Transmission Project Review Process
Stakeholder Meeting

February 4, 2025



Safety Orientation: Remote Workplace

Earthquake

Know the safest places to duck, cover, and hold, such as under sturdy desks and tables.

Fire

Know your exits, escape routes, and evacuation plan. If safe to do so, use your compliant fire extinguisher. Exit the house, and call 911.

Active Shooter

Get out, hide out, take out, and call 911.

Medical Emergency

Know who can perform first aid and CPR. Call 911 if you're alone or share your location with the call leader to send help.

Psychological Safety

- ✓ I'm cared for.
- ✓ People have my back and I have theirs.
- ✓ It's safe to take risks.
- ✓ New ideas are welcome.
- ✓ I practice self-care.

Ergonomics

- ✓ Practice *30/30* (every 30 minutes, move & stretch for 30 seconds).
- ✓ Schedule a virtual ergonomic evaluation through RSI Guard.
- ✓ Don't ignore RSI Guard break reminders.

Emergency Planning

- ✓ Update emergency contacts via *PG&E@Work for Me.*
- ✓ Create or update your personal emergency preparedness plan at PG&E's Safety Action Center online.

COVID-19

- ✓ Maintain at least 6' distance where possible.
- ✓ Wear your mask.
- ✓ Wash hands frequently.
- ✓ Visit the COVID-19 employee site for the latest updates and tips.

Full-Day Virtual Meeting Logistics

Meeting Agreements

- No confidential information will be discussed
- Be mindful that others in this virtual meeting may also have questions
- Please mute your line if you are not speaking
  - *6 to unmute
- Use of parking lot for discussion topics

Engaging in Discussion

- Presenters will present and then take live questions at the end of their allotted time.
- During the presentation you can put a question to chat and the question will be held until the end of the presentation.
- Raise your hand (icon)
- When asking questions, please state your name and organization

Important

- We need to stick to schedule as presenters will be joining throughout the day at a specific times
- We welcome your ideas and feedback on how to improve this meeting in written comments

Agenda

9:00	Welcome
	PDS Summary
	Overview of Data Requests
	Steps Taken to Improve PDS
9:15	Interpreting PDS
9:25	Asset Strategy
10:25	Break
11:00	Stakeholder requested items
12:15	Lunch
1:15	Stakeholder requested items
2:40	Break
2:55	Stakeholder requested items
3:45	Wrap-up

Opening Message

Renardo Wilson – *Chief, Regulatory Relations*

November 2024 TPR Material

Lorenzo Thompson & Nick Medina - *TPR Team*

TPR Process Calendar

November 1, 2024	PG&E releases semi-annual Project Spreadsheet, Authorization Documents, and Procedures.
December 15	Due Date for Stakeholders to provide questions and comments related to the Project Spreadsheet provided on November 1.
January 13, 2025	PG&E distributes and publishes written responses to the December 15 comments and questions.
January 20	CPUC and Stakeholders provide Agenda Items for upcoming Stakeholder meeting.
February 4	PG&E hosts the first Stakeholder Meeting for the TPR Process.
February 19	Stakeholders provide questions and comments within 15 calendar days following the February Stakeholder meeting.
March 13	PG&E distributes and publishes written responses to the February comments and questions from Stakeholders.
April 4	Stakeholders may provide comments to PG&E by this date. There is no expectation that the PG&E will provide a written response to these comments.

You are here!

TPR Material Shared and Questions Submitted

- PG&E's November 1, 2024, submission for all FERC-jurisdictional **transmission** capital projects of **$1 million or more** incurred in **past 5 years** and anticipated to be incurred in the **current year** and **next 4 years:**
  - Project Data Spreadsheet (1,617 projects pulled September 11, 2024)
  - 592 Advance Authorizations and Business Cases. 37 documents redacted in the public version
  - The most current version of PG&E's Prioritization Procedures

- Stakeholder questions received by December 16, 2024
  - CPUC (11+42=53)
  - NCPA (15)

- Project updates will be provided in the May 1, 2025, TPR submission.

Steps Taken to Improve the Project Data Spreadsheet

30. Utility Approval

True – False Logic

TPR Cycle 1 Requested PDS Corrections Inventory

POs < $1M

Data Field 68
% Cost in TAC

RBPPF/IGP
Data Field 25
Update

Interpreting the Project Data Spreadsheet

- Vegetation Management: POs that include costs associated with the Reliability ROW Expansion Program are not included in the Nov 2024 TPR PDS (*Pacific Gas and Electric* Company, 189 FERC ¶ 61,021 (2024)).
- Distribution projects with high side transmission scope are included in TPR PDS (MWC 61)
- TPR Forecast: The annual forecasted expenditures reflect the management approved forecast and is subject to prioritization. Project in-service dates may be misaligned but will eventually be updated to align with current funding.
- Data Field No. 59 Construction Work in Progress Expenditures ($000)
  - E-5252: "Total amount of money that has been spent so far for the project through the last calendar year."
  - CWIP = Total Actuals – 2024 Actuals.

Interpreting the Project Data Spreadsheet

- Project Inclusion:
  - All POs under T.Dot if T.Dot > $1M (POs > $1M if no T.Dot) regardless of ISD
    - Does not include distribution POs, cancelled POs, or POs with no actuals and forecast in TPR window

- Project Exclusion:
  - T.Dot Estimate at Completion (EAC) dropping below the $1M threshold (through actuals or forecast update/transfer)
    - Or PO less than $1M if no T.Dot
  - No longer prioritized with forecast removed (No expenditures in TPR window)
  - Cancelled (actuals transferred or expensed)
  - Designated as Non-CAISO controlled

Asset Management Overview

Maria Ly – *Sr. Director, Trans. & Sub. Asset Management*

Asset Risk Framework

Transmission Line & Substation Asset Risk Framework

Probability of Failure + Consequence of Failure

Asset Attributes
- Age
- Manufacturer/Model
- Threats (corrosion, vibration,
- Hazards (wind, snow, seismic, etc.)

Performance
- Outage history

Condition
- Inspection data
- Maintenance data
- On-line monitoring data
- Field feedback and validation

Wildfire Consequence
- Failure Mode Effects Analysis (FMEA)
- Wildfire spread
- Defensible Space around substations

Public & Employee Safety Consequence
- Proximity
- Public gathering
- Equipment Failure mode

Reliability
- Criticality
- Design / Capability / Configuration
- System impact
- Customer Impact

Emergency Response
- Capital Emergency Material (CEM)
- Substation mobile equipment
- Operational response

Asset Management Programs

Asset Risk Assessment

- Probability of Failure
- Consequence of Failure

Validation

- Inspection & Maintenance
- Diagnostic testing
- Sampling and Strength Testing
- On-line Monitoring
- Failures

Mitigation → Programs

Condition Monitoring

Inspection & Preventative Maintenance Programs
Transmission Line Monitoring Programs
- Tower Sensors
- Early Fault Detectors
- Distributed Temperature Sensing

Substation Online Monitoring Programs
- Transformer dissolved gas sensors
- Transformer partial discharge sensors

Repair

Corrective Maintenance and Repair Program

Life Extension

Transmission Lines Programs
- Shunt Splice Program
- Tower Coating
- Cathodic Protection
- Wood Pole Reinforcements

Substation Programs
- Transformer and Circuit Breaker component replacements
- Refurbishment

Replacement & Removal

Transmission Replacement Programs
- Conductor Segment Replacement
- Wood Pole Replacement

Removal Program
- Idle line management
- Just-In-Time Replacement (JIT)

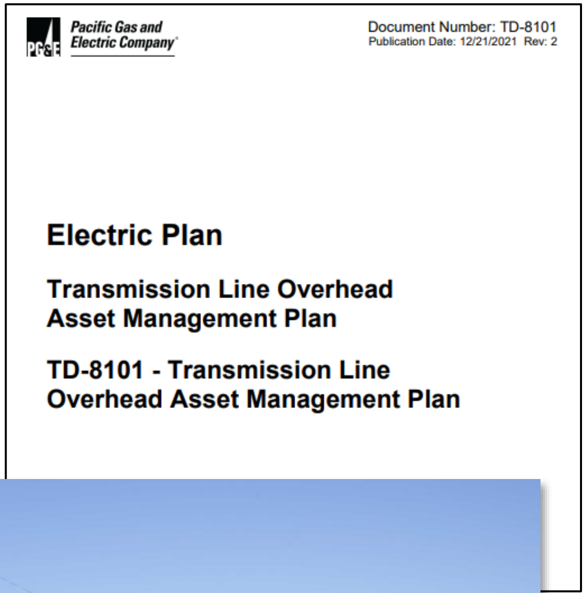
Transmission Line Asset Strategy

Issam El Ayadi – *Director, Transmission Line Asset Management & Regulatory Governance*

Transmission Line Assets Overview

Overhead Assets (Approximate)	
Voltages	500kV, 230kV, 115kV, 70kV, 60kV
Number of Circuits	1,400 lines; 7,800 circuit miles
Conductors	six major types (mix of aluminum, copper, steel)
Towers and Lattice Poles	37,100
Steel Poles	30,500
Non-Steel Poles	79,300
Insulators	Est. 153,000 structures with insulators; three major types (ceramic, polymer, glass)
Switches	2,000 (37% remote/auto operation capable)

Underground Assets	
Voltages	230kV, 115kV, 70kV, 60kV
Number of Circuits	58 – operated & owned by PG&E; Circuit miles = 192 *Not including lines owned by Calpine or lines serving BART which are maintained by T-Line M&C.
Conductors	two major types (fluid filled or solid dielectric)


Pacific Gas and Electric Company
Document Number: TD-8101
Publication Date: 12/21/2021 Rev: 2

Electric Plan

Transmission Line Overhead Asset Management Plan

TD-8101 - Transmission Line Overhead Asset Management Plan


Crag View-Cascade 115 kV Line

This is a brief summary of assets. Please see Asset Management Plan, TD-8101 and TD-8102 for more detailed information.

Transmission Line Asset Highlights 2024

Risk & Compliance

- Updated condition job aids and guidance after asset testing and analysis
- Maintained steady state compliance with ignition-related HFTD/HFRA maintenance notifications, barring external factors

Asset Health Modeling

- Released v2.1 of the Transmission Composite Model which included component specific Bayesian updating and tag condition mapping updates.
- Utilized modeling results for 2025 inspection and targeted mitigation planning
- Enriched asset failure data in alignment with failure modes and effects analysis

Asset Registry

- Continued the improvement of asset information (e.g., checking for completeness, conformity, consistency) on critical data elements
- Matured asset registry with inclusion of operational asset data (e.g., line loading)

Efficiency

- Creation of a work bundling tool for spatial understanding of workplans
- Continued support of Integrated Grid Planning for the 10 year investment plan

System Upgrades

- Tower Replacements - Brighton-Grand Island, Ignacio-Alto-Sausalito
- Conductor Replacements - Manteca #1 (~1mile), Stanislaus-Melones-Manteca (~19 miles), Bellota-Warnerville (~45 miles)
- Idle Line Removal - Brighton-Grand Island, Los Banos-Pacheco
- Generation - Proxima Solar, 300 MW of renewable PV & 150 MW of battery storage

Transmission Line Asset Risk

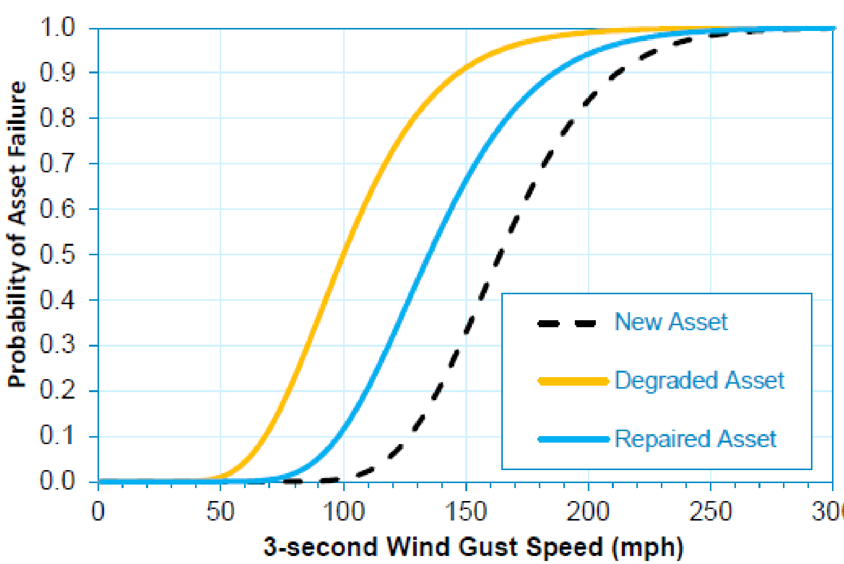
Key Areas of Risk Exposure:

- **Equipment failures and wires down** – continue to better understand the effectiveness of controls/mitigations (i.e., limitations of visual inspections)
- **Wildfire –** updates and improvements to risk model, and expansion of operational mitigations
- **Aging infrastructure** – provide targeted mitigation and monitoring
- **Changing environment** – update standards to reflect climate changes.
- **Seismic** - Address vulnerabilities to UG network and improve monitoring & emergency preparedness

Knowing information about transmission assets, and how they can fail, allows risk modeling across multiple hazards and threats.

- Data is captured on **critical components** (tied to Failure Mode and Effects Analysis)
    - Data captured to be defined, digitized, with data quality rules and part of the as-built process
- Asset data, in conjunction with maintenance, performance and environmental data feed the **Transmission Composite Model** to calculate probability of failure due to various hazards.
- The transmission composite model can be multiplied with **consequence** to determine risk at an asset level, hazard level, or across the system.
- This **risk aims to informs mitigation response for each asset**. (See limitations and use cases on next slide)
- Validation and feedback loop required to improve modeling accuracy and precision

Fragility Curve Example



Risk Matrix to Inform Mitigations

An asset risk matrix is a visual tool used by asset management to assess and prioritize risks associated with various asset components to prioritize and fund work.

