAKING 18-10-007

FEBRUARY 5, 2021

7.3.3.11 Mitigation of Impact on Customers and Other Residents Affected During PSPS Event

WSD Initiative Definition: *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).*

For this initiative, PG&E has several sub-initiatives including:

- 7.3.3.11.1: Generation for PSPS Mitigation:

  This sub-initiative provides an overview of microgrids and back-up generation to mitigate the impact of PSPS events. PG&E then provides more detail concerning five programs as well as responses to certain Action Items:

  A) Generation Enablement and Deployment;

  B) Temporary substation microgrids;

  C) Temporary distribution microgrids;

  D) Back-up power for individual critical customer facilities;

  E) Community Resource Centers; and

  F) Responses to Action Items PGE-49 (Class B) and PGE-50 (Class B).

- 7.3.3.11.2: Substation activities to enable reduction of PSPS impacts; and

- 7.3.3.11.3: Emergency Back-up Generation – PG&E Service Centers & Materials Distribution Centers.

7.3.3.11.1 Generation for PSPS Mitigation

WSD Initiative Definition: *N/A. This is a "PGE-defined sub-initiative" that supports the response for the (parent) WSD-defined Initiative.*

This section addresses Actions PGE-49 (Class B) and PGE-50 (Class B).

1) Risk to be mitigated/problem to be addressed:

De-energization due to PSPS can create public safety risks for customers, as well as broader impacts for communities. Keeping communities and "main street corridors" energized helps to mitigate these risks. Temporary microgrids for PSPS mitigation support both the energization of broader communities and specific "main street corridors" with shared services and critical facilities to minimize the impacts of PSPS events.

2) Initiative selection ("why" engage in activity) – include reference to a risk informed analysis on empirical (or projected) impact of initiative in comparison to alternatives:

PG&E has two microgrid initiatives designed to support customers during PSPS, each of which is configured to address a different type of PSPS impact: (1) temporary Substation Microgrids are focused on keeping safe-to-energize customers online when a substation serving them is impacted by an upstream de-energization; and (2) temporary Distribution Microgrids are focused on energizing "main street corridors" with shared services and critical facilities when the distribution line serving these areas is de-energized. These specific initiatives are described below in subsections B and C. There are two other PSPS mitigation workstreams that leverage temporary generation, these are addressed in subsections D and E.

3) Region prioritization ("where" to engage activity) – include reference to a risk informed analysis in allocation of initiative (e.g., veg clearance is done for trees tagged as "high-risk"):

To determine the appropriate locations for temporary microgrids for PSPS mitigation, PG&E assesses the expected relative frequency of future PSPS impacts through analysis of historical meteorological data, prior PSPS event impacts, and parallel work- in-progress directed at reducing future impacts. The foundational data for selecting temporary microgrid sites for 2021 is an analysis of 10 years of historical weather events and actual 2020 PSPS event data.

Additionally, PG&E seeks to complement our internal location screening process for PSPS microgrids with county and local government collaboration to ensure that local priorities help shape site selection and design where technically feasible.

4) Progress on initiative (amount spent, regions covered) and plans for next year:

Information on the progress of the Temporary Substation Microgrids and Temporary Distribution Microgrids is provided in subsections B and C below.

5) Future improvements to initiative:

In 2021, PG&E intends to expand the pool of contractors and technologies for the development of microgrids, pilot viable non-diesel technologies, and explore opportunities to build a portfolio of non-fossil solutions for the longer term. This improvement is tied to PG&E's desire to meet California's clean energy goals and to increasing the ability of microgrids as one tool to mitigate wildfire risk and increase PSPS resilience.

ACTION PGE-25 (Class B)

1) Integrate discussion on long-term planning within the respective section of each individual initiative.

Response:

PG&E is in the process of shaping long-term plans for our microgrid initiatives, including microgrids for PSPS mitigation, through the Microgrid Order Instituting Rulemaking (OIR) (i.e., Rulemaking 19-09-009). As directed by the Track 2 Decision in that proceeding,[1] PG&E expects to file an application by June 30, 2021 proposing a long-term framework for using generation at substation to mitigate PSPS outages, including consideration of permanent and temporary solutions, the use of diesel alternatives, and the method of considering long-term microgrid solutions against other wires-based solutions. As part of that forthcoming application, PG&E expects to address the continuing evolution of fire risk modeling, which currently creates significant uncertainty regarding the long-term need for PSPS mitigation at specific locations. The framework will therefore need to be flexible, allowing decisions to be based upon the best information available at any given point in time and identifying, based on that information, any long-term microgrid initiatives that are reasonable and prudent across a range of scenarios. The resolution of that Application will determine long-term plan milestones set in future WMPs for this initiative.

A) Generation Enablement and Deployment

1. Risk to be mitigated/problem to be addressed:

The Generation Enablement and Development organization establishes permanent positions comprised of 10 Full-Time Equivalents (FTE) per the following functions: one Senior Manager to oversee the organization; one manager and four supervisors to ensure the safety of internal and

[1] D.21-01-018, App. A, pp. A-6 to A-8.

contractor crews during deployments, operational readiness and PSPS activations; one Operations Lead to coordinate with the Control Center processes and enhancements; one Substation Strategy manager to study effective and efficient utilization of TG at substations; one Process and Project Management to ensure that processes are developed, financial oversight and any operational readiness activities are appropriately project managed; Testing, Standards and New Technology manager in charge of continually improving and evolving a greener generation program.

Program breakdown of 10 FTE's per the below:

- 9 FTEs of this Temporary Generation (TG) organization are geared toward PSPS readiness and scalability processes for PSPS; and

- 1 FTE of this TG organization will Primarily support the Clean Substation pilot projects contemplated by the Microgrid OIR and more generally the transition to a cleaner fleet of TG as contemplated in that Rulemaking.

The TG Project Management Office (PMO) will reside within the Generation Enablement and Development organization with the purpose to coordinate, organize and establish a single source of reporting to senior leadership the operational readiness of procured TG in relation to the four workstreams incorporated within the TG PMO: Substation; Microgrids & Temporary Microgrids; Back-up Power Support; and Community Resource Centers (CRC). The TG PMO will also staff, coordinate and train Emergency Operations Center (EOC) TG members for PSPS event response along with other major emergency events.

2. ***Initiative selection ("why" engage in activity) – include reference to a risk informed analysis on empirical (or projected) impact of initiative in comparison to alternatives:***

   Establish a permanent organization structure to ensure uniformity year over year by managing improvement and efficiency gains by capturing, implementing and documenting the actions taken to support reduction of customer impacts during PSPS events. The new organization structure will also be better prepared to develop and execute longer duration New Technology project pilots and implementation.

3. ***Region prioritization ("where" to engage activity) – include reference to a risk informed analysis in allocation of initiative (e.g., veg clearance is done for trees tagged as "high-risk"):***

   The TG PMO will perform an annual analysis of generation uses as it relates to other system hardening, grid improvements, historical data and meteorological study. This analysis will inform the procurement and deployment of generation throughout the PG&E system for the combined four workstreams. The TG PMO will also engage Transmission and Distribution (T&D) planning and other system planning groups and provide suggestions to help improve electrical infrastructure that might reduce the need of TG for PSPS event.

4. ***Progress on initiative (amount spent, regions covered) and plans for next year:***

In Q1 of 2021, PG&E will establish the new Generation Enablement and Development team, post the above positions and hire successful candidates. The goal of this team will be to procure and deploy TG system wide across the four workstreams as described prior to the start of the 2021 PSPS season. This team will also work closely with stakeholders, vendors and regulators to ensure a transition to a cleaner TG fleet in 2021. The goal for this team is to establish at least one Clean Substation Project candidate site for testing and demonstration in 2021, and work to deploy the project if bids meet CPUC established cost-effectiveness criteria.

5. ***Future improvements to initiative:***

- Support for the filing of an application to establish a long-term framework for the procurement of local generation and other solutions to mitigate grid outages; once approved, carrying out the solicitations, grid upgrades, and other work described in the approved framework;

- The TG department will continue to position the organization to fall into line with the PG&E corporation's goal of meeting the new 60 percent by 2030 Renewable Portfolio Standard (RPS) mandate set forth by Senate Bill 100, as described in our RPS Procurement Plans filed at the CPUC. This will be achieved by continued testing, research, and development by the Generation Enablement and Deployment team to shift current temporary energy solutions to greener solutions that have a significantly lower carbon footprint;

- Support business continuity needs for other TG use cases such as:

  – Winter Storms;

  – Capacity Shortfall;

  – Planned Outages (T&D); and

  – Catastrophic Events (earthquakes, etc.).

- Develop internal represented classification that can perform the TG interconnection process that we are currently contracting.

B) Temporary Substation Microgrids

1. ***Risk to be mitigated/problem to be addressed:***

PG&E transmission lines that run through HFTD areas may be de-energized if weather and operational conditions warrant a PSPS event. It is possible that a distribution substation and its customers could be de-energized even if they physically reside outside of the PSPS event footprint because the transmission line serving the substation is de-energized.

2. ***Initiative selection ("why" engage in activity) – include reference to a risk informed analysis on empirical (or projected) impact of initiative in comparison to alternatives:***

Temporary substation microgrids are focused on keeping customers online when the substation serving them is impacted by an upstream transmission line de-energization and the substation still has safe-to-energize load. During 2020 PSPS events, PG&E was able to energize all substations impacted by a transmission-level outage that still had some safe-to-energize load.

TABLE PG&E-7.3.3-1: 2020 TEMPORARY SUBSTATION MICROGRIDS ENERGIZED

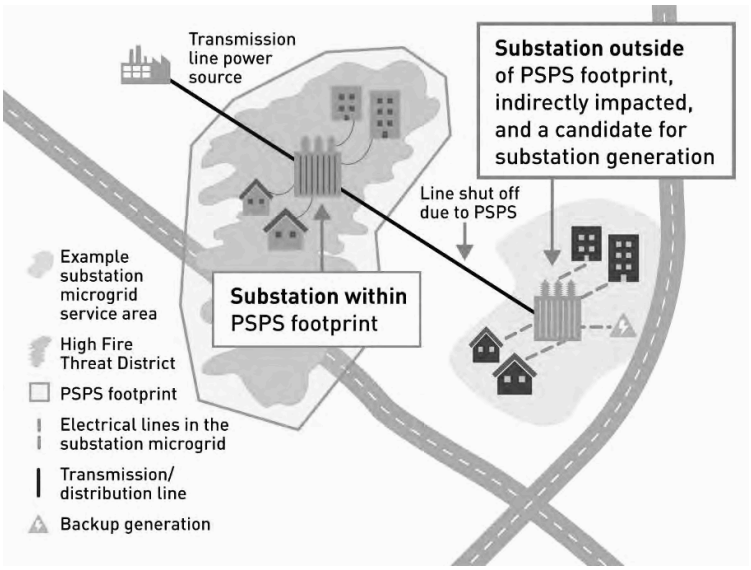
PSPS Event	Substation	Megawatts (MW)	Safe-to-Energize Customer Accounts Served
7-Sep	Brunswick	20	4,191
25-Oct	Hoopa	6	1,791
25-Oct	Willow Creek	12	2,332
25-Oct	Brunswick	20	4,259
25-Oct	Russ Ranch	0.5	2

3. ***Region prioritization ("where" to engage activity) – include reference to a risk informed analysis in allocation of initiative (e.g., veg clearance is done for trees tagged as "high-risk"):***

To determine the appropriate locations for substation temporary microgrids for 2021 PSPS mitigation, PG&E assesses the relative frequency of historical PSPS impacts through analysis of historical meteorological data, actual 2020 PSPS event impacts, and parallel work-in-progress directed at reducing future impacts. The foundational data for selecting temporary substation microgrid sites for 2021 is an analysis of 10 years of historical weather events. This "historical lookback" takes historical weather events and builds the associated PSPS events that would have occurred, including both T&D impacts.

This analysis identifies 28 weather events with 18 potential PSPS events involving transmission-level impacts. Through the historical look-back of these 18 transmission-level events, PG&E identifies substations that are most frequently experience de-energization due to a transmission or distribution PSPS outage. The circuits served by those substations that frequently experience PSPS de-energization in the look-back are screened for the presence of safe-to-energize distribution load. In addition, substations and their circuits are reviewed to determine whether other 2021 PSPS mitigations might remove them from scope (e.g., a switching solution, VM, etc.) or whether an existing solution is already in place (e.g., use of the existing Humboldt Bay Generating Station to create a multi-substation island).

FIGURE PG&E-7.3.3-1: EXAMPLE TEMPORARY SUBSTATION MICROGRID CONFIGURATION



4. Progress on initiative (amount spent, regions covered) and plans for next year:

2020

For 2020, PG&E reserved 350 megawatts (MW) (nameplate capacity) of TG for use across 62 substations in 19 counties. As the 10-year lookback analysis was not yet available, 2020 temp gen substation site selection was based on in-scope substations with safe-to-energize load during 2019 PSPS events.

i. The following substation site selection was used:

1. During 2019 PSPS events, 124 substations were de-energized due to transmission impacts but could carry some or all distribution load;
2. Less 51 substations that had fewer than 2 PSPS impacts caused by upstream transmission outages in 2019;
3. 73 substations had 2 or more transmission impacts with safe-to-energize distribution load;
4. Less 16 substations to be served by Humboldt Bay Generating Station;
5. 57 candidate substations for temp gen 2020; and
6. Additional substations added and removed based on analysis from Subject Matter Experts (SME) in Electric Operations.

PG&E prepared substations to receive TG in 3 different ways. This approach ensured PG&E could cover all 62 substations with 350 MW of TG (less than

the total peak load of all the substations). The strategy accounted for several substation characteristics including, historical frequency of impact, available land, proximity to other substations, and travel time. Table PG&E-7.3.3-2 below describes these distinct preparation strategies and the number of substations allocated to each strategy.

TABLE PG&E-7.3.3-2: TEMPORARY SUBSTATION DEPLOYMENT STRATEGIES AND NUMBER OF SUBSTATIONS IMPACTED

Deployment Strategy	Description of Strategy	Number of Substations and MWs of Generation Allocated
"Ready-to-Energize"	Substations that have generation interconnected, tested and released in advance of a PSPS event.	18 Substations – 225 MW
"Staged at Substation"	Substations that have generation placed at the substation in advance of a PSPS event.	3 Substations – 50 MW
"Hub-and-Spoke"	Substations that have an engineering guide to interconnect generation during a PSPS event. Generators are staged at yards regionally and dispatched to subs as needed.	39 Substations – 75 MW

2021 Planning

While PG&E has not yet completed the substation selection process described above, PG&E is currently planning to prepare at least eight substations to receive TG for 2021 PSPS mitigation. In addition, PG&E plans to pursue at least one clean substation pilot leveraging diesel-alternative technologies. PG&E issued a solicitation for diesel-alternative front-of-the-meter generation in January 2020 and is also exploring potential behind-the-meter and demand response opportunities at substations identified as needing a 2021 PSPS mitigation.

It is likely that a far higher percentage of substations (but not necessarily MWs) will be supported via a "Ready to Energize" (i.e., interconnected and tested) deployment strategy in 2021 than in 2020. This is due to learnings from 2020 PSPS events which indicated that the time between completion of "Playbook D" (identifies substations that will be de-energized) and de-energization can be constrained to less than 48 hours. PG&E's process to select locations and procure temporary generation for 2021 PSPS mitigation is still underway. This forecast and the associated language reflect PG&E's best-available data at the time of this filing. A more complete list of substation candidates for TG in 2021, the total MWs needed to support these substations, and a financial forecast will be submitted in the first quarter of 2021 as part of a Tier 2 Advice Letter required by the CPUC's Track 2 Decision in the Microgrid OIR.[2]

[2] D.21-01-018, App. A, pp. A-1 to A-3.

5. ***Future improvements to initiative:***

   As described above, the following improvements are being made to substation site selection and deployment strategy:

   - Use of 10-year historical lookback and 2020 PSPS event actuals to inform substation selection;
   - Transitioning towards greater reliance upon generation that is pre-interconnected at a substation to reduce in-event execution risk; and
   - Development of at least one clean substation pilot.

C) Temporary Distribution Microgrids

1. ***Risk to be mitigated/problem to be addressed:***

   Temporary distribution microgrids aim to support communities by energizing "main street corridors" with shared services and critical facilities when the distribution line serving these areas are de-energized as a result of a PSPS event.

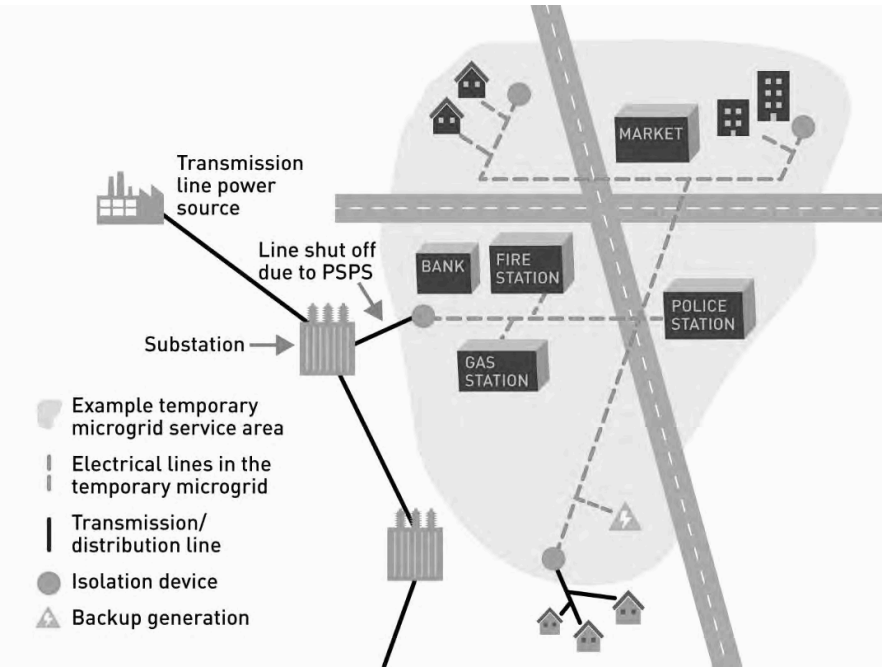
2. ***Initiative selection ("why" engage in activity) – include reference to a risk informed analysis on empirical (or projected) impact of initiative in comparison to alternatives:***

   PG&E's temporary distribution microgrids are designed to reduce the number of customers impacted by PSPS events and support community resilience by powering a cluster of shared resources (e.g., commercial corridors and critical facilities within the energized zones) so that those resources can continue serving surrounding residents during PSPS events. Though each distribution microgrid varies in scale and scope, the following design features are likely for each:

   - Devices used to disconnect the distribution microgrid from the larger electrical grid;
   - A pre-determined space for backup generation and equipment to allow for rapid connections (e.g., pre-installed interconnection hub (PIH)); and
   - The use of temporary generators allowing PG&E to shorten the design and construction time typically required to ready a permanent microgrid for operation.

   The diagram below represents an approximate layout of a temporary microgrid. With safety being the most critical design factor, each temporary microgrid is unique and is designed based on a number of different variables that dictate the size of the microgrid, what community services are served and what elements are included in the design. The layout and dimensions below are approximate and for illustrative purposes only.

FIGURE PG&E-7.3.3-2: EXAMPLE TEMPORARY DISTRIBUTION MICROGRID



3. Region prioritization ("where" to engage activity) – include reference to a risk informed analysis in allocation of initiative (e.g., veg clearance is done for trees tagged as "high-risk"):

To determine the appropriate locations for distribution microgrids, PG&E identifies distribution circuits most likely to be impacted by PSPS events in the future. PG&E reviews these circuits to identify communities with clusters of shared services (i.e., those involving food, fuel, healthcare and shelter) and critical facilities served by electrical infrastructure that would likely be safe to energize during PSPS events. To determine whether distribution microgrids present viable, effective near-term mitigation measures for a particular location, PG&E also reviews them for implementation feasibility (i.e., land availability and construction complexity) and the potential to be served by alternative grid solutions.

4. Progress on initiative (amount spent, regions covered) and plans for next year:

In 2020, PG&E operated four distribution microgrids with PIHs; thereby, energizing over 2,000 unique service points (customers) for as many as four PSPS events per service point (approximately 5,600 customer-events). PG&E committed 40 MW of TG to temporary distribution microgrids in 2020. The distribution microgrids are identified in Table PG&E-7.3.3-3 below.

TABLE PG&E-7.3.3-3: DISTRIBUTION MICROGRIDS THAT OPERATED IN 2020

Site	County	Year PIH Constructed	Approx. qty service pts	Number of 2020 PSPS Events Supported
Angwin PIH	Napa	2019 Pilot	48	4
Shingletown PIH	Shasta	2020	79	4
Calistoga PIH	Napa	2020	1554	3
Placerville	El Dorado	In progress for 2021	487	1

In addition, in late October 2020, PG&E readied two additional distribution microgrids in Lake County using a temporary configuration without a PIH. These distribution microgrids in North and South Clearlake were on standby to support customers if needed during the October 25, 2020 PSPS event and subsequent PSPS events.

For 2021, PG&E is planning to develop at least five additional distribution microgrid PIHs by the end of the calendar year. PG&E will continue to follow the methodology described in above to locate these sites, which considers likelihood of PSPS impacts, presence of shared services in corridors that can likely be safely energized during PSPS events, and implementation feasibility. As in prior years, PG&E will collaborate with county and local government to ensure local priorities help shape site selection and design where technically feasible.

5. Future improvements to initiative:

In 2021, PG&E intends to expand the pool of contractors and technologies for the development of microgrids, pilot viable non-diesel technologies, and explore opportunities to build a portfolio of non-fossil solutions for the longer term. This improvement is meant to further California's clean energy goals, rather than an activity tied to wildfire risk mitigation or PSPS resilience.

Additionally, the temporary distribution microgrid initiative will benefit from operational and administrative improvements derived from the Generation Enablement and Development organization being stood up in 2021 (see Section 7.3.3.11.1 subsection A for more information).

D) Back-Up Power for Individual Critical Customer Facilities

1. Risk to be mitigated/problem to be addressed:

The loss of power at certain critical customer facilities during a PSPS event could pose significant public health and safety risks, especially for prolonged outages (48 + hour).

2. Initiative selection ("why" engage in activity) – include reference to a risk informed analysis on empirical (or projected) impact of initiative in comparison to alternatives:

As a general policy, PG&E does not offer backup generation to individual facilities. However, PG&E's policy allows for granting exceptions for critical facilities when a prolonged outage could have a significant adverse impact to public health or safety.

3. ***Region prioritization ("where" to engage activity) – include reference to a risk informed analysis in allocation of initiative (e.g., veg clearance is done for trees tagged as "high-risk"):***

   PG&E supports individual critical customer facilities through two distinct processes: (1) pre-planned sites; and (2) ad hoc support during an event. For the 2020 wildfire season, PG&E supported intensive care unit hospitals identified in partnership with the California Hospital Association and the Hospital Council of Northern and Central California that were at higher risk of experiencing one or more PSPS-related outages during the 2020 season. PG&E also supported pre-determined vote tabulation centers from October to December for the 2020 national election.

   In-event ad-hoc backup power support occurs during a PSPS event. Customers submit a request for mobile backup generation through their PG&E contact or account manager to our EOC. The request is reviewed, and a determination is made as to whether a prolonged outage for the requesting customer would either directly or indirectly affect public health or safety. If the request is approved, mobile TG is deployed to the requesting customer. There is no pre-determined prioritization of these customers, and the location of these customers is dependent on the scope and location of the ongoing weather event. While there is no pre-determined prioritization, there are pre-determined "societal Impact" locations (sites where power loss may impact public health and safety) for which designated customer representatives execute in-event additional outreach to ensure they have a backup power strategy in place. If these locations do not have a backup power strategy in place, a request for backup power deployment is routed to the EOC.

4. ***Progress on initiative (amount spent, regions covered) and plans for next year:***

   In 2021, PG&E plans to continue to support critical customers with backup power support in exceptional circumstances, utilizing our policy to determine eligibility and prioritization. During the first half of 2021, PG&E will continue our direct engagement with critical customers and in coordination with counties to provide consultative support for readiness and resiliency for all hazard, emergencies and the 2021 fire season.

5. ***Future Improvement to Initiative:***

   Improvements to the program will include streamlining the outreach process prior to and during a PSPS event by PG&E customer team, utilizing more hub locations for quicker deployments to the edges of the service territory, and explore clean generation solutions where applicable.

E) Customer Resource Centers

1. ***Risk to be mitigated/problem to be addressed:***

   To minimize public safety impacts during a PSPS event, PG&E opens CRCs focused on providing essential services to customers affected by PSPS events. The risk to be mitigated is ensuring all CRCs in potential PSPS areas are fully equipped with backup power throughout the PSPS season.

2. ***Initiative selection ("why" engage in activity) – include reference to a risk informed analysis on empirical (or projected) impact of initiative in comparison to alternatives:***

   PG&E mobilizes CRCs in counties and tribal communities potentially impacted by PSPS events to provide customers a safe location to meet their basic power needs, such as charging medical equipment and electronic devices.

3. ***Region prioritization ("where" to engage activity) – include reference to a risk informed analysis in allocation of initiative (e.g., veg clearance is done for trees tagged as "high-risk"):***

   PG&E closely coordinates with counties, local governments and tribes to determine appropriate locations for CRCs. Additional details regarding CRC region prioritization can be found in Section 8.2.1.

4. ***Progress on initiative (amount spent, regions covered) and plans for next year:***

   PG&E pre-staged 77 generators to support indoor CRC sites and ultimately activated 62 indoor CRC sites with TG during PSPS events in 2020. More information regarding progress on the CRC program can be found in Section 8.2.1.

5. ***Future Improvement to Initiative:***

   In 2021, PG&E will continue evaluating additions or changes to our indoor CRC portfolio while taking into consideration factors such as potential PSPS scope, communities impacted by 2020 PSPS events and input from counties and tribes. PG&E will continue to review the program for improvements and efficiencies by reviewing elements such as resources provided, the customer journey and CRC staffing.

F) Responses to Action Items

ACTION PGE-49 (Class B)

Provide additional information about its specific backup generation sites, including

a) the number of times used; and

b) challenges faced with the completion of this project and its operation.

Response:

a) The number of times backup generation sites were used during PSPS events:

During 2020 PSPS events, PG&E utilized a total of eight microgrid sites: four temporary substation microgrid locations and four temporary distribution microgrid locations. In addition, PG&E provided backup power support to 31 critical single—customer facilities, including hospitals, water and wastewater plants, and emergency response personnel such as fire and police stations.

Table PG&E-7.3.3-4 below indicates the number of times these sites were energized during the 2020 PSPS events. Some microgrids and single-customer facilities were energized during multiple events, for a total of 53 backup generation site uses across all PSPS events:

TABLE PG&E-7.3.3-4: NUMBER OF TIMES SITES WERE ENERGIZED DURING 2020 PSPS EVENTS

PSPS Event	Temporary Substation MG	Temporary Distribution MG	Individual Critical Customer Backup Power Support	Total
7-Sep	1	2	11	14
26-Sep		1	3	4
14-Oct		4	2	6
25-Oct	4	4	20	28
2-Dec			1	1
Total	5	11	37	53

For additional information regarding microgrids please see Sections 7.3.3.11.1 subsection B (Temporary Substation Microgrids) and 7.3.3.11.1 subsection C (Temporary Distribution Microgrids).

For additional information regarding backup power support to single -customer facilities that were supported with backup power per event please see Section 7.3.3.11.1 subsection D (Back-up power for individual critical customer facilities).

b) Challenges faced with the completion of this project and its operation:

Challenges with Project Completion:

As described in PG&E's First Quarterly Report, there are two broad categories of limitations to microgrid deployment for PSPS mitigation:

1. Limitations related to the safety of energizing microgrids with overhead lines in the context of high wind conditions that trigger a PSPS de-energization (i.e. overhead lines that run through the "wind polygon"); and

2. Limitations related to space constraints for siting generation for microgrids with high peak MW and megawatt -hour requirements over a 24+ hour period.

While the above limitations presented challenges, PG&E largely fulfilled our objective of providing temporary substation microgrids, temporary distribution microgrids, and critical single -facility sites during PSPS events through the use of TG. Energization challenges were managed through the development of site -specific energization playbooks and an in-event scoping process that ensured that only substations with safe-to-energize load outside of the wind polygon were energized. Safe-to-energize limitations for temporary distribution microgrids were managed by limiting energization only to underground lines or short segments of sufficiently hardened overhead lines reviewed by fire safety specialists.

Space constraints were overcome through the utilization of energy-dense, mobile temporary generators and in some instances, collaboration with local governments and landholders to secure temporary easements in advance of 2020 PSPS events which allowed PG&E to place generation outside of our substation fence. In some instances, available land was insufficient, leading to constraints in the number of temporary generators that could be used to serve potential safe -to -energize load from any particular substation. In the case of the Brunswick substation, which was energized during two PSPS events, space constraints meant that only 20 MW of nameplate generating capacity would fit within the substation footprint. The substation has a peak load of 60 MW. Safe -to -energize limitations for temporary substation microgrids led to very few substations being suitable for energization during 2020 PSPS events.

Challenges with Project Operation:

PG&E managed two major challenges in the operation of these sites:

1. PSPS event wind polygons, and thus the PSPS impact scope, can continue to change throughout the event scoping process. Thus, identification of temporary microgrids with safe -to -energize load that will be de--energized can be identified less than 48 hours before de--energization when the final Transmission -level “playbook” is produced, therefore limiting time available to deploy TG to these sites. To manage this operational challenge, PG&E prepared 18 temporary substation microgrids and all temporary distribution microgrids as “ready -to -energize”, with generation interconnected, tested, and released in advance of a PSPS event. In 2021, it is likely that a far higher percentage of substations will be supported via this strategy to further limit in -event operational constraints; and

2. Given the dynamics of event scoping, sophisticated and ongoing real--time coordination was required between PG&E’s EOC, Electric Distribution Emergency Center, field engineers overseeing TG deployment, and TG contractors delivering and connecting

generators. To manage this operational challenge, PG&E created a specialized EOC "Temporary Generation" Branch within the Operations Section. The TG Branch centralized planning, logistics, and operations functions to ensure as many customers would be supported with TG as safely possible during each event. The TG Branch was staffed with four teams of six individuals each. All individuals who served in the TG Branch underwent significant online training and engaged in at least one of PG&E's PSPS exercises in advance of wildfire season. In 2021, PG&E is seeking to increase staffing for our TG organization to provide a more permanent solution to this resource issue.

ACTION PGE-50 (Class B)

In its 2021 WMP Update, PG&E shall: (1) provide the cost/benefit analysis completed for microgrids as a mitigation, and (2) define what is meant by a "bridge" solution and "other solutions," and (3) include a timeline for how long an interim "bridge" solution would be in place.

Response:

This portion of PG&E's First Quarterly Report was referencing temporary substation and distribution microgrids. In this response, PG&E refers to "temporary microgrids" to include both kinds of microgrids (i.e., substation and distribution).

1) Provide the cost/benefit analysis completed for microgrids as a mitigation:

Decisions regarding the development of temporary microgrids for PSPS mitigation are driven by a location's expected relative impact frequency and near--term implementation feasibility rather than a cost/benefit analysis. This is in line with a temporary microgrid's intent to be used to serve safe -to -energize areas where no alternate grid solutions can be feasibly implemented in the near--term (i.e., within the next fire season) to mitigate PSPS impacts.

As described in Section 7.3.3.11.1, temporary microgrids are considered as potential PSPS mitigations for locations with a high expected relative frequency of future PSPS impacts. If the analysis of historical meteorological data and prior PSPS events indicates that a location can be expected to experience future PSPS impacts, and no alternate solution can be implemented within the next fire season to mitigate those impacts, that location can be studied for technical feasibility of implementing a temporary microgrid to support customers in the near--term.

For the PSPS mitigation use case, PG&E does not use a quantitative cost/benefit analysis to supplement the methodology described above. Quantifying the exact benefits of a temporary microgrid is difficult because the CPUC has not adopted a standard "value of resilience" or other methodology to quantify the benefit of keeping customers energized when they would otherwise be impacted by PSPS events. To maximize benefits

derived from these mitigation measures, in addition to considering expected relative impact frequency, PG&E generally seeks to site temporary substation microgrids in locations that maximize the number of customers that can be safely energized, and temporary distribution microgrids in commercial corridors with critical and shared services that can serve surrounding residents (i.e., to energize "Main Street").

2) Define what is meant by a "bridge" solution and "other solutions":

In the case of temporary microgrids for PSPS mitigation, PG&E used the term "bridge" solution to refer to the near--term implementation feasibility of temporary microgrids at certain locations where other grid solutions might not be viable prior to the next fire season. Temporary microgrids do not present a "bridge" solution for every location—in some locations, they may not be able to be implemented more quickly than an alternate grid solution under consideration.

PG&E used the term "other solutions" to refer to grid solutions that can reduce PSPS scope, and thereby reduce or potentially eliminate the need for a temporary microgrid for PSPS mitigation. "Other solutions" can include undergrounding overhead lines, as well as measures that improve the health score of a transmission line, allow for more granular meteorological event scoping, and enable distribution and transmission sectionalizing.

3) Include a timeline for how long an interim "bridge" solution would be in place:

As PG&E continues to develop and refine our risk modeling (see Section 4.5.1), these developments will drive changes to PSPS scope (see Section 8), and therefore, mitigation solutions designed to address PSPS impacts. Timelines for how long temporary microgrids will be in place as "bridge" solutions will be driven by improvements to PSPS risk modeling and de-scoping criteria, and will vary by location and the demonstrated effectiveness of "other solutions" to mitigate PSPS impacts in those locations.

At certain locations, some of the "other solutions" listed above might be implemented as soon as the year after a temporary microgrid is made operationally ready. At such locations, PG&E would consider adapting site preparation at the start of PSPS season to reflect the availability of an alternate solution. For example, some of the temporary substation microgrids that were made "Ready -to -Energize" in 2020 based on 2019 event actuals might not have generation interconnected and tested on-site in 2021 based on the reduced expected impacts due to improvements to event scoping and transmission health scores. This, however, may not eliminate the potential need for a temporary microgrid solution at these sites altogether. For these sites, PG&E would retain the engineering guide to interconnect generation if needed, even if generators are not staged on-site given the relatively low probability of impacts.

At some locations, "other solutions" may not be available to reduce the need

for temporary microgrids for multiple years. This is particularly true for temporary microgrid sites near undergrounding projects. Upon completion, undergrounding projects may reduce the need for nearby temporary microgrids to mitigate PSPS impacts. However, due to the time -consuming nature of undergrounding work (see Section 7.3.3.16), PG&E expects to continue to rely on temporary microgrids for PSPS mitigation in these locations for multiple years.

The recent Track 2 Decision in the Commission's Microgrid OIR provides additional upcoming opportunities to evaluate alternative solutions for mitigating PSPS impacts. First, the decision directs PG&E to submit an Advice Letter describing the substations at which PG&E proposes to use TG microgrids to mitigate PSPS outages in 2021.[3] That Advice Letter, which PG&E expects to file in the first quarter of 2021, will describe the process by which PG&E evaluated candidate substations, including our evaluations of near--term solutions other than temporary substation microgrids (and noting where those alternative solutions obviated the need to pre--stage TG at certain substations). Second, the decision requires PG&E to file an application by June 30, 2021 proposing a long--term framework for evaluating the need for generation at substations to mitigate PSPS outages.[4] In that application, PG&E expects to present an analytical methodology to consider the longer--term alternatives for mitigating PSPS outages, including further consideration of whether it is reasonable to continue using temporary or longer--term microgrids as a bridge until other solutions can be put in place.

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3 D.21-01-018, App. A, pp. A-1 to A-3.

4 *Id.*, App. A, pp. A-6 to A-8.

7.3.3.11.2 Substation activities to enable reduction of PSPS impacts

WSD Initiative Definition: *N/A. This is a "PGE-defined sub-initiative" that supports the response for the (parent) WSD-defined Initiative.*

1) Risk to be mitigated/problem to be addressed:

The risk to be mitigated are the potential impacts of PSPS events on communities and customers. Risk mitigation efforts include:

Substations Requiring Protection Upgrades

Substation activities that enable the reduction of PSPS impacts include the installation or upgrade of protection equipment and automatic sectionalizing devices at various substations to improve operating flexibility thereby minimizing the frequency, scope, and duration of PSPS events.

Substation Microgrid Locations

Another activity is substation equipment and protection upgrade to accommodate "Microgrids for PSPS Mitigation" initiative that enables the connection of a generation source or tie line to the substation to serve in an island-configuration during a PSPS event. Additional information about the substation and distribution microgrids initiative can be found in Section 7.3.3.11.1 subsection B and 7.3.3.11.1 subsection C above.

2) Initiative selection ("why" engage in activity) – include reference to a risk informed analysis on empirical (or projected) impact of initiative in comparison to alternatives:

Both these risk mitigation efforts support PSPS events. PSPS events can potentially impact many customers given the configuration of PG&E's electrical system. As a result, a power shut-off may occur in areas that are not directly in the weather zone, but is served by facilities that are impacted by the extreme wind/weather conditions. The substation activities will allow for minimizing the scope of PSPS events, enable faster restoration for those impacted and, in some cases, an alternative power source (generation) during PSPS events.

3) Region prioritization ("where" to engage activity) – include reference to a risk informed analysis in allocation of initiative (e.g., veg clearance is done for trees tagged as "high-risk"):

Substations Requiring Protection Upgrades

Relays for substation equipment operate within overlapping layers of protection zones that are set in such a way that the timing allows the relay to operate in a structured sequence. For example, when a line is taken out of service, PG&E is required to maintain coordination within the remaining energized zone. If the substation equipment (i.e., fuse) within

the remaining energized zone does not have the ability to coordinate with the upstream relays, then either the decision is made to de-energize the equipment, remain with the coordinating deficiency, or, if the equipment cannot be adequately protected, then remove it from service.

Substation Microgrid Interconnection

The feedback to determine microgrid locations include but are not limited to transfer capability, infringement to future site plans, adherence to design standards and maintenance considerations. For more details please see Section 7.3.3.11.1 subsection B.

4) Progress on initiative (amount spent, regions covered) and plans for next year:

Substations Requiring Protection Upgrades

Based on system protection reviews, PG&E has identified one substation for protection or SCADA installation, or upgrade noted within Table PG&E-7.3.3-5 below. The specific dates for this work to be operative are preliminary and may change depending on the availability of resources and other prioritized work.

TABLE PG&E-7.3.3-5: SUBSTATION ELIGIBLE FOR UPGRADE, PROTECTION OR SCADA INSTALLATION

Line No.	Substation Name	Operative Year
1	Rincon	2021

Substation Microgrid Interconnection

Information regarding substation microgrid efforts can be found in Section 7.3.3.11.1.

5) Future improvements to initiative:

Substation activities are driven by the PSPS and microgrid strategy in Section 7.3.3.11.1. This work is necessary to ensure safe and reliable operations and protection of the electric grid.

ACTION PGE-25 (Class B)

1) Integrate discussion on long-term planning within the respective section of each individual initiative.

Response:

As stated above, please reference Section 7.3.3.11.1 for more information on future improvements for this initiative.

7.3.3.11.3 Emergency Back-up Generation – PG&E Service Centers & Materials Distribution Centers

WSD Initiative Definition: *N/A. This is a "PGE-defined sub-initiative" that supports the response for the (parent) WSD-defined Initiative.*

1) Risk to be mitigated/problem to be addressed:

While several PG&E facilities have an existing emergency backup system onsite, very few are configured to back up the entire campus. In most cases, the emergency system will supply backup power to existing critical communications, emergency lighting and possibly a storm room or EOC. While this level of backup may have been enough for shorter duration emergency response events, such as a mild winter storm, it can be inadequate for the longer duration PSPS events, which can last several days.

2) Initiative selection ("why" engage in activity) – include reference to a risk informed analysis on empirical (or projected) impact of initiative in comparison to alternatives:

Because the existing emergency generation systems only backup a select number of circuits within the campus, critical systems such as fuel islands, gate operators, exterior lighting, and operations buildings may not be backed up. This can result in operational inefficiencies during PSPS events. Additionally, because some facilities have limited or no existing emergency generation, personnel who would typically work out of these locations have had to work either remotely or at alternate locations in order to support restoration events.

In order to address this issue, PG&E's Corporate Real Estate Strategy and Services (CRESS) department has initiated a three-year (2020-2022) capital project in order to harden a number of service center locations throughout our service territory against the possibility of extended utility power loss events.

As part of this project, 52 locations will be equipped with an emergency generation system capable of backing up the campus in its entirety. In order to achieve this, it is expected that existing emergency generators, automatic transfer switches, and in most cases, main switchboards, will need to either be replaced or reconfigured in order to achieve emergency generation back up the for the entire site.

In addition to the locations mentioned above, another 43 locations will be equipped with generator tap boxes and transfer switches but will not be equipped with permanent generators. This will also allow for the entire campus to be backed up through emergency generation, with the difference being that these locations will be prepared to accept a portable generator instead of being equipped with a permanent generator.

When completed, the electrical reconfiguration and additional equipment installed at these locations will allow these sites to operate with the same amount of functionality as they would if they were being fed from their normal source (utility power). This will ensure that restoration efforts being performed by operational personnel working out of the site can carry on unimpeded.

3) ***Region prioritization ("where" to engage activity) – include reference to a risk informed analysis in allocation of initiative (e.g., veg clearance is done for trees tagged as "high-risk"):***

This three-year project was split into three phases, with one phase being targeted for execution each year (e.g., Phase One (2020), Phase Two (2021), Phase Three (2022)). Each site was evaluated and ranked based on the population of employees working out of the facility and its adjacency to HFTD areas. Sites with higher populations of employees and that are located close to or within an HFTD area were ranked higher and included in Phase One. Sites with lower populations or not adjacent to an HFTD area were ranked lower and included in Phase Three of the project.

Phase One (2020): Phase One of the project will concentrate on the 23 highest priority sites as determined by the facility's location regarding HFTD areas and the workforce population operating out of the facility. As these sites are closest in proximity to the HFTDs they are most likely to be impacted by PSPS event. Prioritizing these sites within the multi-year project thereby presents the greatest benefit to customers since it's most likely that PSPS restoration efforts will be managed out of these locations. By ensuring that these sites are fully operational during an extended power loss events we maximize our operational efficiency during restoration efforts, thereby minimizing outage times for impacted customers.

Phase Two (2021): 2021 will focus on the next highest priorities, again determined by adjacency to HFTD areas and the headcount assigned to the facility. We estimate that approximately 30 sites will be addressed in this phase.

Phase Three (2022): 2022 will focus on the lowest priority sites. These are sites where the likelihood of experiencing a PSPS event is low or the long-term strategy for the facility is currently being evaluated.

4) ***Progress on initiative (amount spent, regions covered) and plans for next year:***

By the end of 2021, at least 23 PG&E Service Centers & Materials Distribution Centers will be equipped to receive permanent or temporary generation. By the end of 2022, the 72 remaining PG&E Service Centers & Materials Distribution Centers will be equipped to receive permanent or temporary generation.

5) Future improvements to initiative:

There are currently no additional plans on this initiative beyond what is described above.

ACTION PGE-25 (Class B)

1) Integrate discussion on long-term planning within the respective section of each individual initiative.

Response:

As stated in the section above, there are no further improvements planned at this time other than the work described above through 2022.

7.3.3.12 Other Corrective Action

WSD Initiative Definition: *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.*

For this initiative, PG&E has several sub-initiatives including:

- 7.3.3.12.1: Distribution substations;
- 7.3.3.12.2: Transmission substations;
- 7.3.3.12.3: Maintenance, Transmission; and
- 7.3.3.12.4: Maintenance, Distribution.

7.3.3.12.1 Distribution Substation

WSD Initiative Definition: *N/A. This is a "PGE-defined sub-initiative" that supports the response for the (parent) WSD-defined Initiative.*

1) Risk to be mitigated/problem to be addressed:

The primary wildfire risk with substations is an arc flash event within the substation that propagates into adjacent wildlands. PG&E has taken two specific actions to address this risk. First, we have initiated a defensible space program for substations located in Tier 2 and Tier 3 HFTD areas. Second, we have improved our animal abatement program.

In addition to these specific actions, we also perform corrective repairs and equipment replacements identified through the enhanced inspections of substations. This work is intended to correct deficiencies identified and ensure that substation equipment operates as designed.

2) Initiative selection ("why" engage in activity) – include reference to a risk informed analysis on empirical (or projected) impact of initiative in comparison to alternatives:

Defensible Space: Defensible space for substations is a 100' perimeter around substation equipment that includes both a 30' clean zone and a 70' reduced fuel zone. Defensible space is normally achieved by removing combustible material (primarily vegetation) from these areas. Defensible space is intended to reduce the risk of an event within a substation, igniting a fire, that propagates outside of the facility. By implementing these requirements, the risk of fire spreading is significantly reduced and provides a higher probability that a fire can be extinguished without involving third party property.

Substation Animal Abatement: PG&E has been conducting an animal abatement program for our substations, with reliability (i.e., lower customer outage) as the main driver. The program was expanded to address wildfire risks by reducing the probability of an arc flash within the substation. Animal contacts may result in a catastrophic failure of equipment that can project ignited materials into HFTD areas.

Repairs and Replacements from Enhanced Inspections: PG&E conducts enhanced inspections in substations located in HFTD areas. These inspections identify deficiencies with substation equipment and components. The repair and replacement work are performed to reduce the risk of an equipment failure or miss operation.

3) Region prioritization ("where" to engage activity) – include reference to a risk informed analysis in allocation of initiative (e.g., veg clearance is done for trees tagged as "high-risk"):

Defensible Space: The program requires defensible space to be established and maintained on substations located in Tier 2 and Tier 3 HFTD areas, where possible. At some locations, it is not possible to attain defensible space due to adjacent structures, third-party property owners, or permitting issues.

Substation Animal Abatement: Animal abatement was identified during the 2019 Wildfire Safety Inspection Program (WSIP) as a mitigation to minimize fire ignition, specifically in Tier 2 and Tier 3 HFTD areas. All substations located in these areas that have achieved defensible space will have animal abatement installed. Substations located in these areas that are not able to achieve defensible space will have additional animal abatement installed to further reduce the likelihood of an animal contact

Repairs and Replacements from Enhanced Inspections: Enhanced inspections are performed at substations located in HFTD areas. As a result of these inspections, corrective work is identified at substations located in HFTD areas. The identified repair and replacement work are prioritized based on risk and completed based on the prioritized schedule.

4) Progress on initiative (amount spent, regions covered) and plans for next year:

Defensible Space: As of December 31, 2020, 96 percent of substations (168 of 175) located in Tier 2 and Tier 3 HFTD areas have attained defensible space. At some locations, it is not possible to attain defensible space due to adjacent structures, third party property owners, or permitting issues.

Substation Animal Abatement: 77 locations have been identified as requiring animal abatement. Of these 77 locations, 18 were completed in 2019, 21 were completed in 2020, and the remaining 38 are being prioritized for completion.

Repairs and Replacements from Enhanced Inspections: PG&E has a total of 126 distribution substations located in HFTD areas. Each of these locations is inspected through the enhanced inspection program. All repair and replacement work identified by the inspections is reviewed, prioritized and scheduled for completion. In 2020, 47 of these substations were inspected by the enhanced inspection program and in 2021, 57 of these substations are planned to be inspected. The repair and replacement work generated from these inspections will be reviewed, prioritized and scheduled for completion.

5) Future improvements to initiative:

At this time, no future improvements have been identified; the programs will continue to execute at the substations that have been identified.

ACTION PGE-25 (Class B)

1) Integrate discussion on long-term planning within the respective section of each individual initiative.

Response:

For the long-term, we will continue with periodic evaluations of the defensible space, animal abatement and the repairs and replacement programs. These evaluations typically include performance trends, inspection results, emerging technology and other risk factors. Updates will be made to the programs based on these evaluations.

7.3.3.12.2 Transmission Substation

WSD Initiative Definition: *N/A. This is a "PGE-defined sub-initiative" that supports the response for the (parent) WSD-defined Initiative.*

1) Risk to be mitigated/problem to be addressed:

The primary wildfire risk with substations is an arc flash event within the substation that propagates into adjacent wildlands. PG&E has taken two specific actions to address this scenario. First, we have initiated a defensible space program for substations located in Tier 2 and Tier 3 HFTD areas. Second, we have improved our animal abatement program.

In addition to these specific actions, we also perform corrective repairs and equipment replacements identified through the enhanced inspections of substations. This work is intended to correct deficiencies identified and ensure that substation equipment operates as designed.

2) Initiative selection ("why" engage in activity) – include reference to a risk informed analysis on empirical (or projected) impact of initiative in comparison to alternatives:

Defensible Space: Defensible space for substations is a 100' perimeter around substation equipment that includes both a 30' clean zone and a 70' reduced fuel zone. Defensible space is normally achieved by removing combustible material (primarily vegetation) from these areas. Defensible space is intended to reduce the risk of an event within a substation, igniting a fire, that propagates outside of the facility. By implementing these requirements, the risk of fire spreading is significantly reduced and provides a higher probability that a fire can be extinguished without involving third party property.

Substation Animal Abatement: PG&E has been conducting an animal abatement program for our substations, with reliability (i.e., lower customer outage) as the main driver. The program was expanded to address wildfire risks by reducing the probability of an arc flash within the substation. Animal contacts may result in a catastrophic failure of equipment that can project ignited materials into HFTD areas.

Repairs and Replacements from Enhanced Inspections: PG&E conducts enhanced inspections in substations located in HFTD areas. These inspections identify deficiencies with substation equipment and components. The repair and replacement work are performed to reduce the risk of an equipment failure or miss operation.

3) Region prioritization ("where" to engage activity) – include reference to a risk informed analysis in allocation of initiative (e.g., veg clearance is done for trees tagged as "high-risk"):

Defensible Space: The program requires defensible space to be established and maintained on substations located in Tier 2 and Tier 3 HFTD areas, where possible. At some locations, it is not possible to attain defensible space due to adjacent structures, third-party property owners, or permitting issues.

Substation Animal Abatement: Animal abatement was identified during the 2019 WSIP as a mitigation to minimize fire ignition, specifically in Tier 2 and Tier 3 HFTD areas. All substations located in these areas that have achieved defensible space will have animal abatement installed. Substations located in these areas that are not able to achieve defensible space will have additional animal abatement installed to further reduce the likelihood of an animal contact.

Repairs and Replacements from Enhanced Inspections: Enhanced inspections are performed at substations located in HFTD areas. As a result of these inspections, corrective work is identified at substations located in HFTD areas. The identified repair and replacement work are prioritized based on risk and completed based on the prioritized schedule.

4) Progress on initiative (amount spent, regions covered) and plans for next year:

Defensible Space: As of December 31, 2020, 100 percent of substations (40 of 40) located in these areas have attained defensible space. In 2020, PG&E spent $1.7 million and in 2021, we are planning to spend $2.5 million on defensible space for transmission substations.

Substation Animal Abatement: nine locations were identified as requiring animal abatement, two were completed in 2019, two are were completed in 2020, and the remaining five are being prioritized for completion. In 2020, PG&E spent $1.0 million and in 2021, we are planning to spend $3.1 million on animal abatement in transmission substations.

Repairs and Replacements from Enhanced Inspections: PG&E has a total of 60 transmission substations located in HFTD areas. Each of these locations is inspected through the enhanced inspection program. All repair and replacement work identified by the inspections is reviewed, prioritized and scheduled for completion. In 2020, 29 of these substations were inspected by the enhanced inspection program and in 2021, 22 of these substations are planned to be inspected. The repair and replacement work generated from these inspections will be reviewed, prioritized and scheduled for completion.

5) Future improvements to initiative:

At this time, no future improvements have been identified; the program will continue to execute at the substations that have been identified.

ACTION PGE-25 (Class B)

1) Integrate discussion on long-term planning within the respective section of each individual initiative.

Response:

For the long-term, we will continue with periodic evaluations of both the defensible space and animal abatement programs. These evaluations typically include performance trends, emerging technology and other risk factors. Updates will be made to the programs based on these evaluations.

7.3.3.12.3 Maintenance, Transmission

WSD Initiative Definition: *N/A. This is a "PGE-defined sub-initiative" that supports the response for the (parent) WSD-defined Initiative.*

1) Risk to be mitigated/problem to be addressed:

Since 2019, PG&E has conducted enhanced transmission inspections (performed with enhanced inspection protocols). Detailed inspections are performed with two vantage points (e.g., by ground and by aerial) to fully capture all asset conditions. These inspections have resulted in a significant increase in the volume of corrective action notifications for maintenance. These maintenance notifications are key to trending, prioritizing and reducing asset risk by correcting identified asset hazards, poor conditions, and non-standard concerns.

2) Initiative selection ("why" engage in activity) – include reference to a risk informed analysis on empirical (or projected) impact of initiative in comparison to alternatives:

The maintenance (repair or replacement) work done as a result of enhanced inspections is an important step in mitigating risk. Although there are general priority timelines given to maintenance notifications when identified, prioritization and additional field safety assessments may be done in order to reduce the wildfire risk and manage the work of the maintenance notifications resulting from enhanced inspections. Furthermore, analysis of inspection and maintenance data provides opportunities for trending and refinement of risk prioritization.

3) Region prioritization ("where" to engage activity) – include reference to a risk informed analysis in allocation of initiative (e.g., veg clearance is done for trees tagged as "high-risk"):

PG&E is prioritizing maintenance on the highest risk notifications and using additional Field Safety Reassessments (FSR) to mitigate the risk and manage this large volume of work.

The process for prioritization of these notifications uses the following definitions:

- Ignition-related notification: Notifications related to components included in the 2019 Failure Modes Effects Analysis (FMEA). Ignition risks can be either time-dependent or time-independent, e.g., a bird's nest or steel crossarm that is "no good/out of standard.";
- Non-ignition-related notification: Notifications that do not pose an ignition risk and are not considered to be a failure mode for a component in the 2019 FMEA, e.g., a missing "high voltage" sign;

- Time-dependent notifications: Conditions that will worsen with time, e.g., mechanical degradation including fatigue, corrosion, can all worsen with time and are time-dependent; and

- Time-independent notifications: Conditions that will not worsen with time, e.g., a missing sign or a missing guy insulator.

Using these definitions, notifications are prioritized as follows:

- Ignition-related notifications on structures in HFTD areas are prioritized over non-ignition-related notifications or notifications in non-HFTD areas;

- Ignition-related notifications are divided into time-dependent and non-time-dependent notifications. Time-dependent notifications are prioritized above non-time-dependent notifications because of the possibility that the condition can degrade further if the repairs are deferred;

- Time-dependent notifications in high fire spread areas are prioritized ahead of notifications in lower spread areas; and

- These considerations result in the following prioritization (highest to lowest):

  – Time-dependent ignition-related notifications in highest fire spread areas of HFTDs;

  – Time-dependent ignition-related notifications in lower fire spread areas of HFTDs;

  – Time-independent ignition-related notifications in HFTDs; and

  – Non-ignition-related notifications in HFTD areas or notifications outside of HFTDs.

4) Progress on initiative (amount spent, regions covered) and plans for next year:

In 2020, approximately 11,900 notifications within HFTD areas were completed (not including those for steel structures, further discussed in Section 7.3.3.15). In 2021, approximately 8,900 notifications within HFTD areas are expected to be completed, not including any urgent priority notifications that may be identified in 2021.

In 2021, PG&E is expecting to complete all ignition-related notifications in HFTD areas found before 2020 and all time-dependent ignition-related notifications found in 2020 on high fire spread areas, in addition to any new urgent priority notifications identified in 2021.

5) Future improvements to initiative:

As data is collected through enhanced inspections and maintenance, trending analysis will allow for understanding of deterioration rates of specific asset conditions and used to influence future inspection frequency and prioritization. Trending of notification find rates can also influence the maintenance strategy for specific lines or sections. This information will also be utilized in the programmatic approach for repair and replace decisions.

ACTION PGE-25 (Class B)

1) Integrate discussion on long-term planning within the respective section of each individual initiative.

Response:

Long term, it is expected that the volume of maintenance notifications generated through enhanced inspections will be executed in accordance with appropriate timelines associated with the damage found. Where notifications cannot be completed per the timeline, field safety reassessments (FSR) are conducted, and information will help to refine the understanding of the damage mode decay rates. This information will also be used to improve guidance to maintenance inspectors. Additionally, it is expected that effectiveness of maintenance will be trended and used to inform future maintenance mitigations, processes, and procedures.

7.3.3.12.4 Maintenance, Distribution

WSD Initiative Definition: *N/A. This is a "PGE-defined sub-initiative" that supports the response for the (parent) WSD-defined Initiative.*

1) Risk to be mitigated/problem to be addressed:

The distribution overhead enhanced inspection program is used to identify potential asset failures and gain a better understanding of asset condition for asset maintenance and replacement. EC notifications are a byproduct of the enhanced inspection process. These maintenance notifications are key to reducing asset risk by correcting identified asset hazards, poor conditions, and non-standard concerns.

2) Initiative selection ("why" engage in activity) – include reference to a risk informed analysis on empirical (or projected) impact of initiative in comparison to alternatives:

Detailed inspections are performed with enhanced inspection protocols. Enhanced inspection activities lead to corrective actions taken on the issues identified during the inspection. Since 2019, distribution assets have been inspected more rigorously than in previous years through PG&E's WSIP. These changes have resulted in a significant increase in the volume of EC notifications based on a FMEA approach. The maintenance (or replacement) work done as a result of the inspections is the final step in mitigating risk in the HFTD area.

3) Region prioritization ("where" to engage activity) – include reference to a risk informed analysis in allocation of initiative (e.g., veg clearance is done for trees tagged as "high-risk"):

Since 2019 the distribution enhanced overhead inspection process has been used on all distribution assets located in Tier 2 and Tier 3 HFTD areas. These enhanced inspections exceed GO 165 five-year cycle times as follows:

- Tier 3 – enhanced overhead inspection yearly; and
- Tier 2 – enhanced overhead inspection every three years.

