Reminders

1. This is a long call. Please be aware of ergonomic risks and risks associated with sitting for long periods of time.


<table>
<thead>
<tr>
<th>Earthquake:</th>
<th>Active Shooter:</th>
</tr>
</thead>
<tbody>
<tr>
<td>❑ Know the safest places to duck, cover and hold, such as under sturdy desks and tables</td>
<td>❑ Get out, hide out, take out</td>
</tr>
<tr>
<td>❑ Call 911, if possible</td>
<td>❑ Call 911, if possible</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Fire:</th>
<th>Medical Emergency:</th>
</tr>
</thead>
<tbody>
<tr>
<td>❑ Know your exits and escape routes</td>
<td>❑ Are you alone or is someone else present to perform first aid/CPR as needed? If alone, be prepared to call 911</td>
</tr>
<tr>
<td>❑ Have a compliant fire extinguisher to be used only when safe to do so</td>
<td>❑ Do you have an AED? If so, ensure that your family or partner knows where it is and how to use it</td>
</tr>
<tr>
<td>❑ Most importantly, get out of the house and call 911</td>
<td></td>
</tr>
</tbody>
</table>
Desired Outcomes

1. Attendees are aware of and understand projects that PG&E and SCE are considering launching on the next wave of the EPIC 3 cycle.

2. Attendees understand next steps for these projects after today’s workshop.

3. Attendees have the opportunity to provide feedback to proposed projects before more detailed project execution plans are developed and before they are launched.

Please note the workshop will be recorded
• On April 28, 2017, PG&E filed A.17-04-028 for the third triennial investment plan period of 2018-2020 (referred to as EPIC 3) which included 43 proposed projects.

• On October 25, 2018 in D.18-10-052, the Commission approved the 43 projects in PG&E’s proposed EPIC 3 Investment Plan with minor modifications.

• The Commission also required the utilities to file a joint application containing a Research Administration Plan (RAP), identifying program administration improvements in response to the 2017 EPIC program evaluation within 180 days and required utilities not to commit, encumber or spend one-third of their EPIC 3 budgets until a subsequent decision that approved RAP.

• On April 23, 2019, the utilities filed their joint RAP application.

• February 10, 2020, the Commission issued D.20-02-003 approving the RAP application and authorizing the utilities to encumber, commit, and spend the remaining one-third of their EPIC 3 budgets.

• Today’s presentation relates to projects that are being planned under the remaining one-third of the EPIC 3 budget released by Commission decision D.20-02-003.
Context of Today’s Presentations

- Currently PG&E has 9 EPIC III projects in different stages of development.
- PG&E is planning to add 5-6 additional projects to its portfolio.
- Today’s projects were selected from 70 internal idea submissions, that went through an internal screening, refining and scoring process.
- Proposals that will be shared will be a combination of projects previously filed in PG&E’s EPIC III Investment Plan and new projects that aim to address emergent needs identified since PG&E’s EPIC III Investment Plan was developed in 2017.
- Any emergent projects that are selected will be submitted to the CPUC for approval in a Tier 3 advice letter pursuant to D.15-09-005 subsequent to this workshop.
- Attendees have the opportunity to provide feedback to proposed projects before more detailed project execution plans are developed and before they are launched.
PG&E EPIC 3 Wave 2 Planning Process Overview

**Internal Ideation & Screening**
EPIC PMO solicits and shapes new project ideas within authorized EPIC Project Categories:
1. Grid Modernization and Optimization
2. Customer Products & Services Enablement
3. Renewable Energy and DER Integration
4. Foundational Strategies & Technologies
EPIC PMO down-selects projects based on fit with EPIC and other criteria

**PG&E Director Scoring**

**Public Workshop**

**PG&E Officer Validation**

**CPUC Approval of Tier 3 Advice Letter**

**Guidance**

**Project Selection**
EPIC PMO prioritizes projects for funding informed by:
- Four sources of guidance
- Sponsor/project team preparedness and
- Portfolio balancing considerations

**Business Plans**
Project teams and PMO develop detailed Business Plan
Project teams seek approval of plan by critical stakeholders and PMO
If Business Plans are not complete in 2 months, projects request extension or are moved to waitlist

**Project Funding & Initiation**

6-12 months (depending on need for Tier 3 A/L)

* Tier 3 Advice Letter approval is **NOT** necessary for projects already identified in the CPUC-approved EPIC 3 investment plan.
**EPIC Areas of Focus**

**EPIC Project Categories & PG&E Strategic Guidance for EPIC projects**

**Foundational Strategies & Technologies**
- Advance smart grid architecture, cybersecurity, telecommunications
- Position PG&E for future, evolving grid
- Enhance and apply tools to better prepare and respond to natural disasters (e.g., wildfires)
- Enhance safety infrastructure and physical security (e.g., utilizing robotics and drones)

**Grid Modernization and Optimization**
- Demonstrate strategies and technologies to optimize utilization of existing assets (e.g., by deferring need for replacement or upgrades)
- Design and demonstrate grid operations of the future
- Further advancement of new processes and technology for T&D Planning
- Increase effectiveness of asset monitoring / asset health

**Customer Focused Products and Services Enablement**
- Enable customer choice
- Advance grid/grid edge capabilities
- Demonstrate technologies to increase EV and Energy Storage adoption

**Renewables and Distributed Energy Resources Integration**
- Enable DER growth and leverage both utility and customer owned DERs as a grid resource
- Demonstrate strategies and technologies to increase renewable resources on the grid
- Enable engagement with internal/external stakeholders (CAISO, aggregators, etc.)
EPIC Areas of Focus

Foundational Strategies & Technologies

- Acceleration of Power Flow Modeling
- RF Line Sensors
- Rate Scenario Engine
- DERMS
- Multi-Customer Microgrid
- Transformer Monitoring
- REFCL
- Maintenance Analytics
- Next Gen Meter
- System Harmonics
- Drone Enablement
- Momentary Outage

Grid Modernization and Optimization

- Operational Veg Mgmt Efficiency
- Early Fault Detection Expanded Study
- Grid Sensor Data Integration and Analytics
- Improved Fault Location
- Multi-Customer Microgrids utilizing FTM and BTM DERs
- EPIC 3.10 Grid Scenario Engine
- Stored Energy Transactions Enablement Platform
- Automated Fire Detection from Wildfire Alert Cameras
- Advanced Condition Monitoring for Remote Diagnostics
- Advanced Electric Inspection Tools Wood Poles

Customer Focused Products and Services Enablement

- FTM and BTM DERs
- Multi-Customer Microgrids
- Transformer Monitoring
- REFCL
- Maintenance Analytics
- Next Gen Meter
- System Harmonics
- Drone Enablement
- Momentary Outage

Renewables and Distributed Energy Resources Integration

- FTM and BTM DERs
- Multi-Customer Microgrids
- Transformer Monitoring
- REFCL
- Maintenance Analytics
- Next Gen Meter
- System Harmonics
- Drone Enablement
- Momentary Outage

Proposed EPIC Projects

- Acceleration of Power Flow Modeling
- RF Line Sensors
- Rate Scenario Engine
- DERMS
- Multi-Customer Microgrid
- Transformer Monitoring
- REFCL
- Maintenance Analytics
- Next Gen Meter
- System Harmonics
- Drone Enablement
- Momentary Outage