The matrices are developed by combining the probability of failure with the consequence, based on various inputs (including but not limited to those listed below)

- **Probability of Failure**
  - Transmission Composite Model (predictive model). Includes:
    - Asset condition (inspection, monitoring, maintenance tags)
    - Environmental factors
  - Performance
  - Design & Application
  - Industry benchmarking

- **Consequence**
  - Wildfire Consequence
  - Safety – Public & Employee
  - Reliability – Grid Integrity & Customer Impact
  - Emergency Response

	Low Probability of failure	Medium Probability of failure	High Probability of failure
High Consequence of Failure			
Med Consequence of Failure			
Low Consequence of Failure			

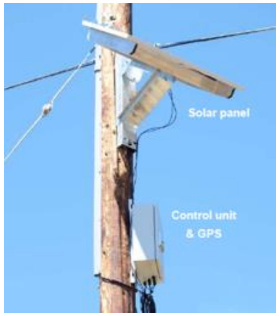
Mitigations for high-risk assets:

1. Condition-Based Assessment and Monitoring
2. Targeted Inspection & Maintenance
3. Emergency response and Preparedness
4. Asset Life Extension
5. Asset Replacement Programs

Condition-Based Assessment and Monitoring

Asset monitoring technology can detect and locate defects in electrical infrastructure prior to failure. Transmission line strategy for monitoring uses a targeted approach to assess the need for potential just-in-time replacement.

- Transmission Line condition monitoring pilots in progress include:
  - Radio frequency scanning and anomaly detection
  - Strain gauges, accelerometers, inclinometers, vibration monitors, etc. for tower change detection
  - LiDAR sensors and processing for conductor sag, horizontal movement, etc.



Four Phased Approach

Phase 1: ID & Research
- Identify Threats
- Research new tech and solutions that can mitigate the threat

Phase 2: Validation
- Evaluate tech in controlled lab setting

Phase 3: Pilot
- Test tech in real world
- Demonstrate capabilities at scale

Phase 4: Operationalize
- Establish Deployment and change management plans
- Develop training and procedures for implementation

Continuous Improvement

Going forward, transmission line asset strategies will focus on improvement in the following areas:

Data collection	• Complete, accurate and traceable asset records in ETGIS & SAP through data improvement efforts and the data quality dashboard for critical date elements • Integration of data enhancements into risk models and resulting asset strategies
Risk	• Enhance risk modeling with expanded consideration of reliability risk • Execute short-term and long-term repair, replacement or full line refurbishment projects and programs through IGP, in alignment with climate resiliency, wildfire and safety goals • Validation and benchmarking of modeling, maintenance and other activities to increase or confirm effectiveness • Develop additional asset risk model health assessment
Technology/Pilot Programs	• Pilot new inspection/testing/monitoring technology to detect conditions leading to failure. • Proactive, targeted ATS testing of components and conditions • Implement ambient adjusted transmission line ratings • Further develop operational mitigations such as Early Fault detection

Substation Asset Strategy

Justin Flores – *Sr. Manager, Substation Asset Management*

Transmission Substation Profile

Substation Summary

Voltages (kV)	Substations	Bus
500, 230, 115, 70, 60	227 Transmission Stations 55 located in HFTD/HFRA	8 Configurations: BAAH, RING, DBDB, DBSB, Main/Aux, SBSB, Loop, Tap

Asset Inventory & Age

Asset Type	Count	Avg. Age (Years)
Bus Systems	374 (BES) 563 (Non-BES)	NA
Transformers	1ph 334* 3ph 129*	1ph 39 3ph 19
Voltage Regulators	1ph 0 3ph 21	1ph N/A 3ph 32
Circuit Breakers	3,683 (outdoor) 91 (GIS)	53 (Oil) 17 (SF6) 10 (VAC)
Circuit Switchers	246	23
Motor Operated Air Switch (MOAS)	1016	18
Batteries (Station)	232	10
Reactive Equipment		
Shunt Capacitors	114	25
Shunt Reactors	234	15
STATCOM	1	3
Series Capacitors	16	15/30
Series Reactors	139	14
SVC	5	15
Synchronous Condensers	0	35

*Includes spares

Substation Key Highlights 2024

Asset Life Cycle Planning

- Development of 5-year strategic sourcing plan of long lead material order
- Developed substation physical security risk tier ranking model aligned with Corporate Security
- Developed asset health risk matrix prioritization model

Asset Maintenance and Inspection

- Spare transformer power factor testing (phased-in approach)
- Substation Routine and Supplemental Inspections Optimization
- Continued installing online DGA/PD bushing monitor

Climate Change/Resiliency

- SF6 leak reduction work – 25 leak repairs targeted, 35 accomplished
- Installed (8) 70kV and (1) 115kV Vacuum/Clean Air breakers
- Targeted high leak-rate SF6 breakers for replacement (4 in 2024)
- Developed a substation risk ranking to address substation flood risk mitigation.

Emergency Preparedness and Support

- Repaired 4 mobiles transmission transformer and received 1 new
- Refined dashboards to keep track of emergency material deployment and availability (breakers, transformers and mobiles)
- Issued bulk orders for 17 CEM transformers in support of emergency replacements over the next 5 years

Workplan Execution – released to operation 2024

- Scoping governance efficiencies
- Successful creation and execution of WMP and commitments
- Major Projects: Palermo 230kV/115kV Bank 1 & 115kV/60kV Bank 3, Rio Oso 230/115kV Bank 1 and El Cerrito G bus upgrade

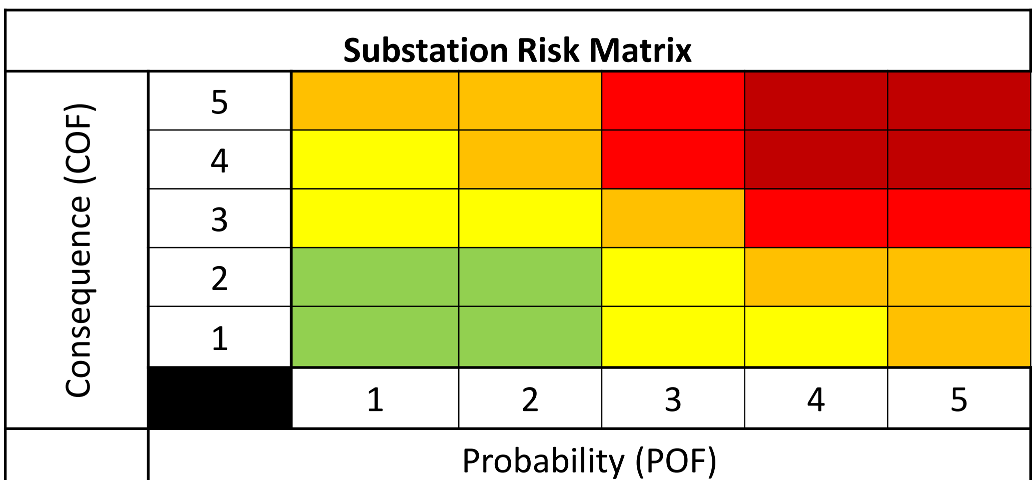
Grid & Interconnection

- Completed 500kV Path 26, 15, 66 rating upgrade project
- Completed 18 EGI load interconnection projects in 2024

Substation System Risk Prioritization

An asset risk matrix is a visual tool used by asset management to assess and prioritize risks associated with various asset components to prioritize and fund work.

Consequence of Failure (COF)	Probability of Failure (POF)
Safety – Public & Employee	Asset Condition (Inspection, Testing, On-line Monitoring, maintenance history)
Reliability – Grid Integrity & Customer Impact	Environmental factors
Wildfire (Defensible Space)	Failure History
	Industry Benchmarking
	Design & Application



Risk Mitigation	Critical	Significant	Moderate	Minor	Negligible

Substation Material Lead Times

Increase in lead times (4X) for Circuit Breakers and Transformers impacting project schedules and emergency response readiness.

Transmission Substation Equipment	Ratings	Lead time as of 1/17/25
Circuit Breaker	70kV,1200/2000A/3000A,31.5kA/ 40kA, Vacuum breakers	9 mos. to 2 years
	115kV, 2000A/3000A,40kA, Vacuum breakers	1 to 2.5 years
	115kV, 2000A/3000A, 63kA, SF6	2.5 to 3 years
	230kV, 2000A/3000A, 63kA, SF6	3 to 3.5 years
	500kV, 3000A/4000A, 63kA, SF6	4 years
Transformer	Primary kV: 500, 230,115 Secondary kV: 230,115, 60,70 MVA: 200,374,420	3.5 to 5 years

- Reduce long lead material delays on projects by bulk material ordering under Other Balance Sheet program (OBS)
- No AFUDC will accrue on upfront payments for bulk material purchases as these will be recorded as deposits.

Continuous Improvement

Objectives

- Reduce in-service failures
- Transition into JIT replacement strategy
- Continue to mature system prioritization methods and increase visibility (system risk matrices)

Risk Mitigation: *Just-In-Time Replacements Strategy- JIT, Short Term Mitigation and Extent of Condition*

- Comprehensive risk review of transformers & breakers for JIT replacement: (transformer, breakers etc.)
- Targeted minor substation equipment replacement
- Compliance with FERC 881 & 1000
- Extent of condition risk evaluation
- Physical security threat mitigation (CIP-14)

Asset Health, Maintenance & Inspection

- Online condition monitoring
- Inspection program optimization - increase failure mode detection
- Phase-in test interval increase for electrical testing of spare transformers
- Incorporate feedback from operations stakeholders into asset management systems

New technology pilots

- Non-SF6 GIS at Ringwood Substation in construction
- Smartwires – Smartvalve Advanced Power flow controller Pilot at Los Esteros Substation
- Online infrared camera monitoring technology

Material Sourcing Strategy and Readiness

- Improve at-risk delivery dates and financial commitments (sourcing)
- Continue to develop/qualify new vendors to meet material demand
- Expedite technical evaluation (Specification and work methods)
- Continue to re-assess equipment needs quarterly and provide forecast to sourcing to work with vendors

Climate Change, Resiliency and Wildfire

- Update standards and design criteria for climate resiliency (temperature, floods, sea level rise)
- Continue SF6 leak rate reduction (CARB)
- Continue to execute defensible space inspections in High Fire Risk Areas

Operational Assets and Systems

Heather Torres - *Protection Engineer, System Protection*

Frankie Au-Yeung - *Automation Engineer, System Protection & Automation*

Vanith Biddappa – *Sr. Manager, Operations Systems*

Operational Assets Overview

General Areas (Assets include physical and cyber forms)	

Grid Operations / Business Applications	• Servers and workstations located at the Transmission Control Centers
	• **EMS:** Redundant Energy Management Systems located at VGCC & RGCC Transmission Control Centers & 16 Front End Field Locations, consisting of:
	    • Over 500K SCADA points in EMS which are telemetered, calculated, and manual.
	    • Production, Test & Training Environments comprised of ~155 Servers and ~250 Workstations
	• **RAS:** 58 total schemes (38 BES RASs and 20 non-BES RASs) jointly maintained by Grid Ops and System Protection
	  • 56 of which are implemented at the substation level
	  • The remaining 2 (PACI RAS and SF RAS) are centralized in the VGCC and RGCC

Protection	• **Relays**: 30,404 units* • **Synchrophasors**: 200 PMUs, 30 data concentrators • **RAS:** 58 total schemes (38 BES RASs and 20 non-BES RASs) jointly maintained by Grid Ops and System Protection *recalibrated the data to only include devices system protection is responsible

Automation / SCADA	• **SCADA** (breakers): 99% overall penetration
	• **RTU**: over 650 installation in substations
	• **MPAC:** over 135 installations in 100 substations (~10K relays installed)
	• **D-Line SCADA**:
	  • Capacitors: ~700 SCADA units. FLISR: 900+ feeder units. Recloser: ~6000 SCADA units.
	  • Sectionalizer: ~180 SCADA units. Switches: ~2,500 SCADA units
	• **EPSS**: Replaced 96 feeder relays with SMP/Beckwith relays to support Enhance Powerline Safe Setting to reduce potential risk of wildfire ignition.

Pacific Gas and Electric Company

Document Number: TD-8104
Publication Date: 11/21/2021 Rev: 2

Asset Management Plan

TD-8104 – Operational Assets and Systems Asset Management Plan

Document Number: TD-8104

November 21, 2021

This is a brief summary of assets. The Operational Assets and Systems consists of assets for operating the electric grid through control, monitor, assess, protect, isolate, and restore functions. Please see Asset Management Plan, TD-8104 for more detailed information.

Operational Asset Highlights 2024

Grid Operations / Business Applications: MWC 63

- EMS SMP Upgrade
- FERC Order 881 – Dynamic Line Rating Implementation
- Completion of Phase 1 of the SFGO RAS Relocation Project
- TSRP: Cutover from RTSCADA to EMS

System Protection: MWC 3F

- Real Time Dashboard for Asset Management
- Developed Relay Health score utilizing MPRs
- Worked on EPSS initiated projects for Transmission Lines

Automation / SCADA: MWC 67

- T&D SCADA Equipment released in Operation
- Reduced cyber vulnerability
- MPAC enclosures

Asset Strategy Plan for EMS Assets

EMS Upgrade

- Vendor support for existing GE EMS 3.2 version is sunsetting – Project in progress to Upgrade EMS application software to GE EMS 3.4/latest version.
- Vendor support for existing Windows Server 2012 Operating System ending in 2026, Equipment is approaching End of Life.
  - Replace all existing EMS servers running Windows 2012 by 2026
  - Replace all Windows 2016/End of Life by 2027
  - Replace all Windows 2019/End of Life by 2028
- Replace all end of life EMS Workstations in 2025/2026

FERC Order 881 – Dynamic Line Ratings

- Implement GE EMS application Modules/Enhancements to support compliance
- Implement Enterprise GE DDLR tool to calculate real-time hourly and 10 day forecasted ratings based on input from PG&E Transmission Ratings Registry / GIS systems and IBM Weather, for PG&E EMS and CAISO

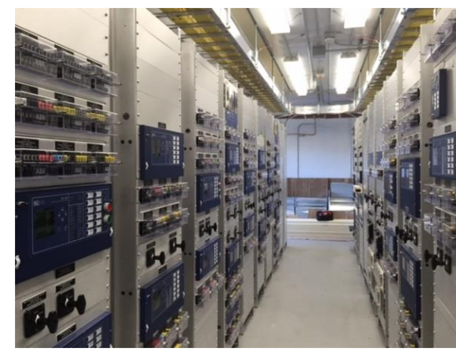
Future EMS Projects

- Phasor Applications Server replacements - Transmits synchrophasor data from field PMU/PDCs for utilization by PG&E analysis tools and CAISO.
- Control Room Video Wall replacements in Vacaville and Rocklin

MWC 67: MPAC (Modular Protection Automation & Control)

MWC 67 includes capital work associated with MPAC (Modular Protection Automation and Control)

MPAC program: Deploy pre-engineered, fabricated, and standardized control building enclosures in various PG&E substations since 2005. (see picture)



Program drivers: MPAC projects are generally performed in an "integrated manner" with other PG&E projects such as capacity expansion projects, bus conversions, deficiency and aging asset replacement, control room condition improvements, reliability, and control center consolidation efforts.