The EC maintenance notifications generated through the enhanced inspection program are assigned a priority based on the potential safety impact. PG&E uses the following priorities:

- A: conditions that require immediate action;
- B: conditions that generally need to be addressed within three (3) months from the date a condition is identified;
- E: conditions that need to be addressed within twelve (12) months from the date the condition is identified or within six (6) months for conditions creating a fire risk located in Tier 3 HFTD areas; and
- F: conditions that need to be addressed within five (5) years from the date the

condition is identified.

Given the high volume of identified tags since 2019, PG&E utilized a risk-informed prioritization approach to address the highest risk issues on PG&E's facilities. The largest volume of identified corrective actions are the E and F tags, which includes findings such as chipped or broken insulators, pole repairs for woodpecker holes, loose cotter keys (E tags), missing markers, signage, or foundation mastic application (F tags). PG&E has prioritized execution of E and F tags based on ignition risk circuit prioritization and plans to continue to make repairs based on this prioritization.

4) Progress on initiative (amount spent, regions covered) and plans for next year:

As of September 30, 2020 (the end of Q3 2020), the following HFTD tag progress has been made since 2019:

- WSIP-Generated Tags: 208,510 tags had been created, 73,359 had been closed (repairs have been completed) and 135,151 remain open; and
- Non-WSIP-Generated Tags: 84,949 tags had been created, 21,305 had been closed (repairs have been completed) and 63,644 remain open.

PG&E is continuing to verify the status of tags in Q4 2020, and thus is currently unable to provide the Q4 2020 information. Open tags will continue to be worked in a risk-based priority including new tags generated through the 2021 inspection program. Priority A and B tags are expected to be completed by the required due date. Due to the high volume of priority E and F tags, a risk ranking utilizing the FMEA severity score will be used. Any tag that contains a "time dependent" element and cannot be completed and beyond the due date will receive an FSR.

5) Future improvements to initiative:

PG&E is evaluating integrating the 2021 Wildfire Distribution Risk Model results into our maintenance program to allow prioritization of notifications by wildfire risk at the tag location level. This would pinpoint specific locations of ignition concern, allowing both the highest probable ignition potential issues as well as the highest consequence areas to be addressed first.

ACTION PGE-25 (Class B)

1) Integrate discussion on long-term planning within the respective section of each individual initiative.

Response:

At this time, there is no long-term plan beyond 2021. However, we will continue to evaluate the risk-based approach for enhanced inspections, including inspection frequency and methods. Additionally, the results of the integration between the

Wildfire Distribution Risk Model and the maintenance program will allow for further analysis and planning.

7.3.3.13 Pole Loading Infrastructure Hardening and Replacement Program Based on Pole Loading Assessment Program

WSD Initiative Definition: *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.*

1) Risk to be mitigated/problem to be addressed:

PG&E started our pole loading program to reduce the risk of potential fire ignitions resulting from pole failures by evaluating poles so that each pole meets GO 95, Rule 44 strength requirements throughout its service life, both when initially installed and while in-service despite changing conditions, impacts from maintenance activities, attachment additions and potential wood strength degradation. Replacing overloaded poles eliminates the risks associated with pole failure, including potential ignition risk. This program also reduces risk by providing asset intelligence to identify locations that require corrective actions driven by pole safety factors or limitations for wind speeds.

2) Initiative selection ("why" engage in activity) – include reference to a risk informed analysis on empirical (or projected) impact of initiative in comparison to alternatives:

During a pole's service life, pole loading calculations are performed when load is added to a pole or if a suspected overload condition is observed during inspection. Pole loading calculations are performed in O-Calc software during the design phase to ensure poles are sized correctly to satisfy GO 95 requirements. When poles are analyzed and determined to be overloaded or the pole loading evaluation indicates that the pole does not satisfy GO 95 requirements, a pole replacement tag is initiated to correct the condition.

3) Region prioritization ("where" to engage activity) – include reference to a risk informed analysis in allocation of initiative (e.g., veg clearance is done for trees tagged as "high-risk"):

PG&E's pole loading program has focused on assessments of poles in the Tier 2 and 3 HFTD areas with the goal to be fully implemented (100 percent poles analyzed) in these areas by 2024. Poles located in non-HFTD areas will follow, with the goal to be fully implemented (100 percent poles analyzed) by 2030.

4) Progress on initiative (amount spent, regions covered) and plans for next year:

PG&E is strengthening pole loading model parameters and variables considering historical data with various meteorological factors (e.g., wind speed). These enhancements include evaluation of advanced wire strength, clearance, and pole loading using acquired imagery and Light

Detection and Ranging (LiDAR) from Inspections, Drones and Helicopters. In addition, the program is using LiDAR to geo-correct pole locations.

In the 2020 WMP, PG&E forecast assessing approximately 230,000 poles in Tier 2 and Tier 3 HFTD areas. However, PG&E did not anticipate the huge volume of poles that our internal estimating teams would be analyzing every year. In addition, we switched vendors and refined quality standards, which slowed down the evaluation process in 2020. As of December 1, 2020, we have completed pole loading analysis of over 160,000 poles, all of which are considered the highest risk poles, either due to the pole characteristics or location (i.e., located in an HFTD area). In 2021, we will continue to focus on HFTD areas and plan to analyze approximately 160,000 poles. PG&E is on-track to finish poles in Tier 2 and Tier 3 HFTD areas by end of 2024 as originally forecast.

5) Future improvements to initiative:

PG&E is reviewing our pole loading calculation software to see if it can enable analysis of multiple pole models at once, enabling span linking to ensure structural connectivity.

ACTION PGE-25 (Class B)

1) Integrate discussion on long-term planning within the respective section of each individual initiative.

Response:

PG&E does not currently have specific long-term planning beyond 2030, since this effort extends until 2030. When poles are determined to be overloaded, their replacement is incorporated into our overall pole replacement program. Please refer to Section 7.3.3.6 for further discussion on pole replacements.

7.3.3.14 Transformers Maintenance and Replacement

WSD Initiative Definition: *Remediation, adjustments, or installations of new equipment to improve or replace existing transformer equipment.*

1) Risk to be mitigated/problem to be addressed:

PG&E's GO 165 Program, which covers distribution transformer maintenance, is primarily focused on the identification, assessment, prioritization, and documentation of abnormal conditions, regulatory conditions, and third party caused infractions that can negatively impact safety or reliability.

2) Initiative selection ("why" engage in activity) – include reference to a risk informed analysis on empirical (or projected) impact of initiative in comparison to alternatives:

Transformers may by maintained, repaired, or replaced based on their condition as assessed during the GO 165 process. The conditions identified during patrols and inspections of PG&E's distribution facilities may occur as a result of operational use, degradation, deterioration, environmental changes or third-party actions.

Transformers that fail in connection with an outage may be replaced as part of PG&E's Routine Emergency or Major Emergency programs. PG&E is also replacing certain transformers on circuits that are included in the System Hardening Program discussed in Section 7.3.3.17.1

3) Region prioritization ("where" to engage activity) – include reference to a risk informed analysis in allocation of initiative (e.g., veg clearance is done for trees tagged as "high-risk"):

This work is covered under PG&E's GO 165 program covers Buffer Zones and all of our service area. GO 165 inspections for HFTD are the same for non-HFTD. However, while the scope of the inspection is the same, the frequency for HFTD and non-HFTD areas is different. The frequency of GO 165 program inspections is 1-3 three years in HFTD areas as opposed to 5 years in non-HFTD areas.

4) Progress on initiative (amount spent, regions covered) and plans for next year:

PG&E will continue to maintain, repair, or replace transformers as warranted by their condition as part of our ongoing GO 165 maintenance program and Emergency programs. PG&E may also replace certain transformers as part of our System Hardening Program.

5) Future improvements to initiative:

PG&E has two Electric Program Investment Charge (EPIC) projects that are evaluating SmartMeters™ technology, data science, and remote monitoring to proactively identify and replace some overloaded transformers before they fail. These projects are covered in depth in Sections 7.1.D.3.12 – EPIC 3.20 and 7.1.D.3.11 – EPIC 3.13.

ACTION PGE-25 (Class B)

1) Integrate discussion on long-term planning within the respective section of each individual initiative.

Response:

Since this initiative is closely related to GO 165 requirements, the long-term vision will be guided by changes/updates to the GO 165 requirements. Please see references in the response to Question 5) above for more context.

7.3.3.15 Transmission Tower Maintenance and Replacement

WSD Initiative Definition: *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 65 kV).*

1) Risk to be mitigated / problem to be addressed:

Maintenance, repair and replacement of transmission towers, particularly those located in Buffer Zones and HFTD areas, are integral means of mitigating risk associated wildfire, public and employee safety, and customer reliability.

2) Initiative selection ("why" engage in activity) – include reference to a risk informed analysis on empirical (or projected) impact of initiative in comparison to alternatives:

PG&E's transmission tower maintenance, repair and replacement program focuses on high-risk steel structures. Many factors feed into determination of high-risk steel structures—including prior inspection conditions, environmental factors (such as location in an HFTD area or corrosion zone), age, structure design, prior outages, prior repairs, etc. Needs associated with Transmission tower maintenance are generally identified through system inspections and patrols.

3) Region prioritization ("where" to engage activity) – include reference to a risk informed analysis in allocation of initiative (e.g., veg clearance is done for trees tagged as "high-risk"):

Prioritization of maintenance, repair and replacement are based on severity of the issue found, fire ignition risk (i.e., risk associated with HFTD areas and HFRA), and time-dependency of the issue. As conditions are identified, they are given a time-based priority based on guidance in PG&E's Electric Transmission Preventative Maintenance Manual. For certain tags (E and F priority tags), additional prioritization occurs based on the damage found. If the repair needed is time-dependent (meaning that the damage can worsen with time), and in an HFTD area, it may be prioritized before other non-time-dependent, non-ignition potential tags.

4) Progress on initiative (amount spent, regions covered) and plans for next year:

In 2020, approximately 5,100 tags associated with steel transmission tower repair were completed within HFTD areas. Of these, approximately 50 tags associated with steel structure painting were completed in 2020 in order to extend structure asset life. In 2021, approximately 4,000 tags associated with steel transmission tower repair have been prioritized for completion within HFTD areas, not including any urgent priority tags that may be identified in 2021. Approximately 500 tags associated with steel structure painting are prioritized for completion in 2021 within HFTD

areas. Overall, in 2021, it is expected to complete all ignition-related tags in HFTD areas found before 2020 and all time-dependent ignition-related tags found in 2020 on high potential wildfire spread lines, in addition to any new urgent priority tags identified in 2021.

5) Future improvements to initiative:

PG&E is piloting additional inspection and asset-life extension technology for steel structures, which is planned to feed into asset health modeling and repair-replace decision for these assets. For example, below-grade foundation inspections (see Section 7.3.4.10) will inform future repairs and replacements. These inspections aim to assess condition of steel structure foundations below the ground-line. Investigation will include a measure of soil resistivity, pH, Redox & Half Cell Measurement as well as a visual assessment with photographic evidence of each excavated foundation leg. The results will validate data from models, inform (preventive) maintenance and repair decisions, and inform locations most requiring of cathodic protection.

ACTION PGE-25 (Class B)

1) Integrate discussion on long-term planning within the respective section of each individual initiative.

Response:

Long term, PG&E will evaluate potential steel structure failure modes through inspection, maintain structures with life-extension methods such as cathodic protection and tower coating, and replace steel structures at a sustainable rate. There are current pilots underway to expand some of the failure mode identification and life extension methods. Successful completion or additional research will be conducted until proven methods can be integrated into the lifecycle management of the assets, system-wide as needed based on risk priority.

7.3.3.16 Undergrounding of Electric Lines and/or Equipment

WSD Initiative Definition: *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).*

1) Risk to be mitigated / problem to be addressed:

Undergrounding electric lines and facilities can significantly reduce wildfire risk by eliminating overhead lines which may be prone to wires down events or otherwise prone to potential wildfire ignitions. The installation of underground facilities is considered among a suite of alternatives to mitigate wildfire risk in areas prone to tree failures. PG&E also considers secondary risks such as PSPS impacts, egress/ingress routes to support fire department response times and public safety, past fire history and effects on available fuels, current system condition, environmental risks to reconstruction activities, and general accessibility considerations to enhance employee safety when determining whether specific facilities should be undergrounded.

2) Initiative selection ("why" engage in activity) – include reference to a risk informed analysis on empirical (or projected) impact of initiative in comparison to alternatives:

Undergrounding can be an effective means of addressing wildfire risk, but it is also time-consuming and costly. Thus, each location must be separately evaluated to determine if undergrounding is a prudent approach for mitigating wildfire risk. PG&E does not, for wildfire mitigation purposes, have a stand-alone targeted program to relocate overhead facilities to underground.[5] Instead, PG&E relocates existing high risk overhead medium voltage lines to underground as part of our System Hardening Program. When considering an underground alternative, it is essential to consider risk reduction from undergrounding as well as all execution risks and costs. Execution risks include accessibility, rights-of-way, public utility easements, private property crossings, the number of services, space for necessary subsurface and pad-mounted equipment, environmental restrictions such as naturally occurring asbestos or endangered species, Archeology and Historic Preservation, soil remediation, and soil conditions.

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5 PG&E has an undergrounding program under Rule 20A, but that program is not related to wildfire mitigation.

3) Region prioritization ("where" to engage activity) – include reference to a risk informed analysis in allocation of initiative (e.g., veg clearance is done for trees tagged as "high-risk"):

The location and prioritization of undergrounding is addressed in the discussion of PG&E's System Hardening Program in Section 7.3.3.17.1

4) Progress on initiative (amount spent, regions covered) and plans for next year:

The progress on undergrounding and plans for 2021 is addressed in the discussion of PG&E's System Hardening Program in Section 7.3.3.17.1

5) Future improvements to initiative:

Future improvements related to undergrounding are addressed in the discussion of PG&E's System Hardening Program in Section 7.3.3.17.1

ACTION PGE-25 (Class B)

1) Integrate discussion on long-term planning within the respective section of each individual initiative.

Response:

As stated above, please reference Section 7.3.3.17.1 for more information on future improvements for this initiative.

7.3.3.17 Updates to Grid Topology to Minimize Risk of Ignition in HFTDs

WSD Initiative Definition: *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.*

For this initiative, PG&E has several sub-initiatives including:

- 7.3.3.17.1: System Hardening – Distribution;
- 7.3.3.17.2: System Hardening – Transmission;
- 7.3.3.17.3: Non-Exempt Surge Arrestor Replacement Program;
- 7.3.3.17.4: Rapid Earth Fault Current Limiter;
- 7.3.3.17.5: Remote Grid; and
- 7.3.3.17.6: Butte County Rebuild Program.

7.3.3.17.1 System Hardening – Distribution

WSD Initiative Definition: *N/A. This is a "PGE-defined sub-initiative" that supports the response for the (parent) WSD-defined Initiative*

In addition to describing PG&E's sub-initiative for our System Hardening Program for electric distribution, this section also provides responses to the following Action Items: Action PGE-3 (Class B), PGE-9 (Class-B), PGE-10 (Class B), PGE-32 (Class B), PGE-35 (Class B), and PGE-36 (Class B).

1) Risk to be mitigated / problem to be addressed:

PG&E's System Hardening Program focuses on the mitigation of potential catastrophic wildfire risk caused by distribution overhead assets. This program targets the highest wildfire risk miles and applies various mitigations such as line removal, conversion from overhead to underground, application of remote grid alternatives, mitigation of exposure through relocation of overhead facilities, and in-place overhead system hardening. The highest wildfire risk miles are separated into three categories:

1. The top 20 percent of circuit segments as defined by PG&E's 2021 Wildfire Distribution Risk Model for System Hardening;

2. Fire rebuild areas; and

3. PSPS mitigation projects.

PG&E also considers secondary risks and benefits as part of the System Hardening Program effort such as PSPS impacts, egress/ingress routes to support fire department response times and public safety, past fire history and effects on available fuels, current system condition, environmental risks to reconstruction activities, and general accessibility considerations to enhance employee safety.

2) Initiative selection ("why" engage in activity) – include reference to a risk informed analysis on empirical (or projected) impact of initiative in comparison to alternatives:

Distribution overhead assets represent high ignition risk due to a combination of a high exposure area (overhead assets traversing HFTD areas) and proximity to risk factors such as vegetation. For utility equipment, estimated distribution-related ignitions per circuit mile are 1.6 times that of transmission-related ignitions. For vegetation drivers, estimated distribution ignitions per mile are up to 6x greater than for transmission circuits. Table PG&E-7.3.3-6 below illustrates the CPUC reportable ignitions from 2015 to September 2020 broken down into major contributing causes in Distribution and Transmission systems.

TABLE PG&E-7.3.3-6: CPUC REPORTABLE IGNITIONS AND ESTIMATED IGNITIONS PER 1,000 CIRCUIT MILES

	2015 - 2020 YTD[1] CPUC Reportable Ignitions in HFTD		Estimated Ignitions per 1,000 Circuit Miles in HFTD[2]	
Initiating Cause	Distribution	Transmission	Distribution	Transmission
Equipment – PG&E	217	30	8.5	5.4
Vegetation	305	11	11.9	2.0
All Other[3]	195	34	7.6	6.1

1. YTD represents data as of the end of September 2020.
2. Circuit mileage in HFTD areas source: 2020 Wildfire Safety Plan – 25,598 of distribution overhead mileage in HFTD areas, 5,542 of transmission overhead mileage.
3. Other includes ignitions primarily driven by 3rd Party and Animal.

PG&E's System Hardening Program is an important initiative that can reduce wildfire ignitions caused by distribution facilities. The System Hardening Program targets the highest wildfire risk miles as identified by PG&E's 2021 Wildfire Distribution Risk Model for system hardening (the 2021 Wildfire Distribution Risk Model is explained in further detail in Section 4.5.1), and also targets overhead structures impacted directly by wildfires, and those areas most impacted by PSPS. There are several ways that locations are identified for system hardening including:

- Identifying circuit segments with the highest wildfire risk using the 2021 Wildfire Distribution Risk Model;
- Locations where past events have identified deteriorated overhead conductor;
- Electric Corrective Optimization Program (ECOP), where a number of identified corrective repair tags on a single segment of line indicate that hardening the line may be more prudent than repairing each tag individually;
- Projects to mitigate the need for PSPS in a certain area;
- Fire damaged line sections requiring rebuild; and
- Idle facilities or other line removal opportunities.

3) Region prioritization ("where" to engage activity) – include reference to a risk informed analysis in allocation of initiative (e.g., veg clearance is done for trees tagged as "high-risk"):

As discussed above, the System Hardening Program identifies locations to perform this work based primarily on PG&E's 2021 Wildfire Distribution Risk Model for system hardening. Projects are prioritized at the circuit segments level, as opposed to regional or full circuit. In addition to the highest priority segments based on the risk model, projects are also included in the system hardening portfolio when needed to address overhead structures damaged directly by wildfires (described in subsection (e) below) and those areas most impacted by PSPS. The following mitigation options (subsections (a)-(c)) are considered for each circuit segment when developing a System Hardening Program project. Those options are evaluated through PG&E's process to consider system hardening alternatives (subsection (d)). Finally, this section also describes PG&E's consideration of Buffer Zones in system hardening (subsection (e)).

(a) Line Removal and Remote Grid

Complete removal of an existing overhead distribution line will also completely eliminate the fire risk associated with that line and is therefore explored for every identified system hardening project. A line removal mitigation can be applied in various ways. The simple application of this mitigation alternative is for known or suspected idle facilities, that are not currently, actively serving customer load. PG&E follows the procedures and requirements in Utility Procedure: TD-2459P-01 "Idle Facility Program" to investigate potential idle facilities and determine if they can be permanently removed. Another line removal alternative is the rearrangement or re-alignment of the existing circuit path. PG&E reviews the targeted circuit segment for redundant distribution ties through high risk areas. It may be possible that removal of certain circuit segments would have little impact on operational flexibility and provide the most cost-effective measure to reduce wildfire risk. Finally, a future removal opportunity lies with the application of the Remote Grid alternative discussed in Section 7.3.3.17.5 below.

(b) Relocation of Overhead to Underground

PG&E will relocate existing high-risk overhead distribution lines to underground as part of this mitigation. When considering an underground alternative, it is essential that all execution risks are considered to provide an accurate cost projection for the installation and lifetime of the asset. Among the cost risks to installing underground assets are: accessibility, rights-of-way, public utility easements, private property crossings, the number of services, space for necessary subsurface and pad-mounted equipment, environmental restrictions such as naturally occurring asbestos or endangered species, Archeology and Historic Preservation, soil remediation, and soil conditions to name a few.

PG&E has found that there are many impediments to underground

construction that limit its viability to be a cost-effective mitigation alternative when compared directly to overhead system hardening. The teams responsible for scoping this work also take tree density and strike potential trees into consideration as well as ingress/egress risks as some of the primary drivers for choosing an underground alternative.

Another impediment to this alternative is its schedule risks. A typical overhead hardening project can advance from idea to execution, documentation, and close out in 13-16 months. Whereas an underground project can often take 18-45 months depending on the various risks presented. The most impactful driver in many cases is land rights. Most of our systems in the high-risk areas have existing overhead rights only and require the acquisition of new underground easements to complete the relocation. As PG&E is often unable to construct underground in the exact same path as the overhead, these easements are often required with customers and/or agencies without current agreements. This land rights acquisition process alone can take 6-18 months and requires the project to be at a fairly mature design stage prior to contacting property owners about the needed rights.

The final consideration, for PSPS mitigation, is that underground construction presents the most reliable method for mitigating the need for PSPS operations. There will be occasions that undergrounding is chosen even when it does not present the best Risk Spend Efficiency (RSE) of the hardening options because it is the most reasonable alternative to mitigate all risks considered.

(c) Overhead Hardening

The most frequently used method for system hardening is overhead hardening in place. Overhead system hardening can be done more quickly than that of many other alternatives through the use of existing rights and easements. After analyzing projected performance of overhead hardened facilities on more than 4,600 outage types, it is projected that overhead system hardening will reduce 62 percent of the distribution overhead asset ignitions from either equipment failures or due to external contact such as vegetation. This alternative has a higher RSE when compared to the undergrounding alternative in many scenarios. Overhead system hardening achieves risk reduction through these foundational elements:

- **Primary and secondary covered conductor replacement**

  Replacement of bare overhead primary (high voltage) conductor and associated framing with conductor insulated with abrasion-resistant polyethylene coatings (sometimes referred to as covered conductor or tree wire) can be an effective mitigation of wildfire ignitions on distribution lines. Installing covered conductor can help reduce the likelihood of faults due to line to line contacts, tree-branch contacts, and faults caused by animals. Installing covered conductor on secondary lines has similar benefits to installing it on primary lines.

- **Pole Replacements**

  All existing poles are evaluated for the strength requirements to withstand the new heavier covered conductor. Often the majority or all poles on a circuit segment will need to be replaced to support the new, heavier covered conductor and associated equipment. When poles need to be replaced, PG&E has tested and confirmed that composite poles and intumescent wrapped poles have increased fire damage resiliency to reduce the risk of a pole failure during a wildfire.

- **Replacement of Non-Exempt Equipment**

  Replacement of existing primary line equipment such as fuses/cutouts, and switches with equipment that has been certified by CAL FIRE as low fire risk is another component of our System Hardening Program. This replacement work eliminates overhead line equipment and devices that may generate exposed electrical arcs, sparks or hot material during their operation.

- **Replacement of Overhead Distribution Line Transformers**

  Upgrading transformers to those that contain “FR3” dielectric fluid as part of PG&E’s current equipment standards (PG&E implemented the transition from mineral oil to FR3 in 2014) can also be an effective wildfire ignition mitigation. Newer transformers are filled with fire resistant “FR3” insulating fluid, a natural ester derived from renewable vegetable oils—providing improved fire safety, transformer life, increased load capability, and environmental benefits. In addition, new transformers are manufactured to achieve higher Department of Energy electrical efficiency standards.

- **Framing and Animal Protection Upgrades**

  Replacing crossarms with composite arms, wrapping jumpers, and installing animal protection upgrades to reduce contacts and pole related ignition risks.

- **Vegetation Clearing**

  Vegetation is a critical component of the System Hardening Program. In order to access our facilities to execute a project, it often requires significant undergrowth clearing which removes vegetation on the ground directly beneath the lines. In addition, some of the previously mentioned components of a system hardening project require additional clearance space to execute. Regulatory requirements mandate 4 feet of clearance all year long, so that if there is a change to a line’s profile, including using taller poles or wider cross-arms, the vegetation must be cleared to be consistent with any changes and provide the required clearing for new overhead lines.

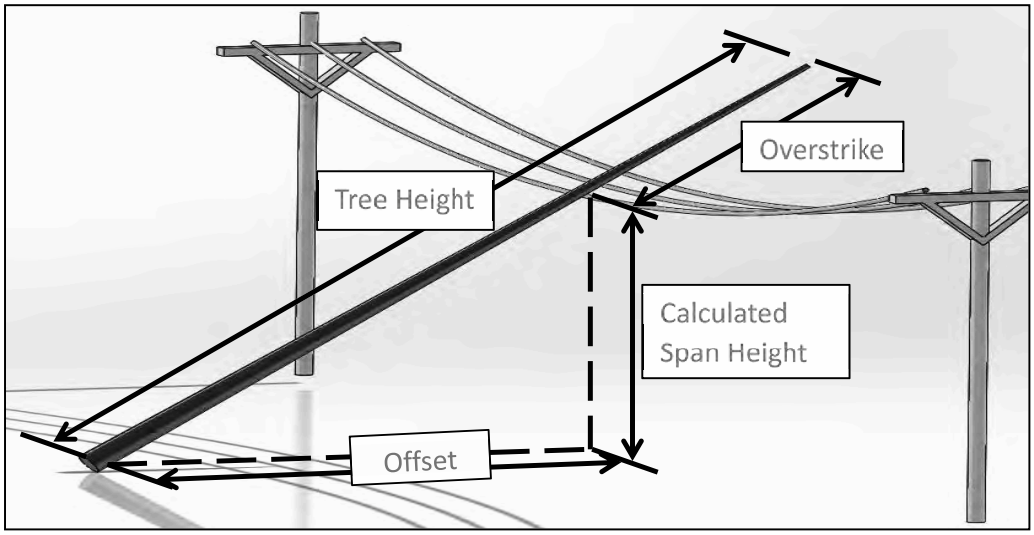
(d) System Hardening Process – Alternatives Consideration and Final Design

Once a circuit segment is targeted for system hardening, a project is launched for a segment that is no larger than 10-miles long. PG&E's Distribution Planning Engineers develop three primary alternatives for construction: (1) all overhead; (2) all underground; and (3) a hybrid alternative utilizing the specific hardening alternative thought to be the best fit for each section in the project. Line removal options are also considered during this scoping phase and, if feasible, thoroughly evaluated as generally the fastest and lowest-cost approach.

The system hardening project design options are brought to a scoping desktop review team made up of various experts to discuss and analyze additional risks such as tree strike potential, ingress and egress, localized fuel types and past fire history, land constraints, environmental risks, PSPS impacts, and general constructability concerns.

The tree strike potential factor is analyzed by PG&E's Applied Technical Services team. LiDAR data processing extracts pole, span, and fall-in tree geospatial information. This data is processed into an excel spreadsheet to determine Tree-span-pole associations. The tree strike threat is calculated as the number of fall-in trees in each span that can touch the line. A "fall-in tree" is simply a tree that is tall enough to potentially strike the span regardless of wind direction (i.e., when there is a non-zero overstrike, as shown in the figure below). Figure PG&E-7.3.3-3 shows an example of the overstrike assumptions used to calculate this risk.

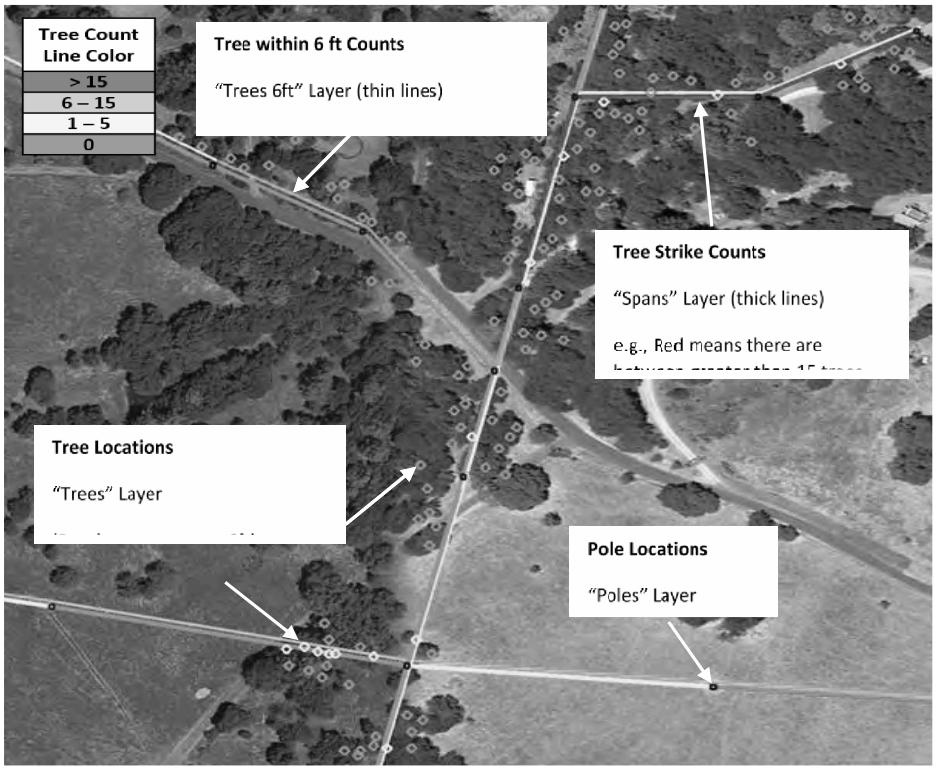
FIGURE PG&E-7.3.3-3: OVERSTRIKE ASSUMPTIONS USED TO CALCULATE RISK



Spans are then ranked based on the number of fall-in trees in each span. The results are outputted to Google Earth for visualization. The lines are color coded to represent the number of fall-in trees that can touch the line: Red for greater than 15, Orange for 6 to 15, Yellow for 1-5, and green for 0.

Figure PG&E-7.3.3-4 below is an example of the tree count and color coding for a potential system hardening project. Cost and constructability are key considerations in which the final mitigation alternative is chosen, but it is important to know and assess this tree fall-in potential risk as it is the largest single remaining risk to an overhead line that has been hardened.

FIGURE PG&E-7.3.3-4: TREE COUNT AND COLOR CODING FOR POTENTIAL SYSTEM HARDENING



Ingress, egress, fuel types and past fire history is also determined and provided by PG&E's Public Safety Specialist (PSS) to the field scoping desktop meeting. The PSS team are PG&E's field fire risk experts, many of them with significant first responder experience (often decades), that help inform PG&E's decision-making process. They analyze the area with a fire fighters' mindset to better understand the fuel types in the area, the historical fires, and the main egress and ingress routes. These experts are invaluable in providing analysis and first-hand experience in these areas, often working with local fire officials to understand the risks and available mitigations. Within the field scoping desktop meeting, it is often recommended to protect main egress routes through undergrounding, relocation or fire resilient poles. Areas where an ignition may be hard to spot are often areas a relocation may be chosen to ensure response times for local first responders are minimized.

The execution of these projects is very challenging with the various environmental and other conditions found in high fire risk areas. Land and environmental specialists analyze the alternatives provided prior to the desktop meeting and Google Earth images are provided to aid in the

analysis. Where significant environmental risks, water features, endangered species and habitats, known cultural areas, and local agencies required for the new rights are identified, appropriate scope, schedule, and cost impacts are discussed to aid in the decision making.

Projected PSPS impacts are also analyzed by meteorology team and provided to the project scoping team to aid in the understanding of past potential frequency and customer impact. In areas where greater than an average of one PSPS event per year has been modeled, or greater than 5,000 customer meters are projected to be impacted, the design alternative for undergrounding is strongly recommended due to the potential PSPS mitigation benefits. This benefit can still be difficult to capture in all cases due to the radial (i.e. "one-way") nature of the majority of PG&E's distribution system. If lines that are targeted for hardening are undergrounded, but the source of electricity is still coming from overhead lines that are likely to be de-energized, the PSPS savings may not be realized until significantly more work is done.

Utilizing all of this information, the field scoping team will review the design alternatives provided, make changes as necessary, and provide a final field scope document to the estimating team. An estimator then performs a field check to analyze the assumptions made during the field scoping desktop meeting to confirm viability of the constructability and execution risks associated with the mitigations chosen.

Once the design alternatives have been vetted to this level, a final economic analysis is performed creating net present values for the lifetime costs of each design approach, including long-term maintenance needs and costs including annual vegetation management, inspections, etc. A final recommendation and associated documentation is then submitted to PG&E's Wildfire Risk Governance Steering Committee (WRGSC) to review the project scope, risk spend efficiency and related analysis. The WRGSC provides guidance and approval for the projects that the System Hardening Program should execute upon and the mitigation action to be taken on each project. Once approved, these projects are scheduled for final design, permitting, and execution.

(e) Urgent Fire Rebuild Targeted for System Hardening

During PG&E's emergency response to a wildfire that has damaged our overhead or underground assets, several alternatives may be considered when restoring services to customers. The following guidance has been provided to the Grid Design Engineers, estimators, and assessment leads when choosing the best rebuild alternative tailored to the needs of the area. These alternatives are provided in the order of consideration for each segment and circuit for evaluation:

- **Removal** – Radial tap lines that are identified as Idle Facilities or circuit back-ties that are not required by our design standards for operational flexibility should not be rebuilt or be removed;

- **Remote Grid or Customer Self-Provided Standalone Power System (SPS)** – Isolated customer(s) in Tier 2/3 HFTD areas fed by >0.5 miles of distribution line that, if removed or not rebuilt, could be served remotely through temporary generation solutions until a permanent SPS is installed;

- **Underground** – Distribution primary conductor in an accessible area with adequate space and rights to facilitate underground infrastructure. Questions to evaluate this option include: Are gas facilities candidates to participate in the trench? Telecoms? Temporary generation may be required to support immediate customer restoration while the underground planning and construction project progresses;

- **Overhead Harden in a Different Location** – Distribution primary conductor through rural, heavily wooded, or inaccessible terrain should be evaluated for relocation to a road or more accessible location. Temporary generation would be required to support immediate customer restoration while the planning and construction project progresses;

- **Overhead Harden in Place** – This solution is appropriate for primary distribution overhead conductor in Tier 2/3 HFTD areas where >4 spans require full reconstruction or large sections of intermittent damage (generally greater than 50 percent of the segment) requires rebuild. These lines often represent mainline or major customer lines that cannot be effectively generated or switched to alternate sources of power and serve large sections of customers/critical facilities;

- **Restore in place** when intermittent damage is found without significant rebuild required; and

- **All of the Above** – some combination of all of the above depending on the circumstances for a given circuit.

Once an entire segment has been assessed, the Grid Design Engineer works closely with the Estimating team to document the damage notifications into a Google Earth image to clearly identify the damage found on the distribution assets. Then routes are determined, and initial recommendations are made for protection, switches and wire size. These designs are sent to estimating to discuss with the incident commander at base camp, to distribution planning for fuse sizes and protection settings, and to land and environmental to begin the process of easement acquisitions and dependency clearing. In some cases, more time dependent alternatives must be rejected in favor of quicker mitigations to support customers by quickly restoring service to a community, for example when local, temporary generation until new assets can be constructed is not practical. The incident commander at the assigned base camps has final authority to ensure the customer needs are being met.

(f) Buffer Zones

In addition to work performed in HFTD areas, PG&E may also perform system hardening into “Buffer Zones.” Buffer Zones are areas immediately

adjacent to an HFTD area. Because a specific distribution line may continue from an HFTD area into a Buffer Zone, hardening the line may include both hardening the HFTD area portions of the line as well as portions of a line in the Buffer Zone.

4) Progress on initiative (amount spent, regions covered) and plans for next year:

In 2019, based on prioritization derived from the 2019-2029 Wildfire Risk Model, the System Hardening Program began with a target of completing 150 miles of hardened facilities. Much of this targeted work was overhead hardened facilities, though there was also undergrounding, and removal included in this target. In total, 171 miles were hardened by the end of 2019. This included targeted hardening work, idle facility removals, fire rebuild miles and hardened facilities associated with New Business and Capacity projects. As the first year of the program 2019 also featured the development of many key processes such as establishing a clearly defined field scoping document and process, the development of ECOP for evaluating sections with a number of identified corrective tags, the beginning stages of the finite element analysis for tree strikes, and building execution capacity to support annually increasing the target.

In 2020, the System Hardening Program established a 220-mile target to harden overhead facilities within the highest fire risk miles based on 2019-2029 Wildfire Risk Model. PG&E completed approximately 342 total miles, which includes approximately 194 miles hardened in HFTD areas during fire rebuild efforts and another 21 miles undergrounded through the Butte rebuild effort described in Section 7.3.3.17.6. The unprecedent wildfires in 2020 and the damage to PG&E led to the development of a more standardized fire rebuild process, which allowed PG&E to complete nearly 200 miles of hardened fire rebuild in the last four months of 2020.

In addition to the system hardening work completed, in 2020, PG&E further built on our 2019 execution progress by developing a standard tree strike analysis utilizing LiDAR data for facilities and tree locations. PG&E standardized the use of wood poles with an intumescent wrap to increase fire resiliency of hardened lines and supplement the supply limitations and design challenges associated with composite poles. Project strategies were refined to better coordinate permitting, easements, vegetation clearing, and other dependencies in advance of construction.

For 2021, PG&E has switched over from REAX to Technosylva as our Wildfire Consequence Modelling tool. The Wildfire Consequence Model was incorporated into PG&E's 2021 Wildfire Distribution Risk Model. This change and other associated improvements in our modeling, data, and understanding of fire risk, has led to a shift in thinking about where to target system hardening resources. PG&E's 2021 Wildfire Distribution

Risk Model resulted in a significant change for PG&E in the targeting of where work would be directed to continue to harden the highest wildfire risk miles.

As mentioned earlier in this section, highest wildfire risk miles are separated into three categories:

1. The top 20 percent of circuit segments as defined by PG&E's 2021 Wildfire Distribution Risk Model for System Hardening;

2. Fire rebuild miles; and

3. PSPS mitigation miles.

PG&E is targeting 180 miles in 2021. In particular, PG&E is targeting that 80 percent of these miles be highest risk miles (one of those three categories above) and 10 percent must be performed through undergrounding or asset removal over the 3-year period from 2021-2023.

While this 2021 target of 180 miles does represent a drop from the 2020 mileage target, this is as a result of the previously referenced improvement in modeling and significant pivot in targeting. PG&E needed to change course, stop previously selected projects and start different projects that are in alignment with our updated risk model. More importantly, the 180 miles targeted in 2021 represent a greater risk reduction value than if we had continued on the previously planned work plan and executed approximately 300 miles in 2021. Under the new risk model the 301 miles of potential system hardening work originally planned for 2021 equated to 125 risk units in PG&E's multi-attribute value function (MAVF) calculation. The 180 miles now targeted for completion in 2021 are worth 198 risk units, a 58% increase in quantifiable risk reduction even though the mileage number is reduced. With the significant pivot in the program this target for 2021 is still aggressive because the cycle time for a system hardening project generally exceeds 12 months, as of late January PG&E is moving aggressively to design and execute the 2021 plan as 60 percent of the planned work is still in first project phase (scoping).

5) Future improvements to initiative:

Although we will be hardening fewer miles in 2021 than previously targeted, PG&E will use this year to rebuild our pipeline of projects in alignment with the new risk model that are identified, vetted, designed and permitted for future construction. In doing so, the pace of system hardening will increase substantially in 2022 and going forward to between 450 to 500 miles per year. Even with the shift in the risk model PG&E anticipates generally aligning with previously outlined system hardening goals for the three-year WMP timeframe (2020-2022). In the 2020 General Rate Case (GRC), PG&E targeted 1,021 miles of system

hardening for this period and our updated WMP plan forecasts completing 992 miles[6], within 3% of the original, GRC plan.

In addition to increasing the pace of system hardening work in upcoming years, as PG&E continues to develop our risk models (as described in more detail in Section 4.5.1), we will be able to incorporate more data sets, make further programmatic refinements and better scope and target our System Hardening Program. We will be analyzing hardened facilities performance with regard to actual outages, incidents and ignitions so that we can continue to refine our strategy and improve the scope of the System Hardening Program. Performance of hardened facilities that experience a wildfire will also continue to validate assumptions on life expectancy and effectiveness of hardened facilities (like wrapped poles) in various conditions. In addition, improvements in protection schemes—such as Rapid Earth Fault Current Limiters (REFCL)—may allow for a reduced level of work required to make safe a line in a high-risk area. Finally, we will seek closer alignment of our system hardening efforts with PSPS mitigation opportunities.

ACTION PGE-25 (Class B)

1) *Integrate discussion on long-term planning within the respective section of each individual initiative.*

Response:

As mentioned above, we will focus on enhancing our risk models and hardened facilities performance analysis to ensure that hardening for at-risk infrastructure is consistent with evolving risk prioritization and strategies. For 2024 and beyond, we are targeting to complete between 450 and 500 miles per year of system hardening. These efforts will also be aligned with PSPS mitigation strategies to maximize the total reduction in wildfire risk.

ACTION PGE-3 (Class B)

1) *Explain why only hardening efforts are identified within a higher risk tranche as a solution for the 7,100 miles scoped for system hardening, and no other initiatives are viable as a solution;*

2) *Define what hardening consists of in regard to the 7,100 miles identified to be hardened;*

3) *Provide the supporting materials and calculations showing that assets in the 7,100 is 2.75 more likely to fail, including all conclusions as to the reason why the failure rate is higher;*

4) *The location of the 7,100 miles; and*

5) *The explanation of the overlap and increase for these 7,100 and the*

[6] 2020 actual: 342 miles, 2021 target: 180 miles, 2022 target:470 miles = 992 from 2020-2022.

5,500 discussed in PGE-5 identified for hardening.

Response:

PG&E is no longer targeting a specific set of miles such as the 7,100 miles or 5,500 miles referenced in the previous WMP. This strategy relies on a stagnant or non-changing risk model and assumes a specific risk reduction from that base value. As PG&E continues to study and enhance the risk model, this value will shift and change. PG&E will continue to harden at-risk infrastructure consistent with the evolving risk prioritization and strategies. For 2021-2023, the target is to harden 1,120 of the highest risk miles as described in Section 7.3.3.17.1. For 2024 and beyond, PG&E is targeting between 450 and 500 miles per year.

1) PG&E is not restricting other mitigation measures from being applied as a short-term wildfire risk mitigation to the highest risk miles. System hardening is a more complete measure as well as a long-term improvement initiative that will take some time to complete. Therefore, it is necessary to consider many other initiatives as part of our risk mitigation efforts both prior to and as part of a system hardening project.

2) A system hardening project can consist of multiple initiatives including but not limited to covered conductor installation, undergrounding, remote grid, PSPS mitigation through undergrounding, non-exempt fuse and surge arrestor replacement and line removal.

3) The calculations that show that the 7,100 miles are approximately 2.75 times more likely to fail are attached (see Attachment 2021WMP_ClassB_Action-PGE-3_Atch01). To get to that result, all probabilities of failure were added for the two groups: (1) targeted miles (i.e., 7,100), and (2) the rest of miles (18,300). Subsequently the sum of these probabilities was normalized per mile which resulted in two numbers that represent the expected failure probability per mile of Distribution lines in HFTD for each group. Lastly, to compare these two numbers, they were divided and the result shows that failure rate per mile of Distribution line in HFTD is approximately 2.75 times higher for the system hardening target miles than for those outside the scope of system hardening at the time. See cell U6:W8 for actual calculations in the attached workbook.

   Regarding the reasons why, the failure rate was higher for certain portions of the distribution system. As previously described in Condition PGE-7, the sub-model #1 for likelihood of failure processed 20 different input variables using a logistic regression algorithm. The results of this sub-model generate a likelihood of failure for a specific circuit segment. The results were later validated with the proper SMEs to corroborate that the areas showing higher failure rates match their knowledge of the system. While the reasons might vary depending on each individual segment of the distribution system being evaluated, typical conclusions that can be deducted from the model were that sections in certain environments, with higher vegetation density, higher frequency of outages, certain materials of construction, higher number of overhead miles in HFTD areas, or a combination of the aforementioned, were more significant in predicting a higher failure rate.

It is worth noting that the results and calculations were objectively reasonable based on the 2018-19 Wildfire Risk Model results, however, PG&E anticipates a change if a similar calculation was to be conducted today given the improvements reflected in the 2021 Wildfire Distribution Risk Model described in Section 4.5.1.

4) Through the improvement of PG&E's risk model as described in Section 4.5.1, the location of the highest risk miles has shifted and the geographic representation of the 7,100 miles as requested is not representative of the current direction of the System Hardening Program.

5) There is not increase from 5,500 to 7,100 miles. As stated in Condition PGE-5, the 5,500 miles was just an observation from the model. The observation captured the fact that the results showed that 95 percent of the wildfire risk prioritization of system hardening was in 22 percent of the distribution line miles. The 5,500 miles was not meant to represent the scope of the System Hardening Program. It should be noted, however, that the 5,500 miles were part of the 7,100 miles identified for hardening at the time.

ACTION PGE-9 (Class B)

1) Provide details on the System Hardening Hybrid Program, particularly when comparing it to covered conductor and the standard system hardening projects discussed within the WMP;

2) When comparing the system hardening hybrid to standard hardening, provide the risk reduction per mile implemented;

3) Provide the locations in which the system hardening hybrid has been deployed and piloted, including an explanation of the rationale and any supporting calculations to determine the use of the hybrid over standard hardening approach in those areas; and

4) Provide the locations in which the system hardening hybrid is planned to be deployed, including an explanation of the rationale and any supporting calculations to determine the use of the hybrid over standard hardening approach in those areas.

Response:

The System Hardening Hybrid Program was being considered as an alternative program in 2020 to help target specific areas of risk for hardening while completing other low impact work to complete in lower risk sections. Specifically, PG&E would target installing covered conductor in areas where tree exposure exists in high risk zones identified by risk modeling and would leave bare conductor in areas with zero tree strike, branch fall, or branch/bark/frond blow in risk. This alternative has not been deployed and we have no plans to implement the System Hardening Hybrid Program at this time. PG&E is focused on reducing risk more fully with an emphasis on alternatives such as undergrounding. It is not believed that the Hybrid alternative addresses enough risk to pursue at this time.

ACTION PGE-10 (Class B)

1) *Provide details on the Wildfire Targeted System Upgrades, particularly when comparing it to covered conductor and other system hardening projects discussed within the WMP*

2) *When comparing the Wildfire Targeted System Upgrades to covered conductor, provide the risk reduction per mile implemented*

3) *Provide the locations in which Wildfire Targeted System Upgrades have been deployed and piloted, including an explanation as to the reasoning and any supporting calculations to determine the use of upgrades in those areas*

4) *Provide the locations in which the upgrades are planned to be deployed, including an explanation as to the reasoning and any supporting calculations to determine the use of upgrades in those areas.*

Response:

The Wildfire Targeted System Upgrades Program was being considered as an alternative program in 2020 to target low-impact risk reduction alternatives in areas with zero tree strike, branch fall, or branch/bark/frond blow in risk. This would include animal protection, re-framing, pole loading calculations, and potentially spreader brackets to ensure mechanical separation between phase conductors. This would provide potentially a higher RSE mitigation in areas that are potentially high consequence risk yet low probability of failure. This alternative has not been deployed and we currently do not plan to implement the Wildfire Targeted System Upgrades Program. PG&E is focused on reducing risk more fully with an emphasis on alternatives such as undergrounding. It is not believed that the Wildfire Targeted System Upgrades alternative addresses enough risk to pursue at this time.

ACTION PGE-32 (Class B)

1) *Explain how the system hardening initiatives provided in this response are prioritized in comparison to one another.*

Response:

PG&E's process for comparing alternatives within the System Hardening Program is described in Section 7.3.3.17.1(d) above.

ACTION PGE-35 (Class B)

1) *Describe the reason behind the increase in RSE for system hardening between 2020-2022 and 2023-2026, and*

2) *Provide the calculations used to determine the RSEs for both date ranges.*

Response:

The RSE for System Hardening increases between 2023-2026 versus 2020-2022 for a number of reasons, most significantly:

Climate change increases the frequency of ignition and therefore the overall risk, hence the outer years (2023-2026) have higher risk reduction[7] by the deployment of this mitigation program.

In the 2020 RAMP Report, PG&E adjusted risk reduction and RSEs for a mitigation program considering a portfolio of mitigations.[8]

- Increased miles of investment in system hardening means a larger contribution to the overall portfolio risk reduction benefits, leading to higher allocation of portfolio risk reduction; and
- Other cross cutting programs have mitigation benefits that expire in the outer years.

For the details of the risk reduction contribution and allocation, please see Attachment 2021WMP_ClassB_Action-PGE-35_Atch01.

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7 Please refer PG&E's 2020 RAMP Report, Pages 10-17

8 As discussed in PG&E's post-RAMP filing workshop held on July 14, 2020 _ see Attachment "2021WMP_ClassB_Action-PGE-35_Atch02".

7.3.3.17.2 System Hardening – Transmission

WSD Initiative Definition: N/A. *This is a "PGE-defined sub-initiative" that supports the response for the (parent) WSD-defined Initiative*

1) Risk to be mitigated / problem to be addressed:

The failure of overhead transmission assets can cause an ignition and create wildfire risk. To address this risk, PG&E has a number of programs designed to address the safety and health of our transmission system. In addition, aspects of the transmission system are upgraded or improved to reduce the impact of PSPS events from transmission facilities. PG&E's programs related to the hardening of the transmission system are described in more detail below.

2) Initiative selection ("why" engage in activity) – include reference to a risk informed analysis on empirical (or projected) impact of initiative in comparison to alternatives:

PG&E does not have a single, specific System Hardening Program for our transmission assets. Rather, transmission related programs target the highest wildfire risk areas as identified primarily by PG&E's Operability Assessment (OA) Model, in conjunction with wildfire consequence and/or weather data. These programs have the effect of hardening PG&E's transmission system and mitigating ignition and wildfire risk.

3) Region prioritization ("where" to engage activity) – include reference to a risk informed analysis in allocation of initiative (e.g., veg clearance is done for trees tagged as "high-risk"):

Transmission line related programs are focused in HFTDs but some are also extended into non-HFTD areas. Efforts associated with these programs are prioritized based on review of OA Model results for asset health, historical performance, wildfire consequence, and PSPS likelihood.

PG&E's programs that are related to hardening the transmission system, including impact reduction of PSPS events, are described below.

(a) Line De-energization, Grounding and Removal

The target of this mitigation program is known or suspected idle facilities. PG&E follows the procedures and requirements in Utility Procedure: TD-1003P "Management of Idle Electric Transmission Line Facilities Procedure" to investigate potential idle facilities. When these facilities are identified and confirmed to be within an HFTD area with no operational needs, they are prioritized for de-energization, grounding, and/or removal. Grounding of an already de-energized line addresses residual wildfire risk of induction from nearby energized line(s), until conductor removal or repurposing of the facilities can occur.

(b) Transmission System Islanding and Temporary Substation Microgrid

In some high wildfire risk scenarios, such as PSPS events, transmission islanding schemes and temporary substation microgrid may be the used to mitigate wildfire risk and reduce customer impact. The islanding schemes (such as the Caribou Power House or Humboldt Bay Power Plant Islands) allow a local area of transmission lines and substations to stay energized via local generation, as the system's primary transmission line sources are de-energized for wildfire safety purposes. The temporary substation microgrid focuses on serving substations that have safe-to-energize load. Both of these mitigations allow for those at-risk lines to be de-energized for wildfire risk mitigation, while keeping customers energized.

c) Overhead Hardening, Inspections, and Maintenance

- **Pole Replacements:** PG&E implemented enhanced design criteria for replacing wood pole structures. Most transmission wood poles are replaced with steel (most commonly light duty steel poles (LDSP)) when warranted based on condition or system capacity needs. LDSP have greater phase-to-phase conductor separation and are designed to accommodate peak wind speeds. Steel structures are also less likely to ignite compared to wood poles and crossarms. LDSP also are designed to reduce bird contact incidents by eliminating the exposure between energized conductors and grounded down guys;

- **Animal Protection Upgrades:** Installation of animal protection upgrades such as bird diverters, crossarm shields, and insulated fiberglass link to reduce contacts and pole related ignition risks is another element of transmission line centric system hardening efforts;

- **Enhanced Inspections and Prioritized Maintenance:** Enhanced inspections are designed to capture condition information aligned with components that can pose an ignition risk. These inspections are performed more frequently in HFTD areas. In addition, inspection methods such as below-grade foundation inspection are being piloted to provide further information on ignition risk failure modes that may not be easily detectable through existing methods. Maintenance work identified through inspections are prioritized (see Section 7.3.3.12.3) based on wildfire risk, wildfire spread consequence and the deterioration mode of the condition found;

- **Sectionalizing Devices:** The addition of transmission line SCADA switches (*see* Section 7.3.3.8.2) provides operating flexibility for lines that traverse HFTD areas. These switches, typically installed at junctions and near substations, can help isolate customers and reduce PSPS impact. During other planned or unplanned line outages, the switches can also be used to reduce outages and shorten restoration time;

- **Asset Replacement:** Though not the sole project driver, asset replacements in HFTD areas help reduce wildfire risk by introducing new assets in place of degraded, out-of-standard, or aged equipment. For major transmission line components – structures, conductor, insulators, and switches, there are corresponding targeted replacement programs to address asset lifecycle and extent of condition concerns. For example, there are several conductor replacement projects for addressing obsolete or failure-prone conductor. In addition, assets may be replaced for compliance or system capacity requirements; and

- **Asset Life Extension:** For some assets not in the highest priority for asset replacements, maintenance programs such as tower coating (see Section 7.3.3.15) and cathodic protection are used to extend useful life of the asset. These programs reduce exposure of steel structures to corrosion, thus maintaining its strength and integrity. Another example of life extension pilot program is installation of buddy bushings in hanger plates, to provide additional support to cold-end hardware such as C-hooks. This fail-safe design is being evaluated for more extensive application.

d) Urgent Fire Rebuild Targeted for System Hardening

During PG&E's emergency response to damaged transmission facilities during the 2020 Lightning Complex wildfire, more robust designs were incorporated into the rebuilt efforts. In addition to hardening the lines upon rebuilding (e.g. replacing prior wood poles with steel), conductor was also replaced to ensure future needs of the circuit or assets are met.

4) Progress on initiative (amount spent, regions covered) and plans for next year:

In 2020, approximately 2,700 wood pole structures within HFTD areas were replaced with steel. Avian protection retrofits were installed on 78 structures, mostly on the Drum-Rio Oso 115 kV Lines, which had a high likelihood of bird incidents. Approximately 216 miles of transmission rights-of-way (ROW) were cleared within HFTD areas. Approximately 103 miles of conductor replacement was completed on lines traversing HFTD areas.

In 2021, approximately 1,500 wood pole structures within HFTD areas are expected to be replaced with steel. Avian protection retrofits are identified and addressed through maintenance notifications based on activities. The level of retrofit is expected to decrease as more wood poles are replaced with steel and insulated fiberglass links are installed on poles in HFTD areas. Approximately 200 miles of Transmission ROW expansion are planned within HFTD areas. Replacement of approximately 92 miles of conductor on lines traversing HFTD, including associated asset hardware, is planned to be in-service in 2021.

Other maintenance tags, sectionalizing devices, and tower coating progress is described in their respective sections.

In addition, asset health and risk models informing future planning of system hardening work will be updated. It is anticipated that enhancements such as digitized design data and refinements to the corrosion model will be integrated into the OA Model (see Section 4.5.1(h)) in 2021. The vegetation LiDAR Risk Score Model (see Section 7.3.5.8) will also continue to be validated and improved in 2021. Finally, in 2020, PG&E switched over from REAX to Technosylva, which PG&E has adopted for wildfire spread and consequence information. This data was incorporated with the OA Model in 2021 to provide another layer of risk information to existing workstreams.

5) Future improvements to initiative:

Continued development/maturity of asset risk models will help focus mitigations and key issues, leading to a better understanding of most effective inspection, repair, and replace decision making timelines based on asset design, environment, age, and performance and maintenance history. A new initiative is developing machine learning/artificial intelligence models to predict the presence of various asset threats, such as mechanical wear and corrosion.

The Transmission Overhead Asset Information Collection will search historic asset records, engineering drawings and other information to provide new, quality data fields into the system of record. This will provide better data to the various asset health and risk models, improving granularity and reducing the number of assumptions needed to be made around fields such as asset age.

Continued exploration of new technology for inspections and repair will close the gap on non-visual failure modes, as well as provide additional life extension techniques for medium-risk assets.

ACTION PGE-25 (Class B)

1) Integrate discussion on long-term planning within the respective section of each individual initiative.

Response:

PG&E is working towards a more granular and centrally accessible asset data in better inform various risk models. These predictive, probability and consequence, models will drive more refined risk-informed maintenance plans, repair prioritization and proactive replacements for all transmission line assets to minimize failure and ignition risk.

Based on maintenance condition assessment and wood pole testing, PG&E projects to replace approximately 56 percent (15,000 of the remaining 26,700) wood poles in the HFTD area with steel poles in the next ten years.

Additionally, PG&E is working towards a steady, sustainable level of replacement for key assets such as structures, conductor, insulators and switches.

Exhibit 9

Environmental & Social Justice Action Plan

Version 2.0 – Draft version for public comment

October 26, 2021

California Public Utilities Commission

Contents

Executive Summary

Background & Progress on Implementation

The CPUC's Environmental and Social Justice (ESJ) Action Plan serves as both a commitment to furthering principles of environmental and social justice, as well as an operating framework with which to integrate ESJ considerations throughout the agency's work. Version 1.0 of the CPUC's ESJ Action Plan was adopted in February 2019.