In Flight EPIC Projects

- Acceleration of Power Flow Modeling
- RF Line Sensors
- Rate Scenario Engine
- DERMS
- Multi-Customer Microgrid
- Transformer Monitoring
- REFCL
- Maintenance Analytics
- Next Gen Meter
- System Harmonics
- Drone Enablement
- Momentary Outage
EPIC Portfolio Mapping (CPUC Policy & Innovation Framework)

**GOALS**
- EMISSIONS REDUCTION
  - R.E. TECH DEVELOPMENT
  - TRANSPORTATION ELECTRIFICATION
  - HYDROGEN
  - BUILDING ELECTRIFICATION
  - ENERGY EFFICIENCY
  - LOW CARBON FUELS

- SAFETY
  - WILDFIRE MITIGATION
  - ASSET MANAGEMENT
  - FAULT DETECTION AND RESTORATION
  - PSPS
  - CYBERSECURITY
  - VEGETATION MANAGEMENT

- RELIABILITY / RESILIENCY
  - MICROGRID DEVELOPMENT
  - ENERGY STORAGE
  - RESOURCE ADEQUACY
  - SYSTEM BALANCING
  - FOREST BIOMASS
  - CLIMATE ADAPTATION

- AFFORDABILITY
  - INTEGRATED RESOURCE PLANNING
  - DEMAND SIDE MANAGEMENT / DERs
  - SYSTEM COST REDUCTION
  - UTILITY BUSINESS MODEL / INCENTIVES

**STRATEGIES**
- PROGRAM DESIGN
- WORKFORCE DEV
- EQUITY
- COST REDUCTION
- UTILITY BUSINESS MODEL
- OUTREACH / EDUCATION

**PROPOSED EPIC PROJECTS**
- 16 Acceleration of Power Flow Modeling
- 21 Operational Veg Mgmt Efficiency
- 104 Early Fault Detection Expanded Study
- 105 Grid Sensor Data Integration and Analytics
- 106 Improved Fault Location
- 110 Multi-Customer Microgrids utilizing FTM and BTM DERs
- 112 EPIC 3.10 Grid Scenario Engine
- 122 Stored Energy Transactions Enablement Platform
- 123 Automated Fire Detection from Wildfire Alert Cameras
- 124 Advanced Condition Monitoring for Remote Diagnostics
- 223 Advanced transformer protection
- 224 Advanced Electric Inspection Tools Wood Poles

**IN FLIGHT EPIC PROJECTS**
- 2.34 RF Line Sensors
- 2.36 Rate Scenario Engine
- 3.03 DERMS
- 3.11 Multi-Customer Microgrid
- 3.13 Transformer Monitoring
- 3.15 REFCL
- 3.20 Maintenance Analytics
- 3.27 Next Gen Meter
- 3.32 System Harmonics
- 3.41 Drone Enablement
- 3.43 Momentary Outage

* CPUC Policy & Innovation Coordination Group (PICG) draft framework for identifying areas for enhanced alignment and coordination on EPIC R&D across administrators.
<table>
<thead>
<tr>
<th>ID</th>
<th>Project Name</th>
<th>Summary</th>
<th>Presenter</th>
<th>Start Time</th>
<th>End Time</th>
</tr>
</thead>
<tbody>
<tr>
<td>16</td>
<td>Acceleration of Power Flow Modeling</td>
<td>Dramatically expedite grid scenario planning and as a result the processes that depend on it including Public Safety Power Shutoff (PSPS,)</td>
<td>JP Dolphin</td>
<td>10:15</td>
<td>10:25</td>
</tr>
<tr>
<td>21</td>
<td>Operational vegetation management efficiency through novel onsite equipment</td>
<td>Learn if new technologies and onsite processes can materially lower vegetation management costs. Test a) small-scale mobile torrefaction, and b) wood baling and other viable technologies.</td>
<td>Jameson Thornton</td>
<td></td>
<td></td>
</tr>
<tr>
<td>104</td>
<td>Early Fault Detection Expanded Study</td>
<td>Expand upon EPIC 2.34 to include Next Generation Early Fault Detection (EFD) Sensor complimentary capabilities with Rapid Earth Fault Current Limiting Technology (REFCL) and Distribution Fault Anticipation (DFA), and evaluate integration of alarms in the Distribution Management System (DMS). Further improve PG&amp;E’s capability in identifying and locating developing hazards on the distribution grid before it materializes.</td>
<td>Kevin Johnson</td>
<td>10:25</td>
<td>10:35</td>
</tr>
<tr>
<td>105</td>
<td>Grid Sensor Data Integration and Analytics</td>
<td>Integrate new combinations of grid sensor data and develop new analytic capabilities to identify, locate, and predict developing hazards for mitigation. Efficiently integrate and present correlated time series data to promote rapid learning of failure patterns and deployment of analytical detection models.</td>
<td>Lisa Kwientniak, Eric Schoenman, David Console</td>
<td>10:35</td>
<td>10:45</td>
</tr>
<tr>
<td>106</td>
<td>Improved Fault Location</td>
<td>Evaluate next generation Smart Meters and other technologies to capture fault induced sag voltage data. This project will use sag voltage and other end of circuit data along with new fault location calculation tools to further advance &amp; improve PG&amp;E’s incipient fault location capabilities to better pinpoint developing hazards before they materialize.</td>
<td>Lisa Kwientniak, Eric Schoenman, David Console</td>
<td>10:45</td>
<td>10:55</td>
</tr>
<tr>
<td>112</td>
<td>EPIC 3.10 Grid Scenario Engine</td>
<td>Develop a wide-scale distribution and/or transmission grid simulator to analyze multiple scenarios and future grid stressors (1) Develop utility microgrid operations, control, and tariff capabilities to island grid infrastructure, for the purpose of mitigating PSPS by utilizing both Front of the Meter (FTM) and customer owned DERs for multiple day islanded operation.</td>
<td>Bill Peter</td>
<td>11:05</td>
<td>11:15</td>
</tr>
<tr>
<td>110</td>
<td>Multi-customer Microgrids utilizing FTM and BTM DERs</td>
<td>Evaluate and assess a software platform that can conduct energy transactions online for customers with DERs to leverage excess energy.</td>
<td>Alex Portilla</td>
<td>11:15</td>
<td>11:25</td>
</tr>
<tr>
<td>122</td>
<td>Advanced transformer protection</td>
<td>Demonstrate and evaluate the use of negative sequence transformer differential protection to provide high sensitivity fault detection and prevent transformer winding failures</td>
<td>Alejandro Avendarbio</td>
<td>11:45</td>
<td>11:55</td>
</tr>
<tr>
<td>123</td>
<td>Automated Fire Detection from Wildfire Alert Cameras</td>
<td>Investigate if an automated fire detection model using machine learning, computer vision, or artificial intelligence (AI) techniques can accurately detect fires based on visual and infrared (IR) camera data streams; optimize for automated fire detection alerts</td>
<td>Ali Moazed, on behalf of Scott Strenfel</td>
<td>11:35</td>
<td>11:45</td>
</tr>
<tr>
<td>223</td>
<td>Advanced Electric Inspection Tools</td>
<td>Demonstrate and evaluate the use of a non-destructive examination method (Radiography Testing) to detect flaws and prevent potential failures on electric distribution wood poles</td>
<td>Tom Nguyen</td>
<td>11:55</td>
<td>12:05</td>
</tr>
<tr>
<td>224</td>
<td>Advanced Condition Monitoring for Remote Diagnostics</td>
<td>Demonstrate advanced real-time sensors for monitoring asset conditions, enabling an increasingly proactive maintenance and grid management operational model utilizing an ensemble of sensors coupled with Distribution Fault Anticipation (DFA) technology.</td>
<td>Jason Pretzlaf</td>
<td>12:05</td>
<td>12:15</td>
</tr>
<tr>
<td>124</td>
<td>Next Generation Distribution Automation, Phase 3 (NDGA 3)</td>
<td>Evaluates and demonstrates the latest advancements in technologies to improve reliability, personnel and public safety and operational efficiencies. One of the key activities of NDGA 3 is duct bank monitoring. Duct bank monitoring will demonstrate the feasibility of utilizing a dynamic modeling tool and real time monitoring system to improve the ability to manage loading of circuits, and better predict the temperature of substation cables, improving upon existing static limits used today.</td>
<td>Kevin Sharp</td>
<td>12:15</td>
<td>12:25</td>
</tr>
</tbody>
</table>
Presentation Format