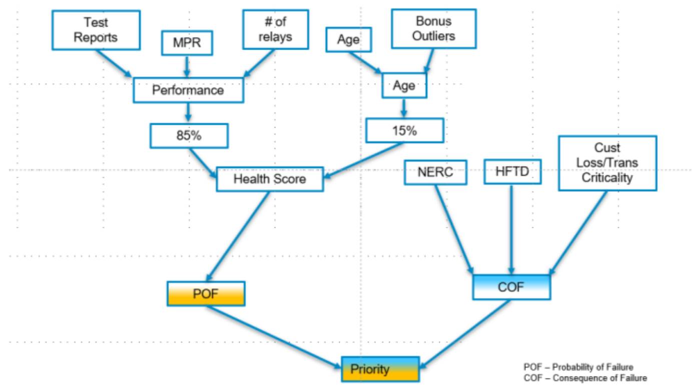
Asset Strategy Plan for System Protection Assets

Asset Management

To determine replacements of System Protection Protective equipment

- Age based targeted replacements for EM, MP and SS relays at end of service life
- Targeted high failure rate/high impact relay types
- Maintenance history
- System Configuration, Environment Issues and Safety Impact
- System Protection coordination or operation concerns
- Compliance driven relay replacements (NERC PRC)

A detailed Health Score will be used that combines the Age, Failure Rate, Maintenance, System Configuration, Environmental Issues and Safety Impact to determine high priority relay replacements in the system

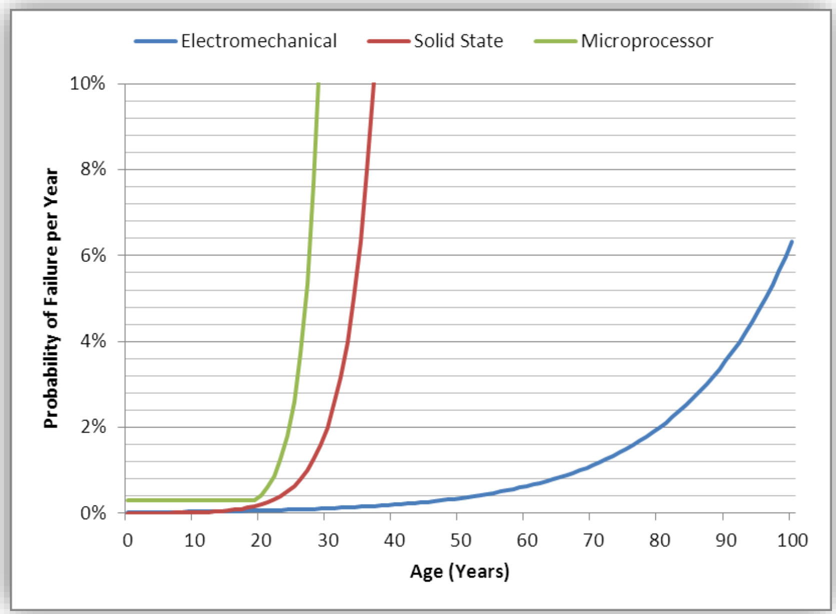


NERC compliance purposes (PRC-004, PRC-005, PRC-012-R5, etc.),

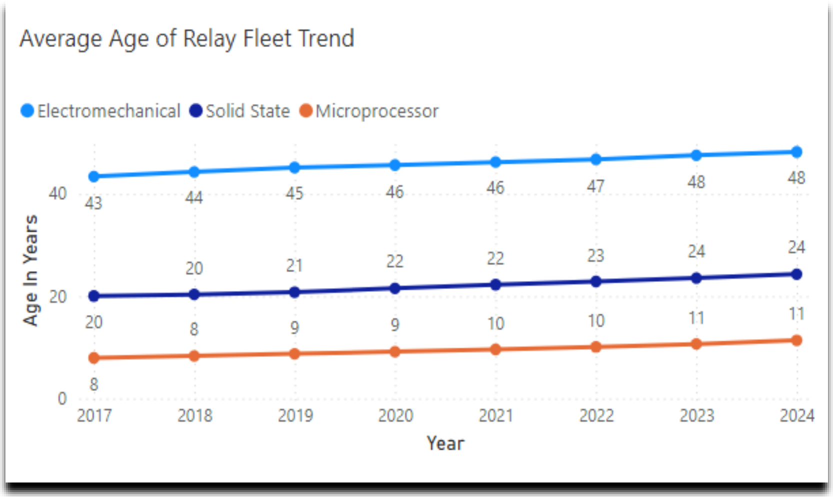
- System Protection group is responsible for evaluation of each of the five components of a Protection System.
  - Protective relays which respond to electrical quantities,
  - Communications systems necessary for correct operation of protective functions
  - Voltage and current sensing devices providing inputs to protective relays,
  - Station dc supply associated with protective functions (including station batteries, battery chargers, and non-battery-based dc supply), and
  - Control circuitry associated with protective functions through the trip coil(s) of the circuit breakers or other interrupting devices.

Age Considerations for Relay Replacement

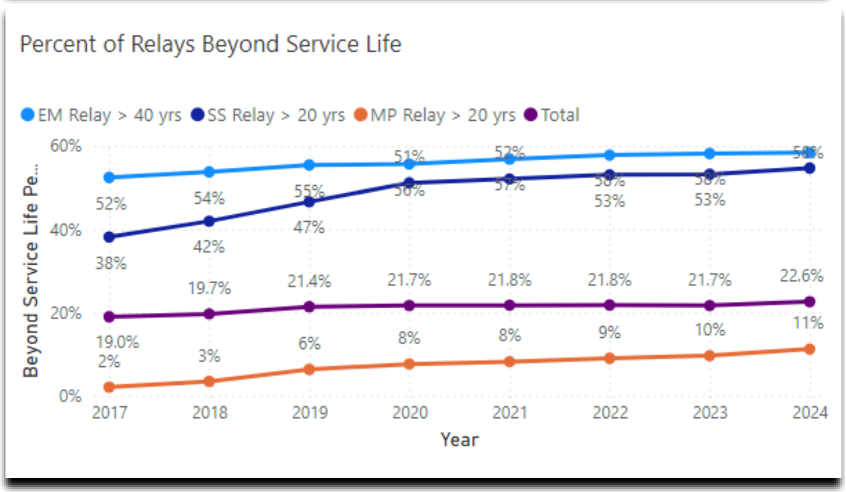
- Age consideration based upon expected service life is as follows (regardless if on transmission or distribution):
  - Electromechanical Relay Life Cycle 40 Years
  - Solid State Relay Life Cycle 20 Years
  - Microprocessor Relay Life Cycle 20 Years
  - SEL 2020 and SEL 2030 (is new in late 2018 and program developed in 2019) Life Cycle 20 Years.
  - DTT And Communication equipment (is new in late 2018 and program developed in 2019) Life Cycle 20 Years.

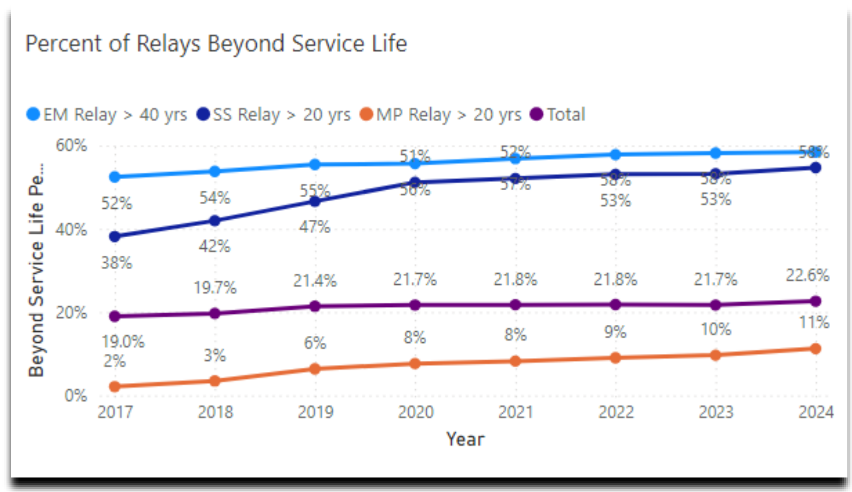


Number of Relays Beyond Expected Service Life



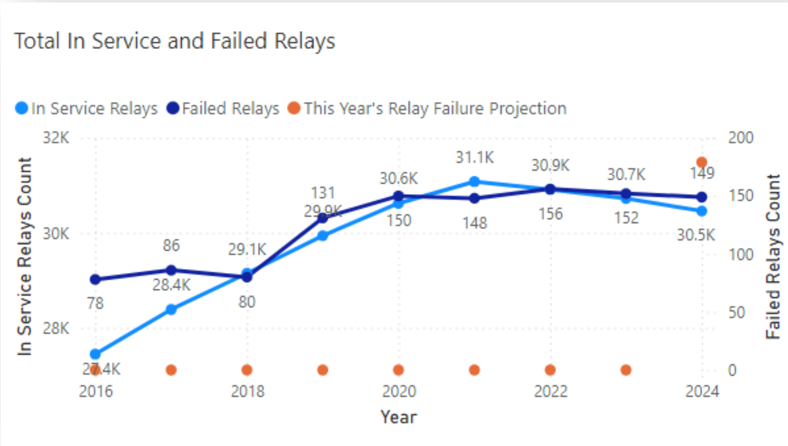
- The EM relay average age is increasing each year since minimal new EM relays are installed and the existing EM fleet continues to age with whatever relays that remain.
- The MP relay fleet average age has been increasing for the last six years.
  - We are not keeping up with the replacement of the aging MP relays

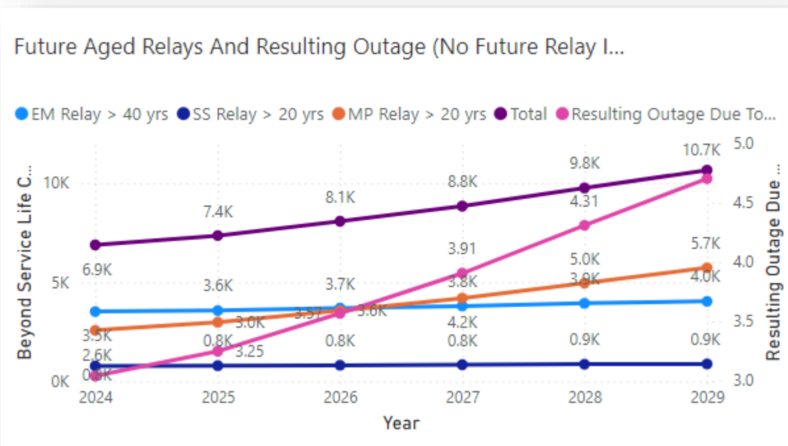




- You can see that even though the number of EM relays beyond 40 years is decreasing, the percent of relays beyond 40 years is increasing for those relays that are left. The same is true for SS relays.

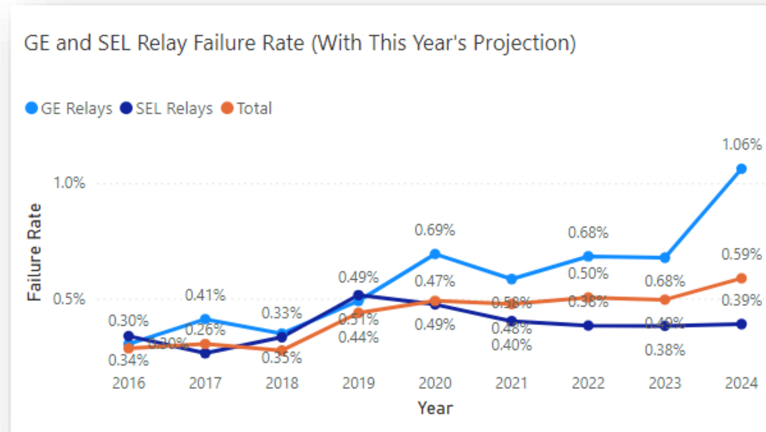
Relay Failure Totals by Year





System Protection's assets performance is measured by tracking failures, outages, maintenance activity, misoperations, and availability.

Many of these measures are part of the Electric Operations Business Performance Review (BPR) dashboard that provides visibility of system performance metrics. Feedback is enhanced by the company's Corrective Action Program (CAP).



Analysis Example:

- GE relay failures are trending up last 5 years and we've seen a big increase in DSP (CT/VT card) failures in older GE relays.
- SEL relay failure rate has been flat last 6 years but this is being masked due to the higher number of SEL relays being installed.

Stakeholder Requested Agenda Item #17: Cottonwood: Install 115kV Bus Diff Relay

Chase Chaussee – *Sr. Consulting Project Manager, Transmission Operations*

Heather Torres – *Protection Engineer, System Protection*

Cottonwood: Install 115kV Bus Diff Relay

In response to Data Request Set 01-25 of the November 2024 cycle (PG&E Response TPR-Process_DR_ED_006-Q025), PG&E provided information showing project milestones from 2019 through 2027, with no project activity during the 2022 through 2025 period. On January 21, PG&E provided cost information on the project in Attachment 1 to Data Request 01-11 of the November 2024 cycle (PG&E Response TPR-Process_DR_ED_006-Q011) showing that $7.751 million has been incurred to date, with just $29,000 on materials and $4.1 million in contract costs, and $1.6 million in AFUDC charges. Please provide a detailed overview of this project, including the contractual provisions for the scope of work and whether the contract includes materials purchases, design and engineering work, or other requirements. The current projected total cost is $10.2 million, which appears to be expensive for a buss difference relay installation. Please include in your discussion the specific issues that are leading to the extended schedule and increased costs, as well as whether this project was ever placed "on hold".