The ESJ Action Plan consists of nine overarching goals, clear objectives, and 95 concrete action items to ensure agency-wide collaboration, accountability, and forward movement in meeting ESJ principles. The goals include:

1. Consistently integrate equity and access considerations throughout CPUC proceedings and other efforts.
2. Increase investment in clean energy resources to benefit ESJ communities, especially to improve local air quality and public health.
3. Strive to improve access to high-quality water, communications, and transportation services for ESJ communities.
4. Increase climate resiliency in ESJ communities.
5. Enhance outreach and public participation opportunities for ESJ communities to meaningfully participate in the CPUC's decision-making process and benefit from CPUC programs.
6. Enhance enforcement to ensure safety and consumer protection for ESJ communities.
7. Promote economic and workforce development opportunities in ESJ communities.
8. Improve training and staff development related to ESJ issues within the CPUC's jurisdiction.
9. Monitor the CPUC's ESJ efforts to evaluate how they are achieving their objectives.

The ESJ Action Plan also establishes a definition of "Environmental and Social Justice (ESJ) Communities" for the purposes of CPUC policy and programs, consisting of:

- Predominantly communities of color or low-income communities;
- Underrepresented in the policy setting or decision-making process;
- Subject to a disproportionate impact from one or more environmental hazards; and
- Likely to experience disparate implementation of environmental regulations and socioeconomic investments in their communities

Targeted communities typically include but are not limited to:

- Disadvantaged Communities, defined as census tracts that score in the top 25% of CalEnviroScreen 3.0, along with those that score within the highest 5% of CalEnviroScreen 3.0's Pollution Burden but do not receive an overall CalEnviroScreen score;[12]
- All Tribal lands;
- Low-income households (Household incomes below 80 percent of the area median income); and
- Low-income census tracts (Census tracts where aggregated household incomes are less than 80 percent of area or state median income).

Since the adoption of Version 1.0 of the ESJ Action Plan, the CPUC has made significant progress in incorporating ESJ considerations into its work, as well as creating a culture that takes into serious account the lived experiences of ESJ communities. An internal implementation structure has been established, consisting of a Core Team and ESJ Liaisons from each of the CPUC's divisions. A Status Report on Version 1.0 was published in May 2020, outlining progress made on implementing each of the action items in the ESJ Action Plan. Highlights of accomplishments thus far include:

- Established internal guidance for staff to scope ESJ issues into all proceedings;
- Added a new Public Comment feature to the CPUC Docket Card to encourage wider public participation;
- Continued and deepened prioritization of ESJ communities and related issues in key proceedings and programs, including the Climate Adaptation proceeding (R.18-04-019) and the Affordability proceeding (R. 18-07-006);
- Established new requirements for utilities to perform in-language outreach in the instance of wildfire in D. 20-03-004;
- Launched an overhauled CPUC website, with a focus on consumer needs;
- Established a session on ESJ issues for the CPUC's New Employee Orientation;
- Began participation in the Capitol Collaborative on Race and Equity (CCORE);

[1] https://calepa.ca.gov/wp-content/uploads/sites/6/2017/04/SB-535-Designation-Final.pdf

[2] This definition of "Disadvantaged Communities" reflects a small change from Version 1.0 of the ESJ Action Plan and is changed to reflect the most recent designation of "Disadvantaged Communities" by the California Environmental Protection Agency (CalEPA). A new version of CalEnviroScreen, Version 4.0, was finalized in October 2021 and CalEPA will make a subsequent designation of "Disadvantaged Community" given the new data. This definition in the ESJ Action Plan will be subsequently updated to reflect this change once it is in effect.

- Entered into a Memorandum of Understanding (MOU) with the California Workforce Development Board (CWDB) to provide expertise and recommendations on maximizing job access for ESJ communities;
- Published "Economic Opportunities in Environmental and Social Justice Communities," outlining the success of the Utility Supplier Diversity Program in reaching ESJ communities;
- Continued to emphasize outreach and engagement with community-based organizations.

Critical Topics for Consideration and Alignment for Version 2.0

In the midst of implementing Version 1.0 of the ESJ Action Plan between 2019 and 2021, certain disruptions and parallel efforts have offered opportunities to deepen and enhance the goals of the ESJ Action Plan. These topics include:

- **Racial Equity + Diversity, Equity, and Inclusion (DEI):** Acknowledging solidarity and alignment with broader racial equity work, specifically the CCORE cohort and the DEI Working Group, being led concurrently with the implementation of the ESJ Action Plan.
- **Engagement with California Native American Tribes:** Working alongside the CPUC Tribal Office to implement the Tribal Land Transfer Policy and the Tribal Consultation Policy.
- **Individuals with Access and Functional Needs (AFN):** Collaborating with communities with AFN to understand and ensure CPUC efforts serve their needs.
- **COVID-19 Pandemic: Immediate Response and the "New Normal":** Taking acting to protect the state's most vulnerable residents with measures such as disconnection moratoriums, arrearage management, and increased access to public meetings and hearings.
- **Wildfire Events:** Continuing to incorporate the needs of ESJ communities in high fire threat districts.
- **Workforce Development and the High Road Transition:** Delivering on principles of economic equity and focusing workforce-related provisions on job quality and access.
- **Priority Populations for Future Consideration in the Definition of "Environmental and Social Justice Communities":** Acknowledging potential gaps in the current definition of "ESJ communities" and consider updating the definition in the future.
- **Timeline for Providing ESJ Action Plan Status Reports and Updates:** Ensure that the ESJ Action Plan is an iterative document with a three-year time horizon upon adoption and should include mid-point Status Report.

ESJ Action Plan 2.0: Updated Goals & Objectives

For Version 2.0 of ESJ Action Plan, the underlying objectives of the nine goals have been enhanced. All the goals remain the same, with the exception of Goal 7 related to workforce development, which has been revised to include an emphasis on job quality and access. Appendix A lists 91 new action items that reflect present-day priorities and efforts.

Goal 1: Consistently integrate equity and access considerations throughout CPUC regulatory activities.

1.1 Build Systematic Approaches for ESJ Priorities

1.2 Expand Opportunities for Access

Goal 2: Increase investment in clean energy resources to benefit ESJ communities, especially to improve local air quality and public health.

2.1 Outreach & Engagement

2.2 Research & Analysis to Understand Impact

2.3 Move Towards Mutual Eligibility & Maximizing Impact

2.4 Address Impacts in ESJ Communities

2.5 Continue Ongoing Investment

Goal 3: Strive to improve access to high-quality water, communications, and transportation services for ESJ communities.

3.1 Equitable Clean Transportation

3.2 Water Customer Resilience

3.3 Extend Rail Safety to ESJ Communities

3.4 Extend Essential Communications Services to ESJ Communities

Goal 4: Increase climate resiliency in ESJ communities.

4.1 Emphasize Adaptive Capacity

Goal 5: Enhance outreach and public participation opportunities for ESJ communities to meaningfully participate in the CPUC's decision-making process and benefit from CPUC programs.

5.1 Improve Communication with ESJ Lens

5.2 Continue to Emphasize Engagement with CBOs

5.3 Build Pathways for Public Participation

5.4 Enhance Engagement with Particular ESJ Communities

Goal 6: Enhance enforcement to ensure safety and consumer protection for all, especially for ESJ communities.

6.1 Protect ESJ Consumers

6.2 Conduct Proactive Action & Analysis in Transportation and Utility Enforcement

6.3 Apply ESJ Lens to CPUC Enforcement Policy

6.4 Maximize Opportunities within Utility Audits

REVISED Goal 7: Promote high road[3] career paths and economic opportunity for residents of ESJ communities.

7.1 Maximize Authority to Promote High Road

7.2 Educate on High Road Careers

7.3 Partner with Utilities and Sister Agencies

Goal 8: Improve training and staff development related to environmental and social justice issues within the CPUC's jurisdiction.

8.1 Bolster Staff Knowledge on ESJ Issues and Resources

8.2 Support Emerging Priorities and Skill Needs

Goal 9: Monitor the CPUC's environmental and social justice efforts to evaluate how they are achieving their objectives.

9.1 Establish Consistent Quantitative Metrics

9.2 Promote Meaningful Feedback Loops

[3] https://leginfo.legislature.ca.gov/faces/codes_displayText.xhtml?lawCode=UIC&division=7.&title=&part=&chapter=2.&article

Introduction & Background

Need for the Environmental & Social Justice (ESJ) Action Plan

The mission of the California Public Utilities Commission (CPUC) is to regulate essential utility services to protect consumers and safeguard the environment, assuring safe and reliable access to all Californians. In accordance with the CPUC's institutional values of accountability, excellence, integrity, open communication, and stewardship, the CPUC has created the Environmental and Social Justice (ESJ) Action Plan to serve as both a commitment to furthering ESJ principles, as well as an operating framework with which to integrate ESJ considerations throughout the agency's work.

"Environmental justice" means the fair treatment of people of all races, cultures, and incomes with respect to the development, adoption, implementation, and enforcement of environmental laws, regulations, and policies.[4] Because the CPUC regulates utility services beyond those tied to the environment, the term "environmental and social justice" has been adopted to capture a broader effort and potential population.

What do you think of when you hear Environmental Justice?

Image 1: Word Cloud from New Employee Orientation. May 2021.

[4] Gov. Code, § 65040.12, subd. (e)

An additional important concept is - "equity," which involves "increasing access to power, redistributing and providing additional resources, and eliminating barriers to opportunity, to empower low-income communities of color to thrive and reach full potential."[5] Environmental and social justice efforts seek to foster equity for marginalized communities, including addressing historic underinvestment that has allowed inequity to flourish.

The CPUC is tasked with serving all Californians, and to do so effectively, it must acknowledge that some populations in California face higher barriers to access to clean, safe, and affordable utility services. To fulfill its mission, the CPUC acknowledges it must focus on communities that have been underserved, as this plan outlines. Additionally, as the CPUC fulfills the goals and objectives listed in this ESJ Action Plan and improves its ability to serve ESJ communities, it will become even more transparent, accessible, and effective for all the communities it serves.

Origins of the ESJ Action Plan – Past Leadership and Version 1.0

The adoption of the original ESJ Action Plan in 2019 builds on many years of prior leadership from the CPUC and the California Legislature on environmental justice and broader social justice issues. For example, the CPUC has instituted directives and programs to invest in ESJ and disadvantaged communities more broadly since the 1990s. Key efforts that demonstrate this leadership include, but are not limited to:

- Since 2001, the CPUC has convened the Low-Income Oversight Board (LIOB)[6] which advises the CPUC on low-income electric and gas customer issues and serves as a liaison for the CPUC to low-income ratepayers and representatives.
- Many of the CPUC's energy-related programs use the CalEnviroScreen tool,[7] developed by the Office of Environmental Health Hazard Assessment (OEHHA) of the California Environmental Protection Agency (CalEPA), as a means of focusing efforts and prioritizing investment in communities disproportionately affected by air pollution and facing socioeconomic burdens. CalEnviroScreen identifies "disadvantaged communities," (DACs)[8] using indicators such as environmental, health, and socio-economic burdens. While the list of indicators is not exhaustive, CalEnviroScreen is one tool available for identifying ESJ communities. Programs utilizing CalEnviroScreen to prioritize investments include Customer Generation programs such as the DAC-Single Family Affordable Solar Homes (DAC-SASH) Program, the Solar on Multifamily Affordable Housing (SOMAH) Program, the DAC-Community Solar, and DAC-Green Tariff Programs, as well as the Self-Generation Incentive Program (SGIP).

[5] https://greenlining.org/publications/reports/2019/making-equity-real-in-mobility-pilots-toolkit/
[6] https://liob.cpuc.ca.gov/
[7] https://oehha.ca.gov/calenviroscreen
[8] California Health and Safety Code Section 39711

- In 2012, California officially passed the Human Right to Water Act,[9] providing that, "every human being has the right to safe, clean, affordable, and accessible water adequate for human consumption, cooking, and sanitary purposes."[10] The CPUC continues to act for all Californians to have access to clean, safe, and affordable water supplies.
- The Clean Energy and Pollution Reduction Act of 2015[11] requires a reduction in greenhouse gases in California by increasing the procurement of renewables and other clean energy resources. The Act also requires the CPUC to prioritize disadvantaged communities in its integrated energy resources planning processes. The statute further requires the establishment of a Disadvantaged Communities Advisory Group (DACAG)[12] to provide advice to the CPUC and the California Energy Commission (CEC) on clean energy and pollution reduction programs and to aid the CPUC in determining whether these programs will benefit disadvantaged communities.
- The CPUC has provided utility bill assistance and consumer education to Californians with limited English proficiency via the TEAM (Telecommunications Education and Assistance in Multiple-Languages) and CHANGES (Community Help and Awareness of Natural Gas and Electric Services) Programs,[13] which were founded in 2006 and 2015, respectively. These programs leverage a statewide network of community-based organizations (CBOs) to provide services in over a dozen commonly spoken languages.
- The 2017 Internet for All Now Act aimed to provide high speed broadband to all Californians, with a focus on reaching previously underserved communities.[14] The goal is to eliminate the "digital divide" by enhancing broadband infrastructure and access of service via key public purpose programs such as California Lifeline and the California Advanced Services Fund.
- Under General Order 156, the CPUC's Utility Supplier Diversity Program[15] monitors supplier diversity in procurement by participating utilities and oversees a clearinghouse of women, minority, lesbian, gay, bisexual, and transgender (LGBT), and disabled veteran-owned business enterprises.

In addition to implementing legislation and spearheading programs, such as those outlined above, the CPUC has broad authority and the administrative discretion to shape programs and direct resources in a manner that furthers its equity objectives. The CPUC can further seek to achieve environmental and social justice goals by strategically targeting investment, engagement, and enforcement efforts in ESJ communities.

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[9] California Water Code Section 106.3

[10] AB 685 (Eng, 2012)

[11] Senate Bill 350 (de Leon, 2015).

[12] https://www.cpuc.ca.gov/dacag

[13] https://www.cpuc.ca.gov/about-cpuc/divisions/news-and-public-information-office/consumer-affairs-branch/team-and-changes-programs

[14] AB 1665 (Garcia, 2017)

[15] https://www.cpuc.ca.gov/supplierdiversity/

Therefore, the overarching function of the ESJ Action Plan is to provide the CPUC with a roadmap for advancing these equity-related goals across the agency's industry areas.

Version 1.0 of the CPUC's ESJ Action Plan was adopted in February 2019. The ESJ Action Plan consists of nine overarching goals, clear objectives, and 95 concrete action items to ensure agency-wide collaboration, accountability, and forward movement in meeting ESJ principles. The ESJ Action Plan was created with

input from stakeholders, including community-based organizations serving ESJ communities, sister state agencies, and the DACAG.

The nine goals of the ESJ Action Plan from Version 1.0 are:

1. Consistently integrate equity and access considerations throughout CPUC proceedings and other efforts.
2. Increase investment in clean energy resources to benefit ESJ communities, especially to improve local air quality and public health.
3. Strive to improve access to high-quality water, communications, and transportation services for ESJ communities.
4. Increase climate resiliency in ESJ communities.
5. Enhance outreach and public participation opportunities for ESJ communities to meaningfully participate in the CPUC's decision-making process and benefit from CPUC programs.
6. Enhance enforcement to ensure safety and consumer protection for ESJ communities.
7. Promote economic and workforce development opportunities in ESJ communities.
8. Improve training and staff development related to ESJ issues within the CPUC's jurisdiction.
9. Monitor the CPUC's ESJ efforts to evaluate how they are achieving their objectives.

Critical to the ESJ Action Plan was the establishment of a definition of **"Environmental and Social Justice Communities" or "ESJ Communities"**[16] where residents are:

- Predominantly communities of color or low-income;
- Underrepresented in the policy setting or decision-making process;
- Subject to a disproportionate impact from one or more environmental hazards; and
- Likely to experience disparate implementation of environmental regulations and socio-economic investments in their communities.

[16] Use of the term "environmental and social justice" is not intended to create a new class of customers. Individual CPUC programs may focus on environmental and social justice communities in different ways.

These communities also include, but are not limited to:

- Disadvantaged Communities, defined as census tracts that score in the top 25% of CalEnviroScreen 3.0, along with those that score within the highest 5% of CalEnviroScreen 3.0's Pollution Burden but do not receive an overall CalEnviroScreen score;[17][18]
- All Tribal lands;[19]
- Low-income households;[20] and
- Low-income census tracts.[21]

Image 2: Residents from the San Joaquin Valley attend CPUC Voting Meeting. December 2018.

[17] https://calepa.ca.gov/wp-content/uploads/sites/6/2017/04/SB-535-Designation-Final.pdf

[18] This definition of "Disadvantaged Communities" reflects a small change from Version 1.0 of the ESJ Action Plan and is changed to reflect the most recent designation of "Disadvantaged Communities" by the California Environmental Protection Agency (CalEPA). A new version of CalEnviroScreen, Version 4.0, was finalized in October 2021 and CalEPA will make a subsequent designation of "Disadvantaged Community" given the new data. This definition in the ESJ Action Plan will be subsequently updated to reflect this change once it is in effect.

[19] Can utilize definition of "California Indian Country" https://www.courts.ca.gov/8710.htm .

[20] Household incomes below 80 percent of the area median income.

[21] Census tracts with household incomes less than 80 percent area or state median income.

Progress on Implementation

Since the adoption of Version 1.0 of the ESJ Action Plan, the CPUC has made significant progress in incorporating ESJ considerations into its work, as well as creating a culture that takes into serious account the lived experiences of ESJ communities.

Implementation Structure

To ensure proper compliance with the actions outlined in the ESJ Action Plan, the CPUC has created an implementation structure to ensure effective coordination and sharing of lessons learned across the agency. Staff from the News and Outreach Office (NOO) in the Executive Division serves as the primary staff lead, with the ability to work across the CPUC to communicate with staff and leadership. NOO staff is supported by advisory staff from the Office of the Commission, Executive Office, and Commissioner offices. Together, these individuals make up the "Core Team" implementing the ESJ Action Plan and work together on coordination and strategic planning.

For the purposes of coordination and communication, the Core Team has established "ESJ Liaisons" in each Division across the CPUC. These ESJ Liaisons are tasked with providing status updates on action items listed in the ESJ Action Plan and participating in an ESJ Working Group. The ESJ Working Group is focused on promoting the goals of the plan across the CPUC and increasing capacity and knowledge on how to address ESJ issues.

Table 1: ESJ Liaison Structure[22]

INDUSTRY DIVISION ESJ LIAISONS	CROSS-COMMISSION ESJ LIAISONS
Communications Division	Administrative Law Judge Division (ALJ)
Energy Division	Legal Division
Water Division	Office of the Commission
Consumer Protection and Enforcement Division (CPED)	News and Outreach Office (NOO)
Safety and Enforcement Division (SED)	Office of Governmental Affairs (OGA)
Rail Safety Division	Executive Office
Safety Policy Division (SPD)	

[22] The following Divisions serve in an advisory capacity and do not have ESJ Liaisons: Human Resources Division (HR), Information Technology Services Division (ITSD), Administrative Services, Office of Internal Audits, Utility Audits, Risk & Compliance.

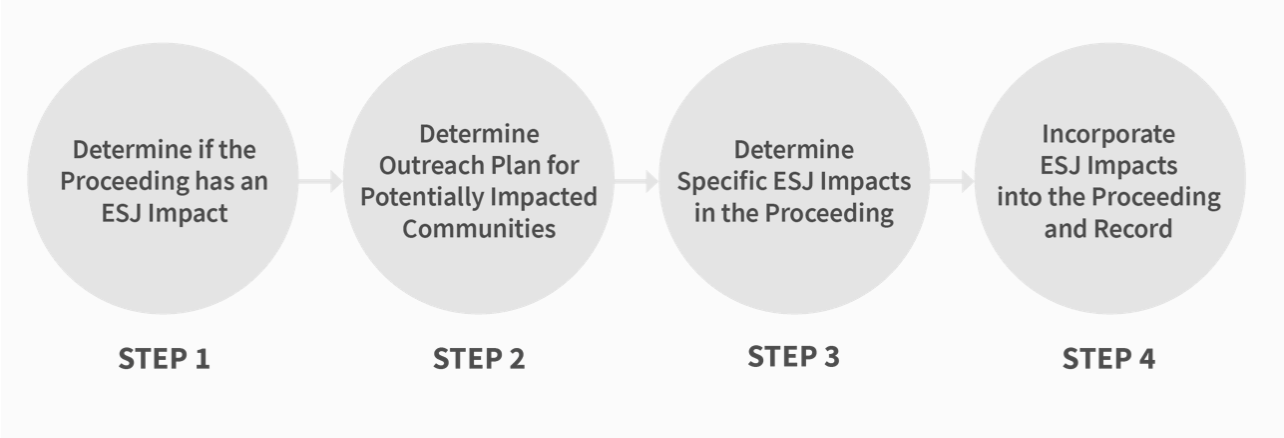
Status Report and Accomplishments Thus Far

As a means of ensuring proper accountability to the commitments made within the ESJ Action Plan, the Core Team and ESJ Liaisons published a Status Report[23] in May 2020, which documented progress on implementing each of the ESJ Action Plan's 95 action items. The Core Team also provided a presentation to the Commission on this progress, alongside lessons learned and opportunities for continued prioritization of ESJ-related work.

The accomplishments highlighted below demonstrate efforts to systemically instill ESJ considerations into CPUC work and culture.

- The CPUC encourages its staff to consider ESJ issues at the beginning of all proceedings to ensure the proceeding record incorporates meaningful discussion regarding potential impacts to ESJ communities. Internal guidance has been circulated to CPUC staff and technical assistance is being provided to CPUC staff by the Core Team and ESJ Liaisons.

Figure 1: Steps for Incorporating ESJ Considerations into CPUC Proceedings



- With the introduction of a new Public Comment feature on the CPUC Docket Card in February 2020,[24] as well as the introduction of remote access for all CPUC meetings in the wake of the COVID-19 pandemic, there has been a significant increase in the ability of people from ESJ communities and the public-at-large to provide public comment and inform CPUC decision-making.

[23] https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/news-and-outreach/documents/news-office/key-issues/esj/esj-action-plan-status-update-presentation-2020.pdf

[24] https://www.cpuc.ca.gov/about-cpuc/divisions/news-and-public-information-office/public-advisors-office/providing-public-comments-at-the-cpuc

- In Decision 20-08-046 from the Climate Change Adaptation[25] proceeding," Decision on energy utility climate change vulnerability assessments and climate adaptation in disadvantaged communities, "the CPUC established a new definition of "disadvantaged vulnerable communities" introducing the concept of adaptive capacity and investigating the specific needs of these communities in the face of climate change. Utilities are required to conduct robust community engagement as part of the process of preparing climate vulnerability assessments.
- Decision 20-07-032 from the Affordability[26] proceeding, "Decision adopting metrics and methodologies for assessing the relative affordability of utility service," offers new affordability metrics that can be utilized across energy, water, and communications industries to understand the impact [27] of potential rate changes and highlights the geographic concentration of unaffordability of key utility services.
- In Decision 20-03-004, "Community Awareness and Public Outreach Before, During, and After a Wildfire," utilities are required to perform in-depth analysis to understand language needs in their service territories, and to extend communication to include indigenous languages. Utilities are also required to perform quantitative and qualitative evaluations concerning the reach and impact of their outreach.
- A new CPUC website[28] launched in July 2021 with a focus on the consumer as the primary audience, presenting easy access to information related to low-income programs and filing complaints.
- CPUC Local Government and Community Liaisons have continued to emphasize relationship-building with grassroots community-based organizations and introducing them to the CPUC process. Their activities have included spearheading a quarterly webinar series highlighting CPUC efforts and organizing tours with CPUC leadership in ESJ communities.
- The CPUC has entered into a Memorandum of Understanding with the California Workforce Development Board (CWDB) to provide expertise and recommendations on how the CPUC can maximize workforce development opportunities in ESJ communities. Recommendations have been incorporated into several rulings, including the Transportation Electrification Framework (R.18-12-006) and Self-Generation Incentive Program proceeding (R.20-05-012).

[25] https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/climate-change

[26] https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/affordability

[27] https://www.cpuc.ca.gov/-/media/cpuc-website/industries-and-topics/reports/2019-annual-affordability-report.pdf

[28] https://www.cpuc.ca.gov/news-and-updates/all-news/cpuc-unveils-new-website-to-better-serve-californians

Image 3: Representatives from Community-Based Organizations discuss the need for in-language outreach. September 2019.

Image 4: CPUC staff attend a Community Engagement and Outreach Workshop in Sacramento. February 2020.

- The Utility Supplier Diversity Program's July 2021 whitepaper, "Economic Opportunities in Environmental and Social Justice Communities," found that significant investment has been made in ESJ communities on the part of utilities, with 42.2 percent of utility spending with diverse firms is within ESJ communities.[29]
- In May 2021, the CPUC's New Employee Orientation established a 2-hour session focused entirely focused on ESJ issues, providing incoming staff with a brief history of redlining and the environmental justice movement, an introduction to the ESJ Action Plan, and offers resources to staff to implement ESJ priorities in their work.
- CPUC staff have been participating in the Capitol Collaborative on Race and Equity (CCORE), which provides in-depth training to state agency cohorts on racial inequities and equips staff with tools and resources to further racial justice within their organizations.[30] The CPUC cohort will produce a Racial Equity Action Plan for the agency in 2021.

[29] https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/news-and-outreach/documents/bco/utility-supplier-diversity-program/economic-opportunities-in-esj-communities-paper.pdf

[30] https://sgc.ca.gov/programs/hiap/racial-equity/

Critical Topics for Consideration and Alignment Across the CPUC

In the midst of implementing Version 1.0 of the ESJ Action Plan between 2019 and 2021, certain disruptions and parallel efforts have offered opportunities to deepen and enhance the goals of the ESJ Action Plan.

Racial Equity + Diversity, Equity & Inclusion

Given that ESJ Communities include communities of color, it is critical for the ESJ Action Plan to both acknowledge solidarity and align with broader racial equity work being led concurrently with the implementation of the ESJ Action Plan.

In 2020, CPUC staff began participating in California's Capitol Collaborative on Race and Equity (CCORE) program. 16 CPUC staff members, representing different divisions across the agency, constitute a cohort that is building a Racial Equity Action Plan for the CPUC with the support of executive sponsors.

In addition to participating in CCORE, the murder of George Floyd in the summer of 2020 centered the Black Lives Matter movement in the consciousness of our society and created a sense of urgency and necessity within the CPUC to embody diversity, equity, and inclusion. This has included the establishment of the staff led Diversity, Equity, and Inclusion (DEI) Working Group, which helps identify, propose, and assist with efforts to achieve diversity, equity, inclusion, and cultural competence at the CPUC. The DEI Working Group implemented a number of initiatives to celebrate diverse communities, highlight their challenges, and improve diversity of recruitment and hiring through training for all CPUC management, hiring panels with diverse representation, and increased recruitment from diverse professional associations.

While the ESJ Action Plan certainly prioritizes communities of color and principles of racial equity, the Plan should not be considered the CPUC's primary effort to further racial equity work. CPUC staff working on implementing the ESJ Action Plan will work alongside and in solidarity with the CCORE cohort and the DEI Working Group to ensure shared goals and efforts are accomplished.

Engagement with California Native American Tribes

While the CPUC has had a Tribal Liaison for several years, since 2019 the work of the agency with tribes has expanded and deepened. The CPUC welcomed a Governor-appointed Tribal Advisor in 2020 to provide executive-level direction on how to effectively engage with tribal governments. The establishment of the Tribal Land Transfer Policy[31], which allows for the transfer of land from investor-owned utilities to

[31] https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/news-and-outreach/documents/bco/tribal/final-land-transfer-policy-116.pdf

Native American tribes with a historical interest in the land, as well as the continued implementation of the Tribal Consultation Policy[32], which provides a framework to establish and maintain effective relationships with Tribes while respecting sovereignty, have deepened the CPUC's relationships in Indian Country and have offered increasing insight into how to further adapt and learn.

Individuals and Communities with Access & Functional Needs

On November 22, 2016, the California Legislature and Governor approved AB 2311,[33] which requires emergency plans to integrate the needs of populations with access and functional needs (AFN). This population includes individuals who live with developmental or intellectual disabilities, physical disabilities, chronic conditions, injuries, limited English proficiency or who are non-English speaking, are 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.[34]

In late 2019, communities across California experienced unprecedented use of Public Safety Power Shutoff (PSPS) events, with over 975,000 customer accounts in 38 counties being affected in PG&E territory with many customers losing power for nearly a week.[35] While electric utilities are to use PSPS events as a tool of last resort only in the highest risk of infrastructure-ignited fire, the impacts of PSPS events can be perilous to individuals with access and functional needs. In order to collaborate with communities with AFN to understand and ensure CPUC efforts serve their needs, the CPUC hired a designated Senior Analyst for Resilient Communities with Access and Functional Needs within the Safety Policy Division to focus on ensuring proceedings, policies, and programs meaningfully account for and include the needs of people with AFN.

COVID-19 Pandemic: Immediate Response and the "New Normal"

On March 4, 2020, California Governor Newsom declared a State of Emergency to prepare additional resources in light of rising case numbers due to the COVID-19 pandemic.[36] Given the immediate threat of the global pandemic to the existence and livelihoods of millions of Californians, the Governor issued a "Stay

[32] https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/news-and-outreach/documents/bco/tribal/tribal-consultation-policy-approved.pdf

[33] CA Govt Code § 8593

[34] AB 2311. https://leginfo.legislature.ca.gov/faces/billCompareClient.xhtml?bill_id=201520160AB2311&showamends=false

[35] Presiding Officer's Decision 2021. https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M385/K400/385400379.PDF

[36] Governor Newsom Declares State of Emergency to Help State Prepare for Broader Spread of COVID-19 | California Governor. https://www.gov.ca.gov/2020/03/04/governor-newsom-declares-state-of-emergency-to-help-state-prepare-for-broader-spread-of-covid-19/

at Home" order on March 19, 2020.[37] In light of this emergency, the CPUC took immediate action to protect the state's most vulnerable residents:[38]

1. The CPUC issued moratoriums on disconnections for nonpayment of service, which continued through 2021.
2. In February 2021, the CPUC opened a proceeding (R.21-02-014) to address the energy utility customer bill debt accumulated during the COVID-19 pandemic. In October 2021, the CPUC ordered investor-owned utilities to implement Percentage of Income Payment Plan (PIPP) pilot programs, which allow a participant to pay a predetermined affordable percentage of their monthly income toward their electricity or natural gas bill, in order to reduce residential disconnections.
3. Moving forward, the CPUC is proactively considering how to ensure Californians disproportionately impacted, such as those in ESJ communities, continue to safely receive reliable utility service.
4. Additionally, the CPUC shifted all CPUC business to virtual platforms, which has facilitated significantly more public access to CPUC meetings and hearings. If the future allows for the opportunity to hold meetings in-person once again, it is likely that virtual engagement opportunities will remain to ensure enhanced and broader access is still available to ESJ communities and the public.

Image 5: Community Meeting regarding Disconnection in San Bernardino. June 2019.

[37] Governor Gavin Newsom Issues Stay at Home Order | California Governor. https://www.gov.ca.gov/2020/03/19/governor-gavin-newsom-issues-stay-at-home-order/

[38] CPUC COVID-19 Actions. https://www.cpuc.ca.gov/news-and-updates/newsroom/covid-19

Wildfire Events

Since Version 1.0 of the ESJ Action Plan, California has experienced the largest wildfires in state history.[39] Additionally, electric utilities have used de-energization strategies more frequently to prevent ignition of wildfires by electric utility infrastructure. These events have had massive implications for ESJ communities, particularly low-income people in rural, high fire threat areas including people with access and functional needs. While the CPUC oversaw the creation of the Wildfire Safety Division and its subsequent move to the California Natural Resources Agency, CPUC staff continue to incorporate the needs of ESJ communities in high fire threat districts as it advises the Commission and evaluates safety compliance and efficacy of wildfire prevention work of the utilities.

Workforce Development and the High Road Transition

With the implementation of the ESJ Action Plan, the CPUC entered into a Memorandum of Understanding (MoU) with the California Workforce Development Board (CWDB) in October 2020 in order to receive expertise from the CWDB about implementing Goal 7, "promoting economic and workforce development opportunities in ESJ communities." Energy efficiency, renewable energy, transportation electrification, building decarbonization, and vegetation management are the five areas or topics of interagency collaboration listed in the MoU, with the first three having been the immediate priority. In developing the MoU, the agencies realized their shared interest in leveraging CPUC policies (e.g., incentive programs, regulations and rulemakings, strategic plans, research studies, etc.) to deliver economic equity – i.e., the elimination or reduction in income inequality and other economic disparities between ESJ and non-ESJ communities.

Through the partnership, the CPUC has gained a much deeper and clearer understanding of the need to leverage its authority and jurisdiction to focus on the jobs created or supported by CPUC policies, as well as the training and services needed to develop a skilled and diverse workforce, addressing issues of quality and access on both fronts. In other words, improving ESJ communities' economic well-being, and advancing economic equity in California, will require more of the CPUC than the conventional approach of simply promoting job training or skill acquisition. As a result, Goal 7 of the ESJ Action Plan is updated to better reflect the imperatives of quality and access in both employment and training, and further promote the high road principles of equity, sustainability, and job quality across the CPUC.

Priority Populations for Future Consideration in the Definition of "Environmental and Social Justice Communities"

Version 1.0 of the ESJ Action Plan established a definition for "ESJ communities," which includes: (1) Disadvantaged Communities; (2) Low Income Census Tracts; (3) Low Income Households; and (4) Tribal Lands. While this definition captures a diverse group of communities in need of prioritization, some

[39] Cal FIRE Stats and Events. https://www.fire.ca.gov/stats-events/

additional priority communities are not specifically named. Notably, communities with AFN and those with other medical vulnerabilities are not specifically captured, nor are communities that experience disproportionate challenges with affording utility service, unhoused individuals, or indigenous populations living off tribal lands. Version 2.0 of the ESJ Action Plan does not propose a revised definition of "ESJ communities," as we recognize there is not a one-size-fits-all definition of what encompasses a potential ESJ community. Rather, we encourage CPUC initiatives to critically consider all the various kinds of populations that warrant prioritization in policies and programs.

Timeline for Providing ESJ Action Plan Status Reports and Updates

Version 1.0 of the ESJ Action Plan calls for it to be an iterative document with a two-year update cycle. Through implementation of the first iteration of the Plan, the ESJ Core Team organized a Status Report delivered to the Commissioners in May 2020 on implementation of the action items. The Status Report outlined forward movement in implementing the Action Items in the ESJ Action Plan and acknowledged opportunities for improvement. This was an effective exercise to ensure accountability for the commitments made in the Plan, empower the ESJ Liaisons in each Division to understand ESJ priorities in their division, and understand where more energy needs to be focused to make strong progress on ESJ Action Plan implementation.

Based on experience implementing the ESJ Action Plan and putting together the Status Report, staff propose for the ESJ Action Plan to aim for a three-year time horizon for an update, with a mid-point status report to the Commission. This will allow for a more reasonable timeframe with which to revisit action items and ensure their proper implementation.

Image 6: CPUC ESJ Liaisons. January 2020.

ESJ Action Plan 2.0: Updated Goals & Objectives

For Version 2.0 ESJ Action Plan, the underlying objectives of the nine goals have been enhanced. All the goals remain the same, with the exception of Goal 7 related to workforce development, which has been revised to include an emphasis on job quality and access. The objectives that relate to each goal have been streamlined and revised to reflect the work of the CPUC for the upcoming three years.

Appendix A includes a detailed list of action items, lead staff, and tentative work plans. The list remains robust and demonstrates commitments from across our various offices and divisions, with an emphasis on more cross-agency activities to deepen impact on ESJ issues.

Goal 1: Consistently integrate equity and access considerations throughout CPUC regulatory activities.

REVISED OBJECTIVES:

1.1 Build Systematic Approaches for ESJ Priorities: Continue building systematic approaches for considering ESJ issues in proceedings and decisions, as well as implementation processes included in advice letters, general orders, and resolutions. Build understanding of critical ESJ concepts and definitions to ensure alignment and deepen impact.

1.2 Expand Opportunities for Access: Continue pursuing innovative approaches to broadening access to CPUC activities and decision-making.

Goal 2: Increase investment in clean energy resources to benefit ESJ communities, especially to improve local air quality and public health.

REVISED OBJECTIVES:

2.1 Outreach & Engagement: Broaden and deepen outreach and engagement with ESJ communities early in proceedings and processes related to resilient, clean energy.

2.2 Research & Analysis to Understand Impact: Further research and analytical opportunities to understand impacts in ESJ communities.

2.3 Move Towards Mutual Eligibility & Maximizing Impact: Better leverage ongoing work by fostering cross-division, cross-Commission, and cross-agency dialogues in order to move towards mutual eligibility and maximizing impact.

2.4 Address Impacts in ESJ Communities: Continue to address ongoing and legacy impacts in ESJ communities in the resilient, clean energy space.

2.5 Continue Ongoing Investment: Continue to make prioritized resilient, clean energy investments in ESJ communities.

Goal 3: Strive to improve access to high-quality water, communications, and transportation services for ESJ communities.

REVISED OBJECTIVES:

3.1 Equitable Clean Transportation: Pursue opportunities for ESJ communities to access clean vehicles and services from Transportation Network Companies (TNCs).

3.2 Water Customer Resilience: Support ESJ customers and communities with discounted rates for low-income customers and sustainable systems.

3.3 Extend Rail Safety to ESJ Communities: Pursue opportunities to bolster safety along rail lines in ESJ communities.

3.4 Extend Essential Communications Services to ESJ Communities: Ensure implementation of new investments that offer ESJ communities access to high quality communications services at affordable rates.

Goal 4: Increase climate resiliency in ESJ communities.

REVISED OBJECTIVES:

4.1 Emphasize Adaptive Capacity: Ensure ESJ communities and considerations around their adaptive capacity is incorporated into relevant programs and activities.

Goal 5: Enhance outreach and public participation opportunities for ESJ communities to meaningfully participate in the CPUC's decision-making process and benefit from CPUC programs.

REVISED OBJECTIVES:

5.1 Improve Communication with ESJ Lens: Continue to build and improve CPUC communications methods and materials to ensure ESJ audiences can better participate.

5.2 Continue to Emphasize Engagement with CBOs: Deepen relationships and network connections with community-based organizations throughout the state.

5.3 Build Pathways for Public Participation: Based on lessons learned and areas of improvement, build additional and enhanced pathways to welcome and involve ESJ stakeholders into CPUC processes.

5.4 Enhance Engagement with Particular ESJ Communities: Consider the specific needs of particular populations and work to create targeted engagement opportunities.

Goal 6: Enhance enforcement to ensure safety and consumer protection for all, especially for ESJ communities.

REVISED OBJECTIVES:

6.1 Protect ESJ Consumers: Track complaints from ESJ communities and protect against fraud and unfair business practices in CPUC-regulated industries.

6.2 Conduct Proactive Action & Analysis in Transportation and Utility Enforcement: Utilize existing data and enforcement authority to focus on serving ESJ communities and understanding their needs.

6.3 Apply ESJ Lens to CPUC Enforcement Policy: Ensure implementation of Enforcement Policy includes opportunities for ESJ communities to benefit from maximum compliance with CPUC rules and regulations.

6.4 Maximize Opportunities within Utility Audits: Incorporate strategies for engaging with ESJ communities and understanding cumulative impact.

REVISED Goal 7: Promote high road[40] career paths and economic opportunity for residents of ESJ communities.

REVISED OBJECTIVES:

7.1 Maximize Authority to Promote High Road: Continue implementing MOU with CA Workforce Development Board to develop proceeding record and outreach to nontraditional partners to understand opportunities for CPUC to maximize jurisdiction and authority to promote high road careers.

7.2 Educate on High Road Careers: Provide opportunities to educate CPUC staff on high road career paths, best practices, and opportunities to integrate into CPUC programs.

7.3 Partner with Utilities and Sister Agencies: Engage sister agencies with authority and expertise on workforce-related issues and regulated utilities in promoting economic opportunity for ESJ communities.

Goal 8: Improve training and staff development related to environmental and social justice issues within the CPUC's jurisdiction.

REVISED OBJECTIVES:

8.1 Bolster Staff Knowledge on ESJ Issues and Resources: Provide ongoing training to new and existing employees on ESJ issues and continue to offer resources and tools to support staff learning.

8.2 Support Emerging Priorities and Skill Needs: Work in solidarity with other ESJ-aligned plans and efforts and offer new training opportunities to support shared goals.

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[40] https://leginfo.legislature.ca.gov/faces/codes_displayText.xhtml?lawCode=UIC&division=7.&title=&part=&chapter=2.&article

Goal 9: Monitor the CPUC's environmental and social justice efforts to evaluate how they are achieving their objectives.

REVISED OBJECTIVES:

9.1 Establish Consistent Quantitative Metrics: Pursue opportunities to standardize metrics related to ESJ communities in CPUC programs and proceedings.

9.2 Promote Meaningful Feedback Loops: Cultivate and deepen avenues to receive feedback from the public and demonstrate resulting impact back to specific members of the public.

APPENDICES

Appendix A: ESJ Action Items

This Appendix includes 93 specific Action Items in service of fulfilling the Goals and Objectives of Version 2.0 of the ESJ Action Plan. Each Action Item includes a title, brief description, identified lead implementor, and a tentative work plan.

Index #	Action Item	Description	Coordination Level	Lead	Tentative Work Plan
Goal 1: Consistently integrate equity and access considerations throughout CPUC proceedings and other efforts. (10 Action Items)					
1.1 Build Systemic Approaches for ESJ Priorities					
1.1.1	**ESJ Impacts in CPUC Processes**	Continue to systematically incorporate ESJ considerations into proceedings, and further pursue opportunities to incorporate ESJ into Advice Letters, Resolutions, and other processes.	Cross-Commission	ESJ Core Team	1- Create guidance for incorporating ESJ into Advice Letters 2- For decisions, resolutions, and advice letters that impact customers, residents, or small businesses in ESJ communities, consider a designated section on ESJ impacts
1.1.2	**Institutionalize Implementation of ESJ Action Plan within Divisions**	Continue ongoing recruitment of ESJ Liaisons to ensure representation from all CPUC Divisions. Bolster opportunities for ESJ Liaisons to lead ESJ Action Plan implementation within their divisions. Ensure staff-level ownership of implementation.	Cross-Commission	ESJ Core Team	1- Continue recruiting ESJ Liaisons for unrepresented Divisions 2- Ensure administrative Divisions receive biannual updates on implementation 3- Provide opportunities for ESJ Liaisons to lead ESJ-related work within their divisions. 4- Provide a mid-point status update on implementation of ESJ Action Plan to Commissioners and the public
1.1.3	**Tracking Federal Initiatives Related to Environmental Justice**	Follow actions of the Biden Administration that relate to the goals of the ESJ Action Plan. Share with ESJ Liaisons and broader CPUC staff opportunities to inform, engage and participate.	Cross-Commission	Office of the Commission	1- Create tracking mechanism for federal environmental justice actions 2- Develop internal information sharing system
1.1.4	**Coordination with ESJ-focused Staff at Regulated Utilities**	Convene and explore opportunities for coordination and collaboration with regulated utility staff that focus on ESJ-related issues. Build understanding across various program and policy areas on shared ESJ-related priorities and work together to ensure strong implementation of the CPUC ESJ Action Plan.	Cross-Commission	ESJ Core Team	1- Outreach to utilities to connect with staff focused on ESJ-related issues; 2- Consider establishing an informal working group to foster conversation and collaboration; 3- Pinpoint priority areas for coordination; 4- Leverage opportunities to meet key ESJ Action Plan goals, such as those related to staff training

1.1.5	**ESJ Definitions: Catalogue and Assess Opportunities for Mutual Eligibility**	Catalogue definitions being used across the CPUC for ESJ purposes and create a framework for the creation of future definitions. Consider opportunities for alignment and mutual eligibility in coordination with industry divisions.	Cross-Commission	Office of the Commission	1- Build upon Appendix B of ESJ Action Plan and create consistently updated catalogue of ESJ-related definitions that is accessible to staff; 2- Create an ESJ Definition Framework that helps with decision-making related to program targets; 3- Work with industry divisions and CPUC leadership to consider opportunities for potential alignment and mutual eligibility of programs, in coordination with Energy Division efforts
1.2 Expand Opportunities for Access					
1.2.1	**Evaluation of Intervenor Compensation Program (ICOMP)**	Conduct an assessment of the current ICOMP successes and challenges, and propose recommendations for future improvements, both administrative and statutory.	Cross-Commission	Office of the Commission	1- Perform analysis of existing ICOMP, including stakeholder experience, analysis of money distributed, and opportunities to build on lessons learned; 2- Present results of evaluation at a Commission Committee Meeting
1.2.2	**Launch Pilot Program for Participation of Community Based Organizations (CBOs)**	Identify a funding source outside of ICOMP and create a pilot program that aims to facilitate deeper involvement of CBOs in CPUC programs and processes.	Cross-Commission	News & Outreach Office	1- Explore and identify funding and staffing sources for the purposes of a pilot program; 2- Understand best practices in CBO programs from sister agencies; 3- Consider development and deployment of a pilot program; 4- Report on lessons learned and opportunities for a permanent program
1.2.3	**Implementation of Tribal Consultation Policy**	Continue to educate CPUC staff and stakeholders on Tribal Consultation Policy and pursue opportunities for updates and deeper engagement with tribal communities.	Cross-Commission	Executive Office - Tribal Advisor	1- Offer presentation to CPUC staff and stakeholders on Tribal Consultation Policy, as well as assistance in implementation; 2-Consider opportunities for updates and/or revisions
1.2.4	**ADA Accessibility of CPUC Internet**	Ensure that CPUC internet and public documents meets all accessibility-related requirements.	Cross-Commission	Executive Office - ADA Coordinator	1- Perform analysis on accessibility of CPUC internet and public documents 2- Remediate documents as necessary 3- Educate and train CPUC staff on accessibility requirements 4- Perform ongoing maintenance
1.2.5	**Host Regular "Participate in CPUC" Sessions**	Host virtual workshops on "Participating in CPUC Processes" to provide education on proceedings, processes, programs, how to engage, etc.	Cross-Commission	News & Outreach Office	1- Develop presentations and materials for each subject; 2- Deliver on a consistent schedule; 3- Post recording to CPUC YouTube and advertise availability to stakeholders

Goal 2: Increase investment in clean energy resources to benefit ESJ communities, especially to improve local air quality and public health. (25 Action Items)					
2.1 Outreach & Engagement					
2.1.1	**Alignment & Coordination Across Marketing, Education & Outreach (ME&O) Plans**	Leverage ongoing work across a multitude of investor-owned utilities (IOU) initiatives and programs to create synergy and deepen impact in ESJ communities, especially related to partnerships with community-based organizations (CBOs).	Energy Division	ESJ Core Team	1- Compare ME&O plans of utilities and look for commonality in approach and CBOs involved 2- Share best practices in ME&O plans across utilities and, if/when appropriate, create template guidance to ensure future alignment; 3- Explore opportunities to diversify CBOs with which IOUs work with for ME&O
2.1.2	**Improve Feedback Loop from Customers to Foster Iterative Process in Program Design**	Conduct more robust outreach to specific ESJ customer segments including households, businesses, and communities to understand program interest and satisfaction. Set mechanisms into place to adjust programs on an ongoing basis based on this feedback. Ensure appropriate data and metrics are utilized that can be built into program design.	Energy Division	Energy Efficiency Procurement & Portfolio Management	1- Conduct workshop with program, community, and customer stakeholders to help inform new customer-centric Pilot Plus/Pilot Deep ESA program design that will target customers with greatest need and that can benefit most from deeper energy savings 2- Identify and track new metrics on customer segments eligible for programs and leverage data to target customer segments that can be better served by and continue to shape the new program design
2.1.3	**Continue Support and Coordination of the Disadvantaged Communities Advisory Group (DACAG)**	Work alongside the California Energy Commission (CEC) to continue convening the DACAG and maximize opportunities to provide feedback to CPUC proceedings, programs, and processes.	Energy Division	Climate & Equity	1- Support regular public meetings of the DACAG, including broad outreach for attendance 2- Continue to build pathways for DACAG feedback to inform CPUC proceedings and programs 3- Coordinate with Low Income Oversight Board (LIOB) on shared interests
2.2 Research & Analysis to Understand Impact					
2.2.1	**Study: Reliability and Emissions Impacts of Fossil Generation In and Around Disadvantaged Communities, including the Impact of Storage Alternatives**	Conduct study within the Integrated Resource Planning (IRP) proceeding related to the retirement of gas resources and ensure considerations for ESJ communities are incorporated, including the role of energy storage technologies to ensure local reliability and reduce emissions.	Energy Division	Generation & Transmission Planning	1- Conduct study as outlined 2- Ensure IRP parties are interviewed for the purposes of the study 3- Consider recommendations that take into account the particular experience of ESJ communities

2.2.2	**Study: Societal Cost Test in Integrated Resource Plans**	Study a three-part Societal Cost Test (SCT) as ordered by Integrated Distributed Energy Resources (IDER) decision including Social Cost of Carbon, Air Quality Adder, and Social discount rate to study the impact of these societal costs on resource procurement.	Energy Division	Generation & Transmission Planning	1- Conduct study as outlined by the IDER proceeding 2- Consider recommendations related to health and air quality in ESJ communities
2.2.3	**Study: Quantifying the Air Quality Impacts of Decarbonization in California**	Conduct a sector-specific study of the air quality impacts of Transportation Electrification, Building Electrification, and other Distributed Energy Resources and ensure considerations for ESJ communities are incorporated.	Energy Division	Generation & Transmission Planning	1- Conduct study as outlined 2- Consider recommendations related to health and air quality in ESJ communities
2.2.4	**Study: Baseline of Greenhouse Gas Emissions of Small-Scale Biomass**	Conduct study on emissions of small-scale biomass facilities to understand greenhouse gas and air emission impacts.	Energy Division	Renewable Procurement & Market Development	1- Conduct study 2- Ensure ESJ community representatives are interviewed for the purposes of the study 3- Consider recommendations that take into account the particular experience of ESJ communities
2.2.5	**Providing Electric Program Investment Charge (EPIC) Research and Development Program Benefits to ESJ Communities**	In implementing EPIC projects, the CPUC will ensure administrators place increasing emphasis on: early engagement with vulnerable communities, ensuring projects benefit California ratepayers, and identify creative ways of engagement and compensation.	Energy Division	Climate & Equity	1- Understand community needs as they relate to energy research 2- Create events, platforms, or other means to increase coordination between researchers and communities
2.3 Move Towards Mutual Eligibility & Maximizing Impact					
2.3.1	**Distributed Energy Resources (DER) Action Plan**	Ensure a strong ESJ lens in the creation of the plan, particularly in the Vision and Action elements.	Energy Division	Grid Planning & Reliability	1- Complete Plan 2- Ensure inclusion of recommendations related to potential impact and benefit to ESJ communities

2.3.2	**Consider Streamlined Application Processes and Enhance Coordination for Low Income and Clean Energy Programs**	Provide customers a single statewide application to enroll in CARE, FERA, ESA programs and explore additional coordination opportunities with other income-qualified and clean energy programs and statewide efforts, including California Air Resource Board's (CARB) Access Clean California (ACC) platform.	Energy Division	Energy Efficiency Procurement & Portfolio Management and Customer Generation	1- Establish a working group to define goals for a Universal Application System, system requirements, and opportunities for inter- and intra-agency solutions with involvement from program and community stakeholders. 2- Define a recommended path forward to develop a Universal Application System solution as a result of working group discussions 3- Conduct public workshop to explore how program administrators can enhance coordination through aligning customer eligibility and increasing referrals and enrollment across multiple programs 4-Coordinate with ESJ Core Team on Commission-wide ESJ definitions and alignment work
2.3.3	**Leverage Scale of California Alternative Rates for Energy (CARE) and Energy Savings Assistance (ESA) Programs to Cross-Refer to Other CPUC Initiatives**	Regulated entities are directed to share information with customers about affordable broadband plans and other clean energy programs. Additionally, energy and water investor-owned utilities (IOUs) are encouraged to exchange information in order to facilitate more enrollment in low-income water assistance programs. Follow implementation and pursue additional opportunities for customer-focused coordination.	Cross-Commission	Energy Efficiency Procurement & Portfolio Management	1- Track effectiveness of cross-marketing and cross-referral efforts 2- Consider opportunities to deepen coordination efforts to maximize program uptake of income qualified, disadvantaged, and hard-to-reach customers, many of which reside in ESJ communities
2.4 Address Impacts in ESJ Communities					
2.4.1	**Understanding Impacts to ESJ Communities in Biomethane Procurement**	Assess potential impacts to ESJ communities when considering and recommending strategies for biomethane procurement.	Energy Division	Building Decarbonization & Renewable Gas	1 - Conduct outreach to ESJ communities to understand issues related to biomethane production 2- Understand impacts and potential benefits of biomethane production 3- Consider recommendations that take into account the particular experiences of ESJ communities
2.4.2	**Long Term Relief Due to COVID-19 Pandemic: Arrears & Disconnections**	Taking lessons learned from the Covid-19 pandemic, pursue opportunities to continue providing bill relief for ESJ customers struggling with arrears and disconnections.	Energy Division	Retail Rates	1- Ensure ESJ communities are meaningfully included in relevant proceedings and their lived experiences documented in the proceeding record 2- Work alongside sister agencies to maximize opportunities to provide bill relief 3- Establish capacity funding for CBOs to assist customers with arrears management

2.4.3	**Pilot Utilization of Affordability Metrics in CPUC Proceeding**	Pilot the use of affordability metrics in a General Rate Case (GRC). Develop pathway for including affordability metrics in future GRCs and consider geographically deaveraged or location marginal pricing.	Energy Division	Retail Rates	1- Select pilot GRC for use of affordability metrics 2- Share lessons learned regarding how affordability metrics impact costs and rates 3- Explore opportunities for wider adoption in CPUC proceedings 4- Coordinate with internal electric costs and retail rate design groups to understand overlap between affordability and the approval of utility revenue requirements and retail rate designs
2.4.4	**Net Energy Metering (NEM): Ensuring Equitable Incentives**	As changes to the NEM tariff are put forth, ensure that non-participating ESJ ratepayers will not be detrimentally impacted by changes to the tariff and will instead benefit.	Energy Division	Customer Generation	1- Ensure meaningful involvement of ESJ communities in relevant proceeding and that potential impacts are thoroughly explored
2.4.5	**Dynamic Pricing: Implementing Rate Flexibility & Management**	In recognition of the need to protect ESJ customers, pursue opportunities to implement dynamic pricing to create more equitable rate structures.	Energy Division	Retail Rates	1- Ensure meaningful involvement of ESJ communities in relevant proceeding and that potential impacts are thoroughly explored
2.4.6	**Long Term Gas Planning**	In the Long Term Gas Planning Rulemaking, ensure meaningful stakeholder involvement and thorough exploration of ESJ-related issues.	Energy Division	Gas Policy & Reliability	1- Conduct proactive outreach to ESJ communities and organizations to encourage becoming a party to the proceeding or submitting public comment 2- Provide expanded opportunities for dialogue related to the existing gas infrastructure landscape and key considerations to be made in the rulemaking
2.4.7	**Understanding Diesel Back Up Generators (BUGs) and Potential Impacts on ESJ Communities**	Monitor and collect data on the use of diesel BUGs and overlap with disadvantaged and ESJ communities.	Energy Division	Demand Response	1- Work alongside stakeholders and state agencies to understand potential impacts
2.4.8	**California Environmental Quality Act (CEQA): Opportunities for Alignment with Local Planning**	As it makes sense within the CPUC's CEQA authority, highlight ESJ considerations in preparation of comments. Consider what local planning efforts have included environmental justice or other social justice elements and ensure that CPUC review takes this into account.	Energy Division	Infrastructure Planning & CEQA	1- On a case-by-case basis, research local General Plans and other key planning documents include an environmental justice element or related component 2- Consider additional opportunities to address ESJ issues in CEQA review 3- Work alongside sister agencies, such as the Office of Planning and Research, to understand how to maximize CPUC effectiveness in this regard

2.5 Continue Ongoing Investment					
2.5.1	**Establish Equity Segment of Program Administrators' Energy Efficiency (EE) Portfolios**	Within EE Portfolios – Implement an Equity Segment that does not have to meet cost effectiveness criteria comprised of programs that provide energy, greenhouse gas, and non-energy benefits to hard-to-reach and underserved customers as well as disadvantaged communities, with the intention of serving households, businesses, and communities that are historically or currently marginalized.	Energy Division	Energy Efficiency	1- Establish working group (WG) comprised of California Energy Efficiency Coordinating Committee (CAEECC) stakeholders and organizations championing ESJ principles 2- WG develop objectives that define success for the Equity segment and its programs 3- Conduct public workshop to engage diverse community members and obtain feedback on important topics, actions, and customer groups 4- WG develop metrics that measure progress toward achieving success 5- Consider opportunities for Equity offerings to enhance the societal benefit of offerings within the Market Support Segment
2.5.2	**Continue Prioritization of ESJ Communities in Building Decarbonization Programs**	Ensure that funding for ESJ communities continues to be prioritized in BUILD and TECH.	Energy Division	Building Decarbonization & Renewable Gas	1- Incorporate definitions that prioritize ESJ communities in new phases of programs
2.5.3	**Expand Investment in Electrification in San Joaquin Valley proceeding**	Follow ongoing implementation of the San Joaquin Valley Affordable Energy program to understand lessons learned in working with CBOs and ESJ communities on an electrification process and determine how to best invest in remaining communities in Phase 3.	Energy Division	Building Decarbonization & Renewable Gas	1- Share lessons learned, especially related to community engagement led by CBOs and how to reach residents of ESJ communities, with broader CPUC staff; 2- Consider expanding pilot to remainder of communities or consider how to merge with the other electrification efforts at the commission; 3- Develop statewide strategies to barriers encountered in SJV communities
2.5.4	**Continued Prioritization of ESJ Communities in Microgrid Incentive Program**	Disseminate $200 million to vulnerable areas and ensure criteria bolsters opportunities for low-income and vulnerable communities, people with access and functional needs, tribal, and people who are on medical baseline or electrically dependent to access funding.	Energy Division	Microgrids & Resiliency	1- Monitor implementation of program, including effectiveness in reaching ESJ communities and those at high risk of electrical outage 2- Ensure proper outreach is conducted to targeted communities