- 3-5 minute project overview
- Followed by Q&A
- If needed time announcements at 3, 5, 8 and 10 minutes.
- For additional questions/comments for projects please email Epic_Info@pge.com until EOD, July 20th
- Please state your name and organization when asking questions or making comments.
16 - Acceleration of Power Flow Modeling

Project Sponsor: Quinn Nakayama

Project Lead: Jameson Thornton

Project Objective
Dramatically expedite grid scenario planning and, as a result, the processes that depend on it.

Concern / Gap Addressed
Grid power flow modeling is slow and in need of automation or alternative modeling by implementing pre-run scenario and parallelizing processes to inform critical real-time decision making such as Public Safety Power Shutoff (PSPS). Current software products are widely adopted in the west, but used in a very small market making it very difficult to invest in new and needed functionality improvements. There may be opportunity for partnership with software developers or across other large utilities.

Short Technology Description
Power flow modeling is completed ahead of all switching and planned outages - including PSPS events to identify and pre-test grid stability and confirm the availability of new fallback conditions (sometimes called N minus 1 minus 1 conditions). This requires significant engineering resources and is an important step in the PG&E Grid Control Center and CAISO. Unfortunately the end-to-end process includes manual steps and the software that completes the analysis is run on local machines. These limitations mean power flow modeling is a bottleneck for many processes. For example, the Grid Control Center required 72 hours of advance warning for Transmission PSPS decisions, limiting the company's ability to adapt to changing weather conditions.

Post EPIC Path to Commercialization:
Alternative computational approaches could be released as an API or micro-service that sits resides in an on-demand based interface that allows for fast access, speed to execute, auditability, and reusability.

Project Timeline
TBD – Pending Advice Letter, ideally before 2021 fire season. (Project duration 24 months)

Proposed Budget

<table>
<thead>
<tr>
<th>Internal Resources: $150K-$435K</th>
<th>External Resources: $850K-$2.5M</th>
<th>Total: $1M – $2.9M</th>
</tr>
</thead>
</table>

Key Stakeholder Groups

- IOU Grid Control Centers & Western Utilities
- CAISO

Project Benefits

5. Safety, Power Quality, and Reliability (Equipment, Electricity System):

- Electric system power flow congestion reduction (Public safety improvement and hazard exposure reduction)
  More scenarios analyzed may allow for the identification of a more optimal solution that impacts fewer customers

- Public safety improvement and hazard exposure reduction
  Dramatic reduction in the time improves PSPS operations. Less time required would allow to be more flexible and adapt to changing weather conditions (especially for transmission modeling)
Project Sponsor: Michael Koffman
Project Lead: Kevin Johnson

Project Objective
Learn if new technologies and onsite processes can materially lower vegetation management costs

Concern / Gap Addressed
• AFFORDABILITY: PG&E is planning to spend hundreds of millions for the foreseeable future on Vegetation Management (EVM), and lacks sufficient crews to proceed at desired speed.
• SAFETY: The cost of fuels management is one of the largest barriers to wildfire magnitude reduction
• CLEANLINESS: California faces a challenging and costly clean energy transition.

Short Technology Description
Demonstrate two high-ranking technology innovations as judged by PG&E and other environmental stakeholders from a recent “woody biomass open innovation challenge” that PG&E hosted, specifically a) small-scale mobile torrefaction, and b) wood baling. Torrefaction and wood baling technologies offer potential to densify woody biomass from vegetation management work and also transform that biomass into a relatively more useful form factor for possible subsequent conversion to value-added products.

Post EPIC Path to Commercialization:
1. Allow vendors to densify VM project wood onsite, then iterate & refine for PG&E context
2. Determine relative value vs. alternatives today (chipping)
3. Pending success, encourage consideration / evaluation by contractors (i.e. during contract negotiation)

Project Timeline
TBD – Pending Advice Letter

Proposed Budget

Internal Resources: $50K-100K
External Resources: $950K-$2.8M
Total: $1M – $2.9M

Key Stakeholder Groups
PG&E Vegetation Management contractors
California forestry industry
California woody biomass processing industry

Project Benefits

3. Economic Benefits
   a. Maintain / Reduce operations and maintenance costs
      AFFORDABLE: Transportation represents 25-50% of delivered wood cost; integration of effective densification, drying, and/or monetization of “non-merchantable” wood would have non-negligible benefits to year-over-year VM contract costs. The wood baling vendor claims that their equipment would also enable crew size reduction by two, freeing scarce labor for more locations.
   g. Co-benefits and co-products (e.g. feed, soil amendment, lithium extraction)
      CLEAN: Woody biomass could be a valuable input for California’s clean energy transition if available affordably, including as feedstock for renewable natural gas or hydrogen.

4. Environmental benefits
   a. GHG emissions reductions, b. criteria air pollution emissions reductions, c. water savings, d. water quality improvement
      Lowering costs for forest fuels management could increase the number of projects undertaken in years ahead to restore ecological forest health and reduce catastrophic wildfire damage.

5. Safety, Power Quality, and Reliability (Equipment, Electricity System)
   d. Public safety improvement and hazard exposure reduction
      SAFE: Could lower the cost barrier for forest management work by groups such as US Forest Service and private landowners, in turn lowering state public safety risk. Sound pollution and dust reduction could also help onsite safety outcomes.
Early Fault Detection Expanded Study

Project Sponsor: Jeff Deal  |  Project Lead: Lisa Kwietniak / David Console

Project Objective: Integrate the Radio Frequency Based Sensors with complementary technologies & capabilities to monitor and improve the detection of imminent failures as well as integrate it with the Distribution Management System to improve the capability in identifying and locating developing hazards on the distribution grid to enable mitigation before faults occur.

Concern / Gap Addressed: Improve the detection of imminent failures will improve wildfire risk mitigation capabilities. Identifying, locating, and predicting developing hazards before they materialize and preventing asset failures before they happen will help to best mitigate wildfire risk and improve public safety.