- **Project Activity:** For 2022 to 2025 period there are still project activities associated with Construction and Project coordination but there are no Major Milestones being meet during this time period. During 2022 – 2024 there were noted issues with funding, personal support, contract negotiations with the EPC contractors and a realignment with the up-coming station re-build.
- **HOLD Status:** This project was not put on holding during the issues with funding in 2022 because it did not meet the hold guidelines of no work for 6 months and there were outstanding contracts associated with IT during the time period.

Cottonwood: Install 115kV Bus Diff Relay

- **EPC Contract:** The contract for this projects is an EPC contract, the $4.1 million in contract costs includes engineering support, material purchase and construction support. The Cottonwood Bus Differential project is a pilot project in 2019 it was implementing Distributed Busbar Protection which was new to PG&E and required vendor support. Late in 2024 due to unforeseen contract installation issues the project scope was modified to install IEC 61850 Bus Differential and to align the project with the Cottonwood Bus conversion project.
- **Project Scope:** The Cottonwood Bus Differential project was developed as a pilot project to install Distributed Busbar Protection on the 115 kV Bus using fiber optic connections. The project was installing a redundant scheme with the existing GE B90 Busbar relay. During the execution of the project, it was determined that the original proposal was having to many unresolvable execution issues and the scope of the project has changed to install the IEC 61850 protocol which is more inline with PG&Es present technology strategy.
- **Additional Issues:** Due to the change in technology used and to align the project with the Cottonwood Bus conversion project the schedule for this project has been extended. For this project the cost has been higher than a typical Bus Differential project but because of the pilot nature of the project, lessons learned and trouble shooting involved the additional cost is expected. In the future, for similar applications of this technology we are expecting an overall project decrease systemwide for similar Bus Differential installation.

Back at 10:40

BREAK

PG&E Project Planning Strategy / Risk Based Portfolio Planning Framework and Integrated Grid Planning Stakeholder Requested Item # 1

Jason Yan – *Sr. Manager, Investment Planning*

Risk-Based Portfolio Prioritization Framework (RBPPF) Guiding Principles

The Guiding Principles of the RBPPF as Captured in RISK-5004S are:

- Establish a consistent and comparable approach to categorizing and valuing proposed investments across PG&E consistent with PG&E's True North Strategy and the CPUC's Risk-based Decision-making Framework (RDF).
- Establish an upfront baseline risk reduction and determine whether risk reduction from the proposed investment portfolio(s) meets or exceeds the baseline risk reduction.
- Establish requirements to ensure a robust review and calibration process related to Value Category scoring and final assignment of proposed investments to Funding Tiers.
- Ensure that records related to implementation of the RBPPF are handled in compliance with the Company's records retention standards and policies and are sufficiently robust and transparent to comply with directives in the CPUC's RDF OIR.

Within-Funding Tier prioritization rubric

	Funding Tier	# of VCs with a score of 5	# of VCs with a score of 4	# of VCs with a score of 3	# of VCs with a score of 2	# of VCs with a score of 1	Final Score
Example Project	5	6	0	0	0	0	5.60000
	5	5	1	0	0	0	5.51000
	5	4	2	0	0	0	5.42000
	5	3	3	0	0	0	5.33000
	5	2	4	0	0	0	5.24000
	5	1	4	1	0	0	5.14100
	5	1	2	3	0	0	5.12300
	4	0	5	0	0	0	4.05000
	4	0	4	1	0	0	4.04100
	4	0	3	2	0	0	4.03200
	4	0	2	3	0	0	4.02300

Digit to left of decimal point is highest score across all Value Categories (VCs)

From Left to Right after decimal point

- First digit is # of VCs with a score of 5
- Second digit is # of VCs with a score of 4
- Third digit is # of VCs with score of 3
- Fourth digit is # of VCs with a score of 2
- Fifth digit is # of VCs with a score of 1

- The proposed scoring rubric gives higher score to proposed investments that have higher value across multiple value categories.
- The proposed rubric results in approximately 120 different scores (based on the 2024 BPD scoring). The highest scoring group (5.40010) includes 18 investments. Average number of investments per scoring group is approximately 10.
- The proposed scoring rubric does not produce a unique score for each proposed investment, but it does provide significantly more granular scoring than the current scoring rubric allowing for some inta-Funding Tier prioritization.
- The proposed scoring rubric produces an “ordinal” score which can be used for ranking and is easy to implement with existing value category scoring information.

RBPPF Granularity

Value Category Scoring

- Risk Reduction
- Compliance
- Capacity
- Reliability
- Other True North Strategy Objectives
- Business Continuity

Generally:
In the TPR: Overall RBPPF is a single score based on highest score of each category (e.g. all categories 5 and one category 5 are both 5)
Because 5 is a minimum threshold – value range in 5 is the widest

Double click into the value categories:
Risk Reduction scoring is based on 1) CBR >1 and 2) RAMP y/n

- CBR is a program calculation (not project by project)
- RAMP risks are determined based on company safety risk ranking

Compliance is based on 1) requirement date and 2) description/severity of compliance/commitment

Capacity and reliability are based on # of critical customers/locations impacted in the scope

True North Strategy is based on level of impact to meeting/improving performance on associate Key Performance Indicators

Key takeaways:
RBPPF is a useful tool/methodology to indicate high priority work and drive discussions.
Attempts at using RBPPF for a 1-N ranking have revealed some of the limitations of this enterprise-wide framework.
PG&E is continuously evaluating the definitions of the value categories to drive better decision-making information

Field 25 "Partial"

The purpose of the "partial" score is to acknowledge that in these major work categories, not all of the work is "plannable" and appropriate for IGP planning.

A typical example of this would be transmission line capital maintenance. A portion of the funding in these programs need to be reserved for emergent short cycle and short due date work.

Much of the work is identified by results of field inspections and needs remediation in a timeframe that is not conducive to the multi-year planning horizon of IGP, thus, the funding allocation to these programs is split based on an estimated portion that is longer duration and plannable, versus short duration.

Cost Benefit Analyses (Data Field 66)
Stakeholder Requested Item # 2

Peter Lee – *Senior Manager, Risk Management*

Joscelyn Wong – *Sr. Manager, Integrated Grid Planning*

Nick Medina – *Sr. Standards & Strategy Engineer, TPR Team*

CBR Framework

PG&E is in the process of refining its approach in reviewing Cost Benefit Ratios (CBRs) for transmission projects

Current Methodology

- PG&Es prioritization models (TCM, WTRM) were used to establish baseline risk at a structure level (wildfire and reliability).
- The overall risk scores align with PG&Es Enterprise Wildfire and Transmission Overhead Risks

	sap_equi… Integer	host_etl String	hftd String	annual_pf Double	wf_conseque… Double	rel_conseque… Double
30	40585016	ETL.1252	Tier 2	0.000	35.608	null
31	40646803	ETL.1252	Tier 2	0.002	67.732	null
32	40652269	ETL.1252	Non-HFTD	0.021	0.277	null
33	40581443	ETL.1270	Non-HFTD	0.001	0.614	1,309,661
34	40659387	ETL.1270	Non-HFTD	0.001	0.274	1,309,661
35	40580961	ETL.1280	Non-HFTD	0.008	0.276	448,191
36	40604217	ETL.1280	Non-HFTD	0.003	0.277	448,191
37	40599796	ETL.1311	Non-HFTD	0.001	0.278	null
38	40584918	ETL.1330	Tier 2	0.007	173.706	11,197,137
39	40584924	ETL.1330	Tier 2	0.003	340.114	11,197,137

Risk = PoF x Consequence

This approach enables us to define a risk per structure

Overall risk calibrated to enterprise risk scores

Formula: CBR = (Baseline Risk X Effectiveness) / Total Project Cost

Future Enhancements to CBR Framework

- Incorporate risks associated with capacity and grid instability
- Account for degrading asset health and PoF in future years
- Enhance reliability consequence modeling
- Incorporate framework into IGP/Copperleaf tool

CBR in November 2024 TPR PDS

Transmission Project Review – Cost Benefit Ratio (CBR)
For the November 2024 TPR Filing, PG&E provided CBRs for 62 projects that include

- MWC 93: Conductor Replacements, Line Rebuilds
- MWC 70: Structure Replacements

Formula:	**CBR = (NPV Baseline Risk X Effectiveness) / NPV Total Project Cost**

Project Definition

- For each project in our investment plan, the specific structures worked were provided.
- These structures were mapped to the baseline risk established leveraging the TCM Analysis.

Effectiveness

- Effectiveness 75% for all projects, which represents restoring line assets to standard operating conditions. This placeholder effectiveness value will be refined in future proceedings and will be informed by data.

Risk Reduction and benefit length

- Risk reduction based on 1st year benefits and accounts for reduced risk over the lifespan of the project (with diminishing rate). Benefit length is estimated at 55 years and is based on a general financial service life for electric transmission assets.

Project Costs

- Project costs are based on net present value.

Future CBR Enhancements

Current CBR Overview

- CBRs are underrepresented because they do not account for capacity and grid stability risks. Inclusion of these attributes would better represent the projects risk-based cost-effectiveness.

- Current approach does not account for degrading asset health and the escalated risk in future years. Based on when investments are planned it would be beneficial to understand the projected risk on these assets to calculate CBRs for.

- Current reliability consequence is based on historic line outages. More investigation on the consequences of failed lines can improve the distribution and accuracy of reliability risk in our CBR calculations.

- Our current program effectiveness and benefit length assumptions are high-level and can improve with better data.

- Copperleaf/Integrated Grid Planning: PG&E will be looking to automate the CBR calculations in Copperleaf when the models reach maturity.

Data Field 66

- 1,221 projects marked N/A for Cost-Benefit Analysis
  - 1,213 Operational/Programmatic Work
  - 8 In-flight
    - 2 with 2024 ISDs (N/A appropriate)
    - 6 with ISDs beyond 2024 (should have been TBD)

- In-Flight projects with no CBR are populated as TBD

Enterprise Project Governance

Randy Smith – *Manager, Enterprise Project Governance*

Project Lifecycle Authorization Gates

New Stage 0 - Business Case

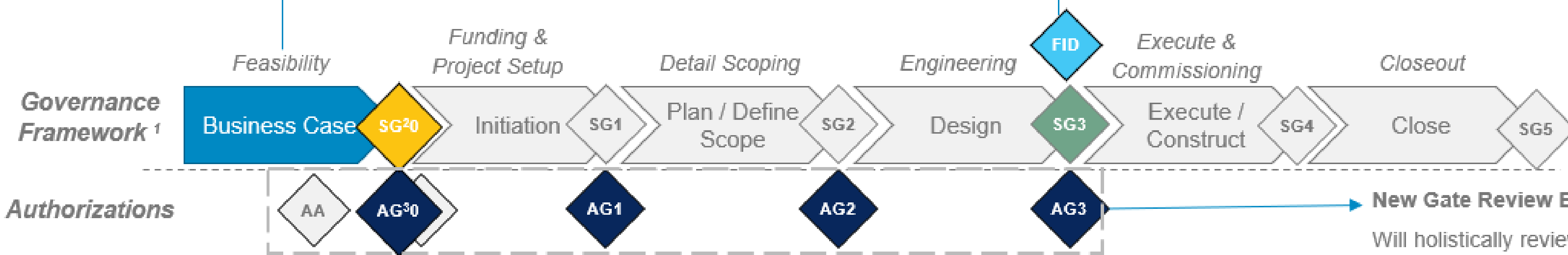
Feasibility to establish the need for a project and get it into BPD.

Final Investment Decision (FID)

FID at AG3 represents a multi-year commitment to fund the Major Project and confirmation funds are allocated in the Investment Plan.

Board Reviews

Board approval is required for Major Projects ≥ $250M at Gate 3 (FID) and prior to Gate 3 if actual costs plus commitments will exceed $50M



New Gate Review Board (GRB)

Will holistically review all Major Projects (>$25 million) at each authorization gate

Delegation of Authority[3]

Approvals will be based on the Expected Case (P50), rather than the High Case (P90 value)

Advance Authorizations Eliminated

Replaced by Business Cases to fund ONLY Initiation Stage (to AG1), strengthening financial oversight early on.

Authorization Gates 0 - 2 (AG0 – AG2)

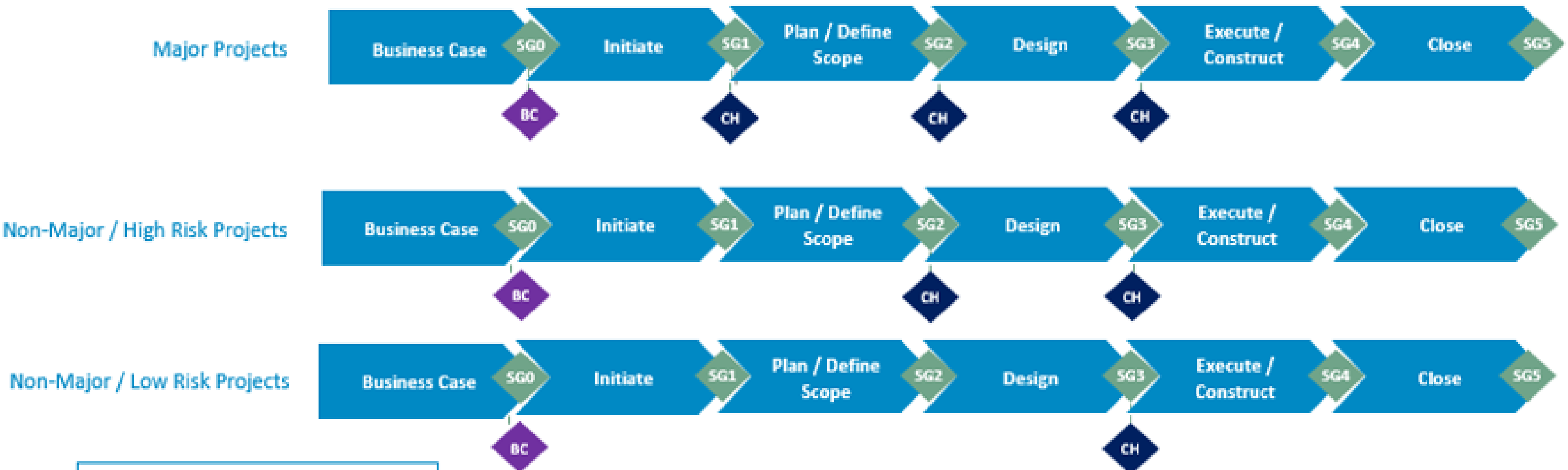
Project is placed into Business Plan Deployment: next stage work, resources, and funding and project lifecycle cost hold minus contingency).