2.5.5	**Improving Access to Electric Vehicle Charging for ESJ Communities**	Between investments made via ratepayer funded transportation electrification (TE) programs and funding the IOUs oversee from Low Carbon Fuel Standard (LCFS) credit revenue, ensure robust equity requirements are incorporated and are in alignment with sister agencies like the California Air Resources Board (CARB) and the California Energy Commission (CEC).	Energy Division	Transportation Electrification	Building on past track record, consider incorporating higher set-asides and prioritization of ESJ and underserved communities for investments 2- Ensure communities are meaningfully involved in the development of program proposals as well as program implementation to ensure buy-in and strong utilization of charging infrastructure in the future
2.5.6	**Continue Tracking and Evaluation of Customer Generation Programs and Improve Effectiveness in Reaching ESJ Communities**	Track outcomes and lessons learned from the following programs to better understand effectiveness of incentive programs and how to ensure maximum impact: Multi-family Affordable Solar Housing (MASH), Single-family Affordable Solar Homes (SASH), Disadvantaged Communities-Single-family Affordable Solar Homes (DAC-SASH), Solar on Multi-family Affordable Housing (SOMAH), Self-Generation Incentive Program (SGIP), Green Tariff (GT), Disadvantaged Communities - Green-Tariff (DAC-GT), Community Solar Green Tariff (CSGT)	Energy Division	Customer Generation	1- Monitor metrics and outcomes of customer generation programs, both those specific to ESJ communities and those that are more broadly available 2- Consider conducting geospatial analysis to understand concentration of program uptake in ESJ communities 3- Explore opportunities for program modifications, stacking incentives, auto-enrollment, and improved outreach to best reach ESJ communities

Goal 3: Strive to improve access to high-quality water, communications, and transportation services for ESJ communities. (17 Action Items)					
3.1 Equitable Clean Transportation					
3.1.1	**Implementation and Monitoring of Accessibility of TNCs and AVs**	Identify opportunities through transportation proceedings and their implementation to improve transportation accessibility for ESJ communities	Consumer Protection & Enforcement Division	Transportation Licensing & Analysis	1- Share all TNC Access for All Staff Reports with the ESJ Action Plan Committee (as ordered in Decisions) 2- Summarize Accessibility data collected in TNCs' Annual Reports and AVs' Quarterly Reports annually

3.1.2	**Implementation of Clean Mile Standard and Impact on Drivers from ESJ Communities**	Consider how TNC drivers from ESJ communities and the communities who rely on TNC transportation will be impacted by the Clean Miles Standard	Consumer Protection & Enforcement Division	Transportation Licensing & Analysis and Administrative Law Judge Division	1- Seek feedback from drivers in ESJ communities as part of the development of Clean Mile Standard 2- Assess CMS impacts on ESJ communities as data become available throughout the life of the program.
3.2 Water Customer Resilience					
3.2.1	**Maximize Customer Assistance Programs (CAPs) and Arrearage Management Plans (AMPs) for Low-Income Water Customers**	Ensure that CAPs and AMPs are appropriately and effectively marketed to ESJ communities. Given the realities of the Covid-19 pandemic, consider new strategies for assisting low-income water customers with water bill payment.	Water Division	Small Company & Compliance	1- Follow implementation and outreach efforts of water company CAPs and AMPs 2- Encourage sharing of best practices and lessons learned 3- Explore additional opportunities to assist low-income water customers
3.2.2	**Understanding and Acting on Affordability of Water Rates**	Given both the opportunity to utilize new affordability metrics and information from the Drinking Water Needs Assessment from the State Water Resources Control Board (SWRCB), continue to understand where ESJ customers are experiencing disproportionately high water rates.	Water Division	ALJ Support & Compliance	1- Consider affordability metrics in water General Rate Cases (GRCs) 2- With the aid of information from the Drinking Water Needs Assessment, evaluate whether there are water systems within CPUC's jurisdiction where customers experience high rates that could be ameliorated with consolidation 3-Consider whether the CPUC should open an OIR on the subject of new standards for consolidation of water utility systems
3.2.3	**Water Resilience and Reliability in the Face of Drought**	Work with water utilities to plan for continued conditions of drought, with emphasis on addressing ESJ community needs.	Water Division	ALJ Support & Compliance	1- Consider and evaluate the resilience and reliability challenges of regulated utilities 2- Consider opening an OIR on Water Resiliency and Reliability to have utilities proactively plan for future resilience needs 3- Work with State Water Resources Control Board (SWRCB) and Department of Water Resources (DWR) on overall water resiliency and reliability planning, as well as the Energy Savings Assistance Program (ESA) and the Low Income Home Energy Assistance Program (LIHEAP) on water conservation measures

3.2.4	**Incorporating ESJ Considerations into Consolidations of Small Water Companies**	When reviewing consolidation applications, utilize Cal Enviro Screen water-related indicators, other tools, and local engagement opportunities to understand if consolidation would benefit an ESJ community.	Water Division	Small Company & Compliance	1- Train Water Division staff on Cal Enviro Screen and water-related indicators 2- Run analysis for every consolidation application 3- Incorporate discussion of ESJ issues into decisions and resolutions
3.3 Extend Rail Safety to ESJ Communities					
3.3.1	**Section 190: Grade Separation at Existing Crossings - Outreach & Prioritizing ESJ Communities**	Revise Section 190 formula to include a prioritization for ESJ communities. Ensure ESJ communities and their local governments are aware of opportunity to apply for Section 190 funding.	Rail Safety Division	Rail Crossings & Engineering	1- Meet with sister agencies to understand prioritization of ESJ communities in other formula-based funding programs 2- Do initial mapping to understand overlap between high accident rates and CalEnviroScreen-defined disadvantaged communities 3- Update formula to include some prioritization of ESJ communities 4- Conduct more proactive outreach to local governments to apply for funding
3.3.2	**Homeless Encampments: Continued Collaboration with Local Governments**	Continue collaboration between Rail Safety Division and the News and Outreach Office to meet with local governments and other transportation partners to triage issues related to homeless encampments and accidents along rail lines.	Rail Safety Division	Railroad Operations Safety Branch and News & Outreach Office	1- Create a plan for outreach in key areas where potential strikes along rail lines are increased due to encampments; schools and businesses; any local activities that may create risks along tracks. 2- Ensure a diversity of local government and community organizations are involved alongside regulated railroad companies
3.3.3	**Opportunities for ESJ Comments in Environmental Letters**	Explore opportunities to incorporate general comments in environmental letters about assuring the consideration of environmental and social justice issues when designing and approving a project.	Rail Safety Division	Rail Crossings & Engineering and Rail Transit Safety	1- Create boilerplate language that can be adapted by staff that speaks to ESJ issues 2- Disseminate amongst staff and provide resource to assist in incorporating comments
3.3.4	**Involving ESJ Communities in Rail Proceedings**	Work with News and Outreach Office to ensure applications and proceedings are proactively publicized to relevant local governments and CBOs, especially those in ESJ communities.	Rail Safety Division	Rail Crossings & Engineering	1- Contact News and Outreach Office when new rail crossing application is received 2- Promote opportunities to provide public comment in the Docket Card

3.4 Extend Essential Communications Services to ESJ Communities					
3.4.1	**Increase Collaboration and Knowledge Share Across Telecommunications Public Purpose Programs**	Bring together Public Purpose Program staff - including Lifeline, California Advanced Services Fund (CASF), California Teleconnect Fund (CTF), California High Cost Fund (CHCF) Parts A & B, and Deaf and Disabled Telecommunications Program (DDTP) - to talk about shared priorities, lessons learned, opportunities to leverage advisory committees, and to understand programmatic impact in ESJ communities.	Communications Division	Consumer Programs	1- Establish staff-level working group. 2-Host meetings to educate each other about programs and shared issues. 3- Conduct cross-program analyses using GIS to assess program impact across different geographical areas.
3.4.2	**Implementation of $6 billion Broadband Legislation**	Given significant new investment and expansion of programs, ensure that investments are benefiting as many ESJ community members as possible, that essential speeds are more available, and that ESJ communities meaningfully participate in the planning and implementation of the programs and investments.	Communications Division	Consumer Programs	1- Ensure planning and implementation meaningfully involves community-based organizations and representatives from ESJ communities. 2- Use GIS to identify ESJ communities that lack fixed broadband speed of 25/3 or better. 3- Further, for areas that do have 25/3 or better, ensure their rates do not create affordability concerns.
3.4.3	**Implementation and Lessons Learned from Tribal Technical Assistance (TA) Program**	Continue conducting outreach to California tribes and disbursing funds as part of the Tribal TA Program. Share lessons learned and best practices related to outreach, program structure, and implementation.	Communications Division	Tribal/Rural Area	1 - Per D. 20-08-005, Communications Division is assigned responsibility and authority to use California Advanced Services Fund state operations funds to provide technical assistance for Tribes. 2- Ensure tribes across the state are aware of available grant funds and opportunities to apply 3 - Continue ongoing outreach 4 - Update leadership and CPUC staff on successes and lessons learned from the program, and how to utilize as a model to reach other key ESJ populations
3.4.4	**Continue Understanding Challenges of ESJ Communities with Communications Affordability**	Understand more about concentrations of unaffordability of communications services in ESJ communities. Explore opportunities to leverage new investments to lower costs and increase essential speeds.	Communications Division	Carrier Oversight & Programs	1- Utilize the Commission-adopted Affordability Framework to inform programmatic and investment work moving forward 2- Continue exploring what fixed broadband speed should be deemed as part of essential communications service.

3.4.5	**Phone and Video Service for Incarcerated Persons**	Follow outcomes and lessons learned from the proceeding. Continue to develop innovative outreach, engagement, and regulatory strategies to alleviate cost for the priority population.	Communications Division	Consumer Programs	1- A proposed Decision has gone out on August 23, 2021 for comment proposing a reduced rate, and if adopted staff may hold compliance meetings with the service providers.
3.4.6	**Lessons Learned from Lifeline Assessment**	Understand lessons learned in conducting a robust program assessment of a public purpose program. Consider recommendations related to prioritizing ESJ communities.	Communications Division	Consumer Programs	1- Complete assessment 2- Understand lessons learned from contractor related to outreach and engagement for the purposes of the assessment 3- Explore opportunities to prioritize ESJ communities in outcomes of assessment
3.4.7	**Continue Efforts to Increase Access to Lifeline Program for Vulnerable Populations**	Continue to pursue a permanent program to improve access for foster youth, after examining lessons learned from the i-Foster pilot program and begin to develop similar programs either pilot or permanent to address special needs of other vulnerable populations such as homeless and recently released incarcerated people.	Communications Division	Consumer Programs	1- Continue monitoring outcomes of extended iFoster pilot program 2-Explore opportunities to partner with state agencies or other organizations to close enrollment gaps for other vulnerable populations 3-Consider permanent program changes to address gaps identified by partners or in the Lifeline Assessment.

Goal 4: Increase climate resiliency in ESJ communities. (3 Action Items)					
4.1 Emphasize Adaptive Capacity					
4.1.1	**Initiate Climate Change Adaptation Planning with Emphasis on Disadvantaged Vulnerable Communities**	The CPUC will ensure electric and gas utilities engage disadvantaged vulnerable communities and describe specific actions they will take in those communities, as they assess the long-term vulnerabilities to climate change of their infrastructure, services, and operations, as well as share best practices that are developed in the process.	Energy Division	Climate & Equity	1-Begin developing Community Engagement Plans 2-Begin conducting climate change vulnerability assessments with community engagement 3- Summarize lessons learned

4.1.2	**Consider Safety Policy Responses to Climate Change**	Develop a visual tool to make California climate change scenarios more accessible to all in the context of utility infrastructure impacts. Understand downstream consequences to ESJ communities and ensure meaningful collaboration with ESJ representatives in adaptation actions.	Safety Policy Division	Security & Resilience	1- Develop GIS tool 2- Develop situation report 3- Ensure findings incorporate ESJ community considerations based on collaborative community engagement
4.1.3	**Framework for Integrating Resiliency Planning and Evaluation into Current Grid Planning Policy**	Devise a standardized view of the concept of resiliency and adaptive capacity, and how it can be measured.	Energy Division	Microgrids & Resiliency	1- Continue alignment with Climate Adaptation proceeding and subsequent implementation, as well as other key processes such as the Risk Assessment Mitigation Phase (RAMP) and General Rate Cases (GRCs) 2- Develop tools to guide utilities in resilience planning

Goal 5: Enhance outreach and public participation opportunities for ESJ communities to meaningfully participate in the CPUC's decision-making process and benefit from CPUC programs. (11 Action Items)					
5.1 Improve Communication with an ESJ Lens					
5.1.1	**Fact Sheets and Collateral Materials**	Continue to update CPUC Fact Sheets and Brochures to ensure information is up-to-date and accessibly written.	Cross-Commission	News & Outreach Office	1- Ensure CPUC website includes collateral materials for key programs and initiatives 2- Revise and post materials in need of updates
5.1.2	**Translation of Key Documents and Collateral Materials**	Translate key Fact Sheets and Brochures, especially those aimed at consumers, into critical languages spoken by Californians, including Spanish, Chinese, and other languages.	Cross-Commission	News & Outreach Office	1- Prioritize what materials are in need of translation 2- Understand what key languages are needed 3- Post to website
5.1.3	**Email Communication and Newsletters**	Explore opportunities to streamline email communications from the CPUC, including establishing a centralized platform for proactive communication.	Cross-Commission	News & Outreach Office	1- Explore opportunities to expand use of existing email software to meet communications need 2- Understand if existing capacity can handle a centralization process 3- Roll out any new plan to relevant CPUC staff
5.1.4	**Interpretation Availability at CPUC Meetings**	Pursue standard policy for when to incorporate interpretation services outside of request process.	Cross-Commission	News & Outreach Office	1- Draft materials and share with CPUC staff regarding how to request interpretation services, both for internal purposes and for external needs 2- Consider a policy with concrete criteria for when to incorporate interpretation on a proactive basis.

5.2 Continue to Emphasize Engagement with Community Based Organizations (CBOs)					
5.2.1	**Statewide Mapping of Engagement CBOs**	Work alongside utilities to understand partnerships with CBOs, including their statewide spread, funding landscape, and opportunities to deepen engagement in ESJ communities.	News & Outreach Office and Energy Division	News & Outreach Office	1- Gather information related to CBO partnerships and their geographic reach 2- Consider opportunities for deeper engagement in key geographies 3- Explore areas for coordination between CPUC outreach efforts and utility partnerships
5.2.2	**Leverage CBOs for CPUC Workshops and Community Engagement**	Consider how CBOs can provide critical services and assistance to CPUC staff in the planning, outreach, and facilitation of proceeding-related workshops and other engagement needs. Pursue opportunities to provide grants or contracts with CBOs with relevant experience.	Cross-Commission	News & Outreach Office	1- Understand from CPUC staff what needs exist for workshop and community engagement 2- Develop a concept for allowing CBOs to contribute to these efforts within existing authority
5.2.3	**Deepen Relationships with CBOs in TEAM and CHANGES**	Continue to explore opportunities to leverage network of CBOs working under TEAM and CHANGES programs.	News & Outreach Office	News & Outreach Office	1- Continue to work with lead contractor to understand what CBOs are learning on the ground 2- Continue to channel feedback within CPUC 3- Consider convening CBO partners to share insights, lessons learned, and explore further collaboration
5.3 Build Pathways for Public Participation					
5.3.1	**Best Practices for Virtual and Hybrid Meetings**	Coming out of COVID-19 Pandemic, promote virtual meetings that facilitate broad participation.	Cross-Commission	News & Outreach Office	1- As events return to being conducted in-person, include a remote access option as appropriate and ensure that remote participants are able to meaningfully participate in event 2- Continually review best practices and lessons learned on hybrid community engagement, including when to incorporate interpretation services, to offer internal guidance for continual improvement

5.3.2	**Public Participation in Transportation Proceedings**	Work to create pathways for CBOs and other intervenors to be able to better participate and provide feedback for proceedings and programs related to transportation network companies (TNCs), autonomous vehicles (AVs), charter-party carriers (TCPs), passenger stage corporates (PSGs), and vessel common carriers (VCCs)	Consumer Protection & Enforcement Division and Administrative Law Judge Division	Transportation Licensing & Analysis	1- Explore opportunities to expand Intervenor Compensation Program (ICOMP) for purposes of funding participation in transportation proceedings 2- Work with PAO to identify CBOs for ESJ communities and proactively engage them to participate through CPUC's public comment options and transportation proceedings
5.4 Enhance Engagement with Particular ESJ Communities					
5.4.1	**Engage and Serve Communities with Access and Functional Needs**	Work with AFN representatives to better understand key issues, collaborate with communities with AFN, and serve their needs in CPUC regulatory policy.	Safety Policy Division	Security & Resilience	1 - Continue with baseline work within Safety Policy Division; 2 - Determine overlapping proceeding work and/or outcomes with ESJ priorities 3 - Determine which CPUC regulatory policies at year 1 and year 2 serve the needs of individuals and communities with AFN.
5.4.2	**Bolster CPUC's Tribal Land Transfer Policy**	Via a rulemaking process, revisit the Tribal Land Transfer Policy and ensure lessons learned thus far ensure that tribal communities can maximize benefits and opportunities available.	Executive Office	Executive Office - Tribal Advisor	1- Open rulemaking to consider key questions in updating the Policy 2- Ensure a diversity of tribal perspectives are included in the rulemaking process 3- Maximize opportunities for tribes to take advantage of the Policy

Goal 6: Enhance enforcement to ensure safety and consumer protection for ESJ communities. (10 Action Items)					
6.1 Protect ESJ Consumers					
6.1.1	**TEAM/CHANGES Program Updates**	Have TEAM/CHANGES contractor present to the Low-Income Oversight Board (LIOB) annually to offer on-the-ground perspectives of customers with Limited English Proficiency (LEP).	News & Outreach Office	News & Outreach Office	1- Work with LIOB to set briefing on calendar 2 - Prepare presentation and post online for remote access 3- Consider other venues and opportunities to share insights
6.1.2	**Strategize Use of Consumer Affairs Data in ESJ Policies**	Work with ESJ liaisons to determine if and how Consumer Affairs Branch (CAB) data can contribute to and inform ESJ policies.	Cross-Commission	News & Outreach Office	1- CAB will present to ESJ liaisons and explain the type of data that is collected 2 - ESJ Liaisons and CAB will brainstorm whether this data could contribute to any existing or future ESJ policies at the CPUC

6.2 Conduct Proactive Action & Analysis in Transportation and Utility Enforcement					
6.2.1	**Proactively Initiate Compliance Checks in ESJ Communities**	Consider opportunities to proactively work in ESJ communities to ensure compliance with CPUC regulations.	Consumer Protection & Enforcement Division	Transportation Licensing & Analysis, Transportation Enforcement, Utility Enforcement	1- Analyze complaint data to understand overlap with ESJ communities and adjust enforcement strategies as appropriate 2- Consider prioritizing ESJ communities when performing compliance checks or conducting field enforcement work
6.2.2	**Include ESJ filters in quarterly scanning of CAB complaints to identify trends and patterns of consumer issues in ESJ communities**	Identify potential targets for inquiries and/or investigations using Census data to identify complaints occurring within ESJ communities.	Consumer Protection & Enforcement Division	Utility Enforcement	UEB analyzes CAB data to identify targets for inquiries and/or investigations. Using Census data, staff will identify ESJ communities to further delineate complaints from these communities 1-Analyze monthly energy and telecommunications CAB complaint data 2-Filter complaints for relating to ESJ communities using census data 3-Identify patterns and changes 4-Target subjects for inquiry or investigation
6.2.3	**Expand Opportunities to Leverage Enforcement Action Settlements for ESJ Purposes**	Building on long-running practice of supporting low-income and ESJ-related programs, consider ESJ communities when considering alternative enforcement options.	Consumer Protection & Enforcement Division	Transportation Enforcement and Utility Enforcement	1- Develop internal CPED guidance on how to optimize settlement agreements to benefit ESJ communities when settlement funds are available stemming from UEB / TEB enforcement actions 2- Implement this practice of considering ESJ communities in all future settlement agreements stemming from enforcement actions when legally permitted
6.2.4	**Analysis of Potential Redlining in ESJ Communities by Transportation Network Companies (TNCs)**	Analyze existing data to understand if passenger carriers are systematically serving ESJ communities differently.	Consumer Protection & Enforcement Division	Transportation Licensing & Analysis Branch	1- Determine if patterns of bias exist in TNC service to ESJ communities compared with others, by analyzing TNC data to include drop-off and pick-up locations, fares charged, and trip acceptance rate 2- Explore opportunities to publish report with findings
6.2.5	**Analysis of Potential Redlining in ESJ Communities by Transportation Network Companies (TNCs)**	Analyze existing data to understand if passenger carriers are systematically serving ESJ communities differently.	Consumer Protection & Enforcement Division	Transportation Enforcement Branch	1- Open an investigation if analysis and report by TLAB suggests probable violations 2- Take appropriate enforcement action as warranted by the facts of the investigation

6.3 Apply ESJ Lens to CPUC Enforcement Policy					
6.3.1	**Develop an ESJ Lens for New CPUC Enforcement Policy**	Based on lessons learned from sister agencies, develop a training on ESJ issues and guidance on how to approach enforcement from an ESJ perspective. Consider pilot opportunities.	Cross-Commission	ESJ Core Team	1- Consult sister agencies on opportunities to do targeted enforcement actions in ESJ communities. Gather best practices. 2- Develop ESJ lens for CPUC Enforcement Policy. 3- Consider pilot exercises.
6.4 Maximize Opportunities within Utility Audits					
6.4.1	**Develop a Community Engagement Step to Gas and Electric Infrastructure Safety Inspection Process**	In performing ongoing audits and inspections of both electric and gas infrastructure, add a step that includes outreach and engagement with the community to develop a more holistic picture of on-the-ground safety conditions. Consider specific guidance for conducting safety inspections in ESJ communities.	Safety & Enforcement Division	Electric Safety & Reliability and Gas Safety & Reliability	1. Add a step to existing safety inspections and audits that engages the community to record any experiences and/or concerns with safety of the infrastructure. 2. Ensure SED staff know how to access support resources and consider training on implementation. Involve New & Outreach staff in area for assistance with community outreach.
6.4.2	**Data Analysis and Mapping of Audit Data and Incident Reports to Understand Geographic Distribution and Potential ESJ Cumulative Impact**	Work with existing data from past gas and electric infrastructure audits and inspections to understand if ESJ communities suffer safety burdens or any potential "hotspots" of issues. Consider development of process for ongoing geographic analysis to identify safety problems in these communities.	Safety & Enforcement Division	Electric Safety & Reliability and Gas Safety & Reliability	1. Conduct a pilot to map selected citation data from selected safety inspections and audits, to identify possible correlation with the number of safety citations in a location and the type of community. 2. When an inspection team audits an operator's records and facilities, SED should confirm that it reviewed an adequate number of field facilities located in ESJ communities. 3. Develop an internal process to continue ongoing geographic analysis of safety incidents and how to handle potential identification of "hotspots". 4. Consider opportunities to publish results of analysis.

Goal 7: Promote high road career paths and economic opportunity for residents of ESJ communities. (5 Action Items)					
7.1 Maximize Authority to Promote High Road					
7.1.1	**Implementation of MOU with CA Workforce Development Board**	Continue working with CWDB to provide recommendations to CPUC proceedings to encourage utilities to foster high road career paths.	Cross-Commission	ESJ Core Team	1- Share lessons learned and best practices developed thus far with CPUC staff 2- Provide direct feedback and recommendations to CPUC staff on what workforce-related components could be incorporated into policies and programs

7.2 Educate on High Road Careers					
7.2.1	**Share CPUC-specific Best Practices**	Provide presentations, training, and resources to CPUC staff regarding strategies and practices of a high road approach to workforce development, as well as other practices already underway within the CPUC and best practices from other regulatory agencies.	Cross-Commission	ESJ Core Team	1- Develop a brief primer on the high road, including Governor's Executive Orders, key principles and definitions, and examples of incorporation into CPUC programs and/or policies 2- Disseminate across CPUC
7.3 Partner with Utilities and Sister Agencies					
7.3.1	**Expand the Impact of Best Practices**	Provide presentations, training, and resources to regulated utilities and sister agencies in support of replicating the high road measures adopted by the CPUC across California's portfolio of clean energy and transportation investments.	Cross-Commission	ESJ Core Team	1- Develop a brief primer on the high road, including Governor's Executive Orders, key principles and definitions, and examples of incorporation into CPUC programs and/or policies 2- Disseminate across state government
7.3.2	**Leverage Sister Agencies to Maximize High Road Opportunities for ESJ Communities**	Build relationships and partnerships with sister agencies with business-related missions, including the Contractors State Licensing Board (CSLB), to maximize high road job opportunities for ESJ communities in industries under CPUC oversight.	Cross-Commission	ESJ Core Team	1- Work with CWDB to understand sister agencies with potential mission and industry alignment 2- Build relationships and pursue partnership opportunities to improve labor practices and working conditions within industries that are under CPUC oversight and target ESJ communities for services and employment
7.3.3	**Furthering Utility Supplier Diversity**	Examine how proceedings impact supplier and workforce diversity and assess resulting impacts on ESJ communities.	News & Outreach Office	News & Outreach Office	1- Follow outcome of proceedings, especially as it relates to supplier diversity and impacts on ESJ communities, workforce diversity, and board diversity 2- Track progress of GO 156 proceeding to monitor how it impacts reporting of board and workforce diversity from regulated entities.

Goal 8: Improve training and staff development related to ESJ issues within the CPUC's jurisdiction. (8 Action Items)					
8.1 Bolster Staff Knowledge on ESJ Issues and Resources					
8.1.1	**Division-Specific Training on Incorporating ESJ Issues into Proceedings**	Work within each CPUC division to provide tailored trainings for staff on how to incorporate ESJ issues into CPUC processes.	Cross-Commission	ESJ Core Team	1- Create a baseline training 2- Engage industry division leadership to schedule training and develop division-specific content 3- Deliver in partnership with ESJ Liaison
8.1.2	**ESJ Session at New Employee Orientation (NEO)**	Continue to host ESJ session at NEO, including background on redlining and the environmental justice movement, key definitions, and where staff can access resources.	Cross-Commission	ESJ Core Team	1- Continue refining curriculum 2- Pursue opportunities to provide similar training to staff that are not new employees
8.1.3	**Web Resources - CPUC ESJ Action Plan Webpage and Internal ESJ Resource Website**	Update and maintain ESJ Action Plan webpage. Build out internal ESJ SharePoint website and ensure it is updated with helpful resources and tools for CPUC staff.	Cross-Commission	ESJ Core Team	1- Update ESJ Action Plan webpage with relevant information and remove old content 2- Update internal ESJ SharePoint to include external guides and resources, as well as library of all internal training materials and additional state resources 3- Ensure staff are aware of different webpages
8.1.4	**Tribal Engagement Training**	Establish commission-wide protocols for training on engaging with tribes.	Cross-Commission	Executive Office - Tribal Advisor	1- Develop training materials to improve staff awareness of best practices for tribal engagement 2-Develop plan for disseminating information to relevant commission staff 3- Consider including Tribal Engagement training in New Employee Orientation or other commission-wide professional development opportunities
8.2 Support Emerging Priorities and Skill Needs					
8.2.1	**Alignment with Upcoming Racial Equity Action Plan (REAP)**	Support CCORE cohort to implement forthcoming CPUC REAP and support any efforts to conduct training for staff on racial equity issues.	Cross-Commission	Office of the Commission	1- Follow development and finalization of Racial Equity Plan 2- Understand where there is alignment with ESJ Action Plan and opportunities for collaboration 3- Be strong, visible allies and proponents of the Racial Equity Plan
8.2.2	**Community Engagement Training for CPUC Staff**	Based on existing Community Engagement and Outreach Curriculum, modify, and implement a training to educate staff on effective and meaningful practices for involving ESJ communities in CPUC efforts.	Cross-Commission	ESJ Core Team	1- Review State Agency CEO Curriculum 2- Confer with CCORE staff on CEO best practices and adapt for CPUC CEO purposes 3- Offer training opportunities on a regular basis 4- Partner with News and Outreach to deliver training

8.2.3	**Advance Diversity, Equity, and Inclusion in Human Resources**	Continue to pursue staff training to foster a work culture that values diversity and aims to be representative of California populations.	Administrative Services	Human Resources Division	1- Continue offering trainings to promote diversity in hiring 2- Detail success, challenges, and opportunities in annual Human Resources Division Annual Review
8.2.4	**Meeting Facilitation Training for Staff**	Offer training to CPUC staff on facilitation and how to run effective workshop and/or community meeting.	Cross-Commission	ESJ Core Team	1- Review existing curricula on effective meetings and workshop ideas 2- Work with HR Training Office to adapt for CPUC purposes 3- Consider having an outside consultant or sister agency deliver components of training 3- Deliver to CPUC staff and offer a virtual option for ongoing access

Goal 9: Monitor the CPUC's ESJ efforts to evaluate how they are achieving their objectives. (4 Action Items)					
9.1 Establish Consistent Quantitative Metrics					
9.1.1	**Metrics to Measure Impact, Community Outreach & Engagement**	Develop metrics, criteria, and guidance to ensure that utility programs and/or funds are having the intended effect and measure meaningful and effective outreach and engagement.	Cross-Commission	ESJ Core Team	1-Catalogue the existing set of data and metrics currently being used by utilities to measure community engagement 2- Review best practices in the field and consult sister agencies 3-Develop customizable set of criteria for utility outreach, engagement, and benefit to community 4- Sync with efforts to align Marketing, Education, and Outreach (ME&O) Plans within Energy Division
9.1.2	**Data Collection: Standardizing Data Requests & Key ESJ Indicators**	Create an internal working group to look at issues related to standardization in data requests, the quality of the data, how it can be shared and used given privacy concerns, and how to utilize key indicators to perform equity/ESJ analyses.	Cross-Commission	Office of the Commission	1- Create Working Group; 2- Create data request templates for various categories of data requests; 3- Highlight key indicators/metrics that should be used to understand ESJ impacts

9.1.3	**Geographic Distribution of Low-Income Programs + Ongoing Analyses**	Institute practice of evaluating geographic distribution of program uptake and policy implementation to understand outreach gaps and if ESJ communities are especially impacted.	Cross-Commission	ESJ Core Team	1- Ensure CPUC staff is well educated in CalEnviroScreen and other equity tools, as well as how to perform simple geospatial analysis 2- Initiate analysis in key programs, with the goal of making it standard practice across all programs 3- If there are particular ESJ impacts (i.e. program not reaching priority communities or a particular policy disproportionately impacting ESJ communities), take steps to address the issue
9.2 Promote Meaningful Feedback Loops					
9.2.1	**Metrics to Measure Satisfaction, Comprehension, and Experience**	Identify qualitative information-gathering strategies of utilities and evaluative spectra to help measure issues such as comprehension, satisfaction, and effectiveness of utility marketing, education, and outreach. Ensure there are pathways to act on information received.	Cross-Commission	ESJ Core Team	1- Review best practices in the field and consult sister agencies 2-Develop customizable set of qualitative criteria for satisfaction, comprehension, and experience 3- Sync with efforts to align Marketing, Education, and Outreach (ME&O) Plans within Energy Division

Appendix B: Summary of February 2021 Workshop

This Appendix provides a summary of the CPUC ESJ Action Plan – Update Workshop held on February 3 & 4, 2021. This summary highlights commentary shared during the various sessions of the workshop and feedback received via email. It is not a full transcript, nor does it include everything submitted via the chat box. To view session recordings and full chat logs from the workshop, please visit: www.cpuc.ca.gov/ESJActionPlan.

Turn Out Numbers for February 2021 ESJ Action Plan - Update Workshop	
External Participants (Utilities, Community Based Organizations, etc.)	438
Internal Participants (CPUC Staff)	190
TOTAL PARTICIPANTS	628

Comments Received via Email	
Small Business Utility Advocates	East Bay Community Energy
Institute for Governance & Sustainable Development (IGSD)	Richard Skaff
California Water Association	HolLynn D'Lil
Pacific Gas & Electric (PG&E)	Connie Arnold
Steven Birdlebough and William Smith	

Key Themes from Workshop

- Partnerships with community-based organizations (CBOs) are essential to reaching and benefitting ESJ communities. Ensure these partnerships are resourced and that CBOs are given room to deploy a variety of strategies to meet community needs.
- Think about what it takes to do meaningful engagement. CPUC meetings and activities should strive to be more accessible and welcoming.
- Coordinate and align as much as possible. In order to best reach ESJ communities and maximize impact, programs and policies should align both eligibility criteria and outreach efforts. Leverage work of sister agencies as well.
- Work towards more transparency of data and information. Provide stakeholder and CPUC staff with tools and resources to facilitate analysis of ESJ issues and impacts.
- Reconsider traditional cost-effectiveness measures. Understand how investments benefit ESJ communities.
- Prioritize accessibility of programs and meetings to populations with access and functional needs.

Workshop Session Summaries

CPUC Programs and Policies

- Introductory remarks from Kathleen Yip (CPUC) focused on how there are many different definitions and terms used to define vulnerable and disadvantaged communities. Definitions are important because they are used to make decisions and to determine eligibility in programs. The goal with this session is to raise awareness around definitions, and to discuss how to update these terms to further ESJ Action Plan goals.
- Remarks from Amee Raval (Asian Pacific Environmental Network) addressed three main points. First, that definitions matter. Definitions especially matter when targeting protections and investments, especially for communities that have experiences historical injustices, such as redlining and underinvestment. Communities face multiple complex challenges, and there is therefore a need for a range of different tools to capture and address those. Second, having an adaptive approach to crafting definitions is important for balancing tension between inclusive approaches and more targeted approaches. A balanced approach, for the purposes of ESJ definitions, means that the definition arrived at will depend on the problems a program or policy is meant to solve. If decision makers take into consideration and evaluate these problems, they should land in an appropriate definition. But they should be guided by some form of general framework. Third, definitions should be guided from a community perspective. A people centered approach helps to maximize community benefits.
- Kathleen Yip (CPUC) notes that having many different definitions can create confusion for both state agency staff and the public. There will be an attempt to catalogue all used definitions with the CPUC. Beyond that, should a framework or template for definitions be developed to help guide CPUC staff and stakeholders?
- Key takeaways from discussion include:
    - No single definition can be applied to a multitude applications and programs. That would be reductive. A definition, just like criteria, needs to be adaptive to sets of issues that are distinct. But a foundation, baseline, or an analysis of overlap and distinctions, would be helpful.
    - We must understand that a group has names for itself that we need to be mindful and respectful of, rather than just calling them "Disadvantaged Communities."
    - There is a need to balance between having very prescriptive, targeted definitions that are hard to communicate with ensuring that wealthier communities do not take advantage of incentives, for example. Collaboration and being adaptive will be key here.
    - Interagency cooperation is very important, both to understand their definitions and priorities and to move quickly to meet climate change demands.

- How do we get communities to the table, what are their barriers and how can they overcome them? We must recognize racism and other inequalities that have ensured that some communities do not even get information on decision-making, and that some communities technically, on paper, do not "exist," and do not even know about their barriers. We must think about adaptive and flexible methods to address their needs.
- Could consider a "baseline" definition with "plug and play" options to help with streamlining definitions.
- Tools like CalEnviroScreen are very useful, but not inclusive of all needs especially around vulnerability. Tools should be adaptive.

BREAKOUT SESSIONS: ESJ in CPUC Industry Divisions

Transportation & Rail

- Matthew Bond (CPUC) and Terra Curtis (CPUC) ask for suggestions of how the ESJ Action Plan can incorporate action items related to transportation network companies (TNCs) and rail safety.
- Section 190 is a state program that funds grade separation for existing at-grade rail crossings. Could consider opportunities to prioritize ESJ communities for this program.
- Data related to TNCs (such as Lyft and Uber) could be looked at in a geographic way to understand impacts in ESJ communities. Especially related to where pick-ups are or are not happening. There has not been much TNC data published publicly since 2015. Within this year, should be able to share more about that question.
- Are there opportunities to regulate TNC-related smog and congestions, such as limiting number of TNC drivers that can be on the road? This is likely a question for local governments and CPUC could engage and collaborate more at the local level on these kinds of questions.
- How can CPUC help with issues of homeless encampments along railroads? How can we bring people together around the issue?
- How can we involve more community in transportation and rail related proceedings? The process can be complicated, and Intervenor Compensation is not available for these categories of proceedings. Need to be proactive in engaging people and seek opportunities to fund down the road.
- Planning for electric vehicle charging infrastructure occurs within the Energy Division, currently being thought through in the Transportation Electrification Framework.

Telecommunications

- Wylen Lai (CPUC) and Michael Minkus (CPUC) ask participants to reflect on the experience of their communities with broadband/internet during the COVID-19 pandemic, about how to better understand the impact of communications public purpose programs from a geographic perspective, and to highlight any other issues.
- Broadband access in rural communities is challenging with such limited infrastructure. Families are having to choose between rent, food, and broadband during this time all while losing employment. Programs and opportunities are not always made to service residents. Without broadband access, can feel cut off from the rest of society.
- Many monolingual families rely on their children to familiarize with technology and how to transition to online learning. Those that have children in school have better access to broadband resources.
- Southern California experiences a lot of challenges, especially related to affordability.
- Need to see big companies, like T-Mobile and Frontier, more involved in these discussions.
- Digital divide is not new, some sort of technical assistance or incentive for jurisdictions to apply to these programs is needed. Also, need to ensure mobile homes are eligible for programs.
- Public purpose programs need to have a true social justice lens and barriers to applying need to be removed. There used to be funding for direct community outreach and support, this approach is stronger than leaving the carriers to do it.
- Consider leveraging existing advisory groups to involve communities. Also, if phone companies having people in parking lots to get customers to sign up for carrier phones, why are they not also signing customers up for Lifeline?
- Can we use examples of creative partnerships formed during the COVID-19 pandemic (between schools and businesses) to better promote broadband access?
- As we move towards more remote access, going to perpetuate same inequities we've always had – monolingual, immigrant, black, brown and people of color being excluded from decision-making process. CPUC and carriers must hear directly from residents about broadband issues.
- Need to also keep an eye on internet speed.
- Rethink cost effectiveness strategies. If we continue to work within that framework, it will continue to perpetuate same inequality we have today.
- Communities are limited in ability to participate on advisory committees. Need to consider having funding and stipends, a welcoming environment, bring information to the community and work on their turf. Also there used to be limitations that if you participated in an advisory committee than you could not participate in CPUC-funded grant projects. Hopefully that has changed.

Wildfire Safety

- Koko Tomassian (CPUC) introduces topic of the Wildfire Threat Maps. These maps were scoped and developed to identify areas prone to catastrophic fires and areas for increased safety regulations. Adopted for a specific proceeding and a specific purpose, with a ten-year refresh schedule. This map underpins utility operations and decision making to mitigate wildfire risk. As use of map evolves and we evaluate how or whether the map should be updated, how can we place ESJ considerations of the map?
    - » Map could be adapted related to the objectives of the CPUC. For example, if the objective to look at prevention, then the map would look different.
    - » Can also consider how does it integrate with other maps (such as the community wildfire protection plans that exist in local government level)?
    - » Could incorporate fire threat map with other programs. How does this map influence other types of decision making? What other contextual factors can the map account for?
    - » What are the goals for the map? Do utilities know where medically vulnerable groups are? Safety is important and need maps of these populations
    - » Need to also consider safety for those who have already experienced fires and the effect of that.
    - » Could also consider a communications dependence overlay. May be useful for evacuation purposes and emergency communications.
- Shrayas Jatkar (CA Workforce Development Board) introduces topic of wildfire preparation industry and vegetation management. This is a very fast-growing industry and there are implications for worker safety, climate change, grid resilience and increased employment opportunities.
    - » Need to think about the quality of jobs. Currently a lot of reliance on foreign guest workers to do work for low pay and in hazardous working conditions. There is no standardized set of skills or training. Some new policy tools, such as SB 247 and a new training program, are helping in this space.
    - » Need to encourage workforce development in this field as there is a big need. Need to be cautious this does not distract utilities from their responsibilities. Should get more voices involved, including wildfire survivors, and more meaningfully consider public comments.
    - » There is a high fatality rate and very little safety training in forestry workforce. Another issue is lack of enforcement. Need to create a requirement that contractors must demonstrate that workers receive adequate training before getting into state contracts.

Systematizing ESJ Considerations: Incorporating ESJ Issues in to CPUC Proceedings and Processes

- Mad Stano (Greenlining Institute) remarks that pollution burden and burden of utility costs are truly life threatening. We must root our thinking on viewing it as such and not just on processes and intending that these processes will resolve impacts at local levels. There is now legislative guidance to require meaningful conversations from communities most impacted by pollution. We cannot decarbonize without centering voices of community, and we cannot implement just and reasonable rates without centering those most impacted. We need to make a case for systematizing this approach. Communities and justice are administered through CPUC activities and actions. How do we reform criteria that leadership is held to when making decisions?
- Administrative Law Judge (ALJ) Ava Tran (CPUC) shares that the CPUC has been working on how to approach ESJ issues within its proceedings. ALJs are being encouraged to discuss ESJ issues within rulings to determine whether or not there are any impacts and to cope in any issues. News and Outreach team can assist by creating an outreach plan to inform interested parties and advise local organizations on how to become parties to proceedings. There are other opportunities to get involved, such as providing public comment. How do we ensure we have sufficient representation in proceedings? How do we better scope ESJ issues into proceedings? What should we be looking at to consider any potential impacts?
- Key takeaways from discussion include:
    - The CPUC has been one of the most difficult organizations to create a pipeline for communication and brining community participation forward. There needs to be an emphasis on hearing from local voices.
    - The San Joaquin Valley Affordable Energy proceeding offers a better model.
    - Incorporating a geographic analysis and pairing that with community engagement can help drive a substantive and long-standing commitment to responding to issues.
    - Could be good to learn from AB 617 Community Air Protection implementation. How can the CPUC both learn from and implement community input through community-based organizations and leveraging ongoing efforts of sister agencies?
    - There is a difference between "service list" outreach and true community engagement and outreach. It is scary to think of the small group of people that are involved as parties and people that are apart of decision-making process, yet their decisions and processes impact a larger population.
    - Intervenor Compensation does not solve the issue of involving communities. One example includes waiting 3-4 years for compensation.
    - Community organizations need more technical assistance to support participation in programs and proceedings. Often a lawyer is needed. Need to think about how community

members can be involved, and be specific (I.e. a different strategy for Spanish speakers and Hmong speakers).

- Need to build more public understanding of the CPUC's role. Local folks to not know the connection or the importance of the CPUC's role.
- While a lot of money has become available because of the pandemic, it has revealed a "digital desert" with communities not having enough expertise to be able to apply to programs to connect communities with resources. Need technical assistance to help with access.
- If there is a way to create meaningful conversations and discussions to allow community members to learn and provide input on proceedings. As a community organization, it is hard to find proceedings, so hard to imagine the energy and work it would take for community members. Encourage the CPUC to make information more accessible- visualization tools, more outreach, videos, translation, —it can empower communities to provide their input.

Tracking and Measuring: Data Collection to Better Understand CPUC Impact in ESJ Communities

- Kathleen Yip (CPUC) opens the session by highlighting the focus being on quantitative data and issues of collection, transparency, tracking, and impact on ESJ communities.
- Jamario Jackson (Transform) remarks that the CPUC should recognize harms and injustices to the communities it serves and protects. To do so, it must ask: what are indicators that can show harms and injustices? Once the CPUC answers that, it can start making improvements. Historically, government and industry have both created these harms. Some are intentional, others are not. All these make for challenges. The CPUC covers many sectors so standardized indicators are different across these, and so we need strategies to tackle that.
- Area where a lot of improvement can be made is to go beyond data and look at how is data collected and its impact. Another area is to consider areas where there is no data, which requires data stewardship, and ethical considerations, both internal and external. Yet another area of improvement is transparency. Data should be accessible and easily discoverable.
- Iain Fisher (CPUC Public Advocates Office) highlights the challenge of getting a person-centered approach to utility data management. In the CPUC, there are a vast range of approaches to data. In sum, each proceeding has a set of question for which it gathers data, which makes that dataset unique to that proceeding and question. But there are in the CPUC examples of broad data collection efforts, e.g. broadband data, which answers many questions that can be used in the future for different purposes. In general, there needs to be more cross-division standardization.
- Kathleen Yip highlights that we cannot fix what we cannot measure. CPUC needs to be accountable and show that we do what we say we will do. One primary issue is the lack of

standardization. Because of this lack, we cannot compare programs or proceedings. Another issue is that utilities can submit data in cumbersome formats and on different scales and metrics. The quality of the data is inconsistent - how to address that? How do we make data both better and more accessible to the public, given privacy and confidentiality issues? How do we measure impact on public policy? One attempt at an answer is to create standard baseline. To do that, we can ask: which indicators ought to be included from an ESJ perspective? What types of data would be useful across proceedings, projects, and programs?

- Iain Fisher points out that to improve quality you need to understand the business process of utilities: what points of the business process do you need to measure?
- Jamario Jackson looks back at the ESJ Action Plan and asks to focus on ensuring protection and benefits to consumers. How do you measure that? Recommend breaking it into smaller chunks and asking the community what the indicators they feel strongly about.
- Iain Fisher reminds that we need to ask what data utilities should collect and what do they have the right to collect.
- Kathleen Yip remarks that a key challenge is to figure out how to publish data that protects privacy on an accessible portal on the CPUC website that can be used by the public. Iain Fisher further mentions that privacy is very important and affects utilities, customers, citizens. Important to mention that part of reason why the CPUC is careful in treading into granular data is privacy issues. Avoids collecting some levels of data for this reason. What we need to do is build a framework on privacy for the CPUC.
- Jamario Jackson mentions one opportunity is that if data from different sources is imported into the same tool, that is an opportunity to explore implications and see patterns. One example could be to see how power shutoff data can be plugged in with redlining data to see if there's correlation. Such an approach would allow advocates to experiment with data. If CPUC provided such data, community organizations could use it. However, even when we have data, sometimes we are not heard by lawmakers and decisionmakers. Strength comes from marrying data with ground troop communities.
- Key takeaways from discussion include:
  - » Being able to standardize data from the three big IOUs, specifically disconnections data, would save a lot of time and energy on the analytical end.
  - » Could consider a geographically focused pilot on standardizing data.
  - » There is some standardization happening in wildfire space with GIS templates used to map utility assets. Still big issues with quality of data and privacy issues when it comes to publishing.
  - » Privacy becomes a hard challenge to manage. With transportation as an example - When you want to improve service or understand behavior, you need pick up and drop off data, and

that can suggest movement patterns. On the other hand - as consumers we release a lot of such data to companies unknowingly and knowingly. Only some people should maybe see it. Merits a larger conversation. Equity and integrity are important.

- There is a dissonance between those that gather data and those that live the disparity. The data gathering and data must be relevant for people affected, people who live the disparity.
- Must be understanding when communities sometimes do not want to share information with government. Need to consider strategies that don't require add-on information (like addresses, etc.)
- Organizational patterns of IOUs might be inappropriate for ESJ data gathering. We need person or community level data. Collecting and ground truthing data with communities can be married with utility level data collection.

Public Comment Session

- Consider how to keep workshop participants in contact and engaged. Could do quarterly or regular engagement.
- All utilities should have a medical baseline program. Additionally, what is the CPUC doing to ensure cell service has backup power during shut off events? What is the CPUC doing to ensure utilities meet Public Safety Power Shut Off guidance? When will funds be added to the Self-Generation Incentive Program (SGIP).
- Need to consider how Community Choice Aggregators (CCAs) play into these ESJ topics and issues.
- Stakeholders with a lot of political and financial capacity can advocate for programs that fit their needs. We need programs with less barriers so that they are equitable. Sometimes regulation results in high barriers and it isn't equitable.
- Take a closer look at consultants who prepare reports and analyses for the CPUC. Consultants from out of state may have little connection to communities and history in California.
- Community is not involved in transition to solar and electrification. Mandates are coming top down and not from community. Need to look at grassroots efforts. Education is missing in these communities.
- On issues related to zero-emission vehicles (ZEVs) and equity, the Governor's Office has pointed to the CPUC. What is the CPUC doing to promote equity with ZEV deployment and charging infrastructure?
- Shocked that there are no comments from the disability community today. It is indicative of a lack of trust between the CPUC and the disability community. Disability needs vary. It is not clumped together in zip codes. It is not a political group even though it has so many common needs.

- Should not use privacy as an excuse to hide or obscure data.
- We need backup power during shutoffs. There is also a lack of cell service during power outages. Additionally, Transportation Network Companies (TNCs) do not provide service to people with physical disabilities.
- Significant challenges with logging in to Web Ex Platform. Zoom should be used.
- CPUC is catering to the interest of the utilities and not disabled people. Concerns are life and death. Knows of someone who had the power shut off by PG&E and died shortly thereafter struggling to breathe. Need to make sure battery backup systems are available to disabled community.

BREAKOUT SESSIONS: ESJ in CPUC Industry Divisions

Energy

- Amy Mesrobian (CPUC) and Alison LaBonte (CPUC) highlight there are currently 65 action items from the Energy Division in the current ESJ Action Plan
- Communities of color and low-income communities require a greater amount of funds to reach them and a more concerted effort. If programs are put out first come-first serve, early adopters and those who are motivated would take first advantage of those opportunities. Therefore, saying that that a budget is "equally available" is not equitable, because it might not reach ESJ communities.
- CPUC and IOUs are outreaching to the same communities and others remain uncontacted. Need more, smaller community organizations who can get outreach contracts as they will have the relationships and time to explain programs to new customers.
- Information that the IOUs request is too detailed and hard for customers to access and provide. Need to increase funding to smaller groups and provide adequate training to those doing outreach.
- Customers on the ground are not as satisfied with the Energy Savings Assistance Program (ESAP). IOUs are number driven and when another grassroots organization does outreach does not produce the same numbers, but they do longer term personal relationships where people go into the homes or on the phone to help these people make the changes. Need to accept a transformation in how we outreach to people to educate and not just dropping literature at people's doors. Need to foster long term behavioral changes, which is a longer process
- CPUC should help community organizations get funding for outreach, education of their staff, and education of the community.
- On solar issues, 80% of people are disqualified because they have bad roofs, so how are we helping ESJ homeowners if we cannot help them repair their roofs?

- As far as avoiding unintended impacts, be realistic and really evaluate what goes into making these programs helpful to families you are trying to reach.
- There are also a lot of scammers out there. The CPUC needs to be more proactive in regulating or screening for those scammers.
- Major challenges with how CPUC looks at cost-effectiveness. Need to consider non-energy benefits which can include pollution reduction, quality of services, and person-oriented decisions. CPUC is instead focused on IOU bottom line.
- To find best practices and good models, look to community organizations that are already doing the work and have funding at risk of being taken away. Seek ways to support them in their ongoing, grassroots efforts.
- Need to understand that a consumer's life choices have many different factors, not just focused on one specific issue. Assumptions in program design often do not take this into account.
- Standing relationships with community organizations can have the most benefit. Build in these relationships when you are building a new program. Also consider working with Community Choice Aggregators (CCAs) on program design issues.
- Create an institutional process map to make it clear to CPUC internally and externally – when and where community engagement can make a difference.
- Consider opportunities to align eligibility criteria across programs, alongside need for home and roof repairs.

Safety & Enforcement

- Liz Podolinsky (CPUC) and Nicole Cropper (CPUC) outline how the Safety and Enforcement Division (SED) deals with both gas and electric safety issues as well as wildfire safety and can identify violations and file citations.
- How can ESJ concerns be overlapped with safety considerations? Once example could be in wildfire context and guidelines for alerting utility customers about events.
- It is important for SED to understand its role in terms of equity. For example, if a community member saw a safety issue and had a concern and they made a call into the CPUC or they provided a public comment. What is the expectation from SED in terms of that response? Is expectation to respond to that in 24-48 hours? How does this relate to response time by utilities?
- Another way to look at this is looking at how public participation is measured. Is there a public participation hearing (PPH) taking place? How is it seen and processed through proceeding? Do public comments end up meeting requirements of proceedings? There needs to be an objective or measure of proceedings in order to implement ESJ lens to this work.

- PPHs are good. There should be no proceeding without a PPH. CPUC needs to ask how hearings can be approached in different ways (due to time pressures in different proceedings but also different community needs). CPUC should not bypass the opportunity to engage community members into proceedings.
- Be descriptive of how public engagement is evaluated and how public participation will be merged into decision making process.
- We must understand what contributes to risks, how are risks different within particular communities—urban, rural environment. Understanding ESJ issues is within the expectations and measurement of tools to understand the full scope of the issue.
- Hammering Home: how you engage the public is how risks can be measured.
- CPUC has recently adopted an enforcement policy to set forth policies for all divisions that are under CPUC to take enforcement actions—investigations, penalties, settling cases. One thing we have started to work on is guidelines when we approve supplemental environmental projects SEPs) in lieu of penalties. How much of a penalty should be mitigated, what the nexus between violation and remedial actions that are taken?
- Examples of SEPs that benefit disadvantaged communities include installing air filtration devices in schools, community centers, and residences to reduce the community's exposure to air pollution; monitoring groundwater quality from infiltrating stormwater to detect harmful contaminants; providing regular health screenings for affected communities; or providing community members training to enable them to identify environmental violations and to notify regulatory agencies of those violations.
- SED could consider using CalEnviroScreen to identify environmentally burdened communities that may need tailored enforcement actions. Maybe those communities could receive more safety audits? Perhaps the penalties for violations in these communities could be higher? Perhaps those communities can get quicker service?

Water

- Steve St. Marie (CPUC) and Jefferson Hancock (CPUC) describe key ESJ-related efforts within the Water Division, including the Low-Income Water proceeding and the Affordability proceeding.
- Interest in workforce development programming and existing partnership with the CA Workforce Development Board, which looks to promote high quality jobs for ESJ communities within CPUC programs and policies.
- Specific to consolidation of small water systems, what are opportunities to streamline the consolidation process with benefits to ESJ communities? Need to better understand barriers for acquisition from the utility perspective. CPUC is mostly interested in the cost of acquisition and subsequent rate impacts to both new and existing customers.

- How is the CPUC looking to diversify its own workforce? Currently has a cohort participating in California Capital Cohort on Race and Equity to develop a CPUC Racial Equity Plan. Also have a new Diversity, Equity, and Inclusion Working Group looking more internally at staff needs.
- Different tools for looking at disadvantaged communities are highlighted, including CalEnviroScreen and tool from Department of Water Resources.
- Consolidation issue is challenging. A system may have low rates but may be poorly maintained with poor water quality. But how do you protect against rate impacts? Sometimes people want to be left alone in rural communities and do not want to be part of larger utility.

Making the Most of Marketing, Education & Outreach (ME&O): Maximizing Impact and Aligning Strategies

- Whitney Richardson (CPUC) remarks that the CPUC has a strong interest in insuring utility customers are well informed of programs and how dollars are being spent to reach program goals. How can the CPUC ensure that programs reach specific customers?
- Alex Garibay (Southern California Edison) explains that utilities develop marketing and education programs for customers and that equity is core to their work. SCE works closely with community-based organizations that can share information across multicultural groups.
- Key takeaways from the discussion include:
    - » Leveraging 211/311 resources in local communities can be helpful. Ready-made infrastructure for outreach.
    - » IOUs often look to quantify information (number of bill inserts, etc.) and in no other industry would a marketing and communication campaign be looked at in such a way. Instead, it Is critical to look at how that communication is being interpreted by the user. Not just the number of pamphlets distributed.
    - » Need time and investment in hard-to-reach communities so they understand programs available. Need to also have patience to have a conversation about the program. Communities are capable of understanding, but a pamphlet may not be enough.
    - » Do not measure success based on cost effectiveness. Sometimes pamphlets do not work all that well. Instead, a meeting with a giant poster may be more effective.
    - » Give community organizations the funding to do this type of engagement.
    - » Continual education is needed to achieve behavior change
    - » With partnerships with community organizations, it takes time and trust to build a collaborative relationship. Make it clear this is teamwork.

- Creative strategies with COVID-19 pandemic – Communities holding meetings through WhatsApp as it uses much less bandwidth and using Facebook Live. Ask community members how they get messages and what it takes to get them to engage. You are asking for community time, have the resident feel valued.
- People can be wary of the CPUC and utilities. Need to take that into account.
- Consider using neighborhood faces in local outreach campaigns. Highlight community organizations doing the work and celebrate it.
- Come up with a list of community organizations throughout the state that people can filter and have easy access to for outreach purposes.

Appendix C:
Key ESJ Definitions & Statutes

This guide is meant to be an initial resource to assist in incorporating ESJ issues into CPUC proceedings, programs, and processes. This guide is NOT an exhaustive list of definitions, nor does it reflect the only definition for a particular term. When using this guide, please note whether a term is defined in statute (and therefore should not be modified for CPUC use) or if a term can be adapted.

This resource will continue to be updated and available internally on the CPUC ESJ SharePoint website.

Environmental Justice and Equity Concepts	
Environmental Justice[41]	Environmental justice is the ***fair treatment*** and ***meaningful involvement*** of all people regardless of race, color, national origin, or income, with respect to the development, implementation, and enforcement of environmental laws, regulations, and policies. This goal will be achieved when everyone enjoys: • the same degree of protection from environmental and health hazards, and; • equal access to the decision-making process to have a healthy environment in which to live, learn, and work.
Equity[42]	Increasing access to power, redistributing and providing additional resources, and eliminating barriers to opportunity, in order to empower low-income communities of color to thrive and reach full potential.
Climate Justice[43]	Ensures that the people and communities who are least culpable in the warming of the planet, and most vulnerable to the impacts of climate change, do not suffer disproportionately because of historical injustice and disinvestment.
Structural Racism[44]	A system in which public policies, institutional practices, cultural representations, and other norms work in various, often reinforcing ways to perpetuate racial group inequity. It identifies dimensions of our history and culture that have allowed privileges associated with "whiteness" and disadvantages associated with "color" to endure and adapt over time. Structural racism is not something that a few people or institutions choose to practice. Instead, it has been a feature of the social, economic and political systems in which we all exist.
Institutional Racism[45]	Institutional racism refers to the policies and practices within and across institutions that, intentionally or not, produce outcomes that chronically favor, or put a racial group at a disadvantage. Poignant examples of institutional racism can be found in school disciplinary policies in which students of color are punished at much higher rates that their white counterparts, in the criminal justice system, and within many employment sectors in which day-to-day operations, as well as hiring and firing practices can significantly disadvantage workers of color.