Short Technology Description: The key purpose of this project is to further evaluate Radio Frequency Based Sensors as a complementary technology to REFCL – a technology rapidly reduces the power in multi-wire distribution power lines when it detects a fault- and Distribution Fault Anticipation (DFA) - a substation-based technology that uses high-resolution voltage and current readings to detect issues on the distribution circuit - as well as to explore integration of alarms with the Distribution Management System. Having a suite of complementary technologies and detection capabilities will further evolve grid monitoring and automation to significantly enhance the ability to identify, locate, and predict developing hazards on the distribution grid before they materialize so that it can be mitigated.

This project will include 4 use cases: (1) Evaluate complementary capabilities of Radio Frequency Based Sensors with REFCL technology to identify and isolate faulted protection zone, (2) Evaluate complimentary capabilities on DFA outfitted distribution circuits to more effectively pinpoint shunt-arcing sources with continuous monitoring, (3) Evaluate integration of alarms with the Distribution Management System to enable Grid Operations to more accurately target field patrols to determine fault locations & causes for corrective actions, (4) Develop a richer set of configurable alarms for REFCL and the Distribution Management System with various thresholds, severities, and accumulation duration for system integration purposes.

Post EPIC Path to Commercialization: Expanded study will evaluate & determine Radio Frequency Based Sensor feasibility as a complementary technology on the Distribution Grid to further monitor & improve the detection of imminent failures. If determined feasible, deployment will be planned by Distribution Operations (and funded by the General Rate Case) as part of the company’s long-term technology roadmap of complementary grid sensing devices. The Radio Frequency Based Sensors will be integrated into the enterprise data platform for grid analytics that will enable Engineering, Operations, and Asset Management organizations to be empowered to leverage and derive value & insights from a rapid and convenient ability to analyze important historical and real-time events for mitigation.

Project Timeline: 24 Months After Advice Letter Approval

Proposed Budget:

| Internal Resources: $1.5M | External Resources: $1M | Total: $2.5M |

Key Stakeholder Groups:
- Investor Owned Utilities
- The State of California
- Communities and the Public

Project Benefits:
- Economic Benefits:
  - Maintain / Reduce operations and maintenance costs
  - Operational Cost: Preventative maintenance is a lower cost compared to emergency response and/or catastrophic events
- Safety, Power Quality, and Reliability (Equipment, Electricity System):
  - Outage number, frequency and duration reductions
  - Reliability: Planned proactive maintenance reduces unplanned outages & improves reliability/customer satisfaction
  - Public safety improvement and hazard exposure reduction
  - Identify and locate developing hazards before they materialize and prevent asset failures before they happen
  - Risk reduction and public safety improvement as preventative maintenance will prevent faults and potential wildfire ignition

Glossary:
- Early Fault Detection technology (Radio Frequency Based Sensor) that detects and locates Partial Discharge.
- Distribution Fault Anticipation (DFA) technology classifies disturbances through feeder current & voltage sampling.
- This is a substation-based technology that uses high-resolution voltage and current readings to detect issues on the distribution circuit.
- Distribution Management System is used to operate the grid.
- Rapid Earth Fault Current Limiting (REFCL) a technology that rapidly reduces the power in multi-wire distribution power lines when it detects a fault.
Early Fault Detection RF Sensor Technology

- EFD Sensors: Radio Frequency (RF) based detection and location of Partial Discharge (PD – arcing, sparking)
- Pole-mounted sensors work in pairs to monitor the line sections between them (~3 Miles)
- After processing & filtering, sensors record PD impulse data (voltage, energy, frequency, duration)
- For matching signal on adjacent sensors, time-of-flight ($\propto$ Distance) is used to determine location of PD source
- +/- 30 foot accuracy detecting PD source location (using GIS asset data)
EFD Sensor Monitoring and Data Detection Samples

Location vs. Date/Time (Left) and Map of Pole with Disturbance (right)

Detection Energy vs. Location

Phase Composition of Detections
EFD Sensors Detecting & Locating Potential Hazards

- Broken Conductor Strands
- Bullet in Conductor
- Squatting Insulator
- Vegetation in Open Secondary
- Bird Caging and Annealing
Grid Sensor Data Integration & Analytics

Project Sponsor: Jeff Deal
Project Lead: Lisa Kwietniak / David Console

**Project Objective**
Integrate novel combinations of grid sensor data and develop new analytic capabilities to identify, locate, and predict developing hazards for mitigation.

**Concern / Gap Addressed**
The ability to identify, locate, predict, and address hazards before they materialize can prevent asset failures and help mitigate wildfire risk. As PG&E has explored various distribution sensor technologies, it has recognized the value of combining sensor data to support this capability. However, PG&E has yet to fully unlock the value of its available grid sensor data due to the manual effort required to combine and analyze data from disparate sources. This also limits ability to apply scalable analytics to the problem.

As an example, Substation Distribution Fault Anticipation technology detects and classifies arcing events, but cannot determine source location without supplemental data from SCADA, Line Sensors, Smart Meters, and other technologies. Grid asset failures often present evidence in data patterns that could be captured by analytical models to produce alarms of appropriate severity. Multiple grid sensor data can be integrated to enable the development of novel advanced analytics to inform new preventative maintenance strategies.

**Short Technology Description**
This project would efficiently present correlated time series data to promote rapid learning of failure patterns and deployment of analytical detection models. This will empower multiple engineering and operations organizations to derive value and insights from rapid and convenient ability to analyze event data. By becoming predictive of developing hazards on the electric distribution system, PG&E will have more opportunities to proactively maintain & repair assets prior to failure.

**Post EPIC Path to Commercialization:**
The project will integrate grid sensor data and develop new and novel analytic capabilities. If successful, a larger scale roll-out will be planned by Distribution Operations and funded through the General Rate Case. These novel analytical capabilities will enable PG&E to optimize the value of existing data sources and distribution sensor technologies, as well as future technologies the company will deploy for the evolution towards automated grid monitoring.

**Project Timeline**
12-18 Months After Advice Letter Approval

**Proposed Budget**

<table>
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<tr>
<th>Internal Resources: $1M</th>
<th>External Resources: $0.5M</th>
<th>Total: $1.5M</th>
</tr>
</thead>
</table>

**Key Stakeholder Groups**

- Investor Owned Utilities
- State of California
- Communities and the Public

**Project Benefits**

3. Economic Benefits
   a. Maintain / Reduce operations and maintenance costs
      -Operational Cost: Preventative maintenance is a lower cost compared to emergency response and/or catastrophic events

5. Safety, Power Quality, and Reliability (Equipment, Electricity System)
   a. Outage number, frequency and duration reductions
      -Reliability: Planned proactive maintenance reduces unplanned outages and improves reliability and customer satisfaction
   d. Public safety improvement and hazard exposure reduction
      -Identify and locate developing hazards before they materialize and prevent asset failures before they happen
      -Risk reduction and public safety improvement as preventative maintenance will prevent faults and potential wildfire ignition
Data Integration & Analytics Concept

Data quality checks, corrections, filters, threshold logic, conversions.