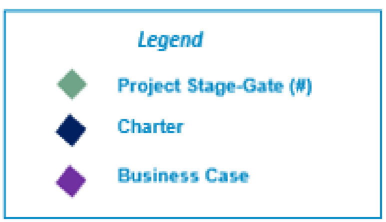
Legend: Existing Process - Grayscale | **New or Updated from Existing Process - Color**

Footnotes:

1. Project DOA Standard applies to all projects with a total expected case cost estimate exceeding $1 million.
2. SG = Stage Gate; PG&E will align to industry Standard nomenclature "Stage" Gate (SG#) vs Phase Gate (PG#).
3. AG = Authorization Gate
4. See Appendix for Delegation of Authority (DoA) details.

Project Authorizations - Scalability





	N/A	*Non-Major, Low-Risk Project*	*Non-major High-Risk Project*	*Major Project*	*Major Project with Board Approval*
Estimated Total Expected Case	< $1M	$1M - <$25M	$1M - < $25M	≥$25M - $250M	>=$250M
Complexity	N/A	Low	Low/High	Low/High	Low/High
Risk	N/A	Low	High	Low/High	Low/High

PG&E's Accounting System Update
Stakeholder Requested Item # 9

Nikki-Rose Apura – *Manager, Capital Accounting*

PG&E’s Accounting System Update

- PG&E did not implement a new accounting system but rather upgraded the company’s existing fixed asset financial system, PowerPlan.

- PG&E implemented PowerPlan in April 2010.

- PowerPlan reached its end-of-life support necessitating an upgrade to version 2023.

- Costs of this upgrade were recorded as expense.

AFUDC and Placing Projects on Hold
Stakeholder Requested Item # 10

Andre Williams – *Project Manager*

Nikki-Rose Apura – *Manager, Capital Accounting*

Nick Medina – *Senior Standards & Strategy Engineer, TPR Team*

Deferred Projects

- PG&E's Capital Management Standard Deferral Criteria
  - Authorization from Director level or higher
  - Interrupted construction or postponement for at least 6 months
  - No additional direct cost will be expended in deferral period
  - Management intends to complete project and funds remain authorized
  - Amount recorded to the order to date is greater than $15M
  - Capital orders with construction delay beyond PG&E control may not be placed in deferred state
- Projects can be placed in deferred status multiple times if the above criteria is met
- Once a project is placed into deferred status, AFUDC stops accruing on the project
- Current Deferred Projects:
  - PO 5794779 Brighton-Grand Island: PH2 I-5 W Piling
  - PO 5767217 REROUTE JEFFERSON_MARTIN 230KV

Automated AFUDC Pause Process

Starting 8/1/2024, PG&E implemented the automated pausing of Allowance for Funds Used During Construction (AFUDC) within its fixed asset financial system, PowerPlan, using the following criteria:

1. AFUDC will automatically pause for capital orders with ≥ 30 days construction period that do not have any direct charges (e.g., labor, materials, contracts) or accounting adjustments (e.g., refunds, billing credits) for 6 consecutive months;
2. Automation does not apply to capital orders with a construction period less than 30 days;
3. For orders with paused AFUDC, order status does not change;
4. AFUDC will begin accruing again when any direct charge or accounting adjustment is recorded to the order;
5. There is no minimum charge threshold for the automation.

Automated Paused AFUDC Orders

As of December 2024, AFUDC on 362 PM orders had AFUDC accruals automatically paused in PowerPlan.

- 135 PM Orders (mapped to POs) were included in the November 2024 TPR PDS
- To be provided after the stakeholder meeting

On Hold Projects in TPR PDS

On Hold Projects in November 2024 TPR PDS

1. CAISO Approved Projects: On Hold only if On Hold in CAISO Transmission Plan.

2. PG&E Approved Projects: On Hold if in
   - SAP Deferred Status (if incurred actuals greater than $15M)
   - P6 Stage of On Hold with no PM Assigned (Subject to Automated AFUDC Process). This does not directly correlate to AFUDC not accruing, or direct charges still being incurred.

NCPA 4 Q14

- 55 Series POs: no AFUDC is accruing (Construction < 30 days)

- 57 Series POs before 8/1/24
  - No AFUDC accrues if in deferred status
  - AFUDC can accrue if project is taken out of deferral and put back into deferred status. On Hold date provided is first deferral date.
  - POs with “20XX Investment Planning Process” as date placed on hold did not meet criteria for deferral and therefore accrued AFUDC

- 57 Series POs after 8/1/24
  - AFUDC accrual subject to automated AFUDC process
  - A project can be “On Hold” but still accruing AFUDC due to reasons such as: outstanding invoices, and permitting costs need to be recorded

T.0000159 Egbert 230kV Switching Station

- Project Status:
  - TPR/TDF/AB970/CPUC Permitting: Externally In-flight and not On Hold (as this project is not On Hold in the 2024 CAISO TPP)
  - Internally On Hold due to prioritization with forecasted capital expenditures for 2027-2031.
- Engineering Completion Date: September 2027 (tentative)
- Construction Start Date: March 2027 (tentative)
- Forecasted In-Service Date: October 2029 (tentative)
  - New in-service dates will be updated after the project resumes.
- POs in Deferred (i.e. On Hold) Status:
  - PO 5767217 REROUTE JEFFERSON_MARTIN 230KV LINE is deferred
  - PO 5767214 NEW EGBERT SWITCHYARD_230KV BUS EXT cannot be deferred due to contractual obligations with storage costs.
  - POs 5767213, 5767645, 5767646, 5767647, and 5767648 do not meet all the criteria required to be deferred (less than $15M in actuals each)

Stakeholder Requested Agenda Item #7: Vegetation Management: Impacts of October 2024 FERC Order on Vegetation Management Capitalization

Nikki-Rose Apura – *Manager, Capital Accounting*

George Kataoka – *Expert Analyst, Capital Recovery*

ET Right of Way Expansion Program

Question 7a: In October 2024, FERC issued a decision that required PG&E to expense, rather than capitalize, its Vegetation Management Right-of-Way Expansion Costs. Please provide an overview of how PG&E has implemented this decision, the years affected, and any ratebase or expense adjustments.

- PG&E Response :
- Included in RY2025 Annual Update:
  - Capital Refund:
    - TO rate base reduced for years 2017-2024 in TO19 and TO20 models
    - Refund includes full revenue requirement, including depreciation expense
    - Total of approximately $202M capital expenditures
  - O&M Expense incremental revenue is from same capital expenditures population, excluding AFUDC
- To include in upcoming RY2026 Annual Update:
  - Approximately $19M additional capital expenditures identified will be included in RY2026 for capital refund and incremental revenue for O&M
    - i.e., grand total identified is ~$221M capital expenditures (=$202M + $19M)

ET Right of Way Expansion Program

Question 7b: Please explain what accounting instructions, standards, or controls PG&E has put in place to ensure that costs associated with expanding electric transmission rights-of-way are not capitalized going forward.

- PG&E Response:
  - PG&E has published a Regulatory Accounting Document for this FERC Order, including the expensing of ET ROW Expansion costs
  - PG&E has clarified its accounting guidelines[1]
  - PG&E has communicated this to PG&E's transmission functional area and business finance job owners
  - PG&E has recorded the necessary journal entries to reclassify previously capitalized costs to expense.

[1] Electric Plant Instruction No. 7(A), Land and Land Rights, allows for first clearing and grading of land and rights of way to be capitalized.

Stakeholder Requested Agenda Item #14: Temporary Power Costs in Capital Orders

Joe Metcalf – *Electric Program Manager, Temporary Generation*

Brandon Ezell – *Construction Supervisor, Temporary Generation*

Temporary Generation

- Temporary generation during planned work is used to provide electric service to customers (i.e., keep customers online) while PG&E performs capital work & takes clearances that would otherwise stop electric service to customers.
- Temporary generation is requested by the project team based on scope of work
- The customer revenue is not credited to the PO for which temporary generation is utilized because: (1) PG&E is not aware of any FERC accounting instruction that requires crediting; and (2) trying to pinpoint a specific portion of retail customer revenues associated with temporary generation would be complex and have a de minimis impact on the overall capital project costs.

Back at 1:15

LUNCH BREAK

CWIP Ratebase Incentive
Stakeholder Requested Item # 3

Jason Castellanos, *Project Manager*

Eyob Embaye, *Project Manager*

Tim Criner, *Project Manager*

Creed Young, *Project Manager*

Marco Rios, *Sr. Manager - Electric Transmission Planning*

T.0009194 Manning New 500kV Sub Connection

Planning Order	Order Description	MWC	T.Dot	Scope Document Approval	Eng Start	Construction Start	FISD
5809641	PANOCHE-EXCELSIOR SW STA #1 & #2 115KV	60	T.0009194	9/26/2025	5/15/2024	5/1/2026	4/28/2028
5809640	MANNING PANOCHE SHOOFLY	60	T.0009194	9/26/2025	5/15/2024	5/1/2026	5/4/2028
5809639	MANNING GATES-PANOCHE #1 & #2 230KV	60	T.0009194	7/31/2025	5/15/2024	5/1/2026	6/1/2028
5809623	MANNING TRANQ POCO MAN-TRANQ#3	60	T.0009194	9/26/2025	5/15/2024	6/1/2026	4/28/2028
5804811	RECONDUCTOR 230KV MANNING - TRANQUILITY#1	60	T.0009194	4/8/2025	1/2/2024	6/1/2026	5/31/2028
5804801	LOOP 2 PANOCHE-TRANQ LINES IN MANNING	60	T.0009194	4/23/2025	1/2/2024	6/1/2027	6/1/2028
5804800	LOOP LOS BAN-GATES#1 & LOS BANO-MID#2	60	T.0009194	4/30/2025	1/2/2024	6/1/2027	6/1/2028
5809979	MANNING SUB - PANOCHE ENG CENTR	61	T.0009194	1/31/2025	8/1/2023	2/5/2027	4/3/2028
5809978	MANNING SUB - LAS AGUILAS SW SUB	61	T.0009194	1/31/2025	8/1/2023	2/5/2027	4/3/2028
5809028	MANNING SUB: MANNING TELECOM & TESTING	61	T.0009194	1/31/2025	8/1/2023	4/29/2026	6/1/2028
5808684	Manning: Panoche Sub Replace CB 102, 132	61	T.0009194	1/31/2025	8/1/2023	1/15/2027	3/31/2028
5804878	MANNING SUB: GATES PROTECTION UPGRADE	61	T.0009194	1/31/2025	8/1/2023	2/5/2027	4/3/2028
5804813	MANNING SUB: TRANQUILITY BAAH	61	T.0009194	1/31/2025	8/1/2023	4/29/2026	4/3/2028
5804806	MANNING SUB: PANOCHE BAAH	61	T.0009194	1/31/2025	8/1/2023	4/20/2026	1/21/2028
5804805	MANNING SUB: MIDWAY PROTECTION UPGRADE	61	T.0009194	1/31/2025	8/1/2023	11/2/2027	4/28/2028
5804804	MANNING SUB: LOS BANOS PROTECTION UPGRAD	61	T.0009194	1/31/2025	8/1/2023	11/2/2027	4/4/2028

Scope:
LS Power to construct a new 500kV/230kV Substation, LS Power to construct 2 new 230kV transmission lines between Manning substation and Tranquility SW Sta. PG&E to loop the Los Banos – Gates No.1 500kV line and the Los Banos – Midway No. 2 500kV line, loop the two existing Panoche – Tranquility 230kV lines into the new 500kV Manning substation, reconductor the two Manning – Tranquility 230kV lines. PG&E to modify the Gates 500kV Series Capacitor Banks 1&2 (SC1 & SC2) reactance to maintain 500kV line compensation and upgrade 500kV line protection. Upgrade Panoche 230kV Bus section D to BAAH and replace all overstressed breakers in Bus Section E. Upgrade line terminals at Tranquility substation. Upgrade 500kV line protection at Los Banos substation as needed. Upgrade 500kV line protection at Midway substation as needed.

T.0009189 Loop Vaca Dixon-Tesla in Collinsville

Planning Order	Order Description	MWC	T.Dot	Scope Document Approval	Eng Start	Construction Start	FISD
5804858	LOOP VACA DIXON-TESLA IN COLLINSVILLE	60	T.0009189	3/3/2025	7/25/2023	07/29/2027	5/30/2028
5804803	PITTSBURG CONNECT 2 230 & INST BUS REAC	61	T.0009189	7/24/2024	7/25/2023	05/17/2027	5/30/2028
5804802	TESLA UPGRADE SYSTEM PROTECTION	61	T.0009189	7/24/2024	7/25/2023	08/19/2027	5/30/2028
5804724	VACADIXON SUB 500KV SERIES CP BK2 MOD	61	T.0009189	7/24/2024	7/25/2023	06/09/2027	5/30/2028

- **Scope:** LS Power to install a new 500kV substation in the town of Collinsville. PG&E to tap on the existing 500kV line to loop in and out of the new substation. PG&E to replace remote end relays at Vaca Dixion and Tesla substations. Furthermore, modify the series Cap bank at Vaca Dixion, install new and relocate existing 230kV line breakers (totaling 4 positions) including installation of 115kV reactors at Pittsburg substation.

- **Status:** Substation and T-line designs are in progress. T-line is incorporating 60% design review comments to complete 95% in July 2025. Pittsburg is at 30% and the other two (Vaca & Tesla) are starting in February 2025.