[41] Gov. Code, § 65040.12, subd. (e)

[42] https://greenlining.org/publications/reports/2019/making-equity-real-in-mobility-pilots-toolkit/

[43] https://www.environmentalhealth.org/index.php/en/what-we-do/climate-justice

[44] https://www.aspeninstitute.org/blog-posts/structural-racism-definition/

[45] https://www.aspeninstitute.org/blog-posts/structural-racism-definition/

Racial Equity[46]	Racial equity refers to what a genuinely non-racist society would look like. In a racially equitable society, the distribution of society's benefits and burdens would not be skewed by race. In other words, racial equity would be a reality in which a person is no more or less likely to experience society's benefits or burdens just because of the color of their skin. This is in contrast to the current state of affairs in which a person of color is more likely to live in poverty, be imprisoned, drop out of high school, be unemployed and experience poor health outcomes like diabetes, heart disease, depression and other potentially fatal diseases. Racial equity holds society to a higher standard. It demands that we pay attention not just to individual-level discrimination, but to overall social outcomes.
Distributive Justice[47]	Fairness in the distribution of rights or resources.
Procedural Justice[48]	Fairness and the transparency of the processes by which decisions are made.
Cumulative Impacts[49]	Result when the effects of an action are added to or interact with other effects in a particular place and within a particular time.
Disproportionate Impacts[50]	Occurs when policies, practices, rules, or other systems that appear to be neutral impact different groups in different ways.
Meaningful Involvement[51]	Means that 1) potentially affected community members have an appropriate opportunity to participate in decisions about a proposed activity that will affect their environment or health; 2) the public's contribution can influence an agency's decision; 3) the concerns of all participants involved will be considered in the decision-making process; and 4) the decision-makers seek out and facilitate the involvement of those potentially affected.
Ground Truth[52]	Information obtained by direct observation of a real system, as opposed to a model or simulation.

[46] https://www.aspeninstitute.org/blog-posts/structural-racism-definition/
[47] https://post.ca.gov/procedural-justice-and-police-legitimacy
[48] https://post.ca.gov/procedural-justice-and-police-legitimacy
[49] https://www.epa.gov/sites/default/files/2014-08/documents/cumulative.pdf
[50] https://www.shrm.org/resourcesandtools/tools-and-samples/hr-qa/pages/disparateimpactdisparatetreatment.aspx
[51] https://www.epa.gov/sites/production/files/2015-02/documents/team-ej-lexicon.pdf
[52] https://www.lexico.com/en/definition/ground_truth

High Road[53]	"High road" means a set of economic and workforce development strategies to achieve economic growth, economic equity, shared prosperity, and a clean environment. The strategies include, but are not limited to, interventions that: (1) Improve job quality and job access, including for women and people from underserved and underrepresented populations. (2) Meet the skill and profitability needs of employers. (3) Meet the economic, social, and environmental needs of the community.

[53]https://leginfo.legislature.ca.gov/faces/codes_displayText.xhtml?lawCode=UIC&division=7.&title=&part=&chapter=2.&article

Spectrum of Community Engagement – International Association of Public Participation[54]

Increasing Impact on the Decision

	Inform	Consult	Involve	Collaborate	Empower
Public Participation Goal	To provide the public with balanced and objective information to assist them in understanding the problem, alternatives, opportunities and/or solutions.	To obtain public feedback on analysis, alternatives and/or decisions.	To work directly with the public throughout the process to ensure that public concerns and aspirations are consistently understood and considered.	To partner with the public in each aspect of the decision including the development of alternatives and the identification of the preferred solution.	To place final decision making in the hands of the public.
Promise to the Public	We will keep you informed.	We will keep you informed, listen to and acknowledge concerns and aspirations, and provide feedback on how public input influenced the decision. We will seek your feedback on drafts and proposals.	We will work with you to ensure that your concerns and aspirations are directly reflected in the alternatives developed and provide feedback on how public input influenced the decision.	We will work together with you to formulate solutions and incorporate your advice and recommendations into the decisions to the maximum extent possible.	We will implement what you decide.

[54] https://sustainingcommunity.wordpress.com/2017/02/14/spectrum-of-public-participation/

CPUC Definitions for Environmental and Social Justice and Disadvantaged Communities	
Environmental and Social Justice (ESJ) Communities	ESJ Communities are commonly identified as those where residents are: • Predominantly communities of color or low-income; • Underrepresented in the policy setting or decision-making process; • Subject to a disproportionate impact from one or more environmental hazards; and • Likely to experience disparate implementation of environmental regulations and socio-economic investments in their communities. They also include, but are not limited to: • Disadvantaged Communities, defined as census tracts that score in the top 25% of CalEnviroScreen 3.0, along with those that score within the highest 5% of CalEnviroScreen 3.0's Pollution Burden but do not receive an overall CalEnviroScreen score;[55][56] • All Tribal lands;[57] • Low-income households;[58] and • Low-income census tracts.[59]
Disadvantaged Communities (DAC)[60]	Refers to the areas throughout California which most suffer from a combination of economic, health, and environmental burdens. These burdens include poverty, high unemployment, air and water pollution, presence of hazardous wastes as well as high incidence of asthma and heart disease. Disadvantaged communities are defined as census tracts that score in the top 25% of CalEnviroScreen 3.0, along with those that score within the highest 5% of

[55] https://calepa.ca.gov/wp-content/uploads/sites/6/2017/04/SB-535-Designation-Final.pdf

[56] This definition of "Disadvantaged Communities" reflects a small change from Version 1.0 of the ESJ Action Plan and is changed to reflect the most recent designation of "Disadvantaged Communities" by the California Environmental Protection Agency (CalEPA). A new version of CalEnviroScreen, Version 4.0, was finalized in October 2021 and CalEPA will make a subsequent designation of "Disadvantaged Community" given the new data. This definition in the ESJ Action Plan will be subsequently updated to reflect this change once it is in effect.

[57] Can utilize definition of "California Indian Country" https://www.courts.ca.gov/8710.htm .

[58] Household incomes below 80 percent of the area median income.

[59] Census tracts with household incomes less than 80 percent area or state median income.

[60] Health and Safety Code Section 39711

	CalEnviroScreen 3.0's Pollution Burden but do not receive an overall CalEnviroScreen score;[61]
Disadvantaged Communities (DAC)[62] **(Water)**	"Disadvantaged community" means the entire service area of a community water system, or a community therein, in which the median household income is less than 80 percent of the statewide annual median household income level.
Disadvantaged Vulnerable Communities (DVC)[63] **(Climate Adaptation)**	"Disadvantaged Vulnerable Communities" or "DVCs" consist of communities in the 25% highest scoring census tracts according to the California communities Environmental Health Screening Tool (CalEnviroScreen); as well as all California tribal lands, census tracts with median household incomes less than 60% of state median income; and census tracts that score in the highest 5% of Pollution Burden within CalEnviroScreen, but do not receive an overall CalEnviroScreen score due to unreliable public health and socioeconomic data.
Low Income Households[64][65]	Low-income households are those with household incomes at or below 80 percent of the statewide median income or with household incomes at or below the threshold designated as low income by the Department of Housing and Community Development's list of state income limits adopted pursuant to Section 50093.
Low Income Communities[66] [67]	Low-income communities are census tracts with median household incomes at or below 80 percent of the statewide median income or with median household incomes at or below the threshold designated as low income by the Department of Housing and Community Development's list of state income limits adopted pursuant to Section 50093.

[61] https://calepa.ca.gov/wp-content/uploads/sites/6/2017/04/SB-535-Designation-Final.pdf

[62] Health and Safety Code Section 116426

[63] D.20-08-046

[64] HSC § 39713

[65] Please note that individual CPUC programs may have low-income designations defined in statute that supersede this definition, or may use federal poverty guidelines to define low-income.

[66] HSC § 39713

[67] Please note that individual CPUC programs may have low-income designations defined in statute that supersede this definition, or may use federal poverty guidelines to define low-income.

Access and Functional Needs (AFN)[68]	This population includes individuals who live with developmental or intellectual disabilities, physical disabilities, chronic conditions, injuries, limited English proficiency or who are non-English speaking, are 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.
California Native American Tribe	"California Native American tribe" means a Native American tribe located in California that is on the contact list maintained by the Native American Heritage Commission for the purposes of Chapter 905 of the Statutes of 2004. See Public Resources Code § 21073. California Native American tribes include both federally recognized and non- federally recognized tribes.
Indian Country	The term Indian country is defined in 18 U.S.C. § 1151 and 40 C.F.R. § 171.3 as: a. all land within the limits of any Indian reservation under the jurisdiction of the United States Government, notwithstanding the issuance of any patent, and, including rights-of-way running through the reservation b. all dependent Indian communities within the borders of the United States whether within the original or subsequently acquired territory thereof, and whether within or without the limits of a state; and c. all Indian allotments, the Indian titles to which have not been extinguished, including rights-of-way running through the same. Consistent with the statutory definition of Indian country, as well as federal case law interpreting this statutory language, lands held by the federal government in trust for Indian tribes that exist outside of formal reservations are informal reservations and, thus, are Indian country.

[68] AB 2311.
https://leginfo.legislature.ca.gov/faces/billCompareClient.xhtml?bill_id=201520160AB2311&showamends=false

Hard-to-Reach (HTR)[69]	Two criteria are considered sufficient if one of the criteria met is the geographic criteria defined below. There are common as well as separate criteria when defining hard-to-reach for residential versus small business customers. The barriers common to both include: • Those customers who do not have easy access to program information or generally do not participate in energy efficiency programs due to a combination of language, business size, geographic, and lease (split incentive) barriers. These barriers to consider include: *Language* – Primary language spoken is other than English, and/or *Geographic* – Businesses or homes in areas other than the United States Office of Management and Budget Combined Statistical Areas of the San Francisco Bay Area, the Greater Los Angeles Area and the Greater Sacramento Area or the Office of Management and Budget metropolitan statistical areas of San Diego County • For small business added criteria to the above to consider: *Business Size* – Less than ten employees and/or classified as Very Small (Customers whose annual electric demand is less than 20kW, or whose annual gas consumption is less than 10,000 therm, or both), and/or *Leased or Rented Facilities* – Investments in improvements to a facility rented or leased by a participating business customer • For residential added criteria to the above to consider: *Income* – Those customers who qualify for the California Alternative Rates for Energy (CARE) or the Family Electric Rate Assistance Program (FERA), and/or *Housing Type* – Multi-family and Mobile Home Tenants (rent and lease)" *Modification*: include disadvantaged communities (as designated by CalEPA) in the geographic criteria for hard-to-reach customers
Socioeconomic Vulnerability Index (SEVI)[70]	The Socioeconomic Vulnerability Index (SEVI) metric represents the relative socioeconomic standing of census tracts, referred to as communities, in terms of poverty, unemployment, educational attainment, linguistic isolation, and percentage of income spent on housing. This metric therefore considers how a rate change may affect one community's ability to pay more than another's.

[69] D.18-05-041

[70] D.20-07-032

Underserved Communities[71]	Underserved community means a community that meets one of the following criteria: • Is a "disadvantaged community" as defined by subdivision (g) of Section 75005 of the Public Resources Code. • Is included within the definition of "low-income communities" as defined by paragraph (2) of subdivision (d) of Section 39713 of Health and Safety Code. • Is within an area identified as among the most disadvantaged 25 percent in the state according to the California Environmental Protection Agency and based on the most recent California Communities Environmental Health Screening Tool, also known as CalEnviroScreen. • Is a community in which at least 75 percent of public school students in the project area are eligible to receive free or reduced-price meals under the National School Lunch Program. • Is a community located on lands belonging to a federally recognized California Indian tribe.
Unserved Household[72] **(Broadband)**	"Unserved household" means a household for which no facility-based broadband provider offers broadband service at speeds of at least 6 megabits per second (mbps) downstream and one mbps upstream.

[71] https://leginfo.legislature.ca.gov/faces/billTextClient.xhtml?bill_id=201920200AB841

[72] https://codes.findlaw.com/ca/public-utilities-code/puc-sect-281.html

Eligibility Criteria Requirements for CPUC Energy, Communications, and Water Consumer Programs	
California Alternate Rates for Energy (CARE)[73]	Income eligibility for CARE participation is set at 200% or less of Federal Poverty Guidelines.
Family Electric Rate Assistance (FERA)[74]	Total family income eligibility for FERA participation is set between 200% and 250% of Federal Poverty Guidelines.
Energy Savings Assistance (ESA) Program[75]	Income eligibility for ESA participation is set at 200% or less of Federal Poverty Guidelines.

Multi-family Affordable Solar Housing (MASH)[76]	• Solar energy system installations on existing multifamily affordable housing that meets the definition of low-income residential housing established in Pub. Util. Code 2852
	• Eligibility under Pub. Util. Code Section 2852 defines "low-income residential housing" as one of the following: Multifamily residential complex financed with one or more of the following:
	  ▪ low-income housing tax credits
	  ▪ tax-exempt mortgage revenue bonds
	  ▪ general obligation bonds
	  ▪ local, state, or federal loans or grants
	• Multifamily residential complex in which at least 20% of the total housing units are sold or rented to lower income households

[73] https://www.cpuc.ca.gov/consumer-support/financial-assistance-savings-and-discounts/california-alternate-rates-for-energy

[74] https://www.cpuc.ca.gov/consumer-support/financial-assistance-savings-and-discounts/family-electric-rate-assistance-program

[75] https://www.cpuc.ca.gov/consumer-support/financial-assistance-savings-and-discounts/energy-savings-assistance

[76] Pub. Util. Code 2852; MASH Program Handbook.

Single-family Affordable Solar Homes (SASH)[77]	• Receive electrical service from Pacific Gas & Electric (PG&E), Southern California Edison (SCE), or San Diego Gas & Electric (SDG&E), • Own and live in their home, • Have a household income that is 80% or below the area median income (AMI), • Live in a home defined as "affordable housing" by California Public Utilities Code 2852.
Disadvantaged Communities-Single-family Affordable Solar Homes (DAC-SASH)[78]	• Available to customers who live in DACs and meet the income eligibility requirements for the CARE and FERA programs or residents of California Indian Country. • Homeowners must live in one of the top 25 % most disadvantaged communities statewide • Be a billing customer of Pacific Gas & Electric (PG&E), Southern California Edison (SCE), or San Diego Gas & Electric (SDG&E)
Solar on Multi-family Affordable Housing (SOMAH)[79]	• Incentives for solar projects on affordable multifamily properties to achieve 300 MWs by 2030 • Available to affordable multifamily properties occupied by households with a majority of tenants with incomes at or below 60% of the area median income or be located in a disadvantaged community as identified by the California Environmental Protection Agency (CalEPA). • Multifamily properties must be in PG&E, SCE, SDG&E, PacifiCorp, or Liberty territories to participate

[77] AB 217; SASH Handbook; https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/demand-side-management/california-solar-initiative/csi-single-family-affordable-solar-homes-program
[78] SB 535 Disadvantaged Communities; AB 327; https://oehha.ca.gov/calenviroscreen/sb535; Decision D.18-06-027; D.20-12-003; https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/solar-in-disadvantaged-communities
[79] AB 693 (2015) "Multifamily Affordable Housing Solar Roofs Program"; Decision 17-12-022; https://www.cpuc.ca.gov/somah; https://calsomah.org/

Green Tariff/Shared Renewables Program (GTSR) **(Enhanced Community Renewables)**[80]	• The 600 MW GTSR program includes a specific 100 MW reservation for customers and projects in areas identified by the CalEnviroScreen tool as being in one of the 20% most disadvantaged census tracts in each IOU • Small projects—those under 1MW capacity—which are developed in EJ Communities are eligible for a Utility Power Purchase Agreement if their prices fall within 200 percent of the maximum executed contract price, rather than 120 percent for standard GTSR power purchase agreements.
Disadvantaged Communities - Green-Tariff (DAC-GT)[81]	• A 158MW program available for Residential customers in DACs who meet the income eligibility requirements for the CARE and FERA programs. • Homeowners must live in one of the top 25 % most disadvantaged communities statewide or the census tracts in the highest 5 percent of CalEnviroScreen's Pollution Burden or; • Be a billing customer of participating utility or Community Choice Aggregator.
Community Solar Green Tariff (CSGT)[82]	• A 41MW program available for Residential customers in DACs or in San Joaquin Valley (SJV) pilot communities identified in R.15-03-010. • CSGT projects must be in DACs within 5 miles of DAC(s) where subscribing customers reside or within 40 miles for SJV pilot communities. • 50% of a project's output must be subscribed by customers eligible for CARE or FERA. • Customers must live in one of the top 25 % most disadvantaged communities statewide or the census tracts in the highest 5 percent of CalEnviroScreen's Pollution Burden or; • Be a billing customer of participating utility or Community Choice Aggregator.

[80] SB 43; https://leginfo.legislature.ca.gov/faces/billNavClient.xhtml?bill_id=201320140SB43
[81] AB 327; Decision D.18-06-027, D.18-10-007 and D.20-07-008; https://oehha.ca.gov/calenviroscreen; https://www.cpuc.ca.gov/SolarInDACs/#DAC_GT
[82] AB 327; Decision D.18-06-027 and D.18-10-007; R.15-03-010; https://oehha.ca.gov/calenviroscreen; https://www.cpuc.ca.gov/SolarInDACs/#CSGT

California Advanced Services Fund (CASF) Broadband Adoption Account[83]	Local governments, senior centers, schools, public libraries, nonprofit organizations, and community-based organizations with programs to increase publicly available or after school broadband access and digital inclusion, such as digital literacy training programs are eligible to apply for grants. Publicly supported communities who are otherwise eligible to apply for grants from the Broadband Public Housing Account are also eligible to submit an application only after all funds available for adoption projects from the Public Housing Account have been awarded.
California Advanced Services Fund (CASF) Rural and Urban Regional Consortia Account[84]	An eligible Consortium may include representatives, of organizations including, but not limited to, local and regional government, public safety, elementary and secondary education, health care, libraries, postsecondary education, community-based organizations, tourism, parks and recreation, agricultural, business, workforce organizations, and air pollution control or air quality management districts. An eligible Consortium is not required to have as its lead fiscal agent an entity with a certificate of public convenience and necessity.
California Advanced Services Fund (CASF) Broadband Infrastructure Account[85]	To determine the funding level for a project, the Commission will consider the following factors: • *Areas with only dial-up or no Internet connectivity (Pub. Util. Code Section (b)(2)(B)(i)* – project areas with no Internet connectivity are eligible for up to 100 percent funding. Projects requesting funding for dial-up-only areas must identify in their application the households that are and are not eligible, so that Staff may calculate the appropriate funding level. • *Location and accessibility of the area* – Project areas meeting two of the following five characteristics: 1) The proposed project area contains rugged or difficult terrain (e.g., mountains, desert, national or state forest); 2) The proposed project area is an unincorporated community; 3) The proposed project area is more than 10 miles from the nearest hospital; 4) The proposed project area is more than 10 miles from the nearest state or federal highway; and/or

[83] AB 1665

[84] Decision (D.) 18-10-032

[85] Pub. Util. Code Section (b)(2)(B)(i)

	5) The proposed project area is located in a rural census block, as defined by the U.S. Census Bureau. • *Existence of communication facilities that may be upgraded to deploy broadband* – project areas in which the applicant relies primarily on existing infrastructure, including poles and conduit, and thus will be less expensive to build. • *Whether the project makes a significant contribution to achieving the program goal* – project areas within a Broadband Consortium region that has not yet reached the goal of deploying broadband Internet service at speeds of 6 mbps download and 1 mbps upload to 98 percent of households are eligible for an additional 10 percent funding. • *Low-income service* – project areas for which Staff determines that the latest Census Bureau American Community Survey (ACS) 5-year median household income falls below the California Alternate Rates for Energy (CARE) income eligibility limit for a family of four, shall be eligible for an additional 30 percent funding. The effective definition of a low-income area, through May 31, 2019, is a median household income no greater than $50,200. Projects with low-income households that offer service to low-income customers at less than $15/month shall be eligible for an additional 10 percent funding.
California Advanced Services Fund (CASF) **Public Housing Account**[86]	CASF Broadband Public Housing Account funding is limited to an eligible publicly supported community (PSCs) owned by either of the following two entities: • A public housing agency that has been chartered by the State, or by city or by county in the State, and has been determined to be an eligible public housing agency by the United States Department of Housing and Urban Development. • An incorporated nonprofit organization as described in Section 501 (c)(3) of the Internal Revenue Code (26 U.S.C. Sec. 501(c)(3)) that is exempt from taxation under Section 501 (a) of that code (16 U.S.C. Sec. 501(a)) and that has received public funding to subsidize the construction or maintenance of housing occupied by residents whose annual income qualifies as "low"-or "very low" income according to federal poverty guidelines.

[86] https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/communications-division/documents/casf-adoption-and-access/bpha_guidelines_august_2020.pdf

	Non-profit housing developers involved in limited partnerships with for-profit entities participating may also be eligible since the IRS considers an exempt organization's participation as a general partner in a limited partnership with for-profit limited partners as consistent with the organization's exempt status under Internal Revenue Code Section 501(c)(3).
California High Cost Fund A (CHCF A)[87]	The 13 small LECs in California that are eligible to draw revenue from the CHCF-A program are: • Calaveras Telephone Company • California-Oregon Telephone Company • Ducor Telephone Company • Foresthill Telephone Company • Happy Valley Telephone Company • Hornitos Telephone Company • Kerman Telephone Company • Pinnacles Telephone Company • The Ponderosa Telephone Company • Sierra Telephone Company • Siskiyou Telephone Company • The Volcano Telephone Company • Winterhaven Telephone Company
California High Cost Fund B (CHCF B)[88]	Carriers of Last Resort (COLRs) are given subsidies for providing basic local telephone service to residential customers in high-cost areas that are currently served by Pacific Bell Telephone Company dba AT&T California, Verizon California Inc., Citizens Telecommunications Company of California dba Frontier Communications of California, and Cox Communications. High cost areas of California are those in which the cost to the COLR to provide service is $36 or more per telephone line.

[87] https://www.cpuc.ca.gov/industries-and-topics/internet-and-phone/california-high-cost-fund-a

[88] https://www.cpuc.ca.gov/industries-and-topics/internet-and-phone/california-high-cost-fund-b

California Lifeline[89]	There are two ways to qualify for the California LifeLine Program. You may qualify for California LifeLine via Program-Based OR Income-Based. *Program-Based Qualification Method:* You can qualify for California LifeLine if you or another person in your household is enrolled in any one of these qualifying public assistance programs: • Medicaid/Medi-Cal • Low Income Home Energy Assistance Program (LIHEAP) • Supplemental Security Income (SSI) • Federal Public Housing Assistance or Section 8 • CalFresh, Food Stamps or Supplemental Nutrition Assistance Program (SNAP) • Women, Infants and Children Program (WIC) • National School Lunch Program (NSL) • Temporary Assistance for Needy Families (TANF) a) California Work Opportunity and Responsibility to Kids (CalWORKs) b) Stanislaus County Work Opportunity and Responsibility to Kids (StanWORKs) c) Welfare-to-Work (WTW) d) Greater Avenues for Independence (GAIN) • Tribal TANF • Bureau of Indian Affairs General Assistance • Head Start Income Eligible (Tribal Only) • Food Distribution Program on Indian Reservations • Federal Veterans and Survivors Pension Benefit Program

[89] https://www.cpuc.ca.gov/consumer-support/financial-assistance-savings-and-discounts/lifeline/california-lifeline-eligibility#qualify

<table>
<tr><td></td><td>
Income-Based Qualification Method:

You can qualify for California LifeLine if your household's total annual gross income is at or less than these annual income limits:
<table>
<tr><th>Household Size</th><th>Annual Income Limits</th></tr>
<tr><td>1-2</td><td>$28,500</td></tr>
<tr><td>3</td><td>$33,100</td></tr>
<tr><td>4</td><td>$40,300</td></tr>
<tr><td>Each Additional Member</td><td>$7,200</td></tr>
<tr><td colspan="2">Effective June 1, 2021 to May 31, 2022</td></tr>
</table>
</td></tr>
<tr><td>California Teleconnect Fund[90] (edited)</td><td>
The CTF Program categorizes applicants (and participants) into seven distinct groups:

<u>Schools</u>

To qualify for the CTF Program, a public school must:

• Provide elementary or secondary education (grades K–12).

• Possess an active County District School code number from California Department of Education.

To qualify for the CTF Program, a private school must:

• Provide elementary or secondary education (grades K–12).

• Possess an active County District School code number from California Department of Education.

• Possess an annual endowment under $50 million.

• File taxes as a nonprofit entity with the Internal Revenue Service.

<u>Libraries</u>

To qualify for the CTF Program, a library must be eligible to participate in state-based plans for funds under the federal Library Services and Technology Act.
</td></tr>
</table>

[90] https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/communications-division/documents/california-teleconnect-fund/ctf_applicant_and_participant_guidebook.pdf

	Eligibility for the CTF Program is further limited to library outlet locations, which are the locations where library services are provided to the community. **Community Colleges** To qualify for the CTF Program, a community college must be a California Community College (as determined by California Education Code Section 70900) and possess a Management Information System (MIS) code. **Government Hospitals/Clinics** Hospitals and health clinics that are owned and operated by a municipal government, county government, or a hospital district may qualify for the CTF Program as a Government Hospital/Clinic. Government Hospitals/Clinics that participate in the CTF Program must have a valid healthcare license and identification number from the Office of Statewide Health Planning and Development. Only locations that provide healthcare services to the community can participate in the CTF Program. **Community-Based Organizations** To qualify for the CTF Program, a CBO must: • File taxes with the Internal Revenue Service as a 501(c)(3) organization. • Offer one or more of the following Qualifying Services to individuals and/or families in the community: *Educational Instruction*: These services include regular, ongoing, preschool or K-12 academic educational or instructional programs that can also include ESL and language education, literacy, job training, technology instructions and information on public benefit and social services programs eligibility and access. Educational instruction must include the use of a CTF-eligible communication service by community members. *Head Start Program*: Refer to the Head Start Center Locator at https://eclkc.ohs.acf.hhs.gov/center-locator. *Job Placement*: These services provide community members with assistance in obtaining employment, including activities related to job recruiting and placement. Eligible job placement services must include the use of a CTF-eligible telecommunication service by community members. *Job Training*: These services provide community members with training or skill-building for the purpose of obtaining employment. Eligible Job Training Services

	must include the use of a CTF-eligible telecommunication service by community members. *Community Lab / Technology Center*: To qualify, these services must provide the community training and/or access to technology and advanced communication services. Eligible Community Technology Programs must include the use of a CTF-eligible communication service by community members. • Offer one or more Qualifying Services directly to individuals at a specific geographic location without charge or at a minimal fee. • Utilize the advanced communication service(s) that receives the CTF discount when providing one or more Qualifying Services. • Provide the community access to the advanced communication service(s) that receives the CTF discount. • Possess annual revenues less than $5 million. • A majority of the CBO's board members must reside in California. **Healthcare Community-Based Organizations** To qualify for the CTF Program, a Healthcare CBO must: • File taxes with the Internal Revenue Service as a 501(c)(3) organization. • Offer healthcare services as their primary function directly to individuals at a specific geographic location. • Have licensed medical personnel on site providing healthcare services to individuals and/or families within the community. • Accept medical plans such as Medi-Cal, Medicare, Department of Veterans Affairs insurance, and/or provide services without charge or at a minimal fee. • Possess annual revenues less than $50 million. • A majority of the Healthcare CBO's board members must reside in California. **2-1-1 Providers** To qualify for the CTF Program, a 2-1-1 Service Provider must: • Have existing authorization from the California Public Utilities Commission (via Resolution) to operate as a 2-1-1 Service Provider. • File taxes with the Internal Revenue Service as a 501(c)(3) organization.

	• Possess annual revenues less than $5 million.
Deaf and Disabled Telecommunications Program[91]	To be eligible to receive free specialized telephone equipment through the Program, a person must: • Live in California • Have telephone service (Please note: The majority of Program equipment only functions with a land line.) • Be certified as having one or more of the following disabilities: o Hearing o Vision o Mobility o Speech o Cognitive There is no age or income requirement.
Water Customer Assistance Programs (CAPs)[92]	Income eligibility for ESA participation is set at 200% or less of Federal Poverty Guidelines.

[91] https://ddtp.cpuc.ca.gov/faqs.aspx#Eligibility_and_Applying

[92] https://www.cpuc.ca.gov/consumer-support/financial-assistance-savings-and-discounts/water-company-assistance

Additional Definitions in State Government	
Socially Disadvantaged Farmers[93]	A farmer or rancher who is a member of a socially disadvantaged group. A "socially disadvantaged group" means a group whose members have been subjected to racial, ethnic, or gender discrimination. These groups include the following: • African Americans • American Indians • Alaskan Natives • Hispanics • Asian Americans • Native Hawaiians and Pacific Islanders • Female farmers and ranchers of color
Disadvantaged Unincorporated Communities (DUCs)[94]	Defined as an area of inhabited territory located within an unincorporated area of a County in which the annual median household income is less than 80 percent of the statewide median household income. State law considers an area with 12 or more registered voters to be an inhabited territory.
Under-resourced Communities[95]	"Under-resourced community" is identified pursuant to one, some, or all of the following sections of the Health and Safety Code: • Section 39711, which reads, "The California Environmental Protection Agency shall identify disadvantaged communities … [that] may include, but are not limited to, either of the following: (1) Areas disproportionately affected by environmental pollution and other hazards that can lead to negative public health effects, exposure, or environmental degradation. (2) Areas with concentrations of people that are of low income, high unemployment, low levels of homeownership, high rent burden, sensitive populations, or low levels of educational attainment. • Subdivision (d) of Section 39713 of the Health and Safety Code, which reads, "(1) 'Low-income households are those with household

[93] AB 1348 - https://leginfo.legislature.ca.gov/faces/billTextClient.xhtml?bill_id=201720180AB1348
[94] SB 244 - https://leginfo.legislature.ca.gov/faces/billNavClient.xhtml?bill_id=201120120SB244
[95] SB 1072 - https://leginfo.legislature.ca.gov/faces/billTextClient.xhtml?bill_id=201720180SB1072

	incomes at or below 80 percent of the statewide median income or with household incomes at or below the threshold designated as low income by the Department of Housing and Community Development's list of state income limits adopted pursuant to Section 50093. (2) 'Low-income communities' are census tracts with median household incomes at or below 80 percent of the statewide median income or with median household incomes at or below the threshold designated as low income by the Department of Housing and Community Development's list of state income limits adopted pursuant to Section 50093. • Subdivision (g) of Section 75005, which reads, "'Disadvantaged community' means a community with a median household income less than 80% of the statewide average. 'Severely disadvantaged community' means a community with a median household income less than 60% of the statewide average."
AB 1550 Priority Populations[96]	Certain populations are especially vulnerable to the impacts of climate change. At least 35 percent of California Climate Investments[97] must benefit these populations, which include disadvantaged communities, low-income communities, and low-income households, also known as "priority populations." Disadvantaged communities are identified by the California Environmental Protection Agency (CalEPA) as the top 25% most impacted census tracts in CalEnviroScreen 3.0 - a screening tool used to help identify communities disproportionally burdened by multiple sources of pollution and with population characteristics that make them more sensitive to pollution. Low-income communities and households are defined as the census tracts and households, respectively, that are either at or below 80 percent of the statewide median income, or at or below the threshold designated as low-income by the California Department of Housing and Community Development's (HCD) 2016 State Income Limits.

[96] https://ww2.arb.ca.gov/sites/default/files/auction-proceeds/communityinvestments.htm

[97] https://www.caclimateinvestments.ca.gov/

Appendix D: Select Case Studies of ESJ in CPUC Proceedings

The below case studies represent examples of how the ESJ Action Plan can be incorporated into proceeding rulings and resolutions. These highlighted examples are not an exhaustive list and only represent a handful of cases where the ESJ Action Plan has been cited in CPUC activities proceedings.

Communications

ORDER INSTITUTING RULEMAKING REGARDING BROADBAND INFRASTRUCTURE DEPLOYMENT AND TO SUPPORT SERVICE PROVIDERS IN THE STATE OF CALIFORNIA.

Rulemaking 20-09-001

Comments Requested

Parties are asked to comment on the following questions:

1. Are the inputs and assumptions of the studies discussed above accurate? How could one improve these studies?

2. Do the findings of these studies provide evidence of a systemic problem in California?

3. Do these studies indicate discrimination based on race, socioeconomic status or otherwise, and, if yes, what are the societal implications?

4. If the Commission were to undertake an investigation into whether ISPs are not serving certain communities or neighborhoods within their service or franchise areas, a practice generally referred to as redlining, how should the Commission conduct that investigation? What data should the Commission rely on for its investigation?

5. Historically, redlining has meant that some neighborhoods, generally with affluent, white residents, have access to a particular service while poorer residents do not. How should the Commission define redlining? In the context of broadband Internet service, should Internet speeds offered to residents be taken into consideration?

6. Does the table in Section 3 of this ruling indicate redlining or some other form of systemic issue? It appears to indicate that poorer communities are more likely to be unserved, and wealthier communities are more likely to be served. Is this analysis accurate? Please explain why it is or is not accurate.

7. Are there other studies or analysis that parties wish to submit for the record in this proceeding?

Energy

DECISION ON LARGE INVESTOR-OWNED UTILITIES' AND MARIN CLEAN ENERGY'S CALIFORNIA ALTERNATE RATES FOR ENERGY (CARE), ENERGY SAVINGS ASSISTANCE (ESA), AND FAMILY ELECTRIC RATE ASSISTANCE (FERA) PROGRAM APPLICATIONS FOR PROGRAM YEARS 2021-2026

Decision 21-06-015

9. Environmental and Social Justice

9.1. Background

On February 21, 2019, the Commission adopted the Environmental and Social Justice (ESJ) Action Plan1052 which serves to expand public inclusion in Commission decision-making and improve services to targeted communities in California, specifically communities of color and/ or low-income communities. The ESJ Action Plan defines environmental and social justice as:

Environmental and social justice seeks to come to terms with, and remedy, a history of unfair treatment of communities, predominantly communities of people of color and/or low-income residents. These communities have been subjected to disproportionate impacts from one or more environmental hazards, socioeconomic burdens, or both.

The overall goals identified by the ESJ action plans include:

- Goal 1: Consistently integrate equity and access considerations throughout CPUC proceedings and other efforts.
- Goal 2: Increase investment in clean energy resources to benefit ESJ communities, especially to improve local air quality and public health.
- Goal 3: Strive to improve access to high-quality water, communications, and transportation services for ESJ communities.
- Goal 4: Increase climate resiliency in ESJ communities.
- Goal 5: Enhance outreach and public participation opportunities for ESJ communities to meaningfully participate in the CPUC's decision-making process and benefit from CPUC programs.
- Goal 6: Enhance enforcement to ensure safety and consumer protection for ESJ communities.
- Goal 7: Promote economic and workforce development opportunities in ESJ communities.

- Goal 8: Improve training and staff development related to ESJ issues within the CPUC's jurisdiction.
- Goal 9: Monitor the CPUC's ESJ efforts to evaluate how they are achieving their objectives.

ESJ communities are also identified as those where residents are predominantly communities of color or low income, underrepresented in the policy setting or decision-making process, subject to a disproportionate impact from one or more environmental hazards, and likely to experience disparate implementation of environmental regulations and socio-economic investments in their communities. On the ground, these targeted communities typically include but are not limited to, DACs, all Tribal lands, and low-income households and census tracts.

9.2. Incorporating ESJ Goals and Efforts into CARE and ESA

As CARE and ESA program eligibility is set at or below 200 percent of FPG, most if not all, ESA and CARE participants are part of an ESJ community. Through this proceeding, we prioritize actions that improve local air quality, benefit public health, increase climate resiliency and provide economic benefits within the ESJ communities. This decision makes great strides in prioritizing ESJ issues and takes actions that advance equity and policies for ESJ communities. Below we outline the efforts directed in this decision that specifically address and further the goals of the Action Plan.

- Requiring that all working groups, (who are tasked with final design and delivery of the program), include representation specifically from community-based organizations, consumer protection/advocates, and other special interest groups, which includes members or representatives from ESJ communities; Furthers Goals 1, 5.
- Requiring the IOUs to hold annual public meetings to discuss program progress with community members; Furthers Goal 5.
- Requiring the consideration of the development of a UAS that would provide low-income customers various registration pathways into multiple affordable programs (including clean energy programs), easing the enrollment process and decreasing barriers to participation; Furthers Goals 1, 2, 5.
- Recommending IOU engagement and collaboration with CARB and GRID Alternatives on the Access Clean California tool, which would provide a single application connecting residents with the state's clean energy and transportation equity programs; Furthers Goals 1, 2, 3, 5.
- Prioritizing the below customer segments for outreach, education, and treatment which are inclusive of ESJ community members; Furthers Goal 1.

By Financials	By Location	By Health Condition
CARE	DAC	Medical Baseline
Disconnected	Rural	Respiratory
Arrearages	Tribal	Disabled
High usage	PSPS Zone	
High energy burden	Wildfire Zone	
SEVI	Climate Zone	
Affordability Ratio	CARB communities	

- Approving advanced treatment offerings, and investment, for specific customer segments which are inclusive of ESJ community members; Furthers Goals 1, 2, 4.
- Requiring the IOUs to track ESA treatment levels and efforts within specific customer segments in their reporting to the Commission; Furthers Goals 1, 9.
- Approving funding agreements to those point persons in Tribal communities that assist with outreach for ESA, FERA and CARE; Furthers Goals 1, 5.
- Requiring the IOUs to extend and encourage participation of the CARE/FERA capitation program in Tribal communities; Furthers Goals 1, 5.
- Leveraging with LifeLine, CETF and water utilities, which include co-promotion and marketing efforts, co-funding of water measures, and data sharing and customer referrals with LifeLine and water utilities; Furthers Goal 3.
- Approving a Building Electrification pilot that will offer high usage, income-qualified single-family households in DACs electrification measures at no cost; Furthers Goals 1, 2, 4.
- Approving a Clean Energy Homes pilot that will provide incentives for low-income housing developers to incorporate electrification into the designs of new construction, with a goal to reduce energy bills for the low-income customer, reduce GHG emissions associated with burning fossil fuels, and ease participation in customer programs; Furthers Goals 1, 2, 4.
- Requiring the IOUs to ensure additional workforce development opportunities and hiring within local communities, specifically in DACs (via IOU partnerships with the California Workforce Development Board's Energy and Climate Jobs Initiative, community colleges, and organizations providing services in DACs); Furthers Goal 7.

- Requiring the IOUs to track ESA workforce, education, and training efforts in their annual reporting to the Commission; Furthers Goals 7, 9.

We are confident that the objectives and actions taken here are necessary and will advance the Commission towards the state's equity goals.

Rail Safety

APPLICATION OF THE CALIFORNIA HIGH-SPEED RAIL AUTHORITY FOR APPROVAL TO CONSTRUCT THREE NEW GRADE SEPARATED CROSSINGS OVER THE PROPOSED HIGH-SPEED RAIL TRACKS OPERATED BY CALIFORNIA HIGH-SPEED RAIL AUTHORITY AT EXCELSIOR AVENUE (MP 218.83), FLINT AVENUE (MP 220.86), AND FARGO AVENUE (MP 221.88) LOCATED IN THE COUNTY OF KINGS, STATE OF CALIFORNIA.

Decision 21-01-007

Alignment with the Commission's Environmental and Social Justice Action Plan

In February 2019, the Commission adopted its Environmental and Social Justice (ESJ) Action Plan as a comprehensive strategy and framework for addressing ESJ issues in each proceeding.

The Final EIR/EIS identifies several impacts that were considered when choosing the route for the Fresno-Bakersfield CHSTS Project, especially in the rural areas that will be affected by the three crossings proposed in A.20-08-015. CHSRA and FRA worked with local, state, and federal officials and stakeholders to identify a route intended to follow existing railway corridors, to minimize relocation impacts and better align with current and planned land uses along the project corridor.

The route, including the three crossings proposed in A.20-08-015, was also designed to ensure agricultural producers in the San Joaquin Valley still have access to railroad service necessary to efficiently move their goods to market.

Here, CHSRA has coordinated with tribal communities and stakeholders in the regions impacted by the project, and access to a high-speed rail option through the San Joaquin Valley would not only provide cleaner transportation options to residents but could improve ambient air quality by reducing the number of personal vehicle trips through the region.

Upon review of the Application and the record of this proceeding, including the Final EIR/EIS, we find that the three grade-separated crossings proposed in this Application align with the Commission's ESJ Action Plan. CHSRA is encouraged to hire local contractors and conduct public

outreach about temporary street closures in multiple languages when constructing the three crossings proposed in A.20-08-015.

Transportation

DECISION AUTHORIZING DEPLOYMENT OF DRIVERED AND DRIVERLESS AUTONOMOUS VEHICLE PASSENGER SERVICE

Decision 20-11-046

4.9. Goal: Equity and Environmental Justice

The December 19, 2019 Ruling asked how the Commission should incorporate equity and environmental justice into its program goals.

4.9.1. Comments

Multiple parties emphasize the importance of ensuring the benefits of AV passenger service are available to all of California's communities including disadvantaged and low-income communities. They reference state law, the Commission's Environmental and Social Justice Action Plan (ESJ Action Plan), and basic principles of equity.

SFMTA and SFCTA along with LADOT argue that, unless the Commission adopts environmental justice goals, profit-driven business models may leave disadvantaged communities behind. UC Davis and LADOT emphasize that even though disadvantaged communities are the communities that could benefit most from improved transportation options, they are the most likely to suffer environmental consequences from transportation operations. Sierra Club agrees.

SFMTA and SFCTA note that the Commission has adopted an ESJ Action Plan that establishes several objectives related to transportation. In the ESJ Action Plan, the Commission states its intent to "promote equitable transportation services regulated by the CPUC; encourage greater utilization of Zero Emission Vehicles (ZEVs) by TNCs within ESJ communities, with a focus on communities that have been underserved by existing transportation options; and encourage that autonomous vehicles be available in disadvantaged communities.

Accordingly, SFMTA and SFCTA propose the goal that "AV Passenger Service should prevent negative impacts on disadvantaged communities and improve transportation options for all, giving priority to disadvantaged communities with unmet transportation needs." SANDAG and SFO support this goal.

While Waymo argues that it is too early to set prescriptive equity goals, they assert that authorizing fare collection encourages companies to expand their service more broadly, including to low-income communities. Waymo gives the example of a partnership they formed with a transit agency in Arizona to provide first- and last-mile service to groups underserved by public transit.

4.9.2. Discussion

The Commission adopts the equity goal to "Improve transportation options for all, particularly for disadvantaged and low-income communities." The environmental justice goal is addressed by ensuring that disadvantaged communities have preferential access to the greenhouse gas and air quality benefits of AVs. The latter goal is addressed more fully in the following section on "Environmental and Climate Impacts."

Parties are correct to highlight that the Commission already recognizes the many burdens faced by DACs including a lack of access to transit options and a disproportionate share of the environmental and health burdens caused by transportation services like particulate emissions from passenger vehicles. As noted in Goal #2 of the ESJ Action Plan, the Commission aims to improve the local air quality (i.e., criteria pollutants and air toxics) and public health in disadvantaged communities. AVs may be an important service to reduce these burdens.

The Commission will collect data to evaluate progress toward this goal including the census tracts in which trips begin and end; the volume and frequency of shared rides in each neighborhood; and narrative descriptions of each permit holder's outreach activities. These data are discussed in more depth in [Section #] of this Decision.

As discussed above, it is too soon for the Commission to set uniform equity targets. Companies will operate under different business models and at different scales. Some companies have stated they intend to provide broad market ride hailing services while other companies focus exclusively on shuttle services for single communities. As the market matures, the Commission can reconsider if and when to impose uniform equity targets.

4.15. Data Reporting Requirements: Equity and Environmental Justice

4.15.1. Comments

Party comments about the data necessary to evaluate the impacts of AV service on equity and environmental justice are largely covered in 4.12 on "AV Operations."

Relevant excerpts:

"Greenlining, SFO, SFMTA and SFCTA, MTC, Sierra Club, and UC Davis all argue that the Commission should expand its data collection to include detailed information about AV operations including the location of pick-ups and drop-offs or at least whether the pick-up or drop-off site is located in a Disadvantaged Community."

"Multiple parties highlight the benefits of collecting location data to understand the impacts of AVs' operations on the environment, equity, and traffic patterns. As Greenlining and Sierra Club note,

location data can be used to determine the level of service and the comparative environmental impact of AVs on DACs."

4.15.2. Discussion

As discussed in 4.12, the Commission requires companies to include in their quarterly program reports information about the pick-up and drop-off locations of each trip, and the fuel type of the vehicle for each trip. This enables stakeholders to compare service to neighborhoods in disadvantaged communities vs neighborhoods outside disadvantaged communities. This provides information about the equity of service as well the trips' environmental impacts.

Water

GOLDEN STATE WATER COMPANY. ORDER AUTHORIZING GOLDEN STATE WATER COMPANY TO ACQUIRE ROBBINS WATER SYSTEM FROM SUTTER COUNTY WATER WORKS DISTRICT NO. 1.

Resolution W-5237

This Resolution addresses Goals #1 and #3 of the ESJ Action Plan, "Consistently integrate equity and access considerations throughout Commission regulatory activities," and "Strive to improve access to high-quality water, communications, and transportation services for ESJ communities."

The Commission recognizes that some populations in California such as those served by Robbins, face higher barriers in accessing safe and affordable utility services. The ESJ Action Plan tasks the Commission with the responsibility to serve Californians in a way that helps address these inequities. The Resolution for the acquisition of Sutter County's Robbins Water System by Golden State created a pathway to provide safe and reliable water service for the Robbins community that currently does not have access to high-quality water with the previously mentioned water quality issues related to arsenic, TDS, chloride, and specific conductance.

Robbins is classified as a disadvantaged community as defined by Health and Safety Code Section 116275, subd. (aa). The California Communities Environmental Health Screening Tool, Version 3 (CalEnviroScreen 3.0) provided by the California Environmental Protection Agency, identifies disadvantaged communities by collecting multiple metrics and outputting a single value at the census tract scale. CalEnviroScreen 3.0 ranks Robbins in the 65-70th percentile of the highest scoring census tracts statewide, the census tract notably falls into the 98th percentile for Impaired Water, and in the 91st percentile for Groundwater Threats. The acquisition provided direct relief to residents of Robbins, who experienced disproportionately poor water quality.

Language Access and Partnership with Community Based Organizations

DECISION ON COMMUNITY AWARENESS AND PUBLIC OUTREACH BEFORE, DURING AND AFTER A WILDFIRE, AND EXPLAINING NEXT STEPS FOR OTHER PHASE 2 ISSUES

Decision 20-03-004

3.3. Discussion

3.3.1. In Language Requirements

Communication before, during and after a wildfire may be a life-or-death matter. The diversity of California's population and the vast number of languages spoken here is part of what makes the state strong, vibrant, tolerant, and forward-looking. We should honor and support all residents of the state, especially when dealing with public safety and catastrophic risk. However, people cannot act on outreach they cannot understand; public safety requires that outreach actually reach the intended audience. Outreach that is not in-language simply will not be effective in protecting all California residents.

Therefore, the Commission will require each of the IOU and SMJU respondents in this proceeding to communicate before, during and after a wildfire with community residents, businesses, state and local first responders, and CBOs in all languages that are prevalent in their service territories. Prevalent means that 1,000 or more people speak the language in an IOU's or SMJU's territory. Further, nothing in this decision limits an IOU or SMJU from communicating in a language that is not prevalent.

The communication methods need not all be the same, because different communities may get their information in different ways. However, all IOUs and SMJUs, at a minimum, should consider using radio, broadcast, cable and print earned and unearned media, shareable video or audio content, door-to-door contact, social media and websites, texting and other communications-based methods such as live phone calls, emergency alerts, emails, or prerecorded messages to communicate with their customers in language.

To identify prevalent languages, the IOUs and SMJUs shall use U.S. Census data, where available, to determine prevalent languages in their service territories, as well as the data sources suggested by CEJA: "California Complete Count," "Hard to Count" data, and the American Community Survey (ACS) tabulated and untabulated data as a screening tool to identify where English-limited individuals are likely to be in their service territory. They should also use lessons from the San Joaquin Valley proceeding, R.15-03-010 to inform them on appropriate language outreach. CEJA shall forward relevant information from that proceeding to the IOUs and SMJUs no later than 30 days after issuance of this decision.

In addition to census analysis, the IOUs and SMJUs should include data based on prior experience and information from CBOs, community representatives and leaders (i.e., identifying key sites like a migrant housing site or mobile home park). To the extent the IOUs' and SMJUs' own customer data reveals language usage or preference, they shall also utilize customer information data to determine language prevalence.

IOUs and SMJUs shall, to the maximum extent, use their existing CBO networks, and partner with new CBOs where they do not have existing relationships with a specific language minority community. Some principles that should guide CBO relationships are the following:

- Ensure partnerships, particularly with community partners, are resourced and include a clear Memorandum of Understanding to articulate roles, responsibilities, and activities. This should include outreach and translation needs.
- Consider strategies such as phone trees to help quickly disseminate information across trusted sources.
- Create a team of cross-sector partners, with a designated coordinator, to be able to work across purposes, share feedback, and steer the effort.
- Include methods and strategies for information sharing and dealing with confidentiality between partner organizations (both CBO and government).

The IOUs and SMJUs should consider the following community partnerships in developing and carrying out community outreach:

- Community Organization Partnerships:
    - Churches, schools, non-profits, medical clinics and hospitals, social service providers, legal services, and small businesses.
- Local Government Partnerships:
    - Emergency services, public health departments, other service providers, and first responders.

The IOUs and SMJUs shall take input from parties to this proceeding in a meet and confer format to ensure they are reaching the appropriate CBOs. They need not communicate their meet and confer process to the Commission unless there are problems or concerns. In the event of problems or concerns, the parties shall first contact and work with Monica.Palmeira@cpuc.ca.gov (the September 2019 workshop moderator), or such other contact person the Commission shall later designate, and s/he will determine whether to involve the ALJ and other parties to the proceeding.

The IOUs and SMJUs shall also reach out to the telecommunications, water, and transportation utilities in their territory in order to partner with language access services and CBO relationships those utilities may have. Further, they shall gather – with the assistance of the parties to this proceeding – information on available governmental and non-governmental communications

before, during and after a wildfire and coordinate their efforts with those communications to the maximum extent possible.

The IOUs' and SMJUs' communications methods shall accommodate language minorities without a common written language, as well as the indigenous languages Mixteco and Zapoteco. At the workshop, it appeared Triqui use is rare, but if it meets the definition of prevalence, the IOUs and SMJUs should also use Triqui.

In summary, the IOUs and SMJUs shall be prepared to conduct the outreach before, during and after a wildfire in time for the 2020 wildfire season.

Metrics for Utility Outreach & Engagement Activities

DECISION ON COMMUNITY AWARENESS AND PUBLIC OUTREACH BEFORE, DURING AND AFTER A WILDFIRE, AND EXPLAINING NEXT STEPS FOR OTHER PHASE 2 ISSUES

Decision 20-03-004

3.3.2. Surveys and Metrics to Determine Effectiveness of Outreach

Public safety requires that the IOUs and SMJUs survey the communities where they conduct outreach and use other metrics to determine that they are using effective methods. Several parties have commented – both in this Phase and in Phase 1 – that community meetings, conference calls or other group events the IOUs hold may not adequately inform communities about wildfire risk.

No later than May 30, 2020, the IOUs and SMJUs shall prepare, file and serve the results of an independent survey that assesses the effectiveness of their community outreach in 2019 pursuant to Public Utilities Code Section 8386(c)(16)(B). For the 2020 wildfire season, the survey results are due no later than December 31, 2020. At a minimum, the IOUs and SMJUs shall:

- Ask communities and individuals to which the IOU or SMJU has conducted outreach if the outreach was effective in helping them before, during and after a wildfire.
- Provide survey responses categorized by type of outreach – e.g., community meetings, over the air broadcast information, social media, print media, etc. – so that there is data in the proceeding showing what outreach is most effective that the Commission and stakeholders may use to direct future outreach.
- File and serve any existing survey results that assess the effectiveness of outreach before, during and after a wildfire conducted since the passage of SB 901.

Prior to conducting either survey, the IOUs and SMJUs, alone or in combination, shall gather input from the parties to this proceeding on appropriate survey questions and methodology through a meet and confer process that is open to all parties. This meet and confer process shall conclude no later than 30 days before the surveys are conducted.

In addition to surveys, the IOUs and SMJUs should use metrics to determine the reach of their efforts. One set of metrics should be quantitative in nature, and include data related to web site visits, click rates, conversions, in-person meetings, radio spots, number of partners, number of customers reached, customer acknowledging information, read receipts, video shares, and other quantitative measurement.

Another set of metrics should document comprehension, especially after a significant wildfire event. Such metrics can be more qualitative in nature and include metrics collected from surveys and post-event interviews/sessions with stakeholders and partners. Metrics should capture satisfaction with outreach and engagement from utility, understanding of information and whether communities or individuals feel equipped to act, and whether communities or individuals feel connected to resources they may call upon before, during and after a wildfire. Potential avenues for collecting this information include debriefs with partners to discuss what could be improved, public listening sessions to discuss what could be improved, and customer surveys to understand what could be improved.

Workforce Development

DECISION SETTING NEAR-TERM PRIORITIES FOR TRANSPORTATION ELECTRIFICATION INVESTMENTS BY THE ELECTRICAL CORPORATIONS

Decision 21-07-028

4.3.1. Equity and Environmental Justice Requirements for Near-Term Priority Program Proposals

- Further the principles of economic equity and promote access to high quality jobs for residents of underserved communities. The IOUs should articulate how each project incorporates any of the following priority provisions:
    - » Job quality measures, such as wage and benefit standards and responsible contractor standards;
    - » Job access measures, such as targeted hire requirements as well as specified targets for residents of underserved communities;

- Comprehensive project agreements that address both job quality and job access, such as application of the Skilled & Trained Workforce requirement, and use of Community Workforce Agreements for large-scale TE projects;
- Funding directed to training partnerships that are guided in their programming to ensure that investments in training are connected to and result in placement in high-quality jobs.

MEMORANDUM OF UNDERSTANDING
BETWEEN THE CALIFORNIA PUBLIC UTILITIES COMMISSION AND THE CALIFORNIA WORKFORCE DEVELOPMENT BOARD ON WORKFORCE DEVELOPMENT FOR ENVIRONMENTAL AND SOCIAL JUSTICE

PURPOSE

Pursuant to the California Public Utilities Commission's (CPUC) Environmental and Social Justice Action Plan (ESJ Action Plan), as well as directives in Governor Newsom's Executive Orders N-79-20 (EO N-79-20)[1] and N-19-19 (EO N-19-19)[2], the CPUC and California Workforce Development Board (CWDB) (collectively the Parties) enter into this Memorandum of Understanding (MOU) to coordinate economic and workforce development planning, analysis, and implementation activities.

The purpose of this agreement is to draw upon the expertise of the CWDB to ensure the state has the workforce and industry-based training partnerships necessary to meet its clean energy and clean transportation goals, while building pathways into the middle class and beyond for Californians who have been historically excluded from opportunity or shouldered a disproportionate share of climate and environmental costs.

The scope of this agreement includes advice and recommendations to ensure CPUC policies and regulated programs create or support high-quality jobs in the energy and transportation sectors and expand access to those jobs for priority populations through high-quality education and training.

BACKGROUND

On October 7, 2015, Governor Brown signed the Clean Energy and Pollution Reduction Act of 2015 (SB 350). SB 350 established new energy efficiency and renewable electricity targets to support California's climate goal of reducing greenhouse gas emissions to 40 percent below 1990 levels by 2030. In addition,

[1] Executive Order N-79-20, September 2020: https://www.gov.ca.gov/wp-content/uploads/2020/09/9.23.20-EO-N-79-20-Climate.pdf
[2] Executive Order N-19-19, September 2019: https://www.gov.ca.gov/wp-content/uploads/2019/09/9.20.19-Climate-EO-N-19-19.pdf

SB 350 directed the California Energy Commission (CEC) and the California Air Resources Board (CARB) to, among other things, study and provide recommendations on barriers for low-income customers to energy efficiency and weatherization investments as well as clean transportation and mobility investments, including those in disadvantaged communities.

On December 2016, the CEC published the *SB 350 Low-Income Barriers Study, Part A- Commission Final Report: Overcoming Barriers to Energy Efficiency and Renewables for Low-Income Customers and Small Business Contracting Opportunities in Disadvantaged Communities* (Study A).[3] Study A recommends promoting well-paying clean energy job opportunities for residents in disadvantaged and low-income communities by creating opportunities to "collaborate with state labor agencies such as the California Labor & Workforce Development Agency, the California Workforce Development Board, and the Employment Development Department on targeted workforce training and job placement initiatives to create strategies that drive clean energy job opportunities in low-income and disadvantaged communities." (Study A, 77.)

In February 2018, CARB published the *SB 350 Low-Income Barriers Study, Part B-Overcoming Barriers to Clean Transportation Access for Low-Income Residents* (Study B).[4] Study B recommends maximizing economic opportunities and benefits for low-income residents from investments in clean transportation and mobility options by expanding workforce training and development. This includes the CWDB taking a lead role, in partnership with other state and local public agencies, to expand opportunities and create connections "for good quality clean transportation jobs in low-income and disadvantaged communities" as well as to expand access to workforce development programs to "support clean transportation jobs and workforce development in low-income and disadvantaged communities, especially for youth." (Study B, 54-55.)