Event Correlation by location, time, and conditions

Event Sequence and Mapping
Data Patterns

Correlations:
Event = f(wind speed)
Event = f(preceding momentary outage)
Event = f(transformer age)
Outputs from Current Manual Process

Series Arcing Event 10 days Before Failure

**EVENT TIMING**

**EVENT LOCATION**

**WEATHER OVERLAY**
106- Improved Fault Location

Project Sponsor: Jeff Deal
Project Lead: Eric Schoenman / David Console

Project Objective
Demonstrate new / novel methods to more accurately identify and locate emerging hazards, and thereby enable to more effectively address these issues before they manifest in asset failures. Past efforts to use captured fault magnitude data and distance to fault location modeling has shown additional data and better tools are necessary.

Concern / Gap Addressed
The ability to identify & locate developing hazards before they materialize and prevent asset failures before they happen will help to best mitigate wildfire risk. When using sensor captured fault magnitudes to determine possible fault location, faults are assumed to be zero impedance. In many cases the impedance is not zero, leading to incorrect calculated location. This may result in missed opportunities to locate & mitigate potential asset failures in a timely manner which increases wildfire risk. Technologies that can provide voltage sag and other voltage anomaly measurements along the circuit during faults are needed to more accurately estimate fault impedance to improve fault modeling & better predict location in smaller sections to more effectively target field patrols to mitigate potential issues.

Short Technology Description
PG&E has evaluated the capability of commercial and pre-commercial sensor technologies to more precisely detect and locate faults and developing hazards before they manifest in asset failure. If the identified issues are addressed prior to failure, this could prevent wildfire ignition. Next generation Smart Meters and other technologies will be evaluated to capture fault induced voltage measurements. This project will use sag voltage and other end of circuit data along with new fault location calculation and analytical tools to further advance & improve incipient fault location capabilities to better pinpoint and resolve developing fire ignition source hazards before they occur.

Post EPIC Path to Commercialization:
The project will use commercially available technologies suitable for evaluation. Results of the project will be used to help inform the longer term grid sensor technology roadmap plans for PG&E’s Distribution Grid Operations. If successful, pilot and deployment plans will be included in the General Rate Case.

Project Timeline
18 Months After Advice Letter Approval

Proposed Budget

| Internal Resources: $1.2M | External Resources: $0.4M | Total: $1.6M |

Key Stakeholder Groups

| Investor Owned Utilities | State of California | Communities and the Public |

Project Benefits
3. Economic Benefits
   a. Maintain / Reduce operations and maintenance costs
      -Operational Cost: Preventative maintenance is a lower cost compared to emergency response and/or catastrophic events

5. Safety, Power Quality, and Reliability (Equipment, Electricity System)
   a. Outage number, frequency and duration reductions
      -Reliability: Planned proactive maintenance reduces unplanned outages and improves reliability and customer satisfaction
   d. Public safety improvement and hazard exposure reduction
      -Identify and locate developing hazards before they materialize and prevent asset failures before they happen
      -Risk reduction and public safety improvement as preventative maintenance will prevent faults and potential wildfire ignition
• Evaluate next generation Smart Meters, Voltage Sag Monitors, & other technologies to capture fault induced sag voltage data.

• Use sag voltage data and other end of circuit data along with new fault location calculation tools to further advance and improve incipient fault location capabilities to better pinpoint developing hazards before they materialize.

• Reduce wildfire risk and improve public safety by identifying and locating potential hazards before they materialize for immediate mitigation and repair.
**112 - EPIC 3.10 Grid Scenario Engine**

<table>
<thead>
<tr>
<th>Project Sponsor:</th>
<th>Quinn Nakayama</th>
<th>Project Lead:</th>
<th>Mike McCarty / Bill Peter</th>
</tr>
</thead>
</table>

**Project Objective**
Develop a wide-scale distribution and/or transmission grid simulator for analyzing multiple scenarios and potential future stressors to the grid.

**Concern / Gap Addressed**
A tool to inform overall strategy for long term grid investments that can inform decision making under a variety of long-term scenarios, answering such questions as:
1. What should the grid look like in 15 to 20 years?
2. What would the grid look like if it were greenfielded?
3. How do we evaluate near-term grid investment decisions under different long-term scenarios?

**Short Technology Description**
The scenario engine could examine the impacts on grid architecture of various inputs, including:
- Changes in usage behavior
- Major economic stressors (e.g., economic depression)
- Increased distributed energy resources (DER) technologies and integration rates
- High electrification (e.g., EV adoption and building electrification)
- Impacts of climate change, including the increased need for resiliency.

The project could leverage work previously done by IIT Comillas or NREL.

**Post EPIC Path to Commercialization:**
- Apply research concepts in a more commercial environment.
- Coordinated across internal teams and explore external options for development
- Inform decision makers in future asset management and grid design
- Inform future design standards

**Proposed Budget**

| Internal Resources: $1.0M | External Resources: $1.0 - $2.0M | Total: $1-2.9M |

**Key Stakeholder Groups**
- IOUs
- National Labs
- Electrification and EV adoption advocates

**Project Benefits**

3. Economic Benefits
   - a. Maintain / Reduce operations and maintenance costs
   - b. Maintain / Reduce capital costs
   - c. Reduction in electrical losses in the transmission and distribution system

5. Safety, Power Quality, and Reliability (Equipment, Electricity System)
   - a. Outage number, frequency and duration reductions
   - d. Public safety improvement and hazard exposure reduction
What should the grid look like in 15 to 20 years?

What would the grid look like if it were greenfielded? How is it different from today’s grid?

How do we evaluate near term grid investment decisions under different long term scenarios?

These are some of the key questions that could be answered by the Grid Scenario Engine.
Develop a wide-scale distribution and/or transmission grid simulator for analyzing multiple scenarios and potential future stressors to the grid.

Inputs (For Illustration Purposes)

- Usage Behavior
- Major Economic Stressors
- DER integration
- EV Adoption/Building Electrification
- Climate Change

Output

High-level grid architecture and design.
112 - EPIC 3.10 Grid Scenario Engine

Remote Grid

Substation Placement

Transmission Line Routing

Hardening/Undergrounding

Distribution System Routing
• The output of the scenario engine will be used to inform high-level decision making.

• Rather than providing a detailed, plug-and-play grid design, the tool will provide guidance on overall grid architecture under various planning scenarios.

• The output could be used to aid in regulatory and policy conversations regarding long term grid design.
Project Sponsor: Quinn Nakayama

**Project Objective**
- Objective 1: Develop utility microgrid operations, control, and tariff capabilities to island grid infrastructure, for the purpose of mitigating Public Safety Power Shutoff (PSPS) by utilizing both front of meter (FTM) distributed energy resources (DERs) and customer owned, behind the meter (BTM) generation and load management for multiple day islanded operation.
- Objective 2: Develop the utility capabilities to use DERs on non event days (i.e. during normal operations) to address the grid management impact of exporting BTM generation.

**Concern / Gap Addressed**
1. Customers are increasingly requesting to participate with utilities to mitigate PSPS impacts using BTM resources supporting multiple customer service points using utility operated grid infrastructure.
2. CA energy policies are moving to clean energy supplied microgrids with less reliance on fossil generation. The utilities are required to adopt battery energy storage system (BESS). Policies are encouraging energy service providers and customers to develop localized sources of energy to mitigate PSPS.
3. GAP: How to form a grid from a small group of grid segments, apply protection schemes during high photovoltaic (PV) gen output (day) and no PV gen output (night) in a limited grid segment area, using the BTM PV to round trip (charge/discharge) FTM batteries. Establishing the role and communications path of the utility owned microgrid controller to operate BTM resources or develop a strategy to overcome the challenges without direct control of BTM resources.