CAISO Rescoping of LS Power Projects

- In November 2024, the CAISO rescoped both the Newark – NRS HVDC project is modified to Newark – NRS 230 kV project, and, Metcalf – San Jose B HVDC project
  - Both projects are still required to be in-service by June 2028

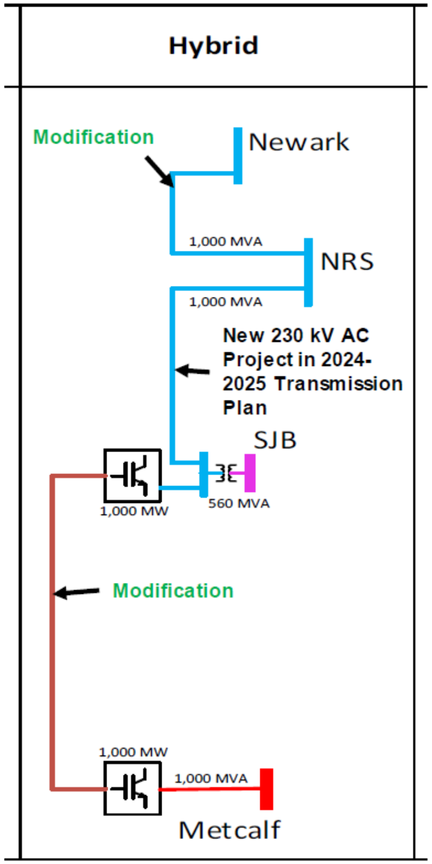
- Drivers for the rescoping of the projects
  - Load increase in the South Bay area, in both SVP and PG&E's areas – 2,100 MW in the 2021-2022 transmission plan to about 3,400 MW in the current TPP
  - Original scope found to be no longer sufficient to meet the projected need
  - Additionally, according to CAISO, LS Power was projecting an increased cost estimate for the HVDC projects

- Third connecting element
  - The CAISO has indicated they are likely to approve a new 230 kV line from NRS to San Jose B supplementing the two projects – the new line is also needed to serve the growing load in the South Bay area reliably
  - The CAISO makes the determination as to whether the new line would be competitively bid

T.0009168 Newark - HVDC Connection

Planning Order	Order Description	MWC	T.Dot	Eng Start	Construction Start	FISD
5806599	NEWARK - HVDC CONNECTION - TLINE	60	T.0009168	9/15/2023	10/17/2025	6/1/2027
5804787	NEWARK - HVDC CONNECTION	61	T.0009168	7/13/2023	10/29/2025	5/28/2027

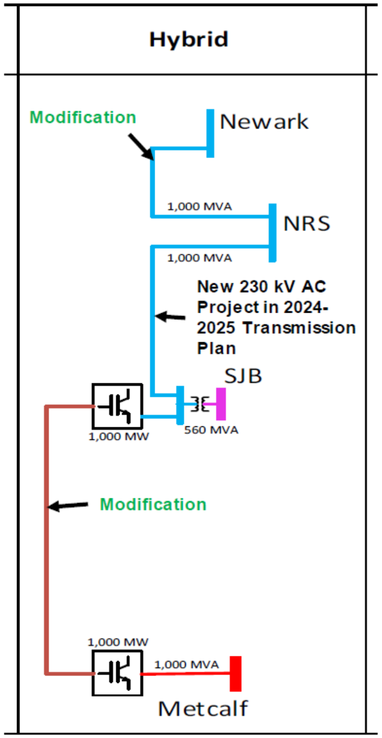
- Based on the CAISO decision in November 2024, the scope of the Newark to NRS connection was changed to a 1,000 MVA 230 kV Alternating Current (AC) circuit.
- The overall impact on the PG&E scope of work and completion timeline due to the CAISO rescoping of the Newark (a.k.a., Power the South Bay) project is being evaluated by PG&E. PG&E estimates that the new scope of work to be performed will be finalized by April 2025.
  - PG&E will evaluate the relevance of the completed engineering after finalizing the impact on PG&E scope.
  - The effect on interconnection process(es) due to CAISO scope change from DC to AC is also being evalulated along with overall impact on PG&E scope.
  - PG&E's ability to recover the costs it incurs to interconnect the project(s) will be evaluated once PG&E scope is finalized.



T.0009169 Metcalf - 500kV HVDC Connection

Planning Order	Order Description	MWC	T.Dot	Eng Start	Construction Start	FISD
5806625	SAN JOSE B - HVDC CONNECTION - TLINE	60	T.0009169	9/15/2023	4/22/2027	12/30/2027
5807758	SAN JOSE B - HVDC - SAN JOSE A RE	61	T.0009169	7/12/2023	4/1/2027	12/30/2027
5807739	SAN JOSE B - HVDC - TRIMBLE RE	61	T.0009169	7/12/2023	7/23/2027	12/30/2027
5804789	SAN JOSE B - HVDC CONNECTION	61	T.0009169	7/13/2023	12/3/2026	12/30/2027
5804788	METCALF - 500KV HVDC CONNECTION	61	T.0009169	7/13/2023	5/12/2027	12/30/2027
5555161	SAN JOSE B - HVDC - SOUTH TRANSITION RE	61	T.0009169	7/12/2023	11/4/2026	12/30/2027
5555160	SAN JOSE B - HVDC - NORTH TRANSITION RE	61	T.0009169	7/12/2023	12/3/2026	12/30/2027

- Based on the CAISO decision in November 2024, the scope of the project was changed to a 1,000 MW HVDC link between Metcalf 500 kV and San Jose B 230 kV substation and a 230/115 kV transformer to connect to PG&E's San Jose B 115 kV substation.
- The overall impact on the PG&E scope of work due to the CAISO rescoping of the Metcalf (a.k.a., Power the Santa Clara Valley) project is being evaluated by PG&E. An initial review indicates that PG&E will have to install a 230kV GIS and a 560MVA 230/115kV autotransformer at San Jose B. PG&E estimates that the new scope of work to be performed will be finalized by July 2025.
  - PG&E will evaluate the relevance of the completed engineering after finalizing the impact on PG&E scope.
  - CAISO did not change the scope from DC to AC for the Metcalf San Jose B line and hence interconnection process(es) will not be impacted.
  - PG&E's ability to recover the costs it incurs to interconnect the project(s) will be evaluated once PG&E scope is finalized.



Stakeholder Requested Agenda Item #4: Load Interconnection Processes

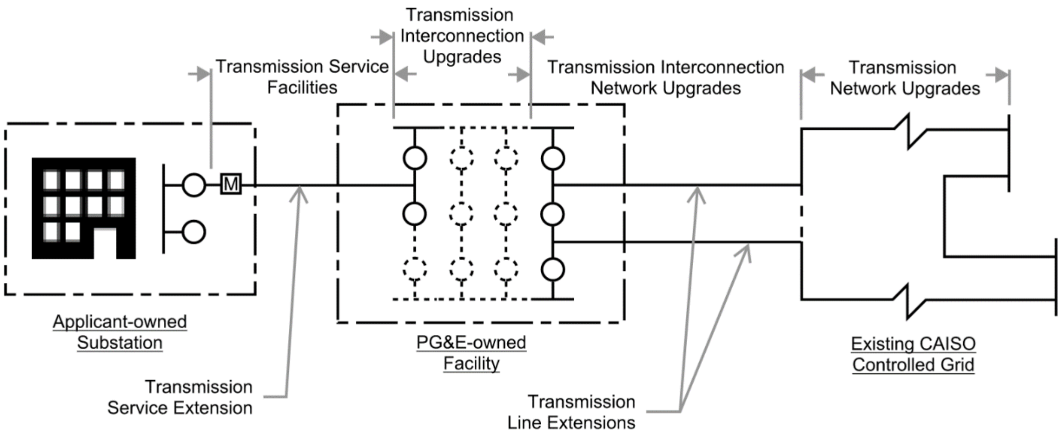
Ben Moffat – *Sr. Manager, Electric Program Management*

Mike Settlemire – *Sr. Manager, Regulatory Tariffs*

Electric Rule 30 - Background

Please provide an overview of PG&E's recent "Rule 30" application to the CPUC and its potential impacts on cost allocations to electric transmission customers. Please include how the results of this application may, or may not, be applied to projects that have already been included in the TPR.

- In November 2024, PG&E submitted proposed Electric Rule 30 to the CPUC. Electric Rule 30 addresses the interconnection of electric retail load customers interconnecting at transmission level voltages (e.g., data centers, EV charging, etc.).
- Electric Rule 30 addresses cost <u>responsibility</u> for retail electric customers for 4 potential facility types.



- Cost <u>recovery</u> (*i.e.*, through CPUC- or FERC-jurisdictional rates) is not addressed in the Electric Rule 30 proceeding. Cost recovery is addressed in the GRC (CPUC-jurisdictional) or Transmission owner (FERC-jurisdictional) rate cases.

Electric Rule 30 – Cost Responsibility

Please describe how PG&E's proposed Rule 30 would affect the cost allocation for data centers and other large load interconnection projects like the California High Speed Rail project?

- Electric Rule 30 addresses cost responsibility for facilities needed to interconnect transmission level customers.
- For Facility Types 1-3, the customer is required to provide an advance and then is invoiced for the actual costs incurred by PG&E above the advance.
- The customer can also elect to build some of the facilities itself or contribute assets (e.g., land) which may lower the overall project costs.
- Consistent with FERC precedent, Facility Type 4 is paid for by PG&E and included in TO rates because it is a transmission network upgrade.
- Customers are eligible for refunds of the advance, actual cost payment, and the value of applicant build/contributions based on subsequent revenue.
- The refund period is limited to 10 years and is based on the Base Annual Revenue Calculation or "BARC" review. The BARC review looks at revenue that will be generated by the customer's facility to determine refunds.
- Customers are eligible for but not guaranteed refunds.
- When an amount is refunded to the customer, the refunded amount will then effectively be included in PG&E's rate base.

Pilot Cluster Process Overview

In particular, at the CAISO Symposium, Jason Glickman mentioned PG&E's efforts to conduct a cluster study with Bay Area data centers to determine all at once the network upgrades needed for these large load interconnections. He mentioned there were 19 applications received. Can PG&E please describe this process in more detail, the jurisdictional split of these upgrades, the cost and timeline for these upgrades, the cost allocation methodology employed, and whether any of these projects are currently included in the TPR Process data.

- In 2024, PG&E piloted a cluster study approach to study the increased number of data center applications received in the San Francisco South Bay area, mainly in Santa Clara and Alameda counties ("Pilot Cluster Process"). The clustering of large data center applications in certain areas and studying them in a serial process created complex, high-cost interconnection, and capacity upgrades. When projects are studied serially, it can be challenging to factor the cumulative impacts of the total load in a geographic area.

- PG&E's Pilot Cluster Process is a streamlined approach for handling applications for large data center loads within a specific geographic area, allowing customers to submit applications and be grouped based on their proximity to PG&E's transmission and distribution system. We also offered customers with active or previously completed applications the chance to restudy, downsize, or change their project's Point of Interconnection within the same calendar year. Customer Engagement Meetings were held during the Pilot Cluster Process to provide each customer a dedicated meeting where PG&E and the customer discussed feasible connection options, available capacity, land, permitting, and planned capacity projects. This helps customers make informed decisions about proceeding with or withdrawing their applications.

- The Pilot Cluster Process also sets clear timelines and procedures for study milestones, customer engagement, and project initiation. Customers will be informed about the expected scope, costs, and duration of their project during the application phase.

- The Cluster Study is still ongoing, and PG&E and the customers have not yet finalized agreements that would address the agreed upon costs, timeline for upgrades, or cost allocation methodology. The total costs, timeline, and jurisdictional cost responsibility will be unique for each project in the study.

Pilot Cluster Process – Expandable Facilities

Please also describe whether the pilot looked at opportunities to build capacity upgrades that are "expandable" or could provide flexible capacity for future interconnections and any cost savings PG&E identified as a result of the cluster study

- PG&E's Pilot Cluster Study looked for ways to efficiently interconnect customers and minimize interconnection as well as capacity upgrade costs. Capacity upgrades were determined by looking at the impacts of the new load wholistically, and solutions were developed with future growth in mind. This helped to avoid rework and rescoping, thus creating efficiencies.
- Estimated cost savings are unknown as PG&E and the Cluster customers are still finalizing agreements.
- PG&E is requiring that proposed new switching stations to serve customer Cluster projects are large enough to expand and accommodate future interconnections. This may reduce the timeline, costs, and challenges to interconnecting future customers.

Stakeholder Requested Agenda Item #8: Grid Enhancing Technologies

Issam El Ayadi – *Director, Transmission Line Asset Management & Regulatory Governance*

Future of Ratings

- Ambient Adjusted Ratings (AAR) and Dynamic Line Ratings (DLR) are expected to enhance grid operation by optimizing the system to perform more accurately to real-time weather conditions rather than a conservative static assumption.
  - This means reducing risk via reduced ratings when appropriate and increasing ratings/total transfer capabilities when we can safely do so.
  - Upon implementation, PG&E is expecting lines to have increased capacity available providing operational flexibility more often than reduced ratings.

- PG&E’s AAR implementation planned by July 2025 is not captured in the November 2024 TPR PDS. AAR Design Phase Funding is an expense order.

Ambient Adjusted Ratings Update

- In compliance with FERC Order No. 881, PG&E has been working towards a July 2025 launch of AAR utilization.
- PG&E has partnered with GE to develop a tool in order to optimize and automate the AAR calculation process.
- A rigorous selection process has identified detailed line exceptions to the AAR process. A few of the high level exceptions identified are:
  - Various known asset health concerns
  - Pending scheduled maintenance work
  - Physical ground or wire clearance issues
  - Concerns on maintaining 500kV system through adjusted ratings

- CAISO has filed an extension request for FERC Order No. 881 to delay launch until end of 2026.

Dynamic Line Ratings Update

- In addition to AAR deployment, PG&E is exploring further dynamic line rating technology through the EPIC program.
- Solutions typically range from digital DLR to sensor based to more novel vibration-based technologies.
- What all of them have in common is a fluctuating dynamic line rating based on the inputs of their tools which considers changing windspeeds.
- Solving for DLR calculations is only one facet of implementing DLR. The true challenge comes with the operational process.
- A planned pilot of 3-4 vendors over approximately 4 circuits over ~12-18 months is expected to occur.
  - PG&E has narrowed the vendor options and is planning to award the winners in the upcoming months.
  - Partnering with EPRI for calibration and validation.
- In addition to the DLR benefits for these chosen vendors, the asset health monitoring capabilities will also be assessed at the selected locations.