In February 2019, the CPUC adopted the Environmental and Social Justice Action Plan to serve as a roadmap to expand public inclusion in Commission decision-making and improve services to targeted communities in California.[5] One of the core tenets of the ESJ Action Plan, Goal 7, tasks the CPUC with

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[3] https://assets.ctfassets.net/ntcn17ss1ow9/3SqKkJoNlvts2nYVPAOmGH/7bc56e2692769abda31a2aace7b00147/TN214830_20161215T184655_SB_350_LowIncome_Barriers_Study_Part_A__Commission_Final_Report.pdf

[4] https://ww2.arb.ca.gov/sites/default/files/2018-08/sb350_final_guidance_document_022118.pdf

[5] www.cpuc.ca.gov/ESJActionPlan

promoting economic and workforce development opportunities in ESJ communities by developing workforce development guidelines in programs overseen by the CPUC or CPUC regulated utilities.

In September 2019, Governor Newsom signed Executive Order (EO) N-19-19 to further California's commitment to mitigate the impacts of climate change. EO N-19-19 directs all aspects of state government to continue to increase efforts to reduce greenhouse gas emissions and mitigate the impacts of climate change to build a sustainable and inclusive economy. In September 2020, Governor Newsom signed Executive Order (EO) N-79-20 to redouble California's efforts to reduce emissions from the transportation sector. EO N-79-20 directs the CPUC and other state agencies to accelerate the deployment of affordable fueling and charging infrastructure for zero-emission vehicles, and promotes the creation and retention of high-road, high-quality jobs in the transition to a carbon neutral economy. These Executive Orders reinforced the ESJ Action Plan goal and solidified CWDB's commitment to collaborate with the CPUC to improve workforce development opportunities.

In March 2020, the CWDB released California's 2020-2023 Unified Strategic Workforce Development Plan (State Workforce Plan)[6] featuring the CWDB's vision of a high road economy which is defined by a set of goals to be achieved simultaneously: greater equity and mobility for workers, higher skills and competitiveness for employers, and long-term environmental sustainability and climate resilience for the state. Strategies to advance the high road vision through policy and programs include administering the High Road Construction Careers (HRCC) and High Road Training Partnerships (HRTP) workforce initiatives, as well as establishing partnerships between the CWDB and other state agencies – including the CPUC – to align California's transition to carbon neutrality with the State's high road vision.

ROLES AND RESPONSIBILITIES

The CPUC regulates energy utilities, telecommunications, water, railroad, rail transit, and passenger transportation companies' services and utilities, protects consumers, safeguards the environment, and assures Californians' access to safe and reliable utility infrastructure and services.

[6] https://cwdb.ca.gov/plans_policies/2020-2023-state-plan-draft/

The CWDB oversees and continuously improves the workforce system in California, which encompasses a wide array of work including: policy development, workforce support and innovation, and performance assessment, measurement, and reporting. In addition to administering innovative workforce development programs, the CWDB works with a multitude of public and private organizations at the state and local levels to develop a common policy vision for the provision of workforce services in the state.

SHARED PRIORITIES

The Parties share the following priorities for effective communication and coordination to support workforce development policies and practices to implement the State's and CPUC'S directives:

1. Establish regular intervals for information sharing on both the management and staff levels, including a process for regular information flow and opportunities for joint planning and goal setting;
2. Develop a near and long-term framework for high road economic and workforce policy and practice to meet the goals of the state including but not limited to those outlined in CPUC's ESJ Action Plan and CDWB's 2020-2023 State Workforce Plan;
3. Identify programs to examine the scope of CPUC workforce development efforts. Possible program areas include energy efficiency, building electrification, renewable energy, transportation electrification and vegetation management programs;
4. Establish or advance a set of principles and practices that can guide any CPUC-regulated program in updating or developing California's economy and workforce in a way that delivers measurable benefits for ESJ communities. These principles and practices should directly aid disadvantaged Californians by building clean energy and clean transportation career pipelines, while taking into consideration ratepayer impacts;
5. Establish targets and analyze metrics to assess economic and workforce development related activities within CPUC programs and ESJ communities.

CPUC RESPONSIBILITIES

In order to achieve optimal results for the shared priorities, the CPUC will perform the activities and functions summarized below:

1. CPUC will provide information and data to CWDB on workforce development in the energy and transportation industries regulated or overseen by the CPUC, which includes but is not limited to the following:
    a. Elements of current workforce development programs overseen by the CPUC or CPUC regulated utilities.
    b. To the extent available, background information on prior and current CPUC efforts to develop and implement workforce development requirements.
    c. Industries and occupations involved in CPUC workforce development efforts.
    d. Strategies used by CPUC to promote and track workforce development programs and outcomes.
2. Review and analyze CWDB's feedback to develop a standardized workforce development framework.
3. Designate CPUC staff and management with relevant experience to support MOU activities including data and information sharing, and other related activities in coordination with CWDB.

CWDB RESPONSIBILITIES

In order to achieve optimal results for the shared priorities, the CWDB will perform the activities and functions summarized below:

1. Provide subject matter expertise related to high road economic and workforce development strategies and best practices.
2. Evaluate, analyze, and provide feedback on CPUC or CPUC regulated industries' workforce development efforts.
3. Provide recommendations on program design, standards, and requirements to promote high road economic workforce development strategies and best practices.
4. Identify opportunities for upgrading workers' skills and contractors' competencies to perform high-quality work that meets clean energy and clean transportation goals.

5. Provide recommendations related to tracking workforce development impacts and outcomes.
6. Provide designated CWDB staff and management with relevant experience to support data and information sharing, and other related activities in coordination with CPUC.

PROTECTION OF CONFIDENTIAL INFORMATION

"Confidential Information" includes, but is not limited to, any information or data obtained pursuant to California Public Utilities Code section 583 and CPUC General Order 66-D, records exempt from public disclosure under the California Public Records Act (Government Code Section 6250, et seq.), Evidence Code section 1040, or any other applicable federal or state law, or information that is appropriately designated by the Parties to be exempt, prohibited, or privileged from disclosure by state or federal law.

The Parties shall take all necessary measures to protect Confidential Information and, consistent with the Public Records Act and any other laws requiring disclosure, treat any shared Confidential Information as confidential. The Parties shall impose all the requirements of this MOU on all of their respective officers, members, employees, and agents with access to Confidential Information. Any Confidential Information obtained by the Parties shall only be used for purposes that are consistent with existing law. The Parties agree to promptly notify each other's legal counsel of any public records act requests they receive seeking information shared or obtained pursuant to this agreement.

All Confidential Information provided to the Parties pursuant to this MOU shall be subject to Government Code Section 6254.5, subdivision (e), which exempts from public disclosure under the California Public Records Act, confidential records that one state or local agency has provided to another state or local agency pursuant to an agreement that the latter will treat the disclosed records as confidential. The Parties agree that, as provided in Government Code Section 6254, subdivision (e), Confidential Information will only be shared with persons authorized in writing by the Executive Officer of the relevant agency (or by their authorized delegate), and that all information obtained by the Parties pursuant to this agreement will be used only for purposes that are consistent with existing law.

Confidential Information provided to the other party, shall be maintained as confidential and shall not be released without an agreement in writing from the other party, unless a court of competent jurisdiction order the release of the Confidential Information.

The Parties will make all reasonable efforts to ensure that disclosure of Confidential Information will not occur. In the event an inadvertent disclosure of Confidential Information occurs, the party making such inadvertent disclosure will notify the other party in writing and will make every reasonable effort to promptly correct the inadvertent disclosure.
If either party receives a request to release, disclose, or access any of the Confidential Information (for example, pursuant to a subpoena, discovery request, or the California Public Records Act), the party receiving the request shall promptly transmit a copy of the request to the other party that originally generated the Confidential Information. The party who originally generated the Confidential Information shall assume the lead responsibility for determining the appropriate response required by California law, and shall consult with the other party during the course of reaching its determination.

SCOPE

This MOU is made for the sole benefit of the Parties and no other person or entity shall have any rights or remedies under or by reason of this MOU. Nothing in this MOU may be the basis of any third-party challenges or appeals. Nothing in this MOU creates any rights, remedies, or causes of action in any person or entity not party to this MOU.

APPROVAL

This MOU is effective upon completion of the signatures listed below. This MOU may be executed in counterparts. Each executed counterpart shall have the same force and effect as an original instrument. Taken together, the executed counterparts shall constitute one and the same agreement.

This MOU shall not be modified except by a written agreement signed by authorized representatives of the Parties. The Parties shall meet and coordinate on issues pertaining to the effectiveness and validity of this MOU on an annual basis, or as mutually agreed upon by the Parties. Any determination that a

provision in this MOU is invalid does not invalidate any other provision of this MOU or the MOU in its entirety.

This MOU shall continue unless or until either party to the MOU determines that the MOU should be terminated. Unless otherwise provided for by the written agreement of both of the Parties, unilateral termination of the MOU shall be effected no sooner than 60 days from the date either party provides written notice of its intent to terminate the MOU. Termination of this MOU shall not affect the obligation of the Parties to maintain the confidentiality of information pursuant to this MOU.

Each party represents and warrants that it has the right, power, and authority to execute this MOU. Each party represents and warrants that it has given any and all notices, and obtained any and all consents, powers, and authorities necessary to permit that party, and the persons executing this MOU for the party to enter into this MOU.

CALIFORNIA PUBLIC UTILITIES COMMISSION:

Rachel Peterson

October 29, 2020

RACHEL PETERSON
Acting Executive Director

CALIFORNIA WORKFORCE DEVELOPMENT BOARD:

October 26, 2020

TIM RAINEY
Executive Director

Tribal Consultation Policy of the California Public Utilities Commission

Introduction:

The CA Public Utilities Commission (CPUC or "Commission") adopts this Tribal Consultation Policy, consistent with Executive Order B-10-11 issued by Governor Edmund G. Brown, Jr. on September 19, 2011). Executive Order B-10-11 declares that "the State is committed to strengthening and sustaining effective government-to-government relationships between the State and the Tribes by identifying areas of mutual concern and working to develop partnerships and consensus." The Executive Order directs state executive agencies and departments to "encourage communication and consultation with California Indian Tribes." It further directs state agencies and departments "to permit elected officials and other representatives of tribal governments to provide meaningful input into the development of legislation, regulations, rules, and policies on matters that may affect tribal communities."

California is home to over 170 California Native American tribes.[1] Executive Order B-10-11 applies to federally-recognized Tribes and other California Native Americans. For purposes of this policy, the terms "tribes" and "tribal governments" refer to elected officials and other representatives of federally- recognized Tribes and other California Native Americans.

This policy is not intended to replace or supplant obligations mandated by federal law. It sets forth provisions for consultation, communication and collaboration with tribes to the extent that a conflict does not exist with applicable laws or regulations. This policy is not a regulation and it does not create, expand, limit, waive, or interpret any legal rights or obligations.

Tribal Liaison:

The Commission's Tribal Liaison will assist with implementing this policy. The Tribal Liaison is responsible for coordinating outreach, communication, education and other activities affiliated with tribal interests. The Tribal Liaison will act as a point of contact for tribal governments enabling participation in Commission proceedings and Commission-approved programs. The Tribal Liaison will facilitate CPUC leadership availability for government to government consultation. Alternatively, tribal governments may contact the Commission's Public Advisor for this assistance (Email: Public.Advisor@cpuc.ca.gov or phone: (866) 849-8390). The Tribal Liaison and/or Public Advisor are additional resources, and tribal governments may continue to directly contact relevant Commission staff regarding ongoing issues.

[1] "California Native American tribe" means a Native American tribe located in California that is on the contact list maintained by the Native American Heritage Commission for the purposes of Chapter 905 of the Statutes of 2004. See Public Resources Code § 21073. California Native American tribes include both federally recognized and non- federally recognized tribes. Nothing in this policy prevents tribal consultation with other Native American groups demonstrating an ongoing connection to a specific place or cultural resource, or issue falling under the jurisdiction of the CPUC.

Tribal Consultation Policy of the California Public Utilities Commission

Policy Goals: The goals of this policy are as follows:

- Recognize and respect tribal sovereignty
- Encourage and facilitate tribal government participation in CPUC proceedings
- Give meaningful consideration to tribal interests in issues within the CPUC's jurisdiction
- Encourage and facilitate tribal government participation in CPUC-approved utility programs
- Protect tribal cultural resources
- Encourage investments by tribal governments and tribal members in onsite renewable energy generation, energy efficiency; low carbon transportation and energy storage.

Background Regarding CPUC Authority:

The range of CPUC activities is extensive and includes regulation of privately-owned utilities, including gas, electric and water utilities, and oil and gas pipeline companies, and approval of the rates they charge to customers. The CPUC also regulates some aspects of telecommunication companies, and the safety of utilities, railroads, common carriers, charter party carriers and other transportation providers, but does not approve those companies' rates. The CPUC implements laws that require the electric utilities to procure renewable electricity to reduce greenhouse gas emissions, and that require electric and gas utilities to offer incentives, grants or rebates for energy efficiency, installation of renewable energy or energy storage, and installation of electric vehicle chargers. The CPUC also implements programs that offer reduced rates for low income gas and electric customers (i.e., the California Alternative Rate for Energy (CARE) and Family Electric Rate Assistance (FERA) programs; "Lifeline" for telephone service; subsidies for broadband services for underserved communities; and utility programs that provide no-cost energy efficiency upgrades to low income customers (the Energy Savings Assistance (ESA) Program).

The CPUC's activities may affect tribal governments in several ways, including but not limited to: 1) impacts on a tribe that is a utility customer at buildings and/or businesses owned or operated by the tribe or tribal members; 2) impacts on the affordability, availability and reliability of services provided to tribal members by utilities; and 3) potential impacts from proposed construction of utility infrastructure on or near tribal property or property containing tribal cultural resources. Tribes may also experience impacts from electricity outages, or de-energizing of power lines during hazardous weather conditions.

Facilitating Tribal Government Participation:

1. The CPUC will encourage and facilitate tribal government participation in its programs and proceedings.

    a. Tribal governments may contact the CPUC's Tribal Liaison for assistance to initiate participation in a proceeding or consultation with CPUC staff or decision-makers. If a tribe identifies a specific issue for consultation with the CPUC, the Tribal Liaison will identify the appropriate Commission staff and/or decision-makers to participate in the discussions and ensure that the matter receives appropriate consideration.

    b. The CPUC will give special consideration to tribal governments' requests to participate in Commission proceedings. Administrative law judges and Commissioners are encouraged to grant a tribal government's request to become a party in a proceeding, even if a request is untimely, if the proceeding can continue under the existing schedule, or if it is reasonable to modify the schedule and consistent with principles of due process.

    c. Commission staff will assist tribal governments in locating relevant information and documents that will help them participate in Commission proceedings and/or Commission-approved programs. If necessary, Commission staff will send the relevant information or documents to a tribal government electronically or by regular mail.

    d. Commissioners and their advisors will make every effort to grant tribal governments' requests for in person meetings with decision-makers, consistent with the applicable law regarding ex parte communications, and the equal time requirements.[2] Other Commission staff will also accommodate tribal governments' request for in person meetings, whenever possible.

    e. When Commissioners travel to different cities for public meetings, they will seek to arrange separate meetings with local tribal governments, as time allows.

    f. Commission staff and Administrative Law Judges shall make efforts to ensure that relevant information the Commission receives from a tribal government is submitted into the record of a proceeding, consistent with the confidentiality provisions of this policy set forth below. Where a tribal government has submitted written comments in a proceeding, the decision shall explain the tribe's concerns and how they are addressed. Where the

[2] Public Utilities Code § 1701.3(h)(3).

CPUC is unable to fully address the tribe's concerns, the CPUC shall clearly explain the legal, practical, or policy considerations underlying its decision.

g. The Commission will make efforts to ensure that tribal governments are aware of Commission- managed grant programs (such as the CA Advanced Services Fund), and various Commission- approved utility incentive and subsidy programs offered by the utilities, especially those that target disadvantaged and/or remote communities. The CPUC's Tribal Liaison will offer informational materials and meetings for tribal governments on these various programs, if requested.

h. Where feasible, Commission staff will provide assistance so that tribal governments and tribal members may seek to participate in (or benefit from) grant programs implemented by the Commission and various Commission-approved incentive and subsidy programs offered by the utilities. The CPUC Tribal Liaison will offer assistance to navigate the application process.

2. In its role as a member of the Pacific Forest and Watershed Lands Stewardship Council, the Commission will encourage prioritizing donation of Pacific Gas & Electric Company property to tribal governments and, where possible, facilitate those donations.

3. In the event that a tribal government believes that consultation has not met the standards set forth in this Policy, it may submit a written letter to the Executive Director of the CPUC explaining the deficiencies. Within 30 days, the Executive Director will either meet with the tribal government, or respond in writing, and will then direct any further consultation that he or she believes is appropriate.

Confidentiality:

- The Commission recognizes that confidentiality of information regarding tribal cultural resources, history, traditions, religious activities and sites, and other matters is important to tribal governments and tribal members.
- The Commission will follow existing laws that protect confidentiality of tribal cultural resources (including Pub. Res. Code §§§ 5097.9, 5097.933 and 21082.3(c); Government Code § 6254(r) and Cal.Code Regs., tit. 14, § 15120(d)).
- The Commission will not include any information provided by a tribal government in environmental documents, or documents it files in proceedings, if it is deemed confidential by the tribal government. The tribal government shall notify the CPUC if any information it provides is confidential, and mark any such documents as confidential.
- If appropriate, the CPUC will work with tribes to enter into a non-disclosure agreement for documents transmitted to the CPUC that contain confidential information.

- If confidential information regarding the presence of tribal cultural resources is relevant to a Commission decision, the Commission will work with the tribal government to reach agreement on how to proceed, in an effort to allow the decision-makers to consider the information, while also protecting its confidentiality.

Tribal Consultation Under CEQA:

For projects where the CPUC is the lead agency under CEQA, the CPUC will comply with the statutory requirements regarding tribal consultation enacted by AB 52 (Gatto, 2014) (Pub. Res. Code §§ 21080.3 *et seq*.). The CPUC may also consult the Governor's Office of Planning and Research *Technical Advisory: AB 52 and Tribal Cultural Resources in CEQA* (June 2017).

Summary of CEQA Consultation Process:

- A tribal government may request CEQA consultation if it is traditionally and culturally affiliated with the geographic area of a proposed project.
- The consultation must take place prior to the release of a negative declaration, mitigated negative declaration, or environmental impact report. (Pub. Res. Code § 21080.3.1(a)). Since the initial consultation occurs early in the agency's CEQA review process (see below under Timing of Consultation), the consultation will occur before the CPUC's release of a draft or proposed negative declaration, mitigated declaration, or environmental impact report.
- The consultation must address alternatives to the project, recommended mitigation measures, or significant effects, if requested by the tribe. (Pub. Res. Code § 21080.3.2(a)).
- If the agency determines that a project may cause a substantial adverse change to tribal cultural resources, the agency must consider mitigation measures. The agency must "when feasible, avoid damaging effects to any Tribal cultural resource." (Pub. Res. Code 21084.3(a)). The statute describes mitigation measures that the agency may adopt, if feasible, to avoid or minimize the impacts. (Pub. Res. § 21084.3(b)).
- The consultation concludes when either 1) the parties agree on measures to recommend to mitigate or avoid a significant effect, if one exists, on a tribal cultural resource (Pub. Res. Code § 21082.3(a)), or 2) a party, acting in good faith and after reasonable effort, concludes that mutual agreement cannot be reached. (Pub. Res. Code § 21080.2.2(b)).

In 2016, Appendix G of the CEQA Guidelines was amended to implement AB 52. The Environmental Checklist in Appendix G of the CEQA Guidelines now directs lead agencies to address tribal cultural resources in Question #11: "Have California Native American tribes traditionally and culturally affiliated with the project area requested consultation pursuant to Public Resources Code section 20180.3? If so, has consultation begun?" Appendix G of the Guidelines also directs the lead agency to identify whether the project would cause a substantial adverse change in the significance of a tribal cultural resource that is: listed or

eligible for listing in the California Register of Historical Resources; is listed in a local register of historical resources; or that is significant pursuant to the criteria in Public Resources Code § 5024.1(c) (CEQA Guidelines, Section XVII).

Advance Request for Notice of Projects:

- Pursuant to AB 52, a tribe may inform agencies in advance that it would like notice of projects subject to CEQA that are seeking the agency's approval and that are within the tribe's traditionally and culturally affiliated area.
- The CPUC's website has a form has a form letter that tribal governments may submit to the CPUC requesting advance notice of CEQA projects in its area. See: http://www.cpuc.ca.gov/tribal/.

Timing of Consultation: The CPUC will follow the statutory deadlines for tribal consultation under CEQA, which generally require the following:

- When a tribe has requested notice of CEQA projects, the CPUC must provide written notice to that tribe of a project in its area, within 14 days of determining that the project application is complete.
- A tribe may request to engage in consultation within 30 days of receipt of the notice, and designate a lead contact person.
- The CPUC will begin the consultation process within 30 days of receipt of the request for consultation.
    - The CPUC will hold a consultation meeting at one of the CPUC offices (in Sacramento, San Francisco or Los Angeles) or at a tribal government office within 30 days.
    - If a meeting at a Commission office is not feasible for the tribal government, the consultation may occur at a mutually agreeable alternative location or by telephone.
    - If the tribe requests that the consultation be scheduled for a time after the 30 day period, the CPUC will accommodate the request.
- The CPUC will participate in additional consultation meetings as necessary to address the issues and work in good faith to reach an agreement with the tribal government on recommendations for project modifications or mitigation measures.
- The CPUC will honor a tribe's request for CEQA consultation that is made more than 30 days after the tribe's receipt of notice, as long as there is still time for meaningful consultation to occur.

Other Situations:

When a tribe has not requested advance notice of all CEQA projects from the CPUC, if the Commission is the lead agency, a request will be made to the Native American Heritage Commission to identify tribal entities interested in the project area. Commission staff will ensure that the identified tribal entities receive written notice of a proposed project in their area at the beginning of the environmental review process. The Commission will carefully consider all tribal government comments regarding potential impacts on tribal cultural resources and suggested mitigation measures.

California Public Utilities Commission
Draft Enforcement Policy

I. INTRODUCTION

A. Background

The California Public Utilities Commission (Commission) regulates a broad array of entities and industries, that include privately owned electric, natural gas, telecommunications, water, railroad, rail transit, and passenger transportation entities (regulated entities). The Public Utilities Act (Public Utilities Code § 201 et. seq.) requires the Commission to enforce the laws affecting regulated entities by promptly investigating and prosecuting alleged violations and imposing appropriate penalties.

The Commission considered its existing enforcement policies and practices when developing this Commission Enforcement Policy (Policy). Nothing in this policy document shall be used as the basis of a regulated entities' defense to any enforcement action or as justification for any ratemaking relief, nor in any way relieve regulated entities of any duties and obligations they may have under statutory law.

This Policy does not apply to any violation that, as of the effective date of the Policy, is the subject of a citation, an Order to Show Cause, an Order Instituting Investigation, or a referral to the Legal Division for the filing of a civil or criminal action.

B. Policy Objectives

The goals of the Policy are to promote maximum compliance with Commission rules and requirements through the adoption and application of consistent enforcement practices and to develop a sufficient record that ensures that regulated entities subject to an enforcement action receive due process (e.g., notice and an opportunity to be heard). The purpose of these goals is to ensure that regulated entities provide services and facilities to the public in a manner that is safe, reliable, non-discriminatory and just, and reasonable. The Commission intends for this Policy to promote a consistent approach among Commission staff[1] to enforcement actions, to make enforcement a high priority, and to promote the Commission's enforcement culture.

[1] As used in this Policy the term "staff" refers to division staff or such other staff as may be designated by the Executive Director or a Deputy Executive Director to carry out the functions involved in taking enforcement action.

The Policy provides guidance on:

1. Achieving a consistent approach to enforcement;
2. Enforcement actions;
3. Settlements; and
4. Setting penalties

C. Policy Components

Guiding Principles

The Commission's enforcement actions will be guided by a standard set of principles, as described in this Policy, within its jurisdictional authority for energy, communications, water, and transportation.

Division Specific Enforcement Teams

This Policy creates division-specific enforcement teams made up of staff handling enforcement work. Among other activities, staff will prioritize enforcement cases, recommend appropriate enforcement actions, and ensure that enforcement activities are monitored and documented and that enforcement actions are made public to the extent possible.

Commission Enforcement Team

The Policy also creates a Commission Enforcement Team made up of at least one enforcement liaison from each division. The enforcement liaisons shall meet at least quarterly to discuss enforcement matters and procedures with the goal of promoting consistency and efficiency throughout the Commission.

Consistent Enforcement Actions

To provide a consistent approach to enforcement, the Policy standardizes enforcement documents and procedures to the extent appropriate.

II. Guiding Principles

A. Ensuring Compliance

The Commission will strive to ensure compliance with statutes, rules, orders and other requirements and provide a meaningful deterrent to violations through its enforcement actions.

B. Consistent Enforcement

Commission enforcement actions shall be consistent, while considering the differences in the Commission's statutory authority and programs for each particular industry. The Commission's enforcement actions shall be appropriate for each type of violation and shall provide consistent treatment for violations that are similar in nature and have similar safety and/or customer protection impacts. Enforcement actions shall also require a timely return to compliance.

C. Firm Enforcement & Meaningful Deterrence

Enforcement actions should provide a meaningful deterrent to non-compliance. This requires, at a minimum, that the Commission seek adequate remedies, including:

1. Refunding or depriving the economic benefit gained by the noncompliance;
2. Penalties that are higher than the amounts required to be refunded or deprived. In setting the penalty amount, Staff shall be guided by statute and the factors in Appendix I, Penalty Assessment Methodology, which include:
    a. Severity or gravity of the offense (including physical harm, economic harm, harm to the regulatory process, and the number and scope of the violations);
    b. Conduct of the utility (including the regulated entity's prior history of violations and actions to prevent, detect, disclose, and rectify a violation);
    c. The financial resources of the regulated entity (including the size of the business, need for deterrence, and constitutional limitations on excessive fines);

d. The totality of the circumstances in furtherance of the public interest; and

e. The role of precedent.

D. Timely Enforcement

The Commission shall pursue timely enforcement, consistent with the needs of each case.

E. Progressive Enforcement

The Commission shall implement progressive enforcement. Progressive enforcement is an important component of consistent and firm enforcement. Progressive enforcement provides an escalating series of actions, beginning with actions such as a warning letter or notification of violation followed by actions that compel compliance and may result in the imposition of penalties or fines (e.g., the issuance of an enforcement order or filing a civil or criminal action). Progressive enforcement may not be an appropriate enforcement response when violations result from intentional or grossly negligent misconduct, where the impacts on ratepayers or other consumers are widespread, or where impacts to safety are significant.

F. Transparency

The Commission shall provide clear and consistent information about its enforcement actions and which entities it regulates. The Commission will monitor and report its enforcement actions in a publicly accessible way, including the extent to which regulated entities return to compliance.

G. Environmental Justice and Disadvantaged Communities

The Commission shall promote enforcement of all statutes within its jurisdictions in a manner that ensures the fair treatment of people of all races, cultures, and income levels, including minority and low-income populations in the state. This includes tailoring enforcement responses to address the needs of vulnerable and disadvantaged communities.

H. Adaptive Management

The Commission shall continuously monitor and update its enforcement tools, programs and authorities to ensure that they remain protective of customers,

ratepayers, and the environment. This includes keeping abreast of new markets, business practices, and consumer abuses that might necessitate changes to the enforcement program and authorities. The Commission will prioritize regular communication among divisions to identify both specific violations and trends.

The Commission should address new consumer issues as they arise. In instances where the Commission lacks jurisdiction, the Commission will work proactively to identify the appropriate local, state, or federal agency that does have jurisdiction and will work with that agency to remedy the harm to consumers.

I. Enforcement Prioritization

It is the policy of the Commission that every violation should result in an appropriate enforcement action consistent with the priority of the violation. In recognition of its finite resources, the Commission shall exercise its enforcement discretion to prioritize enforcement actions. Enforcement prioritization enhances the Commission's ability to leverage its finite enforcement resources and to achieve the general deterrence needed to encourage the regulated community to anticipate, identify, and correct violations. In prioritizing enforcement actions, the Commission shall consider the impact of violations on vulnerable and disadvantaged communities.

III. Enforcement

In carrying out the Commission's mandate, staff may pursue different levels of enforcement action. In some cases, an enforcement response, such as an oral communication followed by a Warning Letter or Email or a Notice of Violation, will be enough to notify a regulated entity that staff identified an issue or violation that requires corrective action. Other cases may warrant a stronger enforcement action in lieu of, or in addition to, a warning or other initial enforcement response. All enforcement actions shall be designed and implemented to ensure that timely action is taken to avoid or correct a violation and return to compliance.

Division Enforcement Teams

Each division that participates in enforcement work shall establish a Division Enforcement Team. The Division Enforcement Team is made up of the managers or their delegates and an attorney[s] from the Commission's Legal Division. The Division Enforcement Teams shall prioritize division cases for enforcement action to ensure the most efficient and effective use of available

resources. The Division Enforcement Teams shall meet at least quarterly to prioritize enforcement cases, continuously improve enforcement processes and procedures, and make recommendations about how to proceed with cases, including which enforcement action is appropriate for each case. The Division Enforcement Team is also responsible for tracking and publishing information about division cases in an enforcement database.

Commission Enforcement Team

The Commission Enforcement Team is made up of enforcement liaisons from each division that maintains an enforcement team and attorney(s) from the Commission's Legal Division. The enforcement liaisons and attorney(s) shall meet at least quarterly to discuss enforcement matters of statewide concern with the goal of promoting consistency and efficiency throughout the divisions.

A. Enforcement Actions

Staff may pursue the following enforcement actions:[2]

1. In Person or Telephone Communication

a. Staff may, but is not required to, inform regulated entities in person or by telephone of violations that must be corrected. Staff may also orally inform regulated entities of weaknesses, safety concerns, or opportunities for improvement that are not violations but should be corrected to avoid a violation or to reduce safety risk. Staff shall keep a detailed written record of such oral communications with the regulated entity in the case file. The minimum requirements for documenting an oral communication with a regulated entity are:

i. Date and time of the communication;

ii. The name of the staff member[s] and the representative[s] of the regulated entity involved in the communication;

iii. The violation, weakness, safety concern, or opportunity for improvement that was discussed;

iv. Actions for correcting the violation or addressing the weakness, safety concern, or opportunity for improvement that were discussed, including required timeframes for completing such actions;

[2] Nothing in this Policy shall be construed to constrain staff or the Commission from pursuing actions that are otherwise authorized but are not specifically mentioned in the Policy.

v. The regulated entity's response to the communication of the violation, weakness, safety concern, or opportunity for improvement; and

vi. The evaluation of whether the response is sufficient and/or warrants a follow-up investigation.

b. All oral communications shall be memorialized in a warning email or letter, Notice of Violation, or other written communication. Oral communications are not required in every case. Staff may issue a Warning Letter or email, citation, Notice of Violation, or refer a case for other enforcement in lieu of an oral communication.

2. Warning Letter or Email

Staff may send a regulated entity a letter or an email that identifies program weaknesses, safety concerns, or opportunities for improvement. A Warning Letter or Email should only be sent to a regulated entity to address issues that are not being cited as violations but should be corrected to avoid a citation or Notice of Violation or to reduce a safety risk. Staff shall verify delivery of the Warning Letter or Email using a Proof of Service form. A Warning Letter or Email shall be placed in the regulated entity case file and recorded in the enforcement database and shall include the following:

a. The date the letter or email was sent;

b. The date staff identified the situation or condition at issue;

c. The circumstances under which staff identified the situation or condition at issue (e.g., during an inspection or by consumer complaint); and

d. Actions recommended to address the situation or condition at issue, including any recommended timeframes to complete such actions.

3. Request for Information

Staff are authorized to inspect the accounts, books, papers, and documents of a regulated entity. Staff may request the production of accounts, books, papers, and documents of a regulated entity. Failure to make such records available may lead to the issuance of a subpoena or other enforcement action.

4. Subpoena

Staff may subpoena records from a regulated entity as permitted by the Public Utilities Act. Staff may also subpoena the attendance of a person for deposition or other examination under oath as permitted by the Public Utilities Act. The issuance of a subpoena is not a prerequisite for the exercise of Commission authority under Public Utilities Code section 313 or any appropriate powers under the California Constitution and the Public Unities Code.

5. Cease and Desist/Stop Work Order

Commission or staff may issue an order to cease and desist an activity or an order to stop work to a regulated entity consistent with existing Commission decisions and orders and as permitted by the Public Utilities Act. Nothing in this Policy is intended to modify existing procedures concerning such actions, including any right to appeal such actions.

6. Notice of Violation

a. When a violation is identified, staff may issue a Notice of Violation to a regulated entity. Staff shall use a Notice of Violation form. Staff shall verify delivery of the Notice of Violation using a Proof of Service form. A Notice of Violation shall be placed in the regulated entity case file and recorded in the enforcement database and shall include:

    i. The law or Commission order, decision or rule violated by the regulated entity;
    ii. The facts that form the basis for each violation;
    iii. Information related to the potential for additional or ongoing violations;
    iv. A directive to correct each violation to avoid additional enforcement action;
    v. A date by which the regulated entity must submit a plan for correcting each violation if a plan is appropriate;
    vi. A date by which the regulated entity must certify that each violation has been corrected;

vii. A penalty amount if the Notice of Violation includes a penalty;[3]

viii. Staff contact information; and

ix. Information about how to respond to the Notice of Violation.

b. A regulated entity that receives a Notice of Violation shall be given an opportunity to respond in writing to that Notice of Violation. The response shall be provided to the enforcing division within 30 days[4] from the date the Notice of Violation was served upon the regulated entity. The response time may be extended or shortened by staff, depending on the exigencies of a case. The response shall include:

i. If the regulated entity disputes that a violation has occurred, a statement of the facts upon which the dispute is based;

ii. A plan to correct any undisputed violations;

iii. Confirmation that the regulated entity will correct any undisputed violations by the date(s) specified in the Notice of Violation or a proposal for a later date with an explanation of the need for additional time; and

iv. Confirmation that a penalty assessed will be paid within 30 days of the issuance of the Notice of Violation or a proposal for a lower penalty amount with an explanation of why the lower amount is appropriate.

c. Staff shall review the regulated entity's response to a Notice of Violation and consider the regulated entity's explanation or defenses. Staff shall determine whether to accept the response or proceed with additional enforcement. The reasons for a determination that the regulated entity's explanation or defenses lack merit should be included in the regulated entity case file. After

[3] Staff may decide that violations that are "administrative" in nature do not warrant the imposition of a penalty given the facts known at the time. Administrative violations do not involve immediate safety implications. Examples of "administrative" violations include: Inadvertent omissions or deficiencies in recordkeeping that do not prevent staff from determining compliance; records not physically available at the time of the inspection, provided the records exist and can be produced in a reasonable amount of time; and inadvertent violations of insignificant administrative provisions that do not involve a significant threat to human health, safety, welfare, or the environment. A recurring "administrative" violation may warrant a penalty.

[4] When referred to in this policy, "days" means calendar days.

reviewing the response, staff may take any appropriate action including any of the following actions:

i. Send the regulated entity a draft Proposed Administrative Consent Order and negotiate a proposed settlement for Commission review;

ii. Request that the regulated entity provide additional information; or

iii. Take the next appropriate enforcement action.

7. Administrative Consent Order

a. A negotiated proposed settlement shall be memorialized in a proposed Administrative Consent Order, prepared using an Administrative Consent Order form. The proposed Administrative Consent Order shall become final upon review and approval by the Commission. All proposed and final Administrative Consent Orders shall be placed in the regulated entity case file and recorded in the enforcement database and shall include:

i. The law or Commission order, resolution, decision, or rule violated by the regulated entity;

ii. The facts that form the basis for each violation;

iii. The number of violations, including the dates on which violations occurred;

iv. Information related to the potential for additional or ongoing violations;

v. An agreement by the regulated entity to correct each violation;

vi. A date by which the regulated entity must certify it corrected all violations;

vii. An agreement by the regulated entity to pay any penalty by a date specified.

b. The Commission's Executive Director shall designate Commission management at the Deputy Director level or higher (or designee) to negotiate a proposed Administrative Consent Order.

c. If a regulated entity does not respond to a Notice of Violation within the required time frame, or if a proposed Administrative Consent Order is not negotiated, staff shall take the next appropriate enforcement action.

8. Citation and Compliance Programs

a. If staff discover a violation that can be addressed under an existing Citation and Compliance Program, staff shall determine whether to issue a citation as allowed under the Citation and Compliance Program or take a different enforcement action. Factors to consider in determining whether a different enforcement action is appropriate include, but are not limited to:

   i. Whether more flexibility in determining the penalty is appropriate for the circumstances, including whether the appropriate penalty is lesser or greater than the administrative limit imposed by the Citation and Compliance program (the remaining factors below may be relevant to this determination);
   ii. The culpability of the regulated entity – e.g., whether the violation was negligent, knowing, willful, or intentional;
   iii. Whether the regulated entity benefitted economically from noncompliance, either by realizing avoided or reduced costs or by gaining an unfair competitive advantage;
   iv. Whether violations are chronic, or the regulated entity is recalcitrant;
   v. Whether violations can be corrected within 30 days;
   vi. Whether the actual or potential harm from a violation is substantial;
   vii. Whether the case warrants specific corrective action requirements that cannot be included in a citation; and
   viii. Whether the case warrants a recommendation for an Order Instituting Investigation and/or civil or criminal action.

b. If staff discover a violation that cannot be addressed through a pre-existing Citation and Compliance program, staff should take the next appropriate enforcement action.

c. Prescriptive and Proscriptive Requirements – All requirements (including, but not limited to, complaint procedures, an action or failure to act identified as a violation in a Citation and Compliance

Program, and requirements to report actual or potential violations to any entity, e.g. local authorities or the Commission), that are otherwise applicable to a regulated entity shall continue to apply and remain enforceable, regardless of whether staff choose to issue a citation for a violation under a Citation and Compliance Program or pursue a different enforcement action.

9. Administrative Enforcement Order

a. Staff may issue a proposed Administrative Enforcement Order to a regulated entity, prepared using an Administrative Enforcement Order form. Staff shall verify delivery of the proposed Administrative Enforcement Order to the regulated entity using a Proof of Service form. Proposed Administrative Enforcement Orders shall be placed in the regulated entity case file and recorded in the enforcement database and shall include:

   i. The law or Commission order, resolution, decision, or rule violated by the regulated entity;
   ii. The facts that form the basis for each violation;
   iii. The number of violations, including the dates on which violations occurred;
   iv. Information related to the potential for additional or ongoing violations;
   v. A directive to correct each violation;
   vi. A date by which the regulated entity must certify that it corrected all violations;
   vii. A directive to pay a penalty by a date specified;
   viii. Staff contact information; and
   ix. Information about how to request a hearing on the proposed Administrative Enforcement Order.

b. The Commission's Executive Director shall designate Commission management at the Deputy Director level or higher (or designee) to transmit a proposed Administrative Enforcement Order to a regulated entity.

c. The regulated entity may request a hearing on the proposed Administrative Enforcement Order by filing a Request for Hearing

form within 30 days of the date the proposed order is served on the entity. The right to a hearing is forfeited if a Request for Hearing is not timely filed. If a timely Request for Hearing is not filed, the proposed Administrative Enforcement Order shall become final upon adoption by the Commission. Corrective action requirements in a proposed Administrative Enforcement Order remain in effect, notwithstanding the filing of a Request for Hearing. Neither payment of the penalty nor filing a timely Request for Hearing shall excuse the regulated entity from curing a violation. The hearing shall be conducted by an ALJ in accordance with the hearing provisions in the Citation Appellate Rules. A draft ALJ resolution approved by the Commission is subject to rehearing pursuant to Public Utilities Code section 1731 and to judicial review pursuant to Public Utilities Code section 1756. The amount of the penalty shall continue to accrue on a daily basis until the violation is corrected or until the appeal, rehearing, and judicial review process is fully concluded, a penalty is found to be appropriate, and the penalty is paid in full. The requirement that a penalty be paid shall be stayed during the hearing and rehearing process. Interest may be charged on unpaid balances and staff may take whatever actions are provided by law to recover unpaid penalties.

10. Order Instituting Investigation

Staff may recommend that the Commission issue an Order Instituting Investigation. Factors that may be considered in determining whether to recommend an Order Instituting Investigation include, but are not limited to:

a. The appropriate penalty for the case exceeds limits set by resolution or decision;
b. The matter is complex;
c. The violations caused fatalities, substantial injuries, and/or involved significant property damage in a widespread area;
d. The matter includes allegations of fraud or knowing, intentional or willful behavior;
e. The regulated entity's potential explanation or defenses; and
f. The entity has repeatedly violated the law or Commission rules and orders.

11. Order to Show Cause

Staff may recommend that the Commission issue an Order to Show Cause - an order that requires a regulated entity to show cause why a specified Commission action should not be taken. In deciding whether to recommend that the Commission issue an Order to Show Cause, Staff shall consider:

a. Whether the regulated entity failed to comply with a Commission order, general order, ruling, rule, data request, or statute; and
b. If the regulated entity failed to comply, whether the failure is a Rule 1.1 violation, a violation of Public Utilities Code section 2107, or its actions meet the criteria for a finding of contempt.

12. Suspension, Alteration, Amendment, and Revocation/Receivership

Commission or staff may suspend, alter, amend, or revoke the license or certification of a regulated entity consistent with existing Commission decisions and orders and as permitted by the Public Utilities Act. Nothing in this Policy is intended to modify existing procedures concerning such actions, including any right to appeal such actions.

13. Civil or Criminal Action

Staff may request that the Commission refer the matter to the Legal Division for the filing of a civil or criminal action, including requests for injunctive relief. Factors staff may consider in determining whether to refer the matter for civil or criminal action include, but are not limited to:

a. The matter includes allegations of criminal behavior;
b. Any of the factors for recommending an Order Instituting Investigation exist; or
c. Referral is appropriate given resource availability.

14. Referral to or from Another Agency

In some circumstances it may be appropriate to refer a case to another local, state or federal agency for consideration of enforcement action. If another agency refers a case to the CPUC,

enforcement actions considered and/or taken will be in accordance with this Policy.

B. Settlement of Enforcement Actions

The Policy does not list the full range of considerations that may be relevant to negotiating a proposed settlement. However, the following general considerations should be evaluated as part of any proposed settlement to be submitted for Commission review:

1. Equitable factors;
2. Mitigating circumstances;
3. Evidentiary issues; and
4. Other weaknesses in the enforcement action that the division reasonably believes may adversely affect the ability to obtain the calculated penalty.

C. Penalties

The Commission and staff that choose not to take enforcement action under a Citation and Compliance Program, shall calculate an appropriate penalty using the methodology set forth in Appendix I (Penalty Assessment Methodology).

D. Monitoring Compliance with Orders, Decisions, and Resolutions

Staff is responsible for monitoring compliance with all final orders (including administrative consent orders), decisions, and resolutions. Staff shall document compliance in the enforcement database and the regulated entity's case file.

Appendix I
Draft Penalty Assessment Methodology

When a regulated entity violates the Public Utilities Act or Commission rules, decisions, or orders, Commission staff may propose, and the Commission may assess a penalty against the regulated entity. The penalty amount for each violation may be proposed or assessed at an amount that is within the statutory range authorized by the Public Utilities Act. This Penalty Assessment Methodology sets forth the factors that staff and the Commission must consider in determining the amount of a penalty for each violation. The factors are consistent with those that the Commission previously adopted and has historically relied upon in assessing penalties and restates them in a manner that will form the analytical foundation for future decisions that assess penalties.

The purpose of a penalty is to go beyond restitution to the victim and to effectively deter further violations by the perpetrator or others. Effective deterrence creates an incentive for regulated entities to avoid violations. Deterrence is particularly important against violations that could result in public harm and other severe consequences. The following factors shall be used in setting penalties that are appropriate to a violation:

I. Severity or Gravity of the Offense

The evaluation of the severity or gravity of the offense includes several considerations:

- Economic harm to victims
- Physical harm to people or property
- Threatened physical harm to people or property
- Harm to the integrity of the regulatory processes, including disregarding a statutory or Commission directive
- The number of violations
- The number of consumers affected

Economic harm reflects the amount of expense that was imposed upon victims. In comparison, violations that cause actual physical harm to people or property are generally considered the most severe, followed by violations that threaten such harm. The fact that the economic harm may be difficult to quantify does

not itself diminish the severity or the need for sanctions. For example, the Commission has recognized that deprivation of choice of service providers, while not necessarily imposing quantifiable economic harm, diminishes the competitive marketplace and warrants some form of sanction.

Many potential penalty cases do not involve any harm to consumers but are instead violations of reporting or compliance requirements. Such violations harm the integrity of the regulatory processes. For example, state law requires all California public utilities to comply with Commission directives:

> "Every public utility shall obey and comply with every order, decision, direction, or rule made or prescribed by the Commission in the matters specified in this part, or any other matter in any way relating to or affecting its business as a public utility, and shall do everything necessary or proper to secure compliance therewith by all of its officers, agents, and employees." (Public Utilities Code § 702).

Such compliance is essential to the proper functioning of the regulatory process. For this reason, disregarding a statutory or Commission directive, regardless of the effects on the public, will be accorded a high level of severity.

The number of the violations is a factor in determining the severity. A series of temporally distinct violations can suggest an on-going compliance deficiency that the regulated entity should have addressed after the first instance. Similarly, a widespread violation which affects a large number of consumers is a more severe offense than one that is limited in scope. For a "continuing offense", Public Utilities Code section 2108 counts each day as a separate offense.

II. Conduct of the Regulated Entity

The evaluation of the conduct of the regulated entity includes several considerations:

- Degree of culpability
- Actions taken to prevent a violation
- Actions taken to detect a violation
- Actions taken to disclose and rectify a violation, including voluntary reporting of potential violations, voluntary removal or resolution efforts

undertaken, and the good faith of the regulated entity in attempting to achieve compliance after notification

- Actions taken to conceal, hide, or coverup a violation
- Prior history of violations

This factor recognizes the important role of the regulated entity's conduct in: (1) preventing the violation, (2) detecting the violation, and (3) disclosing and rectifying the violation. The regulated entity is responsible for the acts of all its officers, agents, and employees:

> "In construing and enforcing the provisions of this part relating to penalties, the act, omission, or failure of any officer, agent, or employee of any public utility, acting within the scope of his [or her] official duties or employment, shall in every case be the act, omission, or failure of such public utility." (Public Utilities Code § 2109).

Prior to a violation occurring, prudent practice requires that all regulated entities take reasonable steps to ensure compliance with Commission directives. This includes becoming familiar with applicable laws and regulations, and most critically, the regulated entity regularly reviewing its own operations to ensure full compliance. In evaluating the regulated entity's advance efforts to ensure compliance, the entity's past record of compliance with Commission directives should be considered.

The Commission expects regulated entities to diligently monitor their activities and operations. When staff determines that regulated entities, for whatever reason, failed to monitor and improve substandard operations, staff will continue to hold the regulated entity responsible for its actions. Deliberate as opposed to inadvertent wrong-doing will be considered an aggravating factor. Staff will also look at the management's conduct during the period in which the violation occurred to ascertain the level and extent of involvement in or tolerance of the offense by management personnel. Staff will closely scrutinize any attempts by management to attribute wrong-doing to rogue employees. Managers will be considered, absent clear evidence to the contrary, to have condoned day-to-day actions by employees and agents under their supervision.

When a regulated entity is aware that a violation has occurred, staff expects the regulated entity to promptly bring it to the attention of Commission staff. The precise timetable that constitutes "prompt" will vary based on the nature of the

violation. Violations that physically endanger the public must be immediately corrected and thereafter reported to the Commission staff. Reporting violations should be remedied at the earliest administratively feasible time.
Prompt reporting of violations and expeditious correction promotes transparency and public trust and furthers the public interest. For this reason, steps taken by a regulated entity to promptly and cooperatively report and correct violations may be considered in assessing any penalty.

III. Financial Resources of the Regulated Entity, Including the Size of the Business

Effective deterrence also requires that staff recognize the financial resources of the regulated entity in setting a penalty that balances the need for deterrence with the constitutional limitations on excessive penalties. Some California regulated entities are among the largest corporations in the United States and others are extremely modest, one-person operations. An accounting rounding error to one company is annual revenue to another. If appropriate, penalty levels will be adjusted to achieve the objective of deterrence, without becoming excessive, based on each regulated entity's financial resources.

IV. Totality of the Circumstances in Furtherance of the Public Interest

An evaluation of the totality of the circumstances in furtherance of the public interest includes several considerations:

- Establishing a penalty that effectively deters further unlawful conduct
- Consideration of facts that tend to mitigate or exacerbate the degree of wrongdoing
- Harm from the perspective of the public interest
- Ensuring that a regulated entity does not have incentives to make economic choices that cause or unduly risk a violation

Setting a penalty at a level that effectively deters further unlawful conduct by the regulated entity and others requires that staff specifically tailor the package of sanctions, including any penalty, to the unique facts of the case. Staff will review facts that tend to mitigate the degree of wrongdoing as well as any facts that exacerbate the wrongdoing. In all cases, the harm will be evaluated from the perspective of the public interest.

An economic benefit amount shall be estimated for every violation. Economic benefit includes any savings or monetary gain derived from the act or omission that constitutes the violation. In cases where the violation occurred because the regulated entity postponed improvements, failed to implement adequate control measures, failed to obtain required Commission authority or did not take other measures needed to prevent the violations, the economic benefit may be substantial. Economic benefit should be calculated as follows:

- Determine those actions required to comply with a permit, decision, or order of the Commission, an enforcement order, or that were necessary in the exercise of reasonable care, to prevent a violation. Needed actions include obtaining regulatory authority or coverage, capital improvements, staff training, plan development, or the introduction of procedures to improve facility management.
- Determine when and/or how often the regulated entity should have taken these actions as specified in the permit, decision, or order, or as necessary to exercise reasonable care, in order to prevent the violation.
- Evaluate the types of actions that the regulated entity should have taken to avoid the violation and estimate the costs of these actions. There are two types of costs that should be considered; delayed costs and avoided costs. Delayed costs include expenditures that should have been made sooner (e.g., for capital improvements such as plant upgrades, training, development of procedures and practices), but that the regulated entity implemented too late to avoid the violation and/or is still obligated to perform. Avoided costs include expenditures for equipment or services that the regulated entity should have incurred to avoid the incident of noncompliance, but that are no longer required. Avoided costs also include ongoing costs such as needed additional staffing from the time the costs should have been incurred to the present.
- Calculate the present value of the economic benefit. The economic benefit is equal to the present value of the avoided costs plus the "interest" on delayed costs. This calculation reflects the fact that the regulated entity has had the use of the money that should have been used to avoid the instance of noncompliance.
- Determine whether the regulated entity gained any other economic benefits. These may include income from unauthorized or unpermitted operations.

The economic benefit should not be adjusted for expenditures by the regulated entity to abate the effects of the unauthorized conduct, or the costs to achieve or return to compliance.
The economic benefit amount should be compared to the penalty amount calculated using the other factors set forth in this appendix.

The penalty amount should be at least 10 percent higher than the economic benefit amount so that regulated entities do not construe penalties as the cost of doing business and that the assessed penalty provides a meaningful deterrent to future violations. Absent express findings of exceptional circumstances or other factors as justice may require, if the penalty amount is lower than the economic benefit amount plus 10 percent, the economic benefit amount plus 10 percent shall be the penalty. It would be unfair to regulated entities that voluntarily incur the costs of regulatory compliance to impose a lower amount absent exceptional circumstances.

V. The Role of Precedent

Penalties are assessed in a wide range of cases. The penalties assessed in cases are not usually directly comparable. Nevertheless, when a case involves reasonably comparable factual circumstances to another case where penalties were assessed, the similarities and differences between the two cases should be considered in setting the penalty amount.

Exhibit 10

Nebraska Department of Environment and Energy
Air Water Land Energy
Nebraska Energy Statistics

Annual Average Electricity Price Comparison by State

Nebraska is the only state that generates electricity entirely by publicly-owned power systems. As of 2019, the statewide average electricity price is the sixteenth-lowest rate in the country, based on the latest federal figures. (States are ranked so that equivalent prices are ranked at the same level.) Nationally, electricity costs 16 percent more than it does in Nebraska. Across all sectors, Hawaii has the highest electricity rate (28.72 cents), and Louisiana has the lowest electricity rate (7.71 cents).

The archive has reports from prior years.

Annual Average Price per Kilowatthour by State
(Lowest to Highest Rate as of 2019)

Rank	State	Average Electricity Rate for All Sectors (Cents per Kilowatthour)
1	Louisiana	7.71
2	Oklahoma	7.86
3	Idaho	7.89
4	Washington	8.04
5	Wyoming	8.10
6	Arkansas	8.22
7	Utah	8.24
8	West Virginia	8.49
9	Texas	8.60
10	Kentucky	8.61
11	Nevada	8.78
12	Oregon	8.81
13	North Dakota	8.85
14	New Mexico	8.99
15	Montana	9.02
16	Nebraska	9.08
16	Iowa	9.08
17	Mississippi	9.28
19	North Carolina	9.45
18	Virginia	9.52
20	Illinois	9.56
21	Ohio	9.58
22	Missouri	9.68
23	Tennessee	9.69

Rank	State	Average Electricity Rate for All Sectors (Cents per Kilowatthour)
24	Pennsylvania	9.81
25	Alabama	9.83
26	Georgia	9.86
27	Indiana	9.91
28	South Dakota	9.96
29	South Carolina	10.02
30	Colorado	10.17
31	Kansas	10.26
32	Minnesota	10.33
33	Florida	10.44
34	Arizona	10.52
34	Delware	10.52
	National Average	10.54
35	Wisconsin	10.66
36	Maryland	11.24
37	Michigan	11.56
38	District of Columbia	12.27
39	New Jersey	13.42
40	Maine	14.04
41	New York	14.34
42	Vermont	15.36
43	California	16.89
44	New Hampshire	17.15
45	Massachusetts	18.40
46	Rhode Island	18.49
47	Connecticut	18.66
48	Alaska	20.22
49	Hawaii	28.72

Sources: ***Electric Sales, Revenue, and Average Price***, Energy Information Administration, Washington, DC. Nebraska Department of Environment and Energy, Lincoln, NE.

Note: States are ranked so that equivalent prices are ranked at the same level.

This table was updated on June 29, 2021.
Typically, there is one year between updates.

Exhibit 11

PUBLIC UTILITIES COMMISSION
505 VAN NESS AVENUE

September 14, 2021

Advice Letter 6204-E, 6204-E-A

Erik Jacobson
Director, Regulatory Relations
Pacific Gas and Electric Company
77 Beale Street, Mail Code B10C
P.O. Box 770000
San Francisco, CA 94177

SUBJECT: Evaluation of Clean Substation Pilot Project Opportunities Pursuant to D.21-01-018.

Dear Mr. Jacobson:

Advice Letter 6204-E, 6204-E-A effective as of September 9, 2021, Per E-5164 ordering paragraphs.

Sincerely,

Edward Randolph

Edward Randolph
Deputy Executive Director for Energy and Climate Policy/
Director, Energy Division

Pacific Gas and Electric Company®

Sidney Bob Dietz II
Director
Regulatory Relations

Pacific Gas and Electric Company
77 Beale St., Mail Code B13U
P.O. Box 770000
San Francisco, CA 94177

Fax: 415-973-3582

June 9, 2021

Advice 6204-E
(Pacific Gas and Electric Company U 39 E)

Public Utilities Commission of the State of California

Subject: **Evaluation of Clean Substation Pilot Project Opportunities Pursuant to D.21-01-018**

I. Purpose

PG&E submits this Advice Letter to: (1) inform the California Public Utilities Commission ("CPUC") of the results of the Request for Proposals for an alternatives to diesel pilot to provide generation support to substations de-energized during Public Safety Power Shutoffs ("PSPS") that have safe-to-energize load; and (2) request approval of a clean substation microgrid project to pilot the use of certain Demand Response ("DR") programs for the purpose of reducing the use of temporary diesel generation at substations during PSPS events, consistent with Decision ("D.") 21-01-018 (the "Decision").[1] For informational purposes, this Advice Letter also describes PG&E's ongoing work to evaluate the use of diesel alternative generation technologies at certain distribution microgrids during 2021.

II. Background and Summary of Request

The Commission initiated Rulemaking ("R.") 19-09-009 to develop a policy framework to facilitate the commercialization of microgrids and related resiliency strategies, and to implement Senate Bill ("SB") 1339 (Stern, 2018).

In Track 1 of the proceeding, the Commission adopted D.20-06-017, ordering short-term actions to accelerate microgrid deployment and related resiliency solutions, including solutions to accelerate interconnection of resiliency projects in advance of the 2020 wildfire season; modernizing existing tariffs to maximize resiliency benefits; solutions to promote collaborative engagement between the utilities and local and tribal governments; and approving an array of resiliency proposals set forth by PG&E and San Diego Gas & Electric Company.

[1] D.21-01-018, App. A, pp. A-4 to A-6 (describing requirements for clean substation microgrid projects).

On January 14, 2021, the Commission adopted the Decision in Track 2 of the proceeding, which, among other items, established a pathway for utilities to reserve temporary generation for 2021 fire season and begin the transition from diesel mobile generation to alternative, cleaner backup power generation. In the Decision, the Commission authorized a utility to track the costs associated with reserving temporary generation in a memorandum account, including diesel as well as other temporary generation technologies, equipment, and services, for the purpose of providing power to the load of safe-to-energize substations during a PSPS outage, under certain conditions.[2] The Decision also authorized the utilities to establish new balancing accounts to recover costs, for among other things, the deployment of approved "clean substation microgrid projects" (sometimes referred to herein as a "Clean Substation Pilot") up to a cap of $350 million per utility.