**Short Technology Description**
1. Develop capabilities for microgrid control programming, large DER and islanded fault protection, BTM DER overgeneration control management, BTM load management, FTM PSPS pre-event preparation schema, operational communication to FTM and BTM DERs, and utility standards to design and operate the systems in island mode and during transitions from normal grid conditions to islanded operations.
2. The project will enhance PG&E’s microgrid test bed capabilities developed to support the EPIC 3.11 Location Targeted DER project (aka. Redwood Coast Airport Microgrid) in order to demonstrate the developed programming, processes, and equipment operation prior to field demonstration.
3. As a secondary objective the project will develop and demonstrate control and communications functions for localized grid management of BTM DER’s using FTM DERs during normal grid operations.

**Post EPIC Path to Commercialization:**
Establish control and protection strategies to include BTM DERs within a microgrid. Establish standard operating protocols for pre-event DER management, in event operations, and grid connected mode localized grid management. Apply these standards, strategies, and processes to future customer requests and PSPS mitigation partnerships.

**Project Timeline**
Upon approval expected project duration is 18-24 months

**Proposed Budget**

| Internal Resources: $1-2M | External Resources: $2-4M | Total : $3-6M |

**Key Stakeholder Groups**
- PG&E: Grid Innovation, Electric Operations, IT Applied Technology Services
- External: Customers with BTM DERs, DER developers, DER technology vendors (e.g. Inverters, controllers), CCAs and other community orgs, CPUC

**Project Benefits**
1. Economic Benefits
   - f. Improvements in system operation efficiencies stemming from increased utility dispatchability of customer demand side management
   - Enhances the role of the utility to plan, decide, and operate the distribution grid and microgrid configurations.

4. Environmental benefits
   a. GHG emissions reductions (MMTCO2e)
   - Allows the utility to leverage DER penetration densities to incorporate cleaner forms of microgrid energy sources.

5. Safety, Power Quality, and Reliability (Equipment, Electricity System)
   a. Outage number, frequency and duration reductions
   - Enables customers to leverage their investments keeping their own facilities energized during a PSPS event and potentially additional customers within the islanded grid segments.
   d. Public safety improvement and hazard exposure reduction
   - Develops PSPS mitigation and customer impact reduction strategies
# Stored Energy Transactions Enablement Platform (SETEP)

<table>
<thead>
<tr>
<th>Project Sponsor:</th>
<th>Jan Berman</th>
<th>Project Lead:</th>
<th>Eban Hamdani</th>
</tr>
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</table>

## Project Objective
Investigate, Evaluate and assess a software platform that can conduct energy transactions online for customers with Distributed Energy Sources (DERs) to leverage excess energy.

## Concern / Gap Addressed
California’s residents have increasingly adopted distributed energy resources (i.e. solar panels and batteries.) Customers have the ability/control to island from the grid at an individual and at a community level. The excess storage of the DERs can be leveraged for the utility as it can assist with demand response, gives a potential monetary value to the generating customer’s excess energy. Development of this platform would serve as a key building block to offer transactive energy as a potential alternative to NEM (Tariff/policy development pending).

## Short Technology Description
The study will focus on researching and prototyping a software platform where energy transactions can take place for customers with stored energy (vehicles, home batteries) to consuming customers or utility.

## Post EPIC Path to Commercialization:
1. Research software platforms that enables customers with DER's to conduct transactions of excess generated energy.
2. Partner with experts in transactive energy space to frame a viable solution
3. Prototype platform to test enablement of transactions and accumulate data points for iterations, document findings
4. Prepare for a potential demonstration with select group of customers (a potential future EPIC project.)

## Project Timeline
TBD – Pending Advice Letter – Estimated project duration is 18 months

## Proposed Budget
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## Key Stakeholder Groups
- DER Community
- Customers and Prosumers
- IOUs

## Project Benefits

1. Potential energy and cost savings
   - Number and percentage of customers on time variant or dynamic pricing tariffs
   - Peak load reduction (MW) from summer and winter programs
     - Assist with demand response & peak shaving
   - Percentage of demand response enabled by automated demand response technology (e.g. Auto DR)
     - Assist with demand response & peak shaving
   - Customer bill savings (dollars saved)
     - Potential to buy energy at lower cost
     - Potential monetary value associated with excess generated energy

2. Environmental benefits
   - GHG emissions reductions (MMTCO2e)
     - Help meet individual decarbonization goals and consume cleaner energy
# Automated Fire Detection from Wildfire Alert Cameras

**Project Sponsor:** Ben Almario

**Project Lead:** Scott Strenfel / Shaun Tanner

**Project Objective**

PG&E, other major CA utilities, and local and federal agencies are installing hundreds of wildfire alert cameras. Data and images from these cameras are publicly available via [http://www.alertwildfire.org/](http://www.alertwildfire.org/). This project will investigate if an automated fire detection model using machine learning, computer vision, or artificial intelligence techniques can more accurately detect fires based on visual and IR camera data streams. The model investigated will be optimized for automation such that near real-time fire detection alerts can be disseminated if smoke and/or an IR fire signature is detected.

**Concern / Gap Addressed**

1. This project leverages the rich camera network that is already available and will be enhanced over the next several years to automatically detect fires. Earlier detection of fires can lead to earlier response times by first responders to help limit a fire’s potential spread and consequence.

2. Wildfires have become a major factor in CA energy policies and models suggest will get worse with climate change.

3. At present, the rich data from these cameras are not being used to automatically detect wildfires. With hundreds of cameras now deployed and hundreds more on the way, analysts will not have the capability to monitor feeds from each camera. This technology aims to complement other forms of fire detection platforms, such as satellite data, to detect fires as fast as possible.

**Short Technology Description**

This project will investigate the optimal technology and model that can be deployed operationally to automatically detect fires from alertwildfire cameras. The project workflow will be similar to how neural networks for self-driving vehicles are being developed. First, images of known smoke plumes and IR signatures from fires are sourced from existing alertwildfire images to train and optimize the model. A subset of the images sources will be utilized as a validation dataset to compute precision and recall and other metrics to determine model performance. The model can then be optimized in an iterative process to limit errors of commission and omission. Next, the model can be tested in real-time against alertwildfire imagery.

**Post EPIC Path to Commercialization:**

After model development, it can be deployed to automatically monitor feeds from each camera and generate alerts for any camera where fire is detected. PG&E has deployed an Fire Detection and Alert System in-house that can geographically display where new fires are located from any source. These alerts can also be integrated directly into the public alertwildfire.org page to highlight those cameras where fires are visible.

**Project Timeline**

TBD – Pending Advice Letter  Expected project duration is 12-24 months

### Proposed Budget

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### Key Stakeholder Groups

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<th>Cal Fire</th>
<th>CalOES</th>
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### Project Benefits

5. Safety, Power Quality, and Reliability (Equipment, Electricity System)

d. Public safety improvement and hazard exposure reduction

Increased public safety, enhanced awareness of emerging incidents to enable rapid response, potentially reduced carbon emissions from wildfire. Faster alerts of fires give firefighters and first responders a better chance to contain incidents by dispatching air and ground resources. Once a fire is detected by the camera, it can be monitored in real time to determine spread and fire behavior.
Project Sponsor: Davis Erwin  |  Project Lead: Alejandro Avendaño

**Project Objective:**
Demonstrate and evaluate the use of negative-sequence transformer differential protection to provide high sensitivity fault detection and prevent catastrophic failures.