High Temperature Low Sag Conductors

Technology: HTLS

Description: Conductors designed to operate efficiently at high temperatures without significant loss of mechanical strength, minimizing sag under thermal stress, allowing for increased capacity and improved reliability. They can be installed on existing structures with minimal changes, making them a cost-effective solution for increasing transmission capacity.

Current Status:

- One type of HTLS has already been deployed.
- An additional type has been identified for further pilot and future deployment opportunities.

Next Steps:

- Considering utilizing HTLS for all reconductoring were feasible.
- Continued pilot opportunities for new installations.
- Monitor existing locations for performance.

Advanced Power Flow Controller

Technology: Advanced Power Flow Controller (APFC)

Description: Advanced power flow controllers are power electronics-based devices used to control power flow by acting as an adjustable series capacitor or series reactor to increase or reduce flow as required by electric grid conditions. These device characteristics and flexible capabilities help extend asset life and increase transmission capacity by unlocking existing grid potential, making it a cost-effective alternative solution to reconductoring transmission lines.

Current Status:

- We are currently piloting Smart Wires SmartValve units, a type of Advanced Power Flow Controller (APFC), at a PG&E substation to mitigate future line overloads. The target in-service date is Q1 2026.

Next Steps:

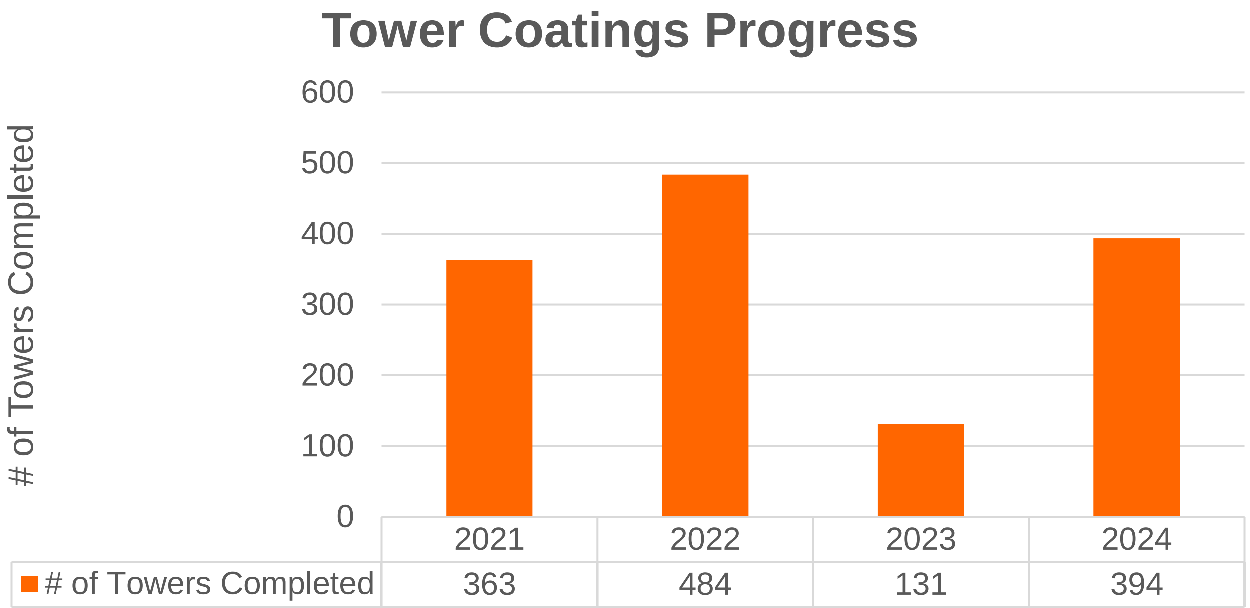
- Assess the SmartValve technology and its performance with pilots
- Evaluate feasibility of additional pilot projects to use SmartValves on five other transmission lines that are projected to see overload conditions in the Bay Area

Stakeholder Requested Agenda Item #5: Tower Coating

Shivani Nigam *(Program Manager)*, Sean Clesen and Chris Nguyen

Transmission Line Tower Insulation and Coating

Tower Coatings Progress



1. In 2021, PG&E initiated a Tower Coating Program which applies a comprehensive coating system that provides a cost-effective corrosion protection barrier to the steel components in transmission towers.
2. Accounting Treatment: Consistent with FERC's approval in February 2022, PG&E is capitalizing the first-time coating application costs associated with this Tower Coating Program as this coating should extend useful life by an estimated 20-25 years and therefore constitutes a substantial addition.
3. 2024-unit cost approx. $62K
4. Units within this chart changed from the previous submission for 2021-2023 due to omitting IT towers, distribution towers and towers that have been replaced.

Tower Coatings Work Plan (2025 – 2028)

	2025	2026	2027	2028
# of Towers*	497	350	425	347

* Units may vary based on approved funding for 2025-2028 and based on draft investment plan/adjustments to the investment plan.

Program Challenges

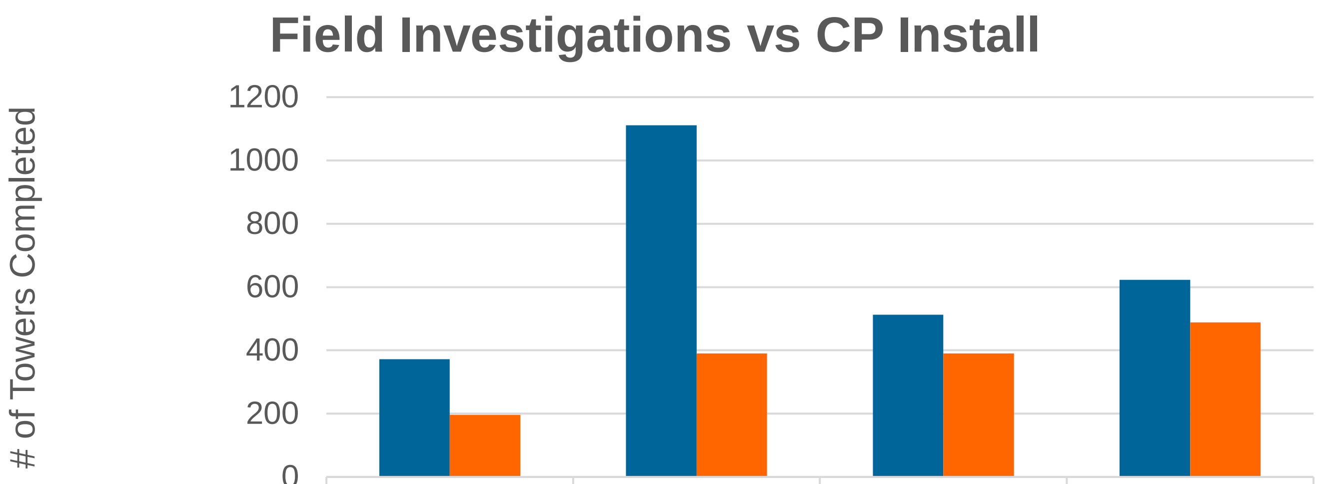
- Prioritization of work
- Inclement weather in Q1 and Q4 historically impact execution of tower coatings.
- Water towers show execution challenges such as:
  - Small window for work due to biological and environmental constraints
  - Access to towers using pontoons, helicopters, boats, barges, etc.

Stakeholder Requested Agenda Item # 6: Cathodic Protection

Shivani Nigam *(Program Manager)*, Sean Clesen and Chris Nguyen

Transmission Line Tower Insulation and Coating

Cathodic Protection (CP) Progress



	2021	2022	2023	2024
Field Investigations	372	1111	513	623
CP Install	196	390	390	488

1. In 2021, PG&E conducted a pilot program for Cathodic Protection across eight geographic regions.
2. A diverse population of towers are prioritized based on varying soil characteristics, land usage, weather, etc. using PG&E’s risk model with a focus on towers with direct buried foundations
   - There are estimated to be over 5,000 existing towers with direct buried grillage within the PG&E transmission tower network to be completed within this program.
3. 2024-unit cost approx. $12K

CP Work Plan (2025 – 2028)

Year	Field Investigations	CP Installs
2025	658	518*
2026	525	500*
2027	525	500*
2028	525	500*

Program Challenges

- Prioritization of work
- The Cathodic Protection Program anticipates completion of its investigation of directly buried foundations on lattice steel towers between 2029-2030
- Towers with remote access provide execution challenges for mobilization of personnel and equipment

* CP Install scope subject to change based on engineering analysis of sites requiring CP

Supply Chain / Stakeholder Requested Item # 13

Alper Ismail Bayrakdar - *Category Lead, T&D Material Sourcing*

Material Supply Chain – Circuit Breakers (Industry)

Demand
Increasing Investments: Growing investments in the industrial sector and infrastructure development

Renewable Energy
Rising installation of renewable energy systems

Market Growth
Projected Growth: The market is expected to grow ~ $30 billion by 2032
Regional Dominance: Asia Pacific leads with a 40% market share

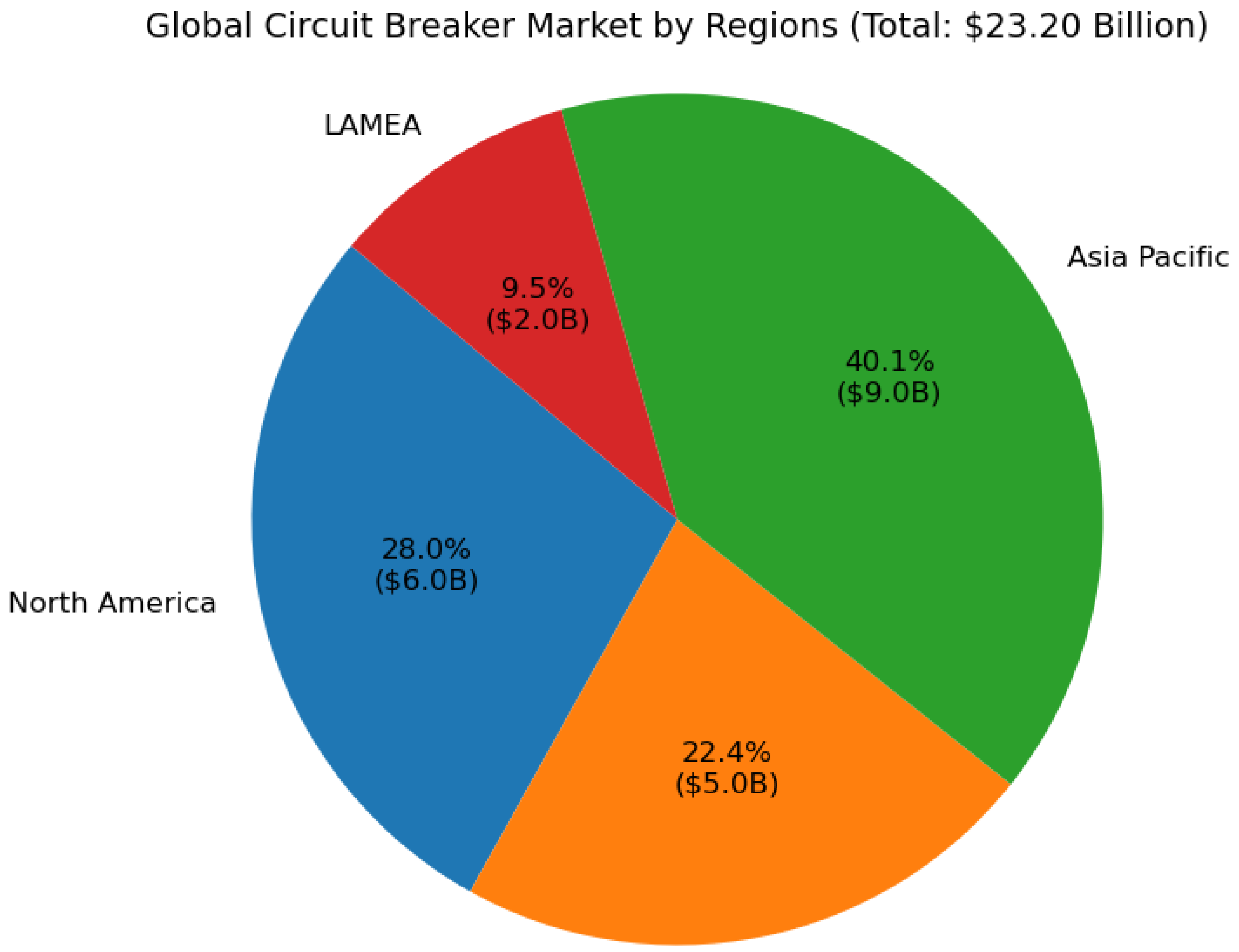
Challenges
High Initial Costs: The high initial cost of advanced circuit breakers

Opportunities
Technological Advancements: Adoption of smart and digital circuit breakers
Eco-friendly Solutions: Innovations in eco-friendly circuit breakers