The Decision required that PG&E submit a Tier 2 Advice Letter to "document [PG&E's] plans to establish clean substation microgrid projects [("Clean Substation Projects")] located at, or able to serve, at least one substation."[3] On March 5, 2021, PG&E submitted a Tier 2 Advice Letter (Advice Letter 6105-E) requesting authority to reserve temporary generation for use at substations in 2021. In the Tier 2 advice letter, PG&E conveyed that it was still evaluating bids for the Clean Substation Pilot and that it would submit one or more Clean Substation Project(s) for review and approval via a future Tier 3 Advice Letter. In a subsequent disposition letter, the CPUC's Energy Division stated that the portions of Advice Letter 6105-E addressing clean substation microgrid projects would be disposed of separately from the request to reserve temporary generation.[4] The Energy Division also stated in that letter that it expected that PG&E would provide additional information regarding clean substation microgrid projects prior to its consideration of an additional disposition.[5]

PG&E is submitting this Tier 3 Advice Letter to address the requirements in the Decision related to clean substation microgrid projects. Specifically, this Advice Letter describes PG&E's efforts to solicit substation-level generation projects, documents the infeasibility of deploying generation alternatives to diesel at substation-level microgrids in 2021 based upon the criteria set forth in the Decision and bids received, describes diesel alternative microgrid pilot projects that PG&E is planning for 2021 at the distribution feeder level, and proposes the expanded use of two existing DR programs as a Clean Substation Microgrid Pilot Project for approval.

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[2] *Id.*, App. A, p. A-1.
[3] *Id.*, App. A, p. A-4.
[4] Disposition Letter from Edward Randolph, CPUC Energy Division, to Erik Jacobson, PG&E, April 14, 2021, p. 1.
[5] *Id.*, p. 7.

III. Analysis of Clean Substation Generation Pilots

A. Summary of Request for Proposals Process

This Section addresses the requirement in the Decision that PG&E document its plans to establish Clean Substation Projects located at, or able to serve, at least one substation[6] and the Request for Proposal ("RFP") evaluation process undertaken by PG&E. The Interim Approach for Reserving Temporary Generation for Safe-to-Energize Substations in 2021 set forth in Appendix A to D.21-01-018 describes two primary goals: Keeping the lights on; and starting the transition to clean temporary generation. With regard to the second goal, the Decision states that the objective is "to increase utility and market experience and understanding of alternatives to diesel generation to facilitate a transition away from diesel in future years."[7] The Decision is technology-agnostic when describing temporary "clean substation microgrid pilots projects" in Section 2 of Appendix A; instead, it sets forth certain cost-effectiveness, operational, and, in certain cases, environmental requirements that must be met by the Clean Substation Pilot Projects. Some of these requirements depend on whether the project is temporary or permanent and on when the project will be operating. For example, the subsection labeled 1.1 on page A-5 of Appendix A sets forth air pollutant emission reduction requirements that must be met by such projects beginning in the 2022 fire season, and it notes that completed permanent projects "must demonstrate a fully renewable microgrid."[8]

PG&E has been actively seeking alternatives to mobile diesel generators for its substation microgrids since it began its Distributed Generation Enabled Microgrid Services ("DGEMS") Program in 2019. More recently, the work included collaboration with ADL Ventures on the relative merits and costs of diesel alternative technologies and "teams" of such technologies, which included both a report submitted into the record of R.19-09-009 and a stakeholder workshop on the report. In anticipation of the need to seek diesel alternatives for the 2021 fire season, PG&E issued a Temporary Generation Request For Information (RFI) on November 3, 2020, and the RFI closed on November 12, 2020. The RFI was broadly distributed to 63 potential vendors. [redacted] of these vendors responded. [redacted] of those vendors indicated they could combine multiple technology types in a single bid, a key attribute of any diesel-alternative pilot. After the close of the RFI, PG&E continued to engage with vendors to discuss potential diesel-alternatives for the 2021 fire season.

Consistent with the requirements in the Decision that PG&E seek at least one Clean Substation Project in 2021, PG&E subsequently issued an all-source Temporary Generation RFP on January 20, 2021, seeking to reserve temporary generation for use

[6] D.21-01-018, App. A, p. A-4.
[7] D.21-01-018, App. A, p. A-1.
[8] *Id.*, p. A-5.

at substations and other temporary generation workstreams for reducing PSPS impacts. Bids in response to the RFP were due on February 3, 2021.

The RFP overview stated: "PG&E is also looking to pilot diesel-alternative generation technologies and welcomes bids for solutions or combinations of solutions including, but not limited to natural gas generators, batteries, and fuel cells, as long as the single technology or combination of technologies meet all of PG&E's operational requirements."[9] Potential vendors were provided with anonymous, site-specific details for three substation sites and three distribution microgrid sites.[10] For each such site, PG&E provided a site description (including load, customer count, and other neighborhood considerations); a load profile; a description of the space constraints and availability; and the availability of pipeline natural gas. PG&E specified that each diesel alternative project is required to be able to serve the substation load for a minimum of 48 hours with a preference for 72 hours.[11] Shortlisted vendors received additional site-specific information. While the solicitation focused on temporary generation, PG&E did indicate it was open to "staged" generation that would remain in one location for the duration of the rental period. This was intended to enable diesel-alternative technologies, which often face mobility hurdles.

59 potential vendors were invited to participate in the all-source 2021 Temporary Generation RFP. [redacted] vendors provided complete bids. [redacted] of these vendors included diesel-alternative generation technology bids for the substation workstream. For the substation workstream, the only diesel-alternative technology bids received were for natural gas-fueled technology paired with battery storage and standalone natural gas technology. In all bids, the primary energy source was natural gas. In bids involving battery storage, battery storage represented less than 1% of the energy needed in a 72-hour event. Bids with natural gas and battery storage used the battery to peak shave and/or minimize engine spinning reserve. PG&E evaluated bids based on a variety of factors, including commercial, pricing, technical, safety, and supply chain responsibility. PG&E compiled a consolidated scorecard for down-selecting to a short-list of suppliers for further negotiations based on the highest scoring suppliers and the capacity information provided to ensure that sufficient supply can be contracted on the most favorable terms. Follow-up conversations with short-listed bidders and negotiations concerning diesel alternatives were ongoing at the time of submission of Advice Letter 6105-E, seeking to reserve conventional temporary generators, but are now complete.

It was PG&E's view throughout the RFP process that while natural gas or natural gas plus storage technologies are still reciprocating engine technologies, they could be used in a Clean Substation Pilot to advance the State's understanding regarding whether and how

[9] *See* Appendix E, Para. 1.1. of PG&E Advice Letter 6105-E.
[10] *See* Appendix F (2021 Substation and Distribution Microgrid Diesel Alternative Pilot Projects) of PG&E Advice Letter 6105-E.
[11] Appendix E, Para. 1.4. of PG&E Advice Letter 6105-E.

the technology can be operationally scaled in these substation use cases and potentially other use cases to reduce or eliminate the reliance on diesel-based generation. However, PG&E ultimately found that a Clean Substation Project utilizing generation alternatives to diesel was infeasible for 2021 given the requirements set forth in the Decision. Instead, PG&E is proposing a demand response-based Clean Substation Project for 2021, as described below. PG&E is also currently exploring deployment of diesel-alternative temporary generation pilots at distribution microgrids[12] for 2021 as part of its effort to implement cleaner solutions for reducing PSPS impacts.

B. Summary of Pilot Site Selection Process

This section summarizes PG&E's process and evaluation criteria for selecting the candidate substation for a Clean Substation Pilot generation project in 2021.

PG&E undertook an analysis of the selection of top dedicated substation candidates for 2021 temporary generation to select a Clean Substation Pilot site. The criteria considered key factors to ensure feasibility and the best chance of meeting requirements set forth in the Decision. PG&E took into consideration the number of events a substation experienced in the 10-year historical lookback[13] and the load of customers expected to be safe to energize at each substation. A preferred candidate would have a strong chance of temporary generation being used during a PSPS event to ensure that the diesel-alternative technology is utilized, but would not be the largest substation served given the pilot nature of these initial projects. PG&E evaluated the space available at each selected substation to install gas, renewables, and battery storage installations that require more room than conventional diesel generators. This included land adjacent to substations that could potentially be leased, and excluded land adjacent to substations that could not reasonably be made ready in time for the 2021 PSPS season. PG&E also considered the distance to potential natural gas fueling sites to ensure reliable fueling of facilities and reduce the challenges of compressed natural gas (CNG) fueling logistics.

Table 1 below summarizes how the substation pilot was selected from the ten selected temporary generation substations. Using this ranking system, the top two Clean

[12] The phrase "distribution microgrid" is used here to describe a microgrid serving customers on a single distribution feeder or portion of a feeder, as opposed to a microgrid serving an entire substation boundary. In the past, PG&E has referred to certain types of distribution microgrids as "Main Street Microgrids" and as "Resilience Zones." The Decision differentiated between substation microgrids and other types of microgrids used for PSPS mitigation and applied the interim framework only to substation microgrids. *See* D.21-01-018, App. A, p. A-1 ("This authorization does not limit or affect in any way the ability of a utility to reserve temporary generation for other purposes, such as providing power to community resource centers or critical facilities during events or serving load during routine grid maintenance, which fall outside the scope of this framework. Throughout the following document, 'temporary generation' refers to this specific use case above, where temporary generation is reserved for energizing safe-to-energize substation load subject to PSPS transmission outages.").

[13] This 10-year historical lookback methodology is described in detail in Advice Letter 6105-E.

Substation Pilot sites were Brunswick and Clear Lake. Given the pilot nature of these projects, Brunswick was not chosen as its peak load is one of the largest of all ten substations. Clear Lake was chosen as its peak load would be a more reasonable test of PG&E's operational ability to deploy a mobile diesel-alternative (e.g., natural gas plus storage or standalone natural gas) installation.

Table 1: Clean Substation Pilot Selection Overview

Substation	Peak Load (MW)	10-Year Lookback Impacts w/ 100+ STE customers	Peak Load per 1000 Feet (MW/1000 ft²)	Distance from CNG Station (Miles)
BRUNSWICK	18	14	0.94[14]	38
CLEAR LAKE	14[15]	13	0.39	74
CLOVERDALE	14	10	0.11	33
HARTLEY	12	12	1.30	65
HOOPA	4	12	0.13	183[16]
KONOCTI	14	10	2.33	73
LOW GAP	1	12	Site Visit Needed[17]	132
PLAINFIELD	23	15	3.43	15
POINT MORETTI	3	10	1.21	47
WILLOWCREEK	6	12	0.11[18]	172

[14] Two-thirds of the area is outside the substation and would require civil work and any associated permits, putting the timeline at risk.
[15] After further subject matter expert review of this location, the peak load was adjusted from the 10 MW stated in PG&E Advice Letter 6105-E to 14 MW in this advice letter.
[16] CNG would need to be stored on-site or at a location equidistant from Hoopa and Willow Creek.
[17] Heavy vegetation and topography make net usable land unknown.
[18] Cell coloring does not include PG&E yard; CNG would need to be stored on-site or at a location equidistant from Hoopa and Willow Creek.

C. Summary of Results

This Section summarizes the bids received by PG&E for Clean Substation Pilot generation projects and its determination not to pursue an alternative to diesel substation pilot in 2021.

As previously mentioned, the only diesel-alternative technology bids for substations received in the 2021 all-source Temporary Generation RFP were for natural gas-fueled paired with battery storage and standalone natural gas technologies. After an evaluation of diesel-alternative bids, PG&E determined that none of the bids met the cost cap requirements set forth in the Decision. The Decision stated that "[t]he cost of the project to ratepayers may not exceed twice the expected cost of utilizing backup diesel generation over the contract period. In total, the cost may not exceed the expected cost of 20 years of diesel rental and operation."[19] Using Tier 4 diesel bids data from the 2021 all-source Temporary Generation RFP, PG&E determined that none of the diesel-alternative bids met this cost requirement. Confidential Attachment 1 provides details of PG&E's cost analysis, including the workpapers underlying the analysis.

Given that none of the developer bids for an alternatives to diesel substation pilot met the cost cap set forth in the Decision, PG&E is not planning to pursue a generation-based clean substation pilot in 2021. PG&E is instead planning to pursue a demand response pilot/use case for substation microgrids.

IV. Proposed Demand Response Clean Substation Microgrid Pilot

A. Summary of Proposal

Although PG&E determined that a generation-based clean substation project is infeasible in 2021, PG&E proposes that the Commission authorize PG&E to test to what extent two existing demand response ("DR") programs that are able to dispatch at the substation level could reduce the use of diesel temporary generation at substations and associated greenhouse gas ("GHG") emissions and criteria pollutants during PSPS events. PG&E proposes that these DR program be triggered under the following conditions: (1) a substation that is both intended to be, and actually is, energized during PSPS via a microgrid; (2) the distribution feeder serving a particular enrolled DR customer or set of customers is safe to energize; and (3) enrolled DR customers fall within the microgrid and safe to energize boundaries.

This pilot will not impact planned procurement for temporary generation at substations in 2021. The intent would be to use lessons learned to explore the expansion of DR as a tool to reduce PSPS mitigation generation costs/emissions in future years.

[19] D.21-01-018, App. A, pp. A-4 to A-5.

B. Description of Base Interruptible (BIP) and SmartAC Programs

In this section, PG&E summarizes the two DR programs that it proposes to utilize for this pilot.

BIP is intended to provide load reduction on PG&E's system on a day-of basis when the California Independent System Operator ("CAISO") issues a curtailment notice. Customers who voluntarily enroll in the program are required to reduce their load down to or below their Firm Service Level ("FSL") when called to do so. Customers are given at least 30 minutes advance notice, and there is a maximum of one event per day and six hours per event. The program includes use limitations, including that there will not be more than 10 events per month, or 180 hours per year. Triggers for calling BIP include: when CAISO has determined that a Stage 1 emergency is imminent; a Stage 1, Stage 2, or Stage 3 emergency; during a transmission system contingency; or when needed based on forecasted system conditions. Customers may enroll directly with PG&E, or customers can sign up with third-party BIP Aggregators. BIP pays a monthly capacity payment, and there is a penalty if the enrolled customer fails to achieve the FSL during a called BIP event. There is no dispatch payment for each event.

SmartAC is a voluntary DR program where a load control device at a customer's premise can temporarily disengage the customer's primary central air-conditioning (A/C) unit or raise the temperature at the thermostat when the device is remotely activated. Smart AC pays a one-time up-front enrollment payment without any ongoing incentives.

C. Basis for Piloting Demand Response Programs at Substations

Utilizing these two existing DR programs for a Clean Substation Microgrid Pilot by authorizing the support of substation-level microgrids during PSPS events as an authorized use case for the programs is a reasonable and practical way to reduce diesel use for the following reasons:

1. **Tariff authority:** Both the BIP and SmartAC tariffs have existing language allowing PG&E to call the resource for reliability and emergency needs. The BIP tariff provides that "PG&E in its sole discretion may dispatch one or more customers to address transmission or distribution reliability needs."[20] Similarly, the SmartAC tariff states that PG&E may dispatch "[d]uring emergency or near-emergency situations."[21] As these programs were developed and designed prior to the consideration of PSPS and substation-level microgrids as a potential use case, PG&E requests Commisison clarification that these existing programs may be

[20] Electric Schedule E-BIP Tariff: https://www.pge.com/tariffs/assets/pdf/tariffbook/ELEC_SCHEDS_E-BIP.pdf

[21] Electric Schedule E-RSAC Tariff. https://www.pge.com/tariffs/assets/pdf/tariffbook/ELEC_SCHEDS_E-RSAC.pdf

dispatched for the PSPS mitigation use case described above. PG&E is therefore seeking a finding through this Advice Letter to clarify that PG&E can dispatch these resources in the narrow circumstances during which they could reduce load that would otherwise be served by backup diesel generation during PSPS outages.

2. **Cost Savings**: Rather than implement a new pilot program, PG&E could utilize existing customers as well as existing infrastructure for communications and dispatch.
3. **Locational dispatch**: PG&E is able to reprogram the dispatch of these resources at the substation level (typically they are dispatched at a broader geographic area for CAISO market purposes) without incurring additional costs.
4. **Potential MW.** As noted in Table 2 below there is a potential of approximately 14 MW in load reduction between the SmartAC and BIP Programs.[22]

Below PG&E summarizes[23] current enrolled DR MW by substation (Table 1), eligible DR MW by substation (Table 2), and number of Service Agreement Identifiers (SAIDs) associated with BIP and Smart AC ("SAC") at the locations (Table 3).

Table 1: Potential Load Reduction (MW) of Enrolled BIP and SmartAC

Substation	BIP	SmartAC	Grand Total
BRUNSWICK	0	0.014	0.014
CLEAR LAKE	0	N/A	0
CLOVERDALE	0	0.018	0.018
HARTLEY	0	N/A	0
HOOPA	0	N/A	0
KONOCTI	0	N/A	0
LOW GAP	0	N/A	0
PLAINFIELD	0	0.080	0.080
POINT MORETTI	[redacted]	N/A	[redacted]
WILLOW CREEK	0	N/A	0
Grand Total	[redacted]	0.112	[redacted]

* SmartAC data only represents areas that will or have already converted from one way to two way Smart AC devices. *Only the Point Moretti substation includes safe to energize and enrolled BIP customers.*

[22] In addition, there is currently room in BIP. The cap on BIP participation is currently set at 494 MW and there are only 183 MW of BIP customers enrolled as of May 13, 2021.

[23] This is a snapshot of all substations based on a February 2021 data for all substations with the exception of Point Moretti, which is a May 2021 snapshot.

Table 2: Potential Load Reduction (MW) of Eligible BIP and SmartAC Customers				
	BIP	BIP	SmartAC	
Substation	Agricultural	Commercial / Industrial	Residential	Grand Total
BRUNSWICK	0	1.235	0.714	1.949
CLEAR LAKE	[redacted]	[redacted]	N/A	[redacted]
CLOVERDALE	0	[redacted]	0.360	[redacted]
HARTLEY	[redacted]	[redacted]	N/A	[redacted]
HOOPA	0	0	N/A	0
KONOCTI	[redacted]	[redacted]	N/A	[redacted]
LOW GAP	0	0	N/A	0
PLAINFIELD	3.333	[redacted]	1.470	[redacted]
POINT MORETTI	[redacted]	0	N/A	[redacted]
WILLOW CREEK	[redacted]	[redacted]	N/A	[redacted]
Grand Total	**3.661**	**4.799**	**2.544**	**11.004**

* BIP potential load reduction is based on the Average Summer Demand from the actual customers.
** * SmartAC data only represents areas that will or have already converted from one way to two way Smart AC devices. Smart AC potential load reduction is based on the estimated average Ex Ante Load Impact kW/Customer by Sub-LAP filing on April 1, 2021 (R.13-09-011) under 1-in-2 weather conditions, assuming that an event would occur at 4 - 9 pm on the PG&E system peak day of the month. Residential Smart AC potential load reduction includes all applicable residential customer excluding medical baseline/life support customers and those not enrolled in another program (e.g., Smart Rate, Capacity Bidding Program, etc.).

Table 3: Total # of Eligible BIP and SmartAC SAIDs				
	BIP	BIP	SmartAC	
Substation	Agricultural	Commercial/ Industrial	Residential	Grand Total
BRUNSWICK	0	15	2,858	2,873
CLEAR LAKE	[redacted]	[redacted]	N/A	[redacted]
CLOVERDALE	0	[redacted]	2,733	[redacted]
HARTLEY	[redacted]	[redacted]	N/A	[redacted]
HOOPA	0	0	N/A	0
KONOCTI	[redacted]	[redacted]	N/A	[redacted]
LOW GAP	0	0	N/A	0
PLAINFIELD	43	[redacted]	5,251	[redacted]
POINT MORETTI	[redacted]	0	N/A	[redacted]
WILLOW CREEK	[redacted]	[redacted]	N/A	[redacted]
Grand Total	**53**	**44**	**10,842**	**10,939**

* Smart AC data only represents areas that will or have already converted from one way to two way Smart AC devices.

The benefits of this Clean Substation Pilot are avoided fuel costs and associated avoided GHG and criteria pollutants. The purpose of this DR Pilot/Use Case is to test the extent to which DR could help lower the amount of diesel used and associated GHG emissions and criteria pollutants. At this time, without BIP customers enrolled or a significant number of Smart AC customers in the area, it is unknown to what extent DR programs may mitigate diesel usage. After this Clean Substation Pilot/Use Case operates, PG&E will be able to calculate the amount of fuel avoided and associated benefits provided in the form of avoided GHG and avoided air emissions associated with standard diesel mobile generator equipment used.

D. Timeline for the DR Clean Substation Pilot Project

As the only change needed to implement this pilot is Commission authorization of the current BIP and Smart AC tariffs for the DR for PSPS use case, the use case could become effective a few weeks after approval of this Advice Letter.

PG&E recommends against trying to establish a new DR program or to establish a new incentive structure within BIP for this use case for 2021 given the delay it would entail related to creating a new program structure, a multiple month recruitment timeline, updated configuration of communications to customers, and billing system upgrades.

For these reasons, PG&E would like to use existing DR programs to lower the amount of temporary generation used during a PSPS event. The existing marketing budget for DR programs as authorized in the DR 2018-2022 Application should be used for marketing, as it would only serve to grow demand response in these substation locations.

E. Compliance with the Clean Substation Microgrid Project Criteria in D.21-01-018.

D.21-01-018, Appendix A, sets forth several criteria that apply to any type of clean substation microgrid project.[24] At a general level, the Decision requires that "[p]roposed projects must be judged technically feasible, safe, and financially competitive by the utility."[25] PG&E has evaluated the proposed DR-based clean substation project and determined that it can be feasibly and safely implemented and that, because it would not require incremental funding beyond the existing DR authorized budget, it is a financially competitive means of transitioning to cleaner substation microgrids to mitigate PSPS outages.

[24] D.21-01-018 also sets forth specific criteria that apply to clean substation microgrid projects utilized beginning in September 2022 and permanent clean substation microgrid projects, but since the proposed Demand Response pilot will be a temporary project used in 2021, these criteria are not applicable and not discussed in this Advice Letter.

[25] D.21-01-018, App. A, p. A-5.

Additionally, D.21-01-018 requires that clean substation microgrid projects meet the following requirements:[26]

a. Design should be capable of islanding for 48 hours.

The use of DR as part of the substation microgrid is not expected to impact the ability of the existing temporary generation-based system to island for at least 48 hours. Any impact of the DR pilot would be to extend the ability of the generators to island the substation by reducing generator fuel consumption and to reduce the fuel usage and associated GHG emissions.

b. Design should be able to black start the substation load.

The use of DR as part of the substation microgrid will not provide black start and is not expected to impact the ability of the existing temporary generation-based system to provide black-start at the substation. While DR program use cases cannot provide black start, any impact by the pilot would reduce black-start loading.

c. Design should meet cold load pickup requirements.

The use of DR as part of the substation microgrid is not expected to impact the ability of the existing temporary generation-based system to meet cold load pickup requirements. Any impact by the pilot would reduce these pickup requirements.

d. Design must meet frequency and frequency response requirements.

The use of DR as part of the substation microgrid is not expected to impact the ability of the existing temporary generation-based system to meet frequency requirements.

e. Design should meet protection requirements or include protection upgrades.

The use of DR as part of the substation microgrid is not expected to impact the ability of the existing temporary generation-based system to meet protection requirements or to require protection upgrades.

f. The cost of the project to ratepayers may not exceed twice the expected cost of utilizing backup diesel generation over the contract period. In total, the cost may not exceed the expected cost of 20 years of diesel rental and operation.

[26] *Id.*

As there is no incremental cost, beyond the existing DR budget authorization, for this Pilot/Use case, it is not expected to exceed twice the expected cost of the diesel generation standing alone.

Additionally, Section 2.5 of Appendix A to D.21-01-018 requires that the "total cost of all [clean substation microgrid projects] over their expected useful life may not exceed $350 million."[27] As there is no incremental cost to this Use Case/Pilot, it will not exceed the $350 million previously authorized.

F. Ratemaking Requirements

D.21-01-018 requires that PG&E submit a Tier 3 advice letter if it intends to seek cost recovery for expenses incurred to develop a clean substation microgrid project.[28] PG&E must also submit a Tier 1 advice letter to modify its electric preliminary statements to create a new Clean Substation Microgrid Program subaccount in its existing Microgrids Balancing Account if PG&E intends to pursue any clean substation microgrid projects.[29] Finally, D.21-01-018 authorized PG&E to allocate the recorded expenditures for an approved clean substation microgrid project to all distribution customers and required PG&E to seek approval for the specific method of cost allocation and recovery via rates as part of this Advice Letter.[30]

These requirements do not apply to the DR-based Clean Substation Pilot because PG&E does not forecast any incremental costs associated with the pilot that would need to be recorded to the Microgrids Balancing Account. Instead, existing DR budget authorization is available to recover the costs of incremental customer recruitment and monthly capacity payments for the BIP. There would be no incremental costs related to use of the SmartAC program since incentives are paid only once at the time of recruitment. PG&E will swap out some of the SmartAC one way switches in these locations for two way switches.

V. Requested Findings

PG&E requests that the Commission issue a Resolution approving this Advice Letter that contains the following findings:

1. PG&E has adequately documented its plans to establish clean substation microgrid projects located at, or able to serve, at least one substation.

[27] D.21-01-018, App. A, p. A-5.
[28] D.21-01-018, p. 120 (OP 15).
[29] *Id.* (OP 16). PG&E submitted Advice Letter 6099-E on February 22, 2021, to establish the Microgrids Balancing Account. Energy Division issued a disposition letter approving the balancing account on April 5, 2021.
[30] *Id.*, p. 121 (OP 17).

2. PG&E has documented the specific conditions that make it infeasible, within the requirements established by D.21-01-018, to undertake a clean substation pilot project utilizing an alternative generation technology to diesel in 2021.

3. The Proposed Demand Response Clean Substation Microgrid Pilot Project is approved as a prudent and reasonable project for deployment in 2021 to start the transition towards diesel alternative substation microgrids.

4. The Proposed Demand Response Clean Substation Microgrid Pilot Project meets all requirements for a clean substation microgrid project set forth in Appendix A, Section I.2, of D.21-01-018.

5. It is reasonable to include within the definition of events that trigger the Base Interruptible Program and the SmartAC demand response programs circumstances in which all of the following are true: (1) a substation that is both intended to be, and actually is, energized during PSPS via a microgrid; (2) the distribution feeder serving a particular enrolled DR customer or set of customers is safe to energize; and (3) enrolled DR customers fall within the microgrid and safe to energize boundaries.

6. PG&E may use the marketing and outreach budget approved in Decision 18-11-029 for purpose of recruiting customers for the Demand Response Clean Substation Microgrid Pilot Project.

7. It is reasonable for PG&E to use the existing authorized funding for BIP to make incremental monthly capacity payments associated with the use of BIP for the Demand Response Clean Substation Microgrid Pilot Project.

VI. Confidentiality Treatment

In support of this Advice Letter, PG&E has provided confidential information within and in the confidential appendices listed below. Pursuant to General Order 66-D and Public Utilities Code 583, PG&E requests confidential treatment for portions of this Advice Letter and the confidential appendices . A separate Declaration Seeking Confidential Treatment is being submitted concurrently with this Advice Letter.

Confidential Appendices

Confidential Attachment 1: Summary of Diesel Alternative Bids and Evaluation Process, and Workpapers Underlying the Cost Analysis of Diesel Alternative Bids

VII. Protests

*****Due to the COVID-19 pandemic, PG&E is currently unable to receive protests or comments to this advice letter via U.S. mail or fax. Please submit protests or comments to this advice letter to EDTariffUnit@cpuc.ca.gov andPGETariffs@pge.com*****

Anyone wishing to protest this submittal may do so by letter sent via U.S. mail, facsimile, or E-mail, no later than **June 29, 2021**, which is 20 days after the date of this submittal. Protests must be submitted to:

CPUC Energy Division
ED Tariff Unit
505 Van Ness Avenue, 4th Floor
San Francisco, California 94102

Facsimile: (415) 703-2200
E-mail: EDTariffUnit@cpuc.ca.gov

Copies of protests also should be mailed to the attention of the Director, Energy Division, Room 4004, at the address shown above.

The protest shall also be sent to PG&E either via E-mail or U.S. mail (and by facsimile, if possible) at the address shown below on the same date it is mailed or delivered to the Commission:

Sidney Bob Dietz II
Director, Regulatory Relations
c/o Megan Lawson
Pacific Gas and Electric Company
77 Beale Street, Mail Code B13U
P.O. Box 770000
San Francisco, California 94177

Facsimile: (415) 973-3582
E-mail: PGETariffs@pge.com

Any person (including individuals, groups, or organizations) may protest or respond to an advice letter (General Order 96-B, Section 7.4). The protest shall contain the following information: specification of the advice letter protested; grounds for the protest; supporting factual information or legal argument; name, telephone number, postal address, and (where appropriate) e-mail address of the protestant; and statement that the protest was sent to the utility no later than the day on which the protest was submitted to the reviewing Industry Division (General Order 96-B, Section 3.11).

VIII. Effective Date

In order to launch the Demand Response Clean Substation Microgrid Project for use in the 2021 fire season, PG&E requests that the Commission issue a final resolution approving this advice letter by no later than **August 19, 2021**.

IX. Notice

In accordance with General Order 96-B, Section IV, a copy of this Advice Letter is being sent electronically and via U.S. mail to parties shown on the attached list and the parties on the service lists **R.19-09-009, R.18-10-007 and A.17-01-012**. Address changes to the General Order 96-B service list should be directed to PG&E at email address PGETariffs@pge.com. For changes to any other service list, please contact the Commission's Process Office at (415) 703-2021 or at Process_Office@cpuc.ca.gov. Send all electronic approvals to PGETariffs@pge.com. Advice letter submittals can also be accessed electronically at: http://www.pge.com/tariffs/.

/S/
Sidney Bob Dietz II
Director, Regulatory Relations

cc: Service Lists R.19-09-009, R.18-10-007 and A.17-01-012

Attachments

California Public Utilities Commission

ADVICE LETTER SUMMARY

ENERGY UTILITY

MUST BE COMPLETED BY UTILITY (Attach additional pages as needed)

Company name/CPUC Utility No.: Pacific Gas and Electric Company (U 39 E)

Utility type:
☑ ELC ☐ GAS ☐ WATER
☐ PLC ☐ HEAT

Contact Person: Stuart Rubio
Phone #: (415) 973-4587
E-mail: PGETariffs@pge.com
E-mail Disposition Notice to: SHR8@pge.com

EXPLANATION OF UTILITY TYPE
ELC = Electric GAS = Gas WATER = Water
PLC = Pipeline HEAT = Heat

(Date Submitted / Received Stamp by CPUC)

Advice Letter (AL) #: 6204-E

Tier Designation: 3

Subject of AL: Evaluation of Clean Substation Pilot Project Opportunities Pursuant to D.21-01-018

Keywords (choose from CPUC listing): Compliance, Demand Side Response

AL Type: ☐ Monthly ☐ Quarterly ☐ Annual ☑ One-Time ☐ Other:

If AL submitted in compliance with a Commission order, indicate relevant Decision/Resolution #:
D.21-01-018

Does AL replace a withdrawn or rejected AL? If so, identify the prior AL: No

Summarize differences between the AL and the prior withdrawn or rejected AL: N/A

Confidential treatment requested? ☑ Yes ☐ No

If yes, specification of confidential information: See Confidential Declaration
Confidential information will be made available to appropriate parties who execute a nondisclosure agreement. Name and contact information to request nondisclosure agreement/ access to confidential information: Quinn Nakayama, 415-973-3732, QJN1@pge.com

Resolution required? ☑ Yes ☐ No

Requested effective date: No. of tariff sheets: 0

Estimated system annual revenue effect (%): N/A

Estimated system average rate effect (%): N/A

When rates are affected by AL, include attachment in AL showing average rate effects on customer classes (residential, small commercial, large C/I, agricultural, lighting).

Tariff schedules affected: N/A

Service affected and changes proposed[1]: N/A

Pending advice letters that revise the same tariff sheets: N/A

[1]Discuss in AL if more space is needed.

Clear Form

	Sidney Bob Dietz II, c/o Megan Lawson Director, Regulatory Relations Pacific Gas and Electric Company 77 Beale Street, Mail Code B13U San Francisco, CA 94177 California 94177 (415)973-2093 (415)973-3582 PGETariffs@pge.com
	District of Columbia

Clear Form

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

DECLARATION SUPPORTING CONFIDENTIAL DESIGNATION
ON BEHALF OF
PACIFIC GAS AND ELECTRIC COMPANY (U 39 E)

1. I, Quinn Nakayama, am the Director of Integrated Grid Planning and Innovation within the Energy Policy and Procurement organization at Pacific Gas and Electric Company ("PG&E"), a California corporation. Fong Wan, the Senior Vice President of Energy Policy and Procurement at PG&E, delegated authority to me to sign this declaration. My business office is located at:

   Pacific Gas and Electric Company
   77 Beale Street
   San Francisco, CA 94105

2. PG&E will produce the information identified in paragraph 3 of this Declaration to the California Public Utilities Commission ("CPUC") or departments within or contractors retained by the CPUC in response to a CPUC audit, data request, proceeding, or other CPUC request.

   Name or Docket No. of CPUC Proceeding (if applicable): R.19-09-009

3. Title and description of document(s): PG&E Advice Letter 6204-E contains confidential information regarding bids submitted into a Request for Offers and customer confidential information pursuant to the Commission's 15/15 Rule established in D.97-10-031 and D.14-05-016. Also, the following attachment submitted in PG&E Advice Letter 6204-E contains confidential information:

   1) Confidential Attachment 1: Summary of Diesel Alternative Bids and Evaluation Process, and Workpapers Underlying the Cost Analysis of Diesel Alternative Bids

4. These documents contain confidential information that, based on my information and belief, has not been publicly disclosed. These documents are marked as confidential, and the basis for confidential treatment and where the confidential information is located on the documents are identified on the following chart.

Check	Basis for Confidential Treatment	Where Confidential Information is located on the documents
☒	Customer-specific data, which may include demand, loads, names, addresses, and billing data (Protected under PUC § 8380; Civ. Code §§ 1798 *et seq.*; Govt. Code § 6254; Public Util. Code § 8380; Decisions (D.) 14-05-016, 04-08-055, 06-12-029)	(1) Certain data fields in Table 1, 2 and 3 of PG&E Advice Letter 6204-E that summarizes number of enrolled BIP customers that are served by certain substations.
☐	Personal information that identifies or describes an individual (including employees), which may include home address or phone number; SSN, driver's license, or passport numbers; education; financial matters; medical or employment history (not including PG&E job titles); and statements attributed to the individual (Protected under Civ. Code §§ 1798 *et seq.;* Govt. Code § 6254; 42 U.S.C. § 1320d-6; and General Order (G.O.) 77-M)	
☐	Physical facility, cyber-security sensitive, or critical energy infrastructure data, including without limitation critical energy infrastructure information (CEII) as defined by the regulations of the Federal Energy Regulatory Commission at 18 C.F.R. § 388.113 (Protected under Govt. Code § 6254(k), (ab); 6 U.S.C. § 131; 6 CFR § 29.2)	
☒	Proprietary and trade secret information or other intellectual property and protected market sensitive/competitive data	(1) Certain data fields in PG&E Advice Letter 6204-E summarizing alternative to diesel

	(Protected under Civ. Code §§3426 *et seq.*; Govt. Code §§ 6254, *et seq*., e.g., 6254(e), 6254(k), 6254.15; Govt. Code § 6276.44; Evid. Code §1060; D.11-01-036)	bids received in a PG&ERFP (2) Confidential Attachment 1: Summary of Diesel Alternative Bids and Evaluation Process, and Workpapers Underlying the Cost Analysis of Diesel Alternative Bids
☐	Corporate financial records (Protected under Govt. Code §§ 6254(k), 6254.15)	
☐	Third-Party information subject to non-disclosure or confidentiality agreements or obligations (Protected under Govt. Code § 6254(k); see, e.g., CPUC D.11-01-036)	
☐	Other categories where disclosure would be against the public interest (Govt. Code § 6255(a))	

5. The importance of maintaining the confidentiality of this information outweighs any public interest in disclosure of this information. This information should be exempt from the public disclosure requirements under the Public Records Act and should be withheld from disclosure.
6. I declare under penalty of perjury that the foregoing is true, correct, and complete to the best of my knowledge.
7. Executed on this 8th day of June, 2021 at Orinda, California.

/s/
Quinn Nakayama
Director – Integrated Grid Planning and Innovation
Energy Policy and Procurement Organization
Pacific Gas and Electric Company

Advice 6204-E
June 9, 2021

Attachment 1

Summary of Diesel Alternative Bids and Evaluation Process, and Workpapers Underlying the Cost Analysis of Diesel Alternative Bids

(Confidential)

PG&E Gas and Electric
Advice Submittal List
General Order 96-B, Section IV

AT&T
Albion Power Company

Alta Power Group, LLC
Anderson & Poole

Atlas ReFuel
BART

Barkovich & Yap, Inc.
California Cotton Ginners & Growers Assn
California Energy Commission

California Hub for Energy Efficiency Financing

California Alternative Energy and Advanced Transportation Financing Authority
California Public Utilities Commission
Calpine

Cameron-Daniel, P.C.
Casner, Steve
Cenergy Power
Center for Biological Diversity

Chevron Pipeline and Power
City of Palo Alto

City of San Jose
Clean Power Research
Coast Economic Consulting
Commercial Energy
Crossborder Energy
Crown Road Energy, LLC
Davis Wright Tremaine LLP
Day Carter Murphy

Dept of General Services
Don Pickett & Associates, Inc.
Douglass & Liddell

East Bay Community Energy Ellison Schneider & Harris LLP Energy Management Service
Engineers and Scientists of California

GenOn Energy, Inc.
Goodin, MacBride, Squeri, Schlotz & Ritchie
Green Power Institute
Hanna & Morton
ICF
IGS Energy
International Power Technology
Intestate Gas Services, Inc.
Kelly Group
Ken Bohn Consulting
Keyes & Fox LLP
Leviton Manufacturing Co., Inc.

Los Angeles County Integrated Waste Management Task Force
MRW & Associates
Manatt Phelps Phillips
Marin Energy Authority
McKenzie & Associates

Modesto Irrigation District
NLine Energy, Inc.
NRG Solar

Office of Ratepayer Advocates
OnGrid Solar
Pacific Gas and Electric Company
Peninsula Clean Energy

Pioneer Community Energy

Redwood Coast Energy Authority
Regulatory & Cogeneration Service, Inc.
SCD Energy Solutions
San Diego Gas & Electric Company

SPURR
San Francisco Water Power and Sewer
Sempra Utilities

Sierra Telephone Company, Inc.
Southern California Edison Company
Southern California Gas Company
Spark Energy
Sun Light & Power
Sunshine Design
Tecogen, Inc.
TerraVerde Renewable Partners
Tiger Natural Gas, Inc.

TransCanada
Utility Cost Management
Utility Power Solutions
Water and Energy Consulting Wellhead Electric Company
Western Manufactured Housing Communities Association (WMA)
Yep Energy

Decision 21-01-018 January 14, 2021

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking Regarding Microgrids Pursuant to Senate Bill 1339 and Resiliency Strategies.	Rulemaking 19-09-009

DECISION ADOPTING RATES, TARIFFS, AND RULES FACILITATING THE COMMERCIALIZATION OF MICROGRIDS PURSUANT TO SENATE BILL 1339 AND RESILIENCY STRATEGIES

be revised.[51] After careful consideration of these requests, we find that these issues are out of scope of this proceeding at this time.

In summary, we direct SCE to file a Tier 2 advice letter within 30 days upon issuance of this decision, to revise its Rule 2 to remove any examples of added or special facilities that might prohibit the construction of microgrids. SCE's Rule 2 revisions should remove any ambiguity that a Rule 2 deviation will be required to construct added or special facilities of microgrids.

3.2. Direct PG&E to Revise Tariff Rule 18, SCE to Revise Tariff Rule 18, and SDG&E to Revise Tariff Rule 19 to Allow Microgrids to Serve Critical Customers on Adjacent Parcels.

Consistent with the Scoping Memo and Ruling,[52] the Administrative Law Judge's Ruling[53] asked parties an array of questions regarding the Staff Proposal's recommendations to direct the IOUs to revise their Rules 18 and 19 to allow microgrids to serve critical customers on adjacent parcels. We summarize the key elements of the Staff Proposal and the parties' positions to it, below.

3.2.1. Staff Proposal Summary

The Staff Proposal recommends that PG&E and SCE revise their respective Rule(s) 18 and SDG&E revise its Rule 19, to allow microgrids to serve critical customers on adjacent parcels.[54] The Staff Proposal reasons Rule 18 and Rule 19 may be a barrier for microgrid commercialization because it limits a microgrid's use and benefit.[55]

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[51] CalSSA Opening Comments at 3; CSEA Opening Comments at 5; and VGIC Opening Comments at 6.

[52] Assigned Commissioner's Amended Scoping Memo and Ruling, July 3, 2020.

[53] Administrative Law Judge's Ruling, July 23, 2020.

[54] Administrative Law Judge's Ruling, July 23, 2020, Attachment 1 – Staff Proposal at page 8-9.

[55] *Id.*

3.3. Direct the IOUs to Form a New Microgrid Tariff.

Consistent with the Scoping Memo and Ruling,[124] the Administrative Law Judge's Ruling[125] asked parties an array of questions regarding the Staff Proposal's recommendations to direct the IOUs to develop a new microgrid tariff. We summarize the Staff Proposal's recommendations and the parties' positions to it, below.

3.3.1. Staff Proposal Summary

The Staff Proposal identifies three main barriers to microgrid commercialization.[126] They are: (1) rate complexity (*i.e.*, regulatory barrier); (2) high initial start-up costs (*i.e.,* financial barrier); and (3) high operating costs (*i.e.,* financial barrier). The Staff Proposal recommends directing the IOUs to develop a microgrid tariff to facilitate the commercialization of customer-sited, customer facing microgrids.[127] In support of this Proposal's recommendation, the Staff Proposal offers several options for implementation.

Option 1 directs, within 30 days upon issuance of a Commission decision, the IOUs to file an advice letter seeking authority to create a separate rate schedule for customer-sited, customer-facing microgrids composed of

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[124] Assigned Commissioner's Amended Scoping Memo and Ruling, July 3, 2020.

[125] Administrative Law Judge's Ruling, July 23, 2020.

[126] The Staff Concept paper provides an overview of the perceived financial barrier to microgrids involving nonbypassable charges, departing load charges and standby charges. It describes these charges, provides historical perspective, and explains policy objectives and regulatory concepts driving their existence. Staff's analysis acknowledges the differing stakeholder perspectives regarding departing load charges and standby charges. It includes analysis of the applicability of standby charges to microgrid operations, recognizes that by virtue of microgrid features and capabilities, that changes to address financial barriers may be warranted. Notably, the Staff Concept Paper acknowledges that policy surrounding these charges for applicability to microgrids should be examined to consider their reduction, restructuring or elimination.

[127] Administrative Law Judge's Ruling, July 23, 2020, Attachment 1 – Staff Proposal at page 8-9.

- Description of the program administrator's reporting requirements and timeline, such as program status reports, project status reports, and quarterly budget status reports;
- Discussion of the approach for allocating program funding amongst the individual IOUs;
- Discussion of the accounting treatment and ratemaking, such as specification that the program may only recover costs once expenditures have been incurred and may not be proactively collected;
- Discussion of the method that shall be used to control program administrative expenses, such as implementing a cap of not more than 10% of the total project cost;
- Development of a program delivery plan handbook as a resource for potential participants;
- Description of approach for program evaluation;
- Description of the public workshops that were convened, including but not limited to the number and type of participants, and their inputs in the discussions.
- Authorize PG&E to propose changes to its Community Microgrid Enablement Program that may be necessary to integrate that Program more fully with the Microgrid Incentive Program.

3.5. Direct the IOUs to Evaluate Low-Cost, Reliable Electrical Isolation Methods.

Consistent with the Scoping Memo and Ruling,[255] an Administrative Law Judge's Ruling[256] asked parties an array of questions regarding the Staff Proposal's recommendations to direct the IOUs to conduct pilot studies of low-cost, reliable electrical isolation methods. We summarize the Staff Proposal's recommendation and the parties' positions to it, below.

[255] Assigned Commissioner's Amended Scoping Memo and Ruling, July 3, 2020.

[256] Administrative Law Judge's Ruling, July 23, 2020.

NFCRC[286] and Doosan oppose Option 1 and Option 2, arguing they take resources away from supporting new rates and tariffs.[287] FuelCell Energy opposes Options 1 and 2, arguing they do not go far enough to support microgrid commercialization.[288] MRC opposes Options 1 and 2, arguing pilots are not needed but rather, the IOUs should be directed to promptly consider low-cost interconnection options in their standard interconnection tariffs.[289] Schneider Electric opposes Proposal 5, asserting there is no need for more pilots.[290]

3.5.3. PG&E, SCE, and SDG&E Shall Develop a Pathway for Diverse Technologies to Support Electrical Isolation of a Premises' Entire Electrical Service During a Grid Outage.

Section 8371(b) requires the Commission, without shifting costs between ratepayers, to develop methods to reduce barriers for microgrid deployment. Additionally, Section 451 provides that rates, terms and conditions of utility service must be safe, just and reasonable.[291] Section 454.51(a)-(b) requires the Commission to assure the public that public utilities develop a portfolio of energy resources that assure the reliability of the state's electric supply.[292]

We adopt Proposal 5, Option 2 with modification. We agree with TURN that Proposal 5, Option 2 unlocks greater functionality and value from existing

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[286] NFCRC Opening Comments at 12.

[287] Doosan Opening Comments at 12.

[288] FCE Opening Comments at 12.

[289] MRC Opening Comments at 24.

[290] Schneider Electric Opening Comments at 9.S

[291] Sections 451, 454 and 728.

[292] Section 454.51, subds. (a) and (b).

smart meters in which ratepayers have already invested billions of dollars.[293] Furthermore, Proposal 5, Option 2 contains a broad set of technology options that further our objectives under Section 451.51(a)-(b) which requires us to develop electrical corporations' portfolio with a diverse set of energy resources for electricity reliability. It also appears likely to lower the costs of installing backup power and energy storage systems which furthers our objectives under Section 451 to ensure safe, reliable service through just and reasonable rates. Finally, and importantly, it develops another program to commercialize microgrids as a broader technology option pursuant to Section 8371.

While we adopt Proposal 5, Option 2, we also make some modifications. We agree with Tesla[294] and SBUA[295] that Proposal 5, Option 2's pilot program could deter electrical isolation technology innovation by prescribing a one-size-fits-all approach through a pilot program. Therefore, instead of a pilot program, we direct PG&E, SCE, and SDG&E to develop a clear pathway by which diverse technologies can provide disconnection of a premises' entire electrical service to support electrical isolation during a wider grid outage. PG&E, SCE, and SDG&E shall include such technologies that use the integral remote disconnect switch, found in most smart meters, as well as other technologies and approaches that support electrical disconnection during a wider grid outage.

This flexible approach supports innovation as some technologies are unlikely to need full pilot scale evaluation because they will not leverage the smart meter disconnection. Rather, they may be predominantly covered by existing national standards, such as the UL 414 Standard for Meter Sockets and

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[293] TURN Opening Comments at 10-11.

[294] Tesla Opening Comments at 22.

[295] SBUA Reply Comments at 12.

UL 1741 Inverters, Converters, Controllers, and Interconnection System Equipment for Use with Distributed Energy Resources. Aside from the UL 1741 Inverters,[296] these other types of technology may not require much evaluation or testing by the IOUs.

Within 30 days upon issuance of this decision, PG&E, SCE, and SDG&E shall file Tier 2 advice letters that suggest definitions for the criteria and evaluation process to assess the different isolation technologies pursuant to section 3.5.3 of this decision. The criteria and evaluation to assess the different isolation technologies should be aimed at evaluating and approving for use legitimate, utility-scale technologies capable of addressing California's complexity and diversity. This includes, but is not limited to, the following:

- Process for submittal of isolation technology by a third party to the IOU;
- Required timeframe for the IOU to respond to the third party with a specific evaluation plan for the submitted technology;
- Required timeframe for completion of an initial evaluation by the IOU;
- Process for engaging with and providing IOU feedback to the submitter of the technology,
- Expectations for engagement by and response to IOU feedback from submitter of the technology;
- Process for identifying which, if any, standards or safety requirements are applicable and must be certified or tested by a Nationally Recognized Testing Laboratory (e.g., Intertek, UL);
- Identification of which evaluation steps can be completed prior to certification or testing by a Nationally Recognized

[296] UL 1471 inverters, because of their novelty, may require both lab and field evaluation by an IOU to ensure safety and reliability.

Testing Laboratory and which must be completed after certification or testing;

- Discussion of circumstances when lab or field testing by IOU will be required in addition to certification by a Nationally Recognized Testing Laboratory to applicable standards (e.g., UL 414, UL 1741);
- Justification by IOU for repeating any testing (e.g., high-voltage, environmental performance testing) already completed as part of certification to a national standard by a Nationally Recognized Testing Laboratory ;
- Identification of an evaluation approach for examining the use of advanced metering infrastructure, and technologies that leverage it, to enable electrical isolation as a viable resilience strategy, as identified on page 4 of the July 3, 2020, R.19-09-009 scoping ruling;
- Discussion of circumstances when customer-supplied technology would be allowed and justification by IOU for any circumstances requiring IOU-supplied technology;
- Discussion and justification of circumstances when IOU believes ownership of any customer-supplied technology must be transferred to the IOU;
- Process and proposed timeframe for completing detailed evaluation by the IOU, inclusive of a determination and explanation regarding whether the proposed technology is approved for use and for reflecting that determination in the utility's service rules; and
- Process and frequency for reporting, to the CPUC, summaries and outcomes of technology evaluations undertaken by the IOU, including information from the perspective of the submitter of the technology and a summary of any irresolvable disputes between the evaluating utility and the submitter of the technology.

PG&E, SCE, and SDG&E shall record the costs for implementing Proposal 5, Option 2 in a new one-way balancing account and shall recover them in distribution rates through the Annual Electric True-up advice letter filing.

Now we turn to the overall cost cap for Proposal 5, Option 2. We agree with SBUA that an overall cost cap of $3 million allocated across the IOUs is more appropriate than the Staff Proposal's recommendation of $1 million per IOU. This approach promotes coordination and collaboration between the IOUs on their evaluation plans and reduces the potential for duplicative effort. If the IOUs need a larger budget, they may include in their Tier 2 advice letter a request for a budgetary increase along with supporting justification demonstrating the need.

In summary, within 30 days upon issuance of this decision, PG&E, SCE, and SDG&E shall file Tier 2 advice letters, pursuant to Section 3.5.3 of this decision, that define the criteria and evaluation process to assess the different isolation technologies.

3.6. Public Utilities Code Section 8371(c)

Consistent with the Scoping Memo and Ruling,[297] an Administrative Law Judge's Ruling[298] asked parties an array of questions regarding the Staff Proposal's recommendations regarding implementation of Section 8371(c). We summarize the Staff Proposal's recommendation and the parties' positions to it, below.

[297] Assigned Commissioner's Amended Scoping Memo and Ruling, July 3, 2020.

[298] Administrative Law Judge's Ruling, July 23, 2020.

existing interconnection working groups and interconnection processes is the correct approach for incorporating microgrids.[308] GPI opposes Options 1, 2, and 3 arguing all are inadequate and urging the Commission to "think bigger."[309]

SDG&E opposes Options 1, 2, and 3 arguing it is not needed because the guidelines required by Section 8371(c) are already developed.[310] MRC opposes Options 1, 2, and 3.[311] AMRC opposes Option 1, arguing the interconnection rulemaking is not well suited to consider microgrid stakeholder interests, but supports Options 2 and 3 to use the Resiliency and Microgrids Working Group to develop solutions.[312]

3.6.3. The Resiliency and Microgrids Working Group Shall Identify Attributes or Characteristics of Microgrids, If Any, That Are Not Adequately Addressed by Rule 21 and Shall Create a Workplan to Consider These Issues.

Section 8371(c) directs the Commission to develop guidelines that determine what impact studies are required for microgrids to connect to the electrical corporation grid.

We adopt Secondary Proposal Section 8371(c) Options 1, 2, and 3. The Resiliency and Microgrids Working Group shall study and report on the particular questions presented in Options 1, 2, and 3. Then, the Resiliency and Microgrids Working Group shall make recommendations based on its findings to the Commission during Track 3 of this proceeding.

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[308] FCE Opening Comments at 13.

[309] GPI Opening Comments at 16-17.

[310] SDG&E Opening Comments at 31-21.

[311] MRC Opening Comments at 25-26.

[312] AMRC Opening Comments at 15.

The Resiliency and Microgrids Working Group is not a Rule 21 interconnection working group as some parties misconstrue. The Resiliency and Microgrids Working Group shall focus on, and prioritize issues related to, microgrids rather than broader issues, such as those concerning Rule 21 interconnection topics within the scope of R.17-07-007.

3.7. Public Utilities Code Section 8371(e).

Consistent with the Scoping Memo and Ruling,[313] an Administrative Law Judge's Ruling[314] asked parties an array of questions regarding the Staff Proposal's recommendations for implementing Section 8371(e).

3.7.1. Staff Proposal Summary

The Staff Proposal offers three options to fulfill Section 8371(e)'s requirement to establish a Resiliency and Microgrids Working Group to further explore issues related to electrical corporation and CAISO microgrid requirements, as well as other issues relevant to the further development of microgrid policy. Launching the working group consists of: (1) developing a draft charter covering objectives, deliverables, ground rules for participation and governance, meeting frequency, and meeting format; (2) convening a kickoff meeting[315] to confirm a charter and identify priority issues; and (3) develop a schedule and milestones for addressing each issue.[316]

The proposals to facilitate the formation of a working group are as follows: (1) Option 1, direct utilities to hire a third-party facilitator for the working group,

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[313] Assigned Commissioner's Amended Scoping Memo and Ruling, July 3, 2020.

[314] Administrative Law Judge's Ruling, July 23, 2020.

[315] On October 13, 2020, Energy Division convened the Microgrids Working Group with stakeholders.

[316] Administrative Law Judge's Ruling, July 23, 2020, Attachment 1 – Staff Proposal at 33-34.

The Staff Proposal also recommends that the CPUC conduct a competitive solicitation for a program evaluator through the State of California Department of General Services contracting process.[348] Upon CPUC authorization, Energy Division would develop a budget change proposal for reimbursable funds to be used for program evaluation.[349] The Staff Proposal recommends a $1 million budget for program evaluation.[350]

3.9.2. Parties' Positions

Most parties did not provide comment on the Staff Proposal's recommendation for a program evaluator. However, MRC supports a third-party evaluator, arguing a thorough review by an independent third party could be valuable if it encompasses a broad view of the future of the grid.[351]

3.9.3. A Neutral-Third Party Shall Review and Evaluate the New Microgrid Tariff, Rates and Rules, the New Incentive Programs, and the Pilot Studies to Assure Competitiveness and Ratepayer Best Interests.

The Staff Proposal recommends that Energy Division hire a neutral third-party contractor through the State of California Department of General Services contracting process to evaluate the activities authorized by this decision and D.20-06-017. The Staff Proposal recommends that the third-party contractor evaluate an array of items, as summarized above.

We agree with the Staff Proposal's recommendation that a neutral third-party should evaluate the activities undertaken by this decision and D.20-06-017. A neutral third-party evaluator shall ensure that conduct, when

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[348] *Id.*

[349] *Id.*

[350] *Id.*

[351] MRC Opening Comments at 7.

implementing this decision, does not favor or otherwise promote inappropriate preferential treatment, promotes financial indifference, and implements microgrid commercialization and policies pursuant to this decision in the public interest.

To promote transparency, we direct Energy Division to hold a workshop addressing topics concerning the scope that will govern the third-party evaluator's work. We adopt Cal Advocates recommendation that this workshop should discuss the following: (1) evaluation length of time; (2) budget; and (3) metrics governing the evaluation.[352]

Once the evaluator is selected through the State of California procurement process, and the program evaluation has concluded, we direct Energy Division to solicit comment from all interested parties on the program evaluator's findings and recommendations.[353] Finally, we modify the Staff Proposal's recommendation of a $1 million budget for program evaluation. We adopt the $1 million budget for program evaluation as a budget cap, subject to downward adjustment by Energy Division.

3.10. Interim Approach for Minimizing Emissions from Generating During Transmission Outages

Consistent with the Scoping Memo and Ruling,[354] an Assigned Commissioner and Administrative Law Judge's Ruling[355] directed parties to comment on an interim approach for minimizing emissions from generation during transmission outages.

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[352] Cal Advocates at 8.

[353] *Id.*

[354] Assigned Commissioner's Amended Scoping Memo and Ruling, July 3, 2020.

[355] Assigned Commissioner and Administrative Law Judge's Ruling, September 4, 2020.

3.10.1. Parties Positions

Overall, the parties' support for the interim approach for minimizing emissions from generation during transmission outages varied in support or opposition.

Some parties favor the use of clean energy where it is technologically and economically feasible[356] or outright argued for zero-emissions sources as permanent and immediate solutions.[357]

Others opposed the interim approach broadly, because: (1) some utilities do not have the need to de-energize as other IOUs do;[358] (2) PG&E has a unique set of issues separate from SCE and SDG&E, and should be handled accordingly;[359] (3) such costs could be excessive for ratepayers to bear;[360] and (4) other proceedings are already tackling this issue with infrastructure hardening and therefore, ratepayers should avoid bearing duplicative costs.[361]

3.10.2. Keeping the Lights on is a Priority Objective for Community Continuity.

To minimize the number of customers affected by a transmission outage during a PSPS event, we adopt an interim approach[362] for reserving temporary

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[356] RCRC Assigned Commissioner and ALJ Response to September 4, 2020 Ruling at 2-6; Sierra Club Assigned Commissioner and ALJ Response to September 4, 2020 Ruling 1-5.

[357] Tesla Assigned Commissioner and ALJ Response to September 4, 2020 Ruling at 5; SunRun E Assigned Commissioner and ALJ Response to September 4, 2020 Ruling at 2-4.

[358] SDG&E Assigned Commissioner and ALJ Response to September 4, 2020 Ruling 2-8.

[359] SCE Assigned Commissioner and ALJ Response to September 4, 2020 Ruling at 4.

[360] TURN Assigned Commissioner and ALJ Response to September 4, 2020 Ruling at 3-5.

[361] Cal Advocates Assigned Commissioner and ALJ Response to September 4, 2020 Ruling 2, and 3-4.