**Concern / Gap Addressed:**
Internal winding faults are one of the most common causes of transformer failure. Catastrophic failures often start as low magnitude turn-to-turn faults that were left undetected and that later developed into a more severe fault. PG&E protective devices presently do not have enough sensitivity to detect inter-turn faults which poses a risk to public and utility worker safety. This project aims to test and apply a novel protective relay that claims to possess enough sensitivity for inter-turn fault detection.

**Short Technology Description:**
Phase 1 would entail the development of computer models to calculate protective relay settings. Phase 2 would entail the construction of a test bed that would test proposed settings and demonstrate the operation of the protective relay. Phase 3 would entail installing the relay on a real transformer and demonstrate the protection operation under real fault conditions in a controlled laboratory environment. If proven successful, this functionality could be enabled at a field location.

**Post EPIC Path to Commercialization:**
If successful, the new protection element could be applied by PG&E system protection engineering to a number of existing protective relays within the PG&E service territory and inform relay life-cycling plans through capital/expense budgets.

**Project Timeline:**
TBD – Pending Advice Letter  Expected project duration is 24 months

**Proposed Budget**

| Internal Resources: $1.5M | External Resources: $0.5K | Total : $2M |

**Key Stakeholder Groups**

| IOUs & Other Utilities | PG&E System Protection |

**Project Benefits**

5. Safety, Power Quality, and Reliability (Equipment, Electricity System)
   d. Public safety improvement and hazard exposure reduction
   e. Utility worker safety improvement and hazard exposure reduction

This project will advance the prevention of catastrophic failures of transformers which are critical assets for maintaining continuity of power to customers. Catastrophic failures of transformers are also a source of BLEVE (Boiling Liquid Expanding Vapor Explosion) that are a risk to public and utility worker safety. This project will aim to reduce this risk through the application of latest advancements in protection technology.
Negative-Sequence Differential Protection*

Fig. 6. Fault trajectories (in red) of the 87Q (a) and 87P (b) elements and their impact on speed of operation.

Project Sponsor: John Birch / Jeff Borders

Project Objective: Demonstrate and evaluate the use of a non-destructive examination method (Radiography Testing) to detect flaws and prevent potential failures on electric distribution wood poles.

Concern / Gap Addressed: Current asset inspection processes primarily rely on what is visible to the human eye. Visual inspection is the first step to pole inspection and is considered the lowest accuracy. Wood pole decay is a common defect and can occur on the inside of the pole which is not visible to the naked eye. Wood poles with internal decay may look perfect externally. However, signs of degradation as well as failure may be detectable through the use of non-destructive examination. The use of non-destructive examination such as RT can supplement traditional inspections (visual, intrusive, etc.).

Short Technology Description: The scope is to inspect wood poles with Radiography Testing (RT). RT will be able to help us identify the remaining quality and strength of the wood pole by understanding the grain structures and evaluate the residual strength of wood pole. RT will also provide information on wood density in which we can determine moisture content to evaluate any risk of biodegradation or wood decay. RT is widely used in Gas Operations on natural gas pipelines. With the large amount of experience in RT, we’ve continued to grow our skills and acquired the latest technology for the work. We are looking to expand the use of RT on electric assets such as wood poles.

Post EPIC Path to Commercialization: The tests will initially be conducted at Applied Technology Services in a controlled environment on various quality wood poles with simulated defects and actual defects. Once testing is proven successful and the right data is selected, collected and analyzed, it can then be performed in field on existing assets as a pilot. Once pilot is successful, technology to be deploy into production.

Project Timeline: TBD – Pending Advice Letter Expected project duration is 18 months

Proposed Budget

| Internal Resources: 800K | External Resources: 200K | Total: $1.0M |

Key Stakeholder Groups

- IOUs & Other Utilities

Project Benefits

5. Safety, Power Quality, and Reliability (Equipment, Electricity System)
   d. Public safety improvement and hazard exposure reduction
      • Provides another method to identify asset defects before failure which will reduce overall risks associated with asset downtime, employee safety, and public safety
      • Allows for an opportunity to proactively replace of equipment which leads to improved customer reliability and lower costs
      • Provides an additional data stream for asset knowledge aiding in the risk assessment for integrity management
**Project Sponsor:** David Console/Jeff Deal  

**Project Lead:** Jason Pretzlaf

**Project Objective**

This project will seek to demonstrate advanced real-time sensors for monitoring asset conditions, enabling an increasingly proactive maintenance and grid management operational model utilizing an ensemble of sensors coupled with Distribution Fault Anticipation (DFA) technology, a substation-based technology that uses high-resolution voltage and current readings to detect issues on the distribution circuit. The project will focus on expanding learnings to identify causes and locations of shunt events, close existing classification engine gaps for shunt arcing, and evaluate the moving of new sensing type technology into line recloser (LR) or switch controller packages.

**Concern / Gap Addressed**

DFA technology excels in the identification of incipient conditions including shunt arcing events. Other sensor technologies currently deployed cannot detect these types of events. Quickly locating these types of events presents a technology gap. There is a need to gain further understanding of this phenomenon and its causes (Phase 1). One strategy is to improve the current classification engine using new sensor technology to further clarify causes. This requires a larger dataset then can be obtained from the sensors currently fielded (Phase 2). Finally, along with an expanded classification engine, moving the sensing technology further out from the substation will hone locating, either through device specific siting or integrating technology directly into field controllers (Phase 3).

**Short Technology Description**

The project is anticipated to consist of three phases with checkpoints prior to initiating the next phase.

1. **Phase 1** will entail continued evaluation of PG&E’s existing 7 DFA instrumented circuits in the North Bay to focus on the shunt arcing incipient condition, and developing an ensemble sensor approach.
2. **Phase 2** will expand the sensor technology deployment to more circuits to increase the training of classification engine on shunt arcing and other unclassified events. Expansion will leverage learnings from Phase 1.
3. **Phase 3** will explore the potential to integrate new sensing technology into LR or switch controllers (5-10 total) to narrow locating of arcing events.

**Post EPIC Path to Commercialization:**

Upon successful completion of the EPIC project, GRC funding will be pursued to expand DFA technology to additional feeders in a phased approach. We anticipate a scaling rate of 50 circuits in the first year and 100-120 circuits every year thereafter until all the Tier 2/3 feeders have DFA. Upon reaching 100 total circuits, IT infrastructure will be upgraded to host the increased number of sensors.