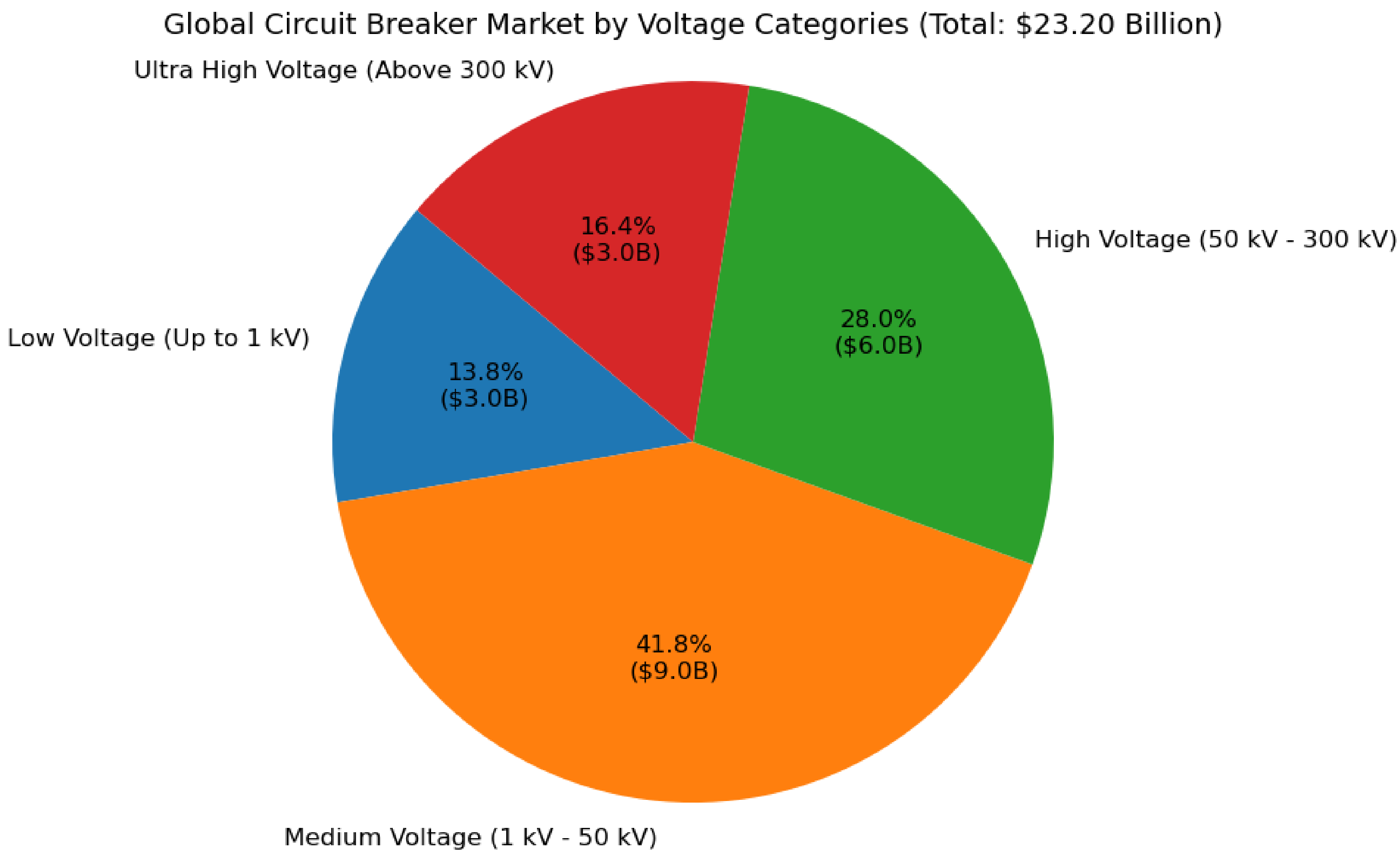
Lead Times
Supply Chain Disruptions: Initial disruptions due to labor and component shortages
Manufacturing Hubs: Asia Pacific remains a key manufacturing hub

Costs
Maintenance Costs: Stringent environmental regulations and high maintenance costs

Material Supply Chain – Circuit Breakers (Market Size)



Material Supply Chain – Circuit Breakers (Market Size)



Material Supply Chain – Circuit Breakers (Suppliers)

- **Mitsubishi Electric** - Roughly 5-10% market share. Mitsubishi Electric is involved in electrical and electronic equipment, including circuit breakers
- **Siemens** - Around 15-20% market share. Siemens offers a wide range of circuit breakers and is a prominent player in the industrial and commercial sectors.
- **Hitachi Energy** (former ABB**)** - About 15-20% market share. ABB is well-known for its electrical equipment and automation products, including circuit breakers.
- **GE Grid Solutions** - Around 5-10% market share. GE offers circuit breakers and other electrical equipment mainly focused on grid solutions.

Material Supply Chain – Circuit Breakers (Mitigation)

- **Diversifying Suppliers**:
  - PGE to diversify its supplier base to reduce dependency on a single supplier and mitigate the risks associated with supply chain disruptions. Engineering team diligently working on approving more manufacturers
- **Building Strong Supplier Relationships**:
  - Developing strong relationships and long-term contracts with key suppliers to ensure priority in production schedules and more reliable delivery times
- **Collaborative Planning with Suppliers**:
  - Engaging in collaborative planning and forecasting with suppliers to align production schedules with demand forecasts, reducing lead times and improving supply chain responsiveness
- **Long-Term Contracts and Agreements**:
  - Establishing long-term contracts with suppliers to lock in production capacity and secure better terms, thereby reducing lead times and ensuring a steady supply of critical components
- **Bulk Purchasing**:
  - In the talks to make bulk purchases to benefit from economies of scale and secure priority in production schedules, helping to mitigate the impact of increased lead times
- **Increasing Inventory Levels**:
  - Revisiting inventory parameters to buffer against supply chain disruptions and reduce the impact of increased lead times.
- **Implementing SAP ordering**
  - Taking an advantages of SAP ordering with standard SKUs

Power Transformer
Market Observations and Strategic Initiatives

Summary

Power Transformers range in power output from 2 to 420MVA. PG&E's transmission class Power Transformers range from 115 to 500kV and are used to transfer energy over long distances. PG&E's distribution Power Transformers range from 60 to 230kV and are used to step down the voltage serving commercial, industrial, agricultural and residential customers. Procurement and Transformer manufacturing is a complex process that requires prequalification of manufacturers, a competitive bidding process on a per project basis, the purchase of raw materials, long lead time subcomponents and special modes of transportation due to their size and weight.

Key Market Observations

- Demand continues to outpace supply. The combination of aging infrastructure, expanding the grid, increased demand from the Commercial and Industrial, Renewable, and Data Center sectors have caused a spike in demand. Lead times have expanded from one year to two to four years. Power Transformer demand is projected to continue to grow for another 10 years
- Cost of Transformers have gone up significantly due to increased market demand and high raw material and subcomponent costs
- Favorable factory lead times do not last long. In a short period of time, factories can oversell their capacity which result in suppliers being selective in the bids they participate, reducing the number of proposals received

Strategic Initiatives

- Due to extended lead times PG&E has been working on expanding our supplier pool. PG&E is in the process of evaluating new suppliers. Four developing suppliers have active pilot awards
- In 2024 PG&E put together a five-year demand forecast and purchased 150 Power Transformers in effort to support projected demand and offset extended lead times
- PG&E is partnering with key suppliers to establish slot programs to support demand outside of the five-year forecast

Back at 2:55

BREAK

Stakeholder Requested Agenda Item #11: Rail Project Updates

Paul Krum – *Electric Program Manager*

Jamie Dean – *Electric Program Manager*

11a. High Speed Rail Update

Please provide an update on any activities on this project, including any revised scope and engineering assessments. Please confirm that no costs for any California High-Speed Rail work has been allocated to ratepayers, pursuant to CPUC Resolution E-4886, Ordering Paragraph #6:

> *PG&E shall not recover costs for the Projects in Commission-established rates until the Commission has issued a final order regarding the cost allocation issues in response to the PG&E application ordered herein. Similarly, PG&E should not recover costs for the Projects in FERC-established rates until the Commission has issued a final order regarding the cost allocation issues from FERC.*

- The technical studies delivered in 2024, based upon the scope of work received in 2023, have expired. New technical studies will have to be performed before California High Speed Rail project can move forward. Given that the California High Speed Rail project is still at the study stage, cost allocation has not been determined, thus PG&E has not sought cost recovery. PG&E plans to submit an application for CPUC and/or FERC approval for any agreements regarding cost allocation when appropriate.

11b. Caltrain Electrification

Please provide a status update on this project., the current status and cost allocation in rates, and describe any future electrification work anticipated with Caltrain.

- Construction of the Caltrain Substation Upgrades Project is complete, and PG&E is proceeding with completion of regulatory requirements in accordance with CPUC Decision 20-05-008 and the Joint Petition for Modification of D.20-05-008.
- Project costs are subject to a cost allocation: 60 percent to PG&E and 40 percent to Caltrain. PG&E's allocation of the distribution-related costs are recovered through the GRC and the transmission-related costs would be recovered through the TO.
- The Project distribution-related costs were approved for recovery through the 2023 GRC Decision.
- No additional electrification work associated with the Substation Upgrades is forecast at this time.

CAISO-approved Policy Projects and Generator Interconnection-Related Network Upgrades Stakeholder Requested Item # 15

Darrin Yoxtheimer – *Electric Program Manager*

Nick Medina – *Sr. Standards & Strategy Engineer, TPR Team*

TPP Policy Projects

Utility Unique ID 2	T Project Name	Status	ITD	EAC	ISD	MW
T.0000043	Bellota-Warnerville 230kV Reinforcement	Operational	$ 98,270	$ 98,223	03/31/24	Note*
T.0002231	Wilson-LeGrand	Operational	$ 9,357	$ 9,357	12/18/23	Note*
T.0008394	Reconductor Rio Oso–SPI Jct–Lincoln 115kV line	Planning	$ -	$ 19,197	12/31/29	Note*
T.0009013	Delevan - Cortina Line Reconductoring	Engineering	$ 437	$ 49,317	04/05/28	Note*
T.0009189	Loop Vaca Dixon-Tesla in Collinsville	Engineering	$ 2,290	$ 114,999	05/30/28	Note*
T.0009194	Manning New 500kV Sub Connection	Engineering	$ 7,417	$ 177,242	06/01/28	Note*
T.0009553	Henrietta 230/115 kV Bank 3 Replacement	Engineering	$ 59	$ 16,059	10/02/28	Note*
T.0009662	Borden-Storey 230 kV 1 and 2 Line Reconductoring	Planning	$ 24	$ 40,729	04/12/30	Note*
T.0010534	North Dublin -Vineyard 230 kV Reconductoring	Planning	$ -	$ 150,000	12/01/31	Note*
T.0010636	Tesla - Newark 230 kV Line No. 2 Reconductoring	Planning	$ -	$ 59,000	12/01/32	Note*
EX113671	Sobrante 230/115 kV Transformer Bank Addition	Planning	$ -	$ 23,000	12/01/31	Note*

*TPP Policy projects are based on CAISO generation portfolio assumptions as of 23/24 TPP cycle

Generator-Related Network Upgrade in TPR

- Please refer to PG&Es TPR-mapped Network Upgrade workbook in the January 2025 CAISO Transmission Development Forum (TDF)
  - To be provided after the stakeholder meeting

- The TDF NU workbook & TPR PDS serve different purposes and audiences. The data fields provided in each report may not be comparable for the following reasons:
  - TDF projects are included at the Network Upgrade ID level
  - A Network Upgrade ID can consist of an entire T.Dot project, a single PO, multiple POs on a given T.Dot, or only a portion of scope for a single PO
  - TPR projects are at the PO level, with all work scopes under each T.dot project
  - PG&E has manually assigned a single PO/T.Dot to the Network Upgrade ID for the purposes of this mapping with the caveat that this may lead to inconsistencies in data and that a network upgrade can span multiple POs or a whole T.Dot

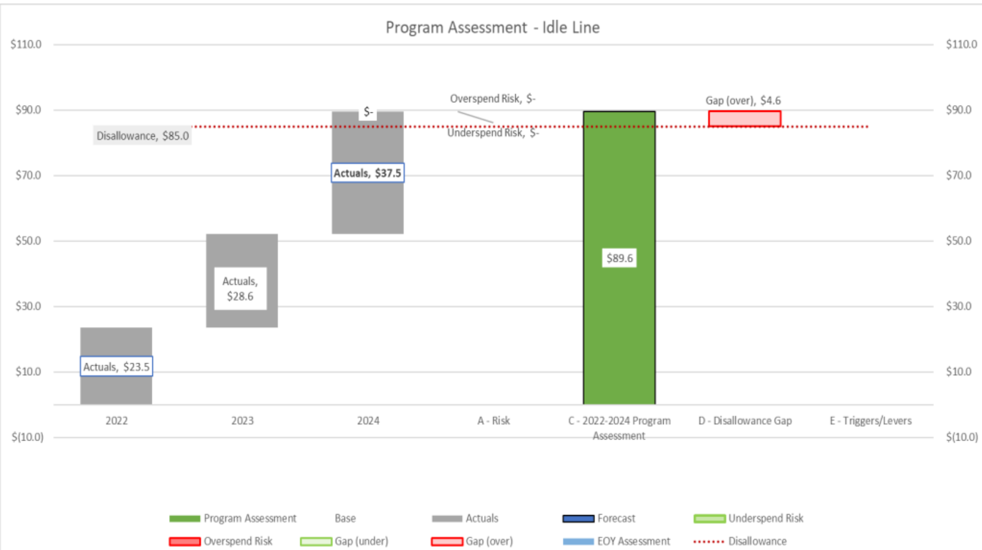
Systemwide Idle Line Removal Updates
Stakeholder Requested Item # 12

Chase Chaussee — *Sr. Consulting Project Manager, Transmission Operations*

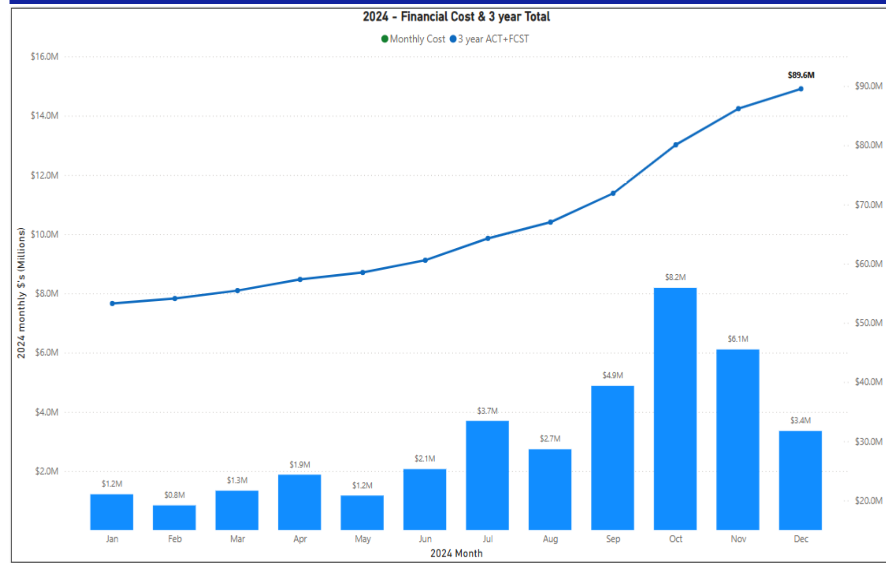