[362] This Decision's Appendix refines the approach illustrated in the Joint Assigned Commissioner and Administrative Law Judge's Ruling (September 4, 2020) for adopting an interim approach for minimizing emissions from generation during transmission outages.

generation for safe-to-energize substations for 2021, as well as a process for transitioning to clean temporary generation after 2021. The interim approach is attached as Section I of Appendix A to this decision. This is an interim step that may inform our regulatory approach beyond 2021, *if* the utility has filed an application for a transition to clean temporary generation. The process for transitioning to clean temporary generation *after* 2021 is attached as Section II of Appendix A. A ratemaking process corresponding to the interim approach is attached as Section III of Appendix A of this decision.

The Interim Approach in Section I of Appendix A allows utilities to begin procurement of clean alternatives where clearly reasonable to do so, taking an immediate first step in the transition to clean generation. As part of reserving temporary generation, the Interim Approach requires that the utilities pursue at least one clean substation microgrid project. No process or method for completing the transition to clean generation has been adequately reviewed or presented for thorough comment in this proceeding. As such, the process to complete the transition to clean generation should be taken up and deliberated in the utility application required by Section III of Appendix A.

For cost recovery purposes in 2021-2022, if an IOU seeks to implement a temporary generation program for the specific purpose of providing power at substations during a transmission outage, they may track associated expenditures in the Microgrids Memorandum Account, using separate annual subaccounts. If the IOU intends to recover these costs, they must either file an application or include these costs as part of their respective 2023 general rate cases.

For 2021-2022 clean microgrids projects, we allow the IOUs to recover in rates the costs for clean substation microgrid projects. These costs may include,

but are not limited to, capital investment, permanent generation or, if the IOU has contracted for power purchases, the resulting expenses for the power purchasing agreement. These costs are subject to $350 million cap. An IOU must file a Tier 3 advice letter seeking Commission authorization for such rate recovery.

Keeping the lights on to preserve community continuity is a priority objective for the public health, welfare, and safety of all Californians. As we stated above in Section 3.4.3, we have a duty to balance our various statutory obligations under Section 451, Section 454.51, and Section 8371. With that balancing, we agreed with parties that without increased resiliency, the burden of extended power shutoffs will continue to fall most heavily and inequitably upon "a small number of highly impacted counties."[363] Therefore, expenditures for clean substation microgrids projects shall be allocated to all distribution customers to ensure the strain of wildfire events and PSPS events are not unevenly borne by a small number of highly impacted counties.

Finally, in D.20-06-017, we approved PG&E's temporary generation program for 2020 only, and its Make Ready program for 2020-2022. We also directed PG&E to record the costs for its Make Ready and temporary generation programs in separate subaccounts in the Microgrids Memorandum Account for a reasonableness review which we anticipated would be reviewed in a separate track of this proceeding. Instead we direct PG&E to file a separate application for cost recovery consideration of its 2020 temporary generation program and its 2020 Make Ready program.

[363] CforAT Opening Comments at 4.

4. Conclusion

In conclusion, this decision adopts microgrid rates, tariffs, and rules for large investor-owned electrical corporations. These microgrid rates, tariffs, and rules facilitate the commercialization of microgrids pursuant to Senate Bill 1339. First, we direct SCE to revise its Rule 2 to permit installing added or special facilities microgrids. Second, we direct SCE and PG&E to revise their Rule 18, and SDG&E to revise its Rule 19, to allow microgrids to serve critical customers on adjacent parcels. A subscription limit of ten Rule 18 or Rule 19 microgrid projects is permitted across each of the large investor-owned electrical corporations' service territories.

Third, SCE, PG&E, and SDG&E shall each form a microgrid tariff for their respective service territories. Fourth, SCE, PG&E, and SDG&E shall jointly develop a Microgrid Incentive Program. Fifth, we direct SCE, PG&E, and SDG&E to develop pathways for the evaluation and approval of low-cost, reliable electrical isolation methods.

This decision also creates a Resiliency and Microgrids Working Group. This decision directs the Commission's Energy Division to identify microgrid-specific policy issues that are not adequately addressed by existing venues at the Commission, California Energy Commission, California Air Resources Board, and California Independent System Operator, if any, and to create a workplan for considering these issues within the Resiliency and Microgrids Working Group and Track 3 of this proceeding. This decision also directs the Energy Division to include the subject of codifying standards and protocols necessary to meet California electrical corporation and California Independent System Operator microgrid requirements in the Resiliency and Microgrids Working Group work plan. This decision requires SCE, as the lead investor-owned utility,

Appendix A

I. Interim Approach for Reserving Temporary Generation for Safe-to-Energize Substations for 2021

The interim approach, outlined below, has two guiding aims:

1. Keep the lights on: To maximize the ability to keep power on during a transmission outage where safe to do so in 2021, while ensuring just and reasonable rates.
2. Start the transition towards clean temporary generation: To increase utility and market experience and understanding of alternatives to diesel generation to facilitate a transition away from diesel in future years.

1. Keep the Lights On:

CPUC regulated utilities have recently been allowed to utilize Public Safety Power Shutoffs (PSPS) to reduce the risk of wildfire ignition from electrical facilities during high wind events. Since SDG&E started utilizing this tool in 2013 and PG&E in 2018, the usage of this tool has increased resulting in dramatic, and previously unexpected, customer disruptions to utility service based on utility-controlled transmission outages. To minimize the number of customers affected by a transmission outage during a PSPS event, the utility is authorized to reserve temporary generation in advance specifically to have the capability to power the load of safe-to-energize substations. This temporary generation is intended to keep the lights on specifically during a transmission outage caused by a PSPS event, a circumstance that was not previously envisioned during the past few decades of utility transmission and substation electric grid planning.

This authorization does not limit or affect in any way the ability of a utility to reserve temporary generation for other purposes, such as providing power to community resource centers or critical facilities during events or serving load during routine grid maintenance, which fall outside the scope of this framework. Throughout the following document, 'temporary generation' refers to this specific use case above, where temporary generation is reserved for energizing safe-to-energize substation load subject to PSPS transmission outages. A utility seeking to reserve temporary generation for this specific use case would be required to submit a Tier 2 Advice Letter detailing how the conditions described below have been met.

This framework is an interim step that may apply beyond 2021 if and only if 1) the utility has filed an application pursuant to the process for transitioning to clean generation described below under section II and; 2) the CPUC has not yet issued a decision on that application.

The CPUC authorizes a utility to track the costs associated with reserving temporary generation in a memorandum account, including diesel as well as other temporary generation for the purpose of providing power to the load of safe-to-energize substations during a PSPS outage, under the following conditions:

1.1. The utility reserves temporary generation capacity equivalent to 120% or less of the coincident peak deployment of temporary generation in the immediately previous year.

Or

The utility justifies the scope and scale of the need for providing temporary generation by

providing the basis and justification why it is reasonable to prepare for specific substations to be de-energized, including but not limited to:

a. Historical meteorological data showing probability of public safety power shutoff.
b. Historical outage data.
c. Fire spread modelling and incorporation of consequences to customers.
d. Transmission asset condition information; and
e. Transmission operability assessment information.

Rationale: Meeting this condition indicates that the utility is reserving the appropriate quantity of temporary generation.

1.2. The utility's previous temporary generation program, if any, has proven effective at serving loads of safe-to-energize substations that would have otherwise been without power during PSPS or other outage events, if and when it was activated to do so.

Rationale: Meeting this condition indicates that the Temporary Generation Program contributes to the aim of keeping the lights on where safe to do so.

1.3. The utility provides evidence that there is resource scarcity that makes it prudent to pay a nonrefundable reservation fee which guarantees generator availability for the duration of fire season in advance of need, or that advance reservation is necessary for logistical reasons to safely mobilize and stage equipment.

Rationale: Meeting this condition indicates that it is reasonable to reserve temporary generation in advance.

1.4. The utility demonstrates that it has undertaken an analysis of the all-inclusive costs associated with reserving and deploying the temporary generation and that the costs are reasonably close to that associated with deploying similar equipment under normal conditions, such as for a planned maintenance outage.

Rationale: Meeting this condition indicates that the costs associated with reserving and deploying temporary generation are reasonable.

1.5 The utility demonstrates ongoing consultation with local air quality agencies,[376] aimed at ensuring the deployment of temporary generation at substations complies with applicable regulations.

Rationale: Use of the California Air Resources Board (ARB) Portable Engine Reservation Program (PERP) program is not intended to thwart local air district jurisdiction and applicable permitting requirements for new stationary sources of air pollution. Meeting this

[376] Local air quality agencies may include local air pollution control districts or air quality management districts.

condition demonstrates that PG&E has addressed legal and regulatory issues related to emissions and public health with local air districts.

In addition, the utility may reserve or contract to make available temporary generation resources for up to 3 years. Any generation contracted for more than a year must reduce PM and NOx emissions compared to a Tier 2 diesel engine by at least 90 percent.

Given the particularly high emissions of harmful air pollutants from Tier 2 diesel engines and conventional diesel fuel, the Commission expects a utility to minimize its use of Tier 2 diesel—and use alternative fuels like hydrotreated vegetable oil (HVO)—where alternatives are safe, cost effective, and feasible.

For purposes of transparency, the utility shall file a compliance filing in this proceeding by March of the following year, containing a report detailing the use of temporary generation under this framework. This report shall detail: (a) the total number of diesel generators employed; (b) each deployment location and run time of generators by date and time; (c) the reasons why the use of backup power was needed; (d) Cal EnviroScreen percentile for the generator location; (e) number of customers served; (f) fuel types used, extent of use by fuel types, and description of the refueling logistics; (g) a summary of emissions by greenhouse gas (GHG) and criteria air pollutant emissions factors; (h) lessons learned from an after-event analysis of the fire season experience; and (i) recommendations for continuous improvement.

2. Start the Transition towards Clean Generation

A utility seeking to reserve temporary generation under this framework would also be required, in its Tier 2 Advice Letter, to document its plans to establish clean substation microgrid projects located at, or able to serve, at least one substation. This opportunity is intended to be open to projects that are novel or not commercially tested, i.e. pilot projects, as well as permanent projects in general, even if they are commercially tested and available.

In order to facilitate the development of projects that primarily involve stationary installation of generation at substations for longer than 3 years, the utility must identify three top candidate substations that best fit condition 2.2 below, in its Tier 2 advice letter.

If the utility determines, based on the conditions described below, that it is not feasible to move forward with such projects, it must document the specific conditions that have not been met in its Advice Letter.

The following conditions apply to the clean substation microgrid pilot projects:

2.1. Projects may be either mobile or stationary, and either temporary or permanent.

2.2. Projects that involve stationary installation of generation at a substation for longer than 3 years can only be pursued at substations where, with high confidence:

a. Transmission lines serving the substation may be de-energized because of the fire risk, despite safe-to-energize load at the substation. The probability of transmission-level power loss affecting otherwise safe-to-energize load is relatively high and expected to persist; and

b. Either, the utility does not have ongoing, planned, or proposed grid hardening investments that would significantly reduce the risk of de-energization at this substation over the next 10 years; or

c. Or,alternatively, the cost of proposed grid hardening investments exceed $10 million multiplied by the peak substation load in MW, and a permanent microgrid would replace the need for grid hardening.[377]

2.3. Proposed projects must be judged technically feasible, safe, and financially competitive by the utility. At minimum, these solutions should meet the following requirements:

a. Design should be capable of islanding for 48 hours.
b. Design should be able to black start the substation load.
c. Design should meet cold load pickup requirements.
d. Design must meet frequency and frequency response requirements.
e. Design should meet protection requirements or include protection upgrades.
f. The cost of the project to ratepayers may not exceed twice the expected cost of utilizing backup diesel generation over the contract period. In total, the cost

[377] The $10 million figure comes from taking the Commission's estimate for the cost of diesel rental (used as a proxy for back up generation), multiplying that by 15 years to reflect the likely contract period for permanent solutions, and rounding up.

may not exceed the expected cost of 20 years of diesel rental and operation.

1.1. Proposed solutions should meet the following general criteria:

a. If safe to do so, it is permissible for a subset of the project generation and/or storage resources to enter operation before the entire project is completed, allowing the project to progress in stages.

b. By the 2022 fire season, September 1, 2022, emission from islanding the substation during PSPS events should be significantly reduced, including:

i. At least a 90 percent reduction in PM emissions and NOx emissions compared to what would have been emitted if large Tier 2 Diesel Generators had been used instead of the project.

ii. Greenhouse gas emissions roughly equivalent to, or less than, emissions from the current grid mix.

iii. Although only criteria (b) above need to be met by the 2022 fire season, as an interim milestone, completed permanent projects must demonstrate a fully renewable microgrid.

iv. The project may be capable of export during normal conditions, but it is not required to do so.

2.5 Total cost of all projects over their expected useful life may not exceed $350 million.

Requiring a utility to initiate clean substation microgrid projects gives room for multiple different solutions to be tested, and a broader baseline of knowledge be developed, while working on a full framework in 2021 for future years (see process proposal below). The accompanying conditions ensure that projects are feasible, clean, cost-effective, and low risk. Based on the threshold costs and limited number of projects in the earlier CPUC proposal, expenditures by the utility may not exceed a total of $350 million dollars.[378]

[378] Given the earlier proposed limit of no more than three projects with a cost cap of $500 per kw-year, and assuming substations of average size among those with safe-to-energize load (about 15 MW) and contracts of 15 years, the total expenditures could be as high as $350 million over the three projects' lifetimes. With the limit on the number of projects removed, it makes sense to cap total expenditures at $350 million.

Although these alternatives should be partially or fully ready for commercial operation by the 2021 fire season, permanent projects may run into delays that make this date unfeasible. Thus, as a contingency or fallback plan, the Commission would authorize the utility to reserve temporary generation to cover these three substations as well, to the extent the utility determines this is necessary.

II. Process for Transitioning to Clean Generation for Safe-to-Energize Substations After 2021

In order to make investments to provide power to customers subject to transmission outages during PSPS events that are served by safe-to-energize substations, a utility must file an application by June 30, 2021. The Application will demonstrate the utilities' plan for transitioning to clean sources of generation in future years to power customers during PSPS events. The application must detail the utility's plan for generation investments, justified with a comparative analysis of alternatives considered, the expected persistence of the need and why it will not be reduced or eliminated by other infrastructure investments, and its proposed procurement framework for the generation.

In detailing its plan, the utility must provide information about the locations[379] that will remain unmitigated (and thus subject to potential public safety power shutoffs) due to lack of cost-effective and feasible wires solutions. The utility will also need to include the basis for why the transmission lines and/or distribution lines and/or distribution circuits are unable to remain energized during adverse weather conditions including assessments of transmission line condition in high fire threat areas and their propensity to fail under specific conditions. For example, the utility must provide a detailed explanation of the rationale for each transmission line de-energization previously initiated during recent fire seasons PSPS events in its Application.

This also means that the utility would provide specific information such as a list of substation locations where transmission related PSPS outages are expected to persist for 3 years or longer or where other alternatives including but not limited to hardening, reconstruction, or undergrounding of utility infrastructure to eliminate, mitigate, or reduce incidences of PSPS are shown to be uneconomic over any timeframe. The utility may rely on or refer to its Wildfire Mitigation Plan and other documents or data from other proceedings in preparing the Application.

A section of the Application will include analysis of the alternatives considered for addressing the problem statement and proposed solution at each substation. This analysis would form the basis and justification supporting the IOUs' capital investment plan for the resilience solutions that the IOU proposes in its Application. By presenting the alternatives considered and a comparative analysis, stakeholders would have open transparent information to understand the IOUs recommendation with full visibility to the investments under consideration in the IOU Wildfire Mitigation Plan. The utilities have indicated in this and other proceedings that they may use and

[379] Including substation name, related distribution circuits, prior PSPS events, county, peak megawatt served, addressable megawatt, number of total customer accounts, and number of addressable customer accounts.

include the results of modeling techniques and actual experience gained during prior fire seasons to justify the need for generation.

The comparative analysis of available alternatives should incorporate the results of advanced modelling such as weather modelling, transmission system powerflow modelling, wildfire fire spread modelling, and transmission line condition assessment. It should also consider grid hardening, undergrounding, enhanced vegetation management, sectionalizing, and other mitigation strategies that would be options for enabling the distribution circuit to remain energized when safe to do so.

Utilities' applications must address the following topics:

1. How will the utility scope the need for temporary generation? Indicate how these methods may be improved over time to enhance accuracy and precision regarding how much generation is needed and where it should be deployed.
2. How will the utility minimize the need for temporary generation over the next 5/10 years in a cost-effective way? Provide an approximate timeline detailing, at minimum:
    a. Transmission line exclusion from PSPS scoping.
    b. Tower Replacement, for example, PG&E Wildfire Mitigation Plan (WMP) Section 5.3.3.15.
    c. Targeting undergrounding for certain transmission circuits or portions of transmission circuits, per WMP section 5.3.3.16.
    d. Transmission Line System hardening or equipment replacement, per WMP Section 5.3.3.17.5.
    e. Increased grid flexibility and sectionalizing.
    f. Permanent microgrid development.
3. How will the utility support the development of clean temporary generation resources? This support should include, but is not limited to:
    a. A testing process for vendors of cleaner temporary generation products, so that products that meet the technical requirements in controlled tests can be quickly field tested and the utility can gain confidence in the logistical and operational capabilities of new vendors.
    b. A review to validate the technical and logistical requirements for temporary generation, focusing on the requirements that present the largest barriers to the use of clean generation resources.
4. Present an overall timeline, detailing how the combination of improvements in scoping, minimization of the need for temporary generation, and support for cleaner temporary generation products will reduce the need to deploy diesel and other fossil resources over the next 5/10 years.
5. Referring to the overall timeline and other included information, lay out a set of criteria and/or targets for the procurement of temporary generation resources that could apply over the next 5/10 years.
6. Referring to the overall timeline and other included information, lay out a set of criteria and/or targets for the development of permanent generation resources that replace the need for temporary generation over the next 5/10 years.
    a. Address whether resilience needs and resource adequacy needs would be addressed within this form of procurement.
    b. Address whether, due to the circumstances of the Governor's emergency proclamation related to the stage 3 emergency of August 2020, there are short term

reliability and resiliency needs that need to be expedited, and how should these circumstances be addressed in this procurement process.

c. In the event ARB offsets are used, ensure they are fully compliant with 17 Code of California Regulations, section 95970.

7. Establish and justify clear targets for reducing the emissions associated with temporary generation and permanent generation.
8. Identify criteria to be used to evaluate generation and storage technologies and vendors to be considered in the long-term plan for temporary or permanent generation.
9. Describe a process for subjecting any proposed contracts with temporary or permanent generation providers to oversight and review.
10. Document any solicitation protocols to be used to procure resources needed to provide temporary or permanent generation over time.
11. Describe a process for engaging the local air quality agencies, community choice aggregators (CCAs) and local governments for their input regarding the development of permanent generation resources to replace temporary generation that is consistent with CPUC jurisdiction.
12. Propose an approach for cost control, allocation, and recovery for all costs associated with temporary or permanent generation over the covered period of the application that addresses the rate treatment of bundled and unbundled customers served by the generation.
13. Propose an ongoing process for subjecting the utility's temporary or permanent generation emissions targets, needs, plans, evaluation criteria, solicitation protocols, and costs to oversight and review.

Exhibit 13

Emissions Performance Standard Workshop

Presenting PG&E Supplemental Testimony in A. 21-06-022

October 29, 2021

California Public
Utilities Commission

WebEx and Call-In Information

Join by Computer:

https://cpuc.webex.com/cpuc/j.php?MTID=m046b493b13e6da18769315a1c1511117

Event Password: 1029

Meeting Number: 2482 960 6014

Join by Phone:

- Conference Number: 1-415-655-0002
- Participant Code: 2482 960 6014

Notes:

- Today's presentations were made available in a Service List email on October 27.

Context: Proposed Emissions Standard

CPUC Emissions Performance Standard Put Forth in Track 2 Decision	PG&E Proposed Emission Standard in Long-Term Substation Procurement Framework Application for PSPS Substation Microgrids
1. **"[a]ny generation [used for substation-level PSPS mitigation]** contracted for more than a year must reduce PM and NOx emissions compared to a Tier 2 diesel engine by at least 90 percent."	For any Multi-Season Solution (i.e., contracted for more than 1 year), **the mix of DERs that is intended be used to serve a given substation's load** must reduce PM and NOx emissions compared to a Tier 2 diesel engine by at least 90 percent
2. Second, with specific reference to **clean substation pilot projects**, the Commission ordered that, beginning September 1, 2022, emissions from a substation-level microgrid solution for PSPS mitigation would need to achieve (1) "[a]t least a 90 percent reduction in PM emissions and NOx emissions compared to what would have been emitted if large Tier 2 Diesel Generators had been used instead of the project; and (2) "**[g]reenhouse gas emissions roughly equivalent to, or less than, emissions from the current grid mix.**"	**Any Multi-Season Solution** must meet **lifecycle GHG emissions** roughly equivalent to, or less than, emissions from the current grid mix. **"Current grid mix" refers to** the prior calendar year's million metric tons CO2eq/MWh, calculated with CAISO reported GHG emissions and actual demand[1]
3. Any "**completed permanent projects must demonstrate a fully renewable microgrid**."	**For any Multi-Season Solution, any generation or storage technology that is included within the mix of DERs is capable of running on renewable fuels,**[2] as confirmed by manufacturer certification.

Notes

1. Current grid mix standard for 2021 is calculated with 2020 CAISO "Greenhouse Gas Emission Tracking Report" and 2020 CAISO Actual Demand*
2. Renewable fuels are fuels that are defined as renewable in the latest version of the CEC Renewable Portfolio Standards Eligibility Commission Guidebook

**Update to current grid mix calculation provided in supplemental testimony and will be reviewed in today's workshop*

Engines and fuels evaluated in this study

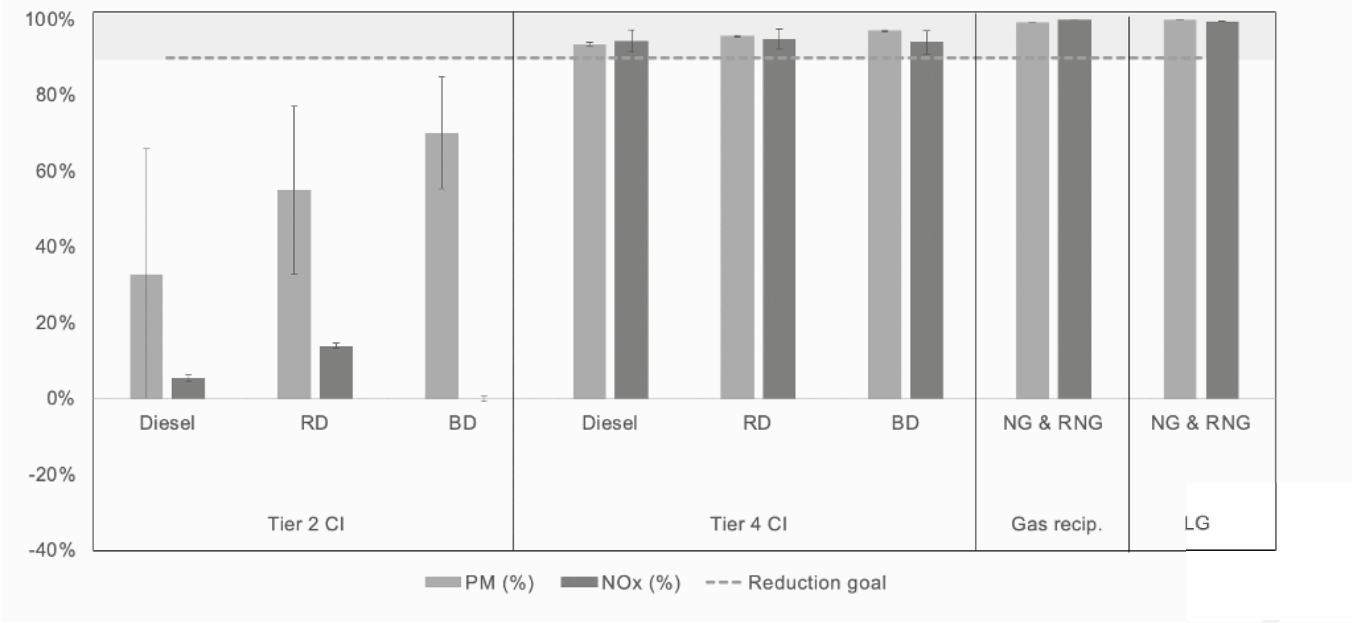
Engines	Tier 2 CI	An emission standard adopted by the EPA and CARB to limit PM, NOx and CO emissions from off-road compression ignition diesel engines. Tier 2 emission standards were phased-in from 2004 to 2009, but are phased-out and replaced by Tier 3 regulations over the period of 2017-2025.
	Tier 4 CI	Tier 4 is the most current emission standards adopted by EPA and CARB for off-road compression ignition diesel engines. It began being phased-in in 2008. The regulation set out to reduce NOx, PM, CO, and hydrocarbon emissions substantially with respect to tier 2 emission standard.
	Spark ignition (SI) gas reciprocating engines	Typically used for backup, standby, or emergency power, SI gas engines are now becoming increasingly popular for larger utility-scale power generation applications. It employs a spark from a spark plug to ignite the air-fuel mixture.
	Linear Generator (LG)	A linear motor used as a generator, using fuel-based chemical energy to drive oscillating magnets back and forth and converting this mechanical energy to electrical energy.
Fuels	Diesel	A liquid hydrocarbon fossil fuel that is used for powering on-road and off-road engines.
	Natural Gas (NG)	A gaseous fossil fuel mixture sourced from underground gas wells.
	Biodiesel (BD)	Non-hydrocarbon fuel produced from the same feedstocks as renewable diesel.
	Renewable Diesel (RD)	Premium-quality, non-petroleum hydrocarbon fuel made from 100% renewable raw materials.
	Renewable Natural Gas (RNG)	A gaseous fuel mixture chemically similar to fossil natural gas but sourced from renewable sources, including but not limited to landfills and anaerobic digestion.

Average PM & NOx emissions of different engine/fuel configurations

Engine	Fuel	PM (lbs/MWh)	NOx (lbs/MWh)
Tier 2 CI	Diesel	0.2954	13.3280
	Renewable diesel (RD)	0.1979	12.1285
	Biodiesel (B100 or BD)	0.1317	14.1011
Tier 4 CI	Diesel	0.0282	0.7869
	Renewable Diesel (RD)	0.0189	0.7161
	Biodiesel (B100 or BD)	0.0126	0.8325
SI rich burn gas reciprocating engine	NG & RNG	0.0030	0.0035
Linear Generator	NG & RNG	0.0000	0.0500
CARB Tier 2 off-road engine (>= 560kW emission standard (baseline)	Diesel	0.4409	14.1096

- *CI - compression ignition; SI - spark ignition; NG - natural gas; RNG - renewable natural gas*
- *Values above are zero hour emissions*
- *All the genset units analyzed in this study are 500 kW - 1000kW*
- *Diesel engine emissions are provided by Aggreko and Peterson, gas reciprocating engine by Enchanted Rock and linear generator by Mainsprings*
- *Emissions of RD and BD are evaluated by their emissions reduction relative to diesel, as provided by fuel vendors and a relevant Department of Energy (DOE) study*
- *RNG is assumed to have the same chemical composition as NG, though realistically, certain RNG pathways might have lower CH4% than natural gas*

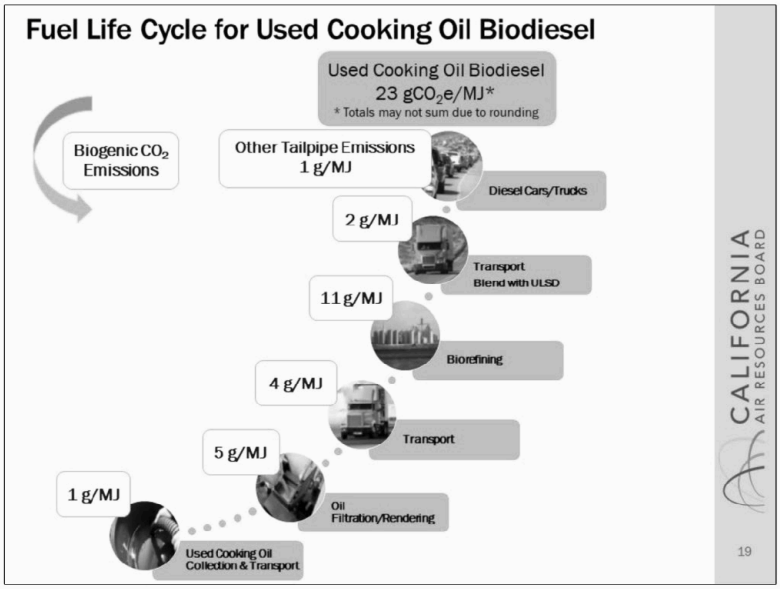
PM and NOx emissions reductions relative to CARB Tier 2 off-road CI engine emission standard



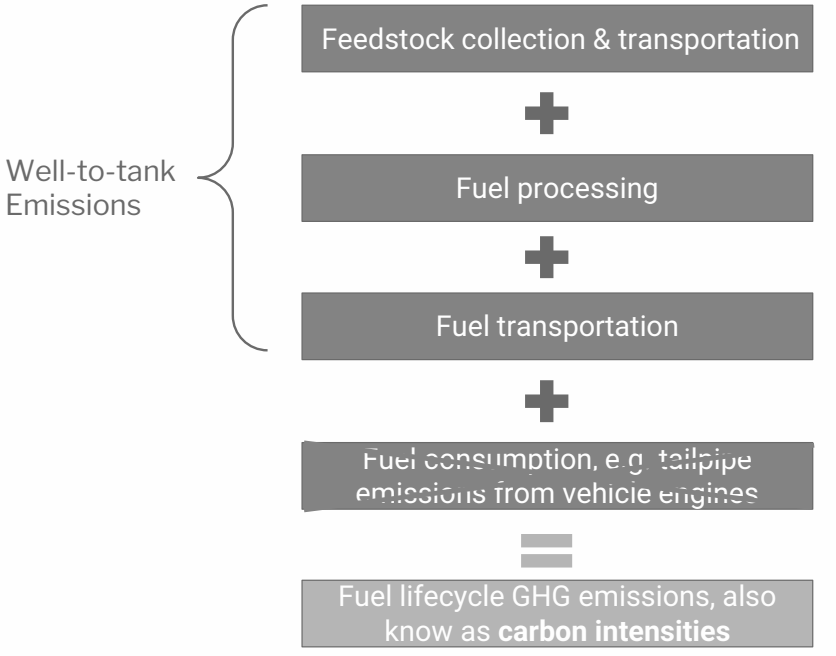
Error bars indicate the variation within each group based on engine makes and models

Fuel lifecycle GHG emissions calculation framework by CARB

- CARB's Low Carbon Fuel Standard (LCFS) program has created a framework for fuel producers to determine total fuel lifecycle GHG emissions, also known as fuels' carbon intensities
- This metric takes into account the GHG emissions associated with all of the steps of producing, transporting, and consuming a fuel—also known as a complete "life cycle" of that fuel
- Carbon intensity is expressed in grams of carbon dioxide equivalent per megajoule of energy provided by that fuel



Modifying CARB's fuel lifecycle emissions framework for point generation



Engine	Heat rate (MMBtu/MWh)
Tier 2 CI	7.91
Tier 4 CI	7.93
Rich burn SI gas recip.	9.72
Linear Gen	9.00

**Heat rate is one efficiency measure of electrical generators/power plants that convert input fuels into heat and electricity. Defined as the amount of input fuel required to generate one unit of electricity.*

Fuel consumption, e.g. direct genset GHG emissions

$CO_2 \times GWP_{CO2} + CH_4 \times GWP_{CH4} + N_2O \times GWP_{N2O}$

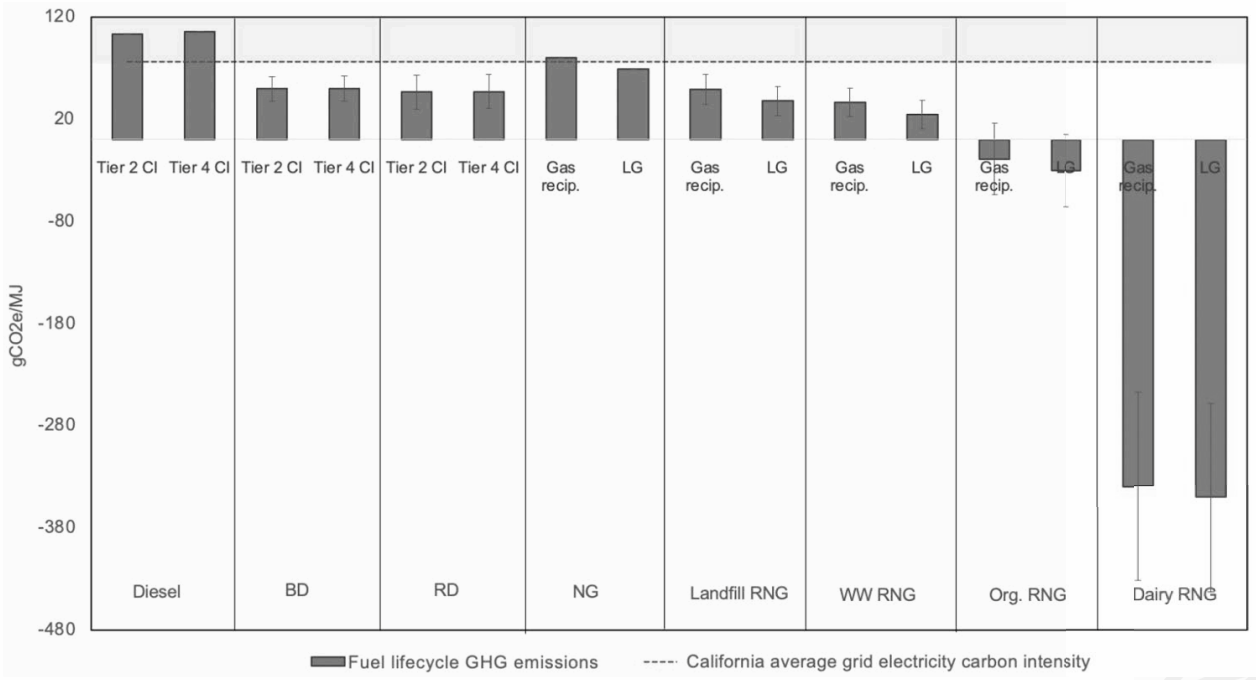
CO_2 emission factor: EPA AP-42 Table 3.4-1
CH_4 & N_2O emission factor: 40 CFR Appendix Table C-2 to Subpart C of Part 98

Results: Average fuel lifecycle GHG emissions

Engine	Fuel	Fuel well-to-tank emissions (gCO_2e/MJ)	Genset GHG emissions during combustion (gCO_2e/MJ)	Total fuel lifecycle GHG emissions (gCO_2e/MJ)
California grid average (for reference)				**75.93**
Tier 2 CI	Diesel	25.59	77.47	**103.06**
	BD	45.49	4.38	**49.87**
	RD	42.42	4.38	**46.80**
Tier 4 CI	Diesel	25.59	80.43	**106.02**
	BD	45.49	4.55	**50.04**
	RD	42.42	4.55	**46.97**
SI rich burn gas recip.	NG	18.48	61.76	**80.24**
	Landfill RNG	-12.55	61.76	**49.22**
	Wastewater RNG	-25.53	61.76	**36.23**
	Organic waste RNG	-80.67	61.76	**-18.91**
	Dairy RNG	-400.88	61.76	**-339.11**
Linear generator	NG	18.48	50.45	**68.93**
	Landfill RNG	-12.55	50.45	**37.90**
	Wastewater RNG	-25.53	50.45	**24.92**
	Organic waste RNG	-80.67	50.45	**-30.22**
	Dairy RNG	-400.88	50.45	**-350.43**

- *California average grid electricity carbon intensity provided in CARB 2021 update*
- *As adopted by the LCFS program, biogenic carbon is subtracted from bio--based fuels' lifecycle emissions*
- *Well-to-tank emissions data sources:*
  - ***BD**: average from 67 soybean, canola and corn oil biodiesel fuel producers*
  - ***RD**: average from 14 soybean, canola and corn oil renewable diesel fuel producers*
  - ***Landfill RNG**: average of 119 landfill RNG producers*
  - ***Wastewater RNG**: average of 9 wastewater RNG producers*
  - ***Organic waste RNG**: average of 5 organic waste RNG producers*
  - ***Dairy RNG**: average of 36 dairy manure RNG producers*

Fuel lifecycle GHG emissions relative to CA grid average carbon intensity



Emissions performance of various engine/fuel combinations relative to CPUC emission standards

Engine	Fuel	PM	NOx	Lifecycle GHG
Tier 2 CI	Diesel	x	x	x
	BD	x	x	●
	RD	x	x	●
Tier 4 CI	Diesel	●	●	x
	BD	●	●	●
	RD	●	●	●
SI rich burn gas recip.	Fossil NG	●	●	x
	Landfill RNG	●	●	●
	Wastewater RNG	●	●	●
	Organic waste RNG	●	●	●
	Dairy RNG	●	●	●
Linear generator	Fossil NG	●	●	●
	Landfill RNG	●	●	●
	Wastewater RNG	●	●	●
	Organic waste RNG	●	●	●
	Dairy RNG	●	●	●

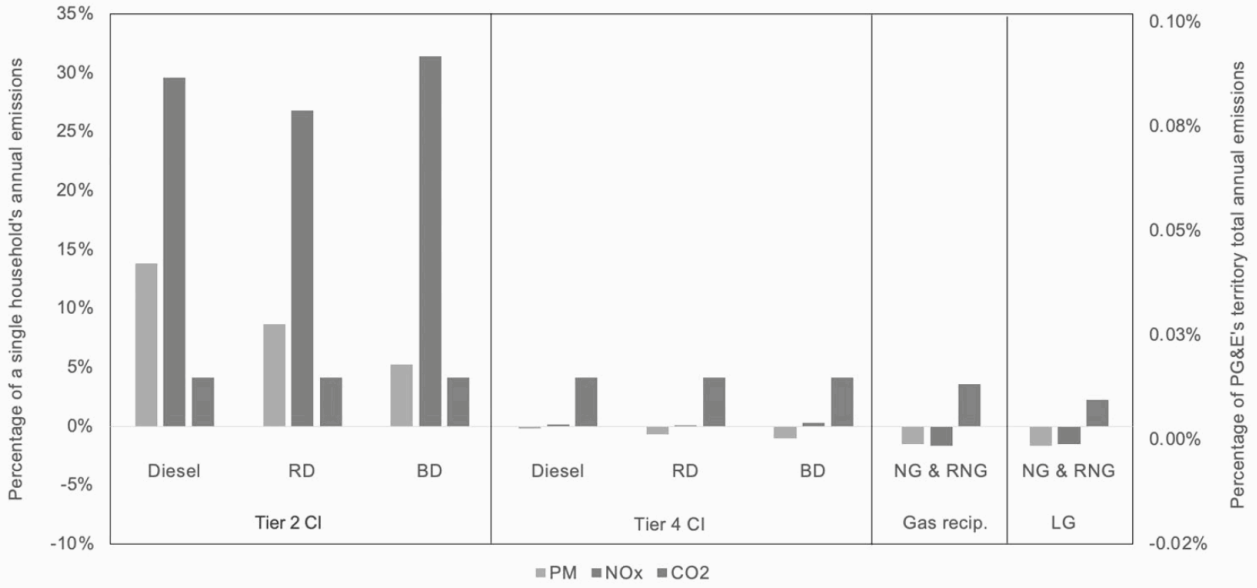
Contextualization of emissions impact

As it is difficult to comprehend or visualize the scale and scope of emissions and pollutant impacts, it is worth comparing the total volume of emissions relative to business-as-usual conditions in the absence of PSPS events.

To perform this exercise, we begin with the following assumptions based on historical PSPS event data:

- There will be **three PSPS events** in a representative year, with each event lasting **48 hours**.
- Five substations will be supported by temporary generation during a representative PSPS event, with a cumulative average load of **40 MW**.
- Thus, total PSPS generation capacity will be **5,760 MWh** (40MW x 3 events x 48 hrs/event).

Incremental increase of PM, NOx and CO_2 emissions from PSPS generation on a household basis (left axis) and a PG&E territory-wide basis (right axis)



- *CO_2 emissions include the direct emissions of engines, and omit biogenic emissions savings*
- *CH_4 and N_2O are omitted to maintain an apples-to-apples comparison with EIA California state electricity emissions data*

Exhibit 14

LCFS Pathway Certified Carbon Intensities

In keeping with section 95488.8(d) of the LCFS Regulation, all certified fuel pathways with their respective carbon intensities are provided below.

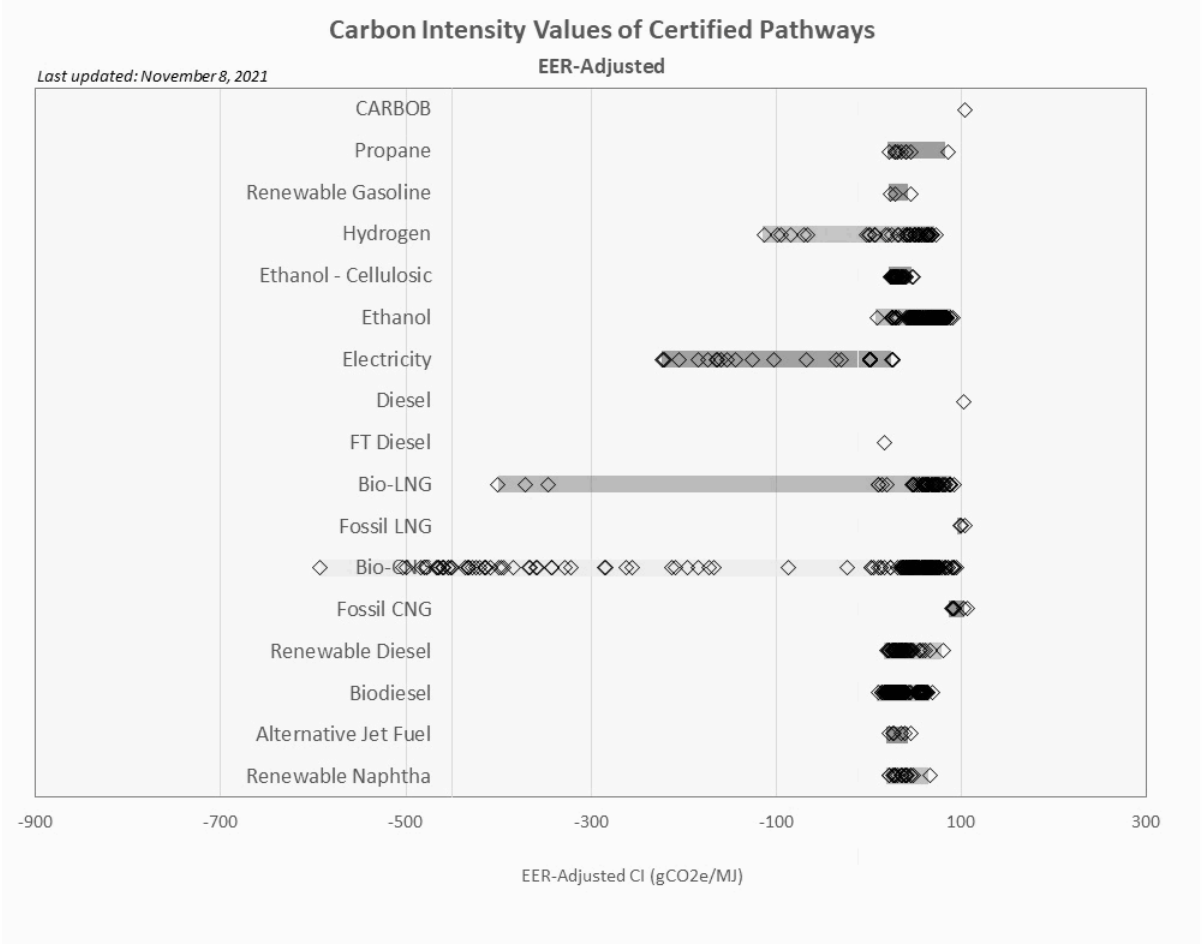
CATEGORIES

Programs Low Carbon Fuel Standard

Type Information

The alternative fuel's carbon intensity (CI) value is divided by its Energy Economy Ratio (EER) in order to obtain the EER-adjusted CI value, representing the emissions that occur from the use of alternative fuel per MJ of conventional fuel displaced.

The graph below shows the ranges of CI for each type of fuel compared to the two baseline fuels (gasoline and diesel). Each marker represents an individual certified fuel pathway CI, adjusted by the EER. The length of each bar indicates the range of carbon intensity that may be achieved by a fuel pathway. The wide range of carbon intensities is due to the life cycle emissions methodology of the LCFS, variations in feedstock types, origin, raw material production processing efficiencies, and transportation, all of which contribute to an individual producer’s fuel pathway CI. All valid CI values shown are certified including legacy, Tier 1, Tier 2 and Lookup Table pathways.



Fuel Pathway Table

The Current Fuel Pathways spreadsheet is searchable and sortable by feedstock, fuel, classification and/or facility name of your choice.

- Lookup Table: CARB internally developed the Lookup Table fuel pathways using the CA-GREET3.0 model.
- Tier 1/Tier 2: New Tier 1 and Tier 2 fuel pathways are modeled using the CA-GREET3.0 model.
- Legacy Pathways: Legacy pathways certified using CA-GREET2.0 are available for reporting through 2020 (or until they are replaced by a CA-GREET3.0 pathway).

To view the Substitute Pathways and Default Blend Levels for LCFS Reporting for Specific Fuel Transaction Types, visit Substitute Pathway Table.

Public Comments

Section 95488.7(d) of the LCFS Regulation requires that Tier 2 applications be posted for public comments before they can be certified by the CARB Executive Officer. Such pathways will be posted for public comments for a period of ten business days. At the end of the comment period, staff will review posted comments and if deemed substantive, request a formal response from the applicant. If the response from the applicant is deemed adequate, staff will recommend certifying the pathway. If deemed inadequate, the pathway application will be denied and the applicant may submit a new application for future consideration. In addition, section 95488.5(d) of the LCFS Regulation provides for an annual update to Lookup Table pathways for electricity. The CA-GREET3.0 model inputs and data sources used to calculate the annual update to the CA Average Grid Electricity CI will be posted for 45 days for public comment prior to certification. Public comments, applicant responses, and staff recommendations will be available on this webpage:

- Pathways Available for Public Comments

Additional Resources

- Apply for LCFS Fuel Pathway
- Life Cycle Analysis Models and Documentation
- Land Use Change Assessment

(800) 242-4450 | helpline@arb.ca.gov
1001 I Street, Sacramento, CA 95814
P.O. Box 2815, Sacramento, CA 95812

Exhibit 15

APPLICATION OF PACIFIC GAS AND ELECTRIC COMPANY (U 39-E) PROPOSING FRAMEWORK FOR SUBSTATION MICROGRID SOLUTIONS TO MITIGATE PUBLIC SAFETY POWER SHUTOFFS
(A.21-06-022)
DATA REQUESTS, FIRST SET
SMALL BUSINESS UTILITY ADVOCATES

TO:	PGE, M. Grady Mathai-Jackson (via email to Grady.Mathai-Jakson@pge.com)
FROM:	Michael Brown, on behalf of Small Business Utility Advocates
DATE SENT:	October 12, 2021
RESPONSES DUE:	November 15, 2021

Please provide your responses electronically, via email if possible, to each of the following people:

James Birkelund
Small Business Utility Advocates
548 Market St., #11200
San Francisco, CA 94080
Tel: (415) 602-6223
Email: james@utilityadvocates.org

Michael Brown
548 Market St., #11200
San Francisco, CA 94080
Tel: (415) 699-0261
Email: michael@visalialawyers.com

Jeffrey Winmill
Small Business Utility Advocates
548 Market St., #11200
San Francisco, CA 94080
Tel: (415) 602-6223
Email: jeff@utilityadvocates.org

Responses are requested immediately upon availability if possible prior to the requested due date. If PG&E has any questions or objections regarding these data requests, please call us right away. Please identify the person who provides the response and a contact phone number; please assume that these are ongoing requests and include updated responses that become available during these proceedings.

General Requests:

1. The interim approach set forth in D.21-01-018 required that PG&E evaluate low-cost, reliable electric isolation methods. Does PG&E only have the ability to disconnect customers at the distribution level? If so, who approves the PSPS shutdown of specific areas of distribution customers?

2. Does PG&E have the ability to shut down higher voltage lines in coordination with CAISO for PSPS events?
3. The interim approach set forth in D.21-01-018 required that PG&E study and report on the resiliency and microgrids not addressed in the Rule 21 proceedings. What has PG&E done to meet this requirement?
4. Does PG&E propose to contract with any companies to provide temporary generation products or services which prevent PG&E or other companies from repairing the technology which is installed? Are there "right to repair" clauses in any of the diesel or other types of generators which are required?
5. Why does PG&E believe that hydrogen or other clean fuel cell technologies are infeasible for providing temporary generation on a microgrid scale?
6. Why has PG&E not included a proposal for hiring additional staff for the projects proposed in this proceeding?
7. Has PG&E discovered the cause of the failures in the Lake County substations which require backup generation?
8. As part of PG&E's proposal for capitalizing "make ready" costs for upgrading its substations to receive and utility temporary generators is PG&E only proposing additional protection relays and wires, or is it proposing to install additional transformers?
9. Is PG&E proposing in this proceeding to offer contracts to any small business with less than 100 employees?

PACIFIC GAS AND ELECTRIC COMPANY
Long Term Procurement Framework for Generation to Mitigate PSPS
Application 21-06-022
Data Response

PG&E Data Request No.:	SBUA_001-Q01		
PG&E File Name:	LongTermProcureFrameworkforGenerationtoMitigatePSPS_DR_SBUA_001-Q01		
Request Date:	October 26, 2021	Requester DR No.:	001
Date Sent:	November 15, 2021	Requesting Party:	Small Business Utility Advocates
PG&E Witness:	Mark Esguerra	Requester:	Jeffrey Winmill

QUESTION 01

The interim approach set forth in D.21-01-018 required that PG&E evaluate low-cost, reliable electric isolation methods. Does PG&E only have the ability to disconnect customers at the distribution level? If so, who approves the PSPS shutdown of specific areas of distribution customers?

ANSWER 01

As part of PG&E's Public Safety Power Shutoff (PSPS) program, PG&E has the ability to de-energize customers at both the transmission and distribution levels.

Please see the attached (LongTermProcureFrameworkforGenerationtoMitigatePSPS_DR_SBUA_001-Q01_Atch01) excerpts from "RESPONSE OF PACIFIC GAS AND ELECTRIC COMPANY TO ENERGY SAFETY REMEDY PG&E-21-29 AND CHANGE ORDER REPORT" submitted on September 30, 2021 for a detailed description of PG&E's PSPS protocols.[1] Please also refer generally to PG&E's Post-Event De-Energization reports to the CPUC.

[1] The complete filing is available at: https://efiling.energysafety.ca.gov/Search.aspx?docket=2021-WMPs

PACIFIC GAS AND ELECTRIC COMPANY
Long Term Procurement Framework for Generation to Mitigate PSPS
Application 21-06-022
Data Response

PG&E Data Request No.:	SBUA_001-Q02		
PG&E File Name:	LongTermProcureFrameworkforGenerationtoMitigatePSPS_DR_SBUA_001-Q02		
Request Date:	October 26, 2021	Requester DR No.:	001
Date Sent:	November 15, 2021	Requesting Party:	Small Business Utility Advocates
PG&E Witness:	Mark Esguerra	Requester:	Jeffrey Winmill

QUESTION 02

Does PG&E have the ability to shut down higher voltage lines in coordination with CAISO for PSPS events?

ANSWER 02

Yes. PG&E has the ability to de-energize Transmission lines during PSPS events with coordination with the CAISO. Please see the attachment (LongTermProcureFrameworkforGenerationtoMitigatePSPS_DR_SBUA_001-Q01Atch01) and links referenced in PG&E's response to Question 1 for additional details.

PACIFIC GAS AND ELECTRIC COMPANY
Long Term Procurement Framework for Generation to Mitigate PSPS
Application 21-06-022
Data Response

PG&E Data Request No.:	SBUA_001-Q03		
PG&E File Name:	LongTermProcureFrameworkforGenerationtoMitigatePSPS_DR_SBUA_001-Q03		
Request Date:	October 26, 2021	Requester DR No.:	001
Date Sent:	November 15, 2021	Requesting Party:	Small Business Utility Advocates
PG&E Witness:	N/A	Requester:	Jeffrey Winmill

QUESTION 03

The interim approach set forth in D.21-01-018 required that PG&E study and report on the resiliency and microgrids not addressed in the Rule 21 proceedings. What has PG&E done to meet this requirement?

ANSWER 03

PG&E objects to the question as it calls for a legal conclusion, asserts facts not in evidence, and is vague.

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PG&E Data Request No.:	SBUA_001-Q04		
PG&E File Name:	LongTermProcureFrameworkforGenerationtoMitigatePSPS_DR_SBUA_001-Q04		
Request Date:	October 26, 2021	Requester DR No.:	001
Date Sent:	November 15, 2021	Requesting Party:	Small Business Utility Advocates
PG&E Witness:	Quinn Nakayama	Requester:	Jeffrey Winmill

QUESTION 04

Does PG&E propose to contract with any companies to provide temporary generation products or services which prevent PG&E or other companies from repairing the technology which is installed? Are there “right to repair” clauses in any of the diesel or other types of generators which are required?

ANSWER 04

PG&E’s Long-Term Procurement Framework for Generation to Mitigate PSPS does not propose criteria for vendors to perform repairs. This data request is therefore outside the scope of this application. Notwithstanding and subject to that objection, PG&E provides the following response:

PG&E does not contract with any companies to provide temporary generation products or services which prevent PG&E or other companies from repairing the technology which is installed. PG&E allows the provider of temporary generation products or services to provide repairs prior to seeking an alternative provider.

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Data Response

PG&E Data Request No.:	SBUA_001-Q05		
PG&E File Name:	LongTermProcureFrameworkforGenerationtoMitigatePSPS_DR_SBUA_001-Q05		
Request Date:	October 26, 2021	Requester DR No.:	001
Date Sent:	November 15, 2021	Requesting Party:	Small Business Utility Advocates
PG&E Witness:	Arti Dave	Requester:	Jeffrey Winmill

QUESTION 05

Why does PG&E believe that hydrogen or other clean fuel cell technologies are infeasible for providing temporary generation on a microgrid scale?

ANSWER 05

PG&E objects to this question because it assumes facts not in evidence. Notwithstanding and subject to that objection, PG&E's proposed long-term framework for procurement of substation microgrid solutions does not assume that hydrogen or other clean fuel cell technologies are infeasible. Any technology that meets the applicable eligibility criteria may bid into the competitive solicitations that would result from the framework.

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Data Response

PG&E Data Request No.:	SBUA_001-Q06		
PG&E File Name:	LongTermProcureFrameworkforGenerationtoMitigatePSPS_DR_SBUA_001-Q06		
Request Date:	October 26, 2021	Requester DR No.:	001
Date Sent:	November 15, 2021	Requesting Party:	Small Business Utility Advocates
PG&E Witness:	Quinn Nakayama	Requester:	Jeffrey Winmill

QUESTION 06

Why has PG&E not included a proposal for hiring additional staff for the projects proposed in this proceeding?

ANSWER 06

PG&E did not see a need to identify hiring additional staff for the projects proposed in this proceeding and therefore did not include it in the application.

PACIFIC GAS AND ELECTRIC COMPANY
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PG&E Data Request No.:	SBUA_001-Q07		
PG&E File Name:	LongTermProcureFrameworkforGenerationtoMitigatePSPS_DR_SBUA_001-Q07		
Request Date:	October 26, 2021	Requester DR No.:	001
Date Sent:	November 15, 2021	Requesting Party:	Small Business Utility Advocates
PG&E Witness:	Arti Dave	Requester:	Jeffrey Winmill

QUESTION 07

Has PG&E discovered the cause of the failures in the Lake County substations which require backup generation?

ANSWER 07

PG&E objects to this question on the basis that it is outside the scope of the proceeding and because it is vague. Notwithstanding and subject to that objection, PG&E interprets the question as requesting information about the cause of temporary generation equipment malfunctions in Lake County. At this time, PG&E is not aware of any temporary generation failures at substations in Lake County.

PACIFIC GAS AND ELECTRIC COMPANY
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PG&E Data Request No.:	SBUA_001-Q08		
PG&E File Name:	LongTermProcureFrameworkforGenerationtoMitigatePSPS_DR_SBUA_001-Q08		
Request Date:	October 26, 2021	Requester DR No.:	001
Date Sent:	November 15, 2021	Requesting Party:	Small Business Utility Advocates
PG&E Witness:	Quinn Nakayama	Requester:	Jeffrey Winmill

QUESTION 08

As part of PG&E's proposal for capitalizing "make ready" costs for upgrading its substations to receive and utility temporary generators is PG&E only proposing additional protection relays and wires, or is it proposing to install additional transformers?

ANSWER 08

Make ready costs cover substation upgrades required to operationalize temporary generation at a given location. Equipment needed to connect temporary generation is site specific. PG&E does not propose what kind of equipment is needed at the site as that will be dependent on the types of technologies that are being requested for interconnection and must be handled on a case-by-case basis.

PACIFIC GAS AND ELECTRIC COMPANY
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Data Response

PG&E Data Request No.:	SBUA_001-Q09		
PG&E File Name:	LongTermProcureFrameworkforGenerationtoMitigatePSPS_DR_SBUA_001-Q09		
Request Date:	October 26, 2021	Requester DR No.:	001
Date Sent:	November 15, 2021	Requesting Party:	Small Business Utility Advocates
PG&E Witness:	Quinn Nakayama	Requester:	Jeffrey Winmill

QUESTION 09

Is PG&E proposing in this proceeding to offer contracts to any small business with less than 100 employees?

ANSWER 09

PG&E holds an open request for offer for any bidders interested in providing a solution for substation microgrid. Bidders may include those with less than 100 employees.