**Project Timeline**

Expected project duration is 24 months

**Key Stakeholder Groups**

- IOUs & Other Electric Utilities
- U.S. Department of Energy

**Project Benefits**

3. **Economic benefits**
   a. Maintain / Reduce operations and maintenance costs  
   Lower operational cost: Preventative maintenance is lower cost than emergency response and prevents the collateral facility damage of equipment failures

5. **Safety, Power Quality, and Reliability (Equipment, Electricity System)**
   a. Outage number, frequency and duration reductions  
   Improved reliability: Planned proactive maintenance will reduce unplanned outages
   d. **Public safety improvement and hazard exposure reduction**  
   Preventative maintenance to prevent faults & potential wildfire ignition

**Proposed Budget**

| Internal Resources: $130k (Phase 1), TBD (Phase 2), TBD (Phase 3) | External Resources: $220k (Phase 1), TBD (Phase 2), TBD (Phase 3) | Total : $350k (Phase 1), TBD (Phase 2), TBD (Phase 3) - High Priority |

<table>
<thead>
<tr>
<th>Key Resource Group</th>
<th>Budget Information</th>
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<td>IOUs &amp; Other Electric Utilities</td>
<td>$130k (Phase 1), TBD (Phase 2), TBD (Phase 3)</td>
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<td>U.S. Department of Energy</td>
<td>$220k (Phase 1), TBD (Phase 2), TBD (Phase 3)</td>
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35
What is shunt arcing and why is it hard to detect?

DFA captures five different types of arcing events in two general areas: shunt and series. Shunt-arcing is an important indicator of both faulted conditions and incipient events. **DFA is the only sensor technology that can identify and measure shunt arcs.**

- Arcing events are not faults, they are low energy events. Typically they last for only a few cycles.
- Detection by magnitude tripping is not possible – relays and line sensors cannot detect shunt arcing.
- Cumulative RF sensors can be either periodic or continuous in their sampling approach. Periodic sensors have probabilistic chance of capturing these arcing events. For either sampling approach, shunt-arcing one-off events give weak cumulative signals.

![Example of Arc Current Signal Extraction](image)

![Arcing Events Collected by Type](image)

![Typical Shunt Arcing Event RMS Signal (2 cycle event)](image)
Project Sponsor: Brandon Tolentino  
Project Lead: Jim Palma

Project Objective:
The goal of SCE’s Duct Bank Monitoring project is to empower System Operators to better balance circuit load and also prevent excessive duct bank planned cable temperatures due to circuit overloading, which could lead to premature, catastrophic cable failure. Having an accurate Duct Bank Monitoring Amperage Limit Estimation Model tool and real-time monitoring system for existing substation duct banks would allow for the avoidance of this overheating by providing the ability to manage circuit loading.

Concern/Gap Addressed:
This project is aimed at strengthening and modernizing its electric grid. More specifically, this project will help demonstrate and ultimately enable the following technological capabilities:
• Advance the Distribution Sensing & Monitoring Capability by providing real-time monitoring and modeling capabilities of substation amperage and duct bank cable temperature which allows SCE to perform and formulate effective load management strategies to reduce wear on SCE grid assets.
• This project advances the Data Driven Decision-Making capability of providing tools and solutions to analyze substation, duct bank and cable data and deriving business value.

Short Technology Description:
The proposed system will have sensing, communications and computational modeling and analysis components. The key elements of the proposed system would include a preliminary lab modeling configuration (for preliminary validation) followed by a more representational operational configuration such as implementation in the GMS.

Post-EPIC Path to Commercialization:
If proven to be accurate, this real-time model will help validate or enhance future cable ampacity modeling.

Project Timeline: Q3/2020 – Q4/2022

<table>
<thead>
<tr>
<th>Proposed Budget</th>
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<td>Internal Resources</td>
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<td>$600K</td>
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Key Stakeholder Groups
Distribution Engineering | Distribution Apparatus Engineering | IT Cybersecurity & Compliance | Asset & Engineering Strategy

Project Benefits
Grid Strengthening & Modernization and Operational & Service Excellence
• Ability of System Operators to temporarily exceed the historic circuit amperage limit in order to enhance real-time load management, without violating cable temperature ratings
• Ability to get more utilization from the SCE Distribution network, deferring system upgrades
• Reduce complex reconfiguration and switching operations presently used to balance load
Deck will be uploaded to pge.com/epic page in a week.

For additional questions/comments for projects please email Epic_Info@pge.com until EOD, July 20th

Thank you!
In addition to contacting the leads, please copy Epic_Info@pge.com on your correspondence with PG&E projects.

<table>
<thead>
<tr>
<th>ID</th>
<th>Project Name</th>
<th>Presenter</th>
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<tr>
<td>16</td>
<td>Acceleration of Power Flow Modeling</td>
<td>JP Dolphin</td>
<td><a href="mailto:J.P.Dolphin@pge.com">J.P.Dolphin@pge.com</a></td>
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<tr>
<td>21</td>
<td>Operational vegetation management efficiency through novel onsite equipment</td>
<td>Kevin Johnson</td>
<td><a href="mailto:Kevin.Johnson@pge.com">Kevin.Johnson@pge.com</a></td>
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<tr>
<td>104</td>
<td>Early Fault Detection Expanded Study</td>
<td>Lisa Kwietniak</td>
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<tr>
<td></td>
<td></td>
<td>Eric Schoenman</td>
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<td>David Console</td>
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<td>105</td>
<td>Grid Sensor Data Integration and Analytics</td>
<td>Lisa Kwietniak</td>
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<td>106</td>
<td>Improved Fault Location</td>
<td>Lisa Kwietniak</td>
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<tr>
<td>112</td>
<td>EPIC 3.10 Grid Scenario Engine</td>
<td>Bill Peter</td>
<td><a href="mailto:William.Peter@pge.com">William.Peter@pge.com</a></td>
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<td>110</td>
<td>Multi-customer Microgrids utilizing FTM and BTM DERs</td>
<td>Alex Portilla</td>
<td><a href="mailto:Alex.Portilla@pge.com">Alex.Portilla@pge.com</a></td>
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<td>122</td>
<td>Transactive Energy Platform for Facilitation of Two-Way Transactions from Distributed Energy Resources</td>
<td>Eban Hamdani</td>
<td><a href="mailto:Eban.Hamdani@pge.com">Eban.Hamdani@pge.com</a></td>
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<td>123</td>
<td>Automated Fire Detection from Wildfire Alert Cameras</td>
<td>Ali Moazed on behalf of Scott Strenfel</td>
<td><a href="mailto:Scott.Strenfel@pge.com">Scott.Strenfel@pge.com</a></td>
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<tr>
<td>223</td>
<td>Advanced transformer protection</td>
<td>Alejandro Avendaño</td>
<td><a href="mailto:Alejandro.AvendanoCecena@pge.com">Alejandro.AvendanoCecena@pge.com</a></td>
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<td>224</td>
<td>Advanced Electric Inspection Tools</td>
<td>Tom Nguyen</td>
<td><a href="mailto:Tom.Nguyen@pge.com">Tom.Nguyen@pge.com</a></td>
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<td>124</td>
<td>Advanced Condition Monitoring for Remote Diagnostics</td>
<td>Jason Pretzlaf</td>
<td><a href="mailto:Jason.Pretzlaf@pge.com">Jason.Pretzlaf@pge.com</a></td>
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<tr>
<td>SCE</td>
<td>Next Generation Distribution Automation, Phase 3 (NDGA 3)</td>
<td>Kevin Sharp</td>
<td><a href="mailto:Kevin.Sharp@sce.com">Kevin.Sharp@sce.com</a></td>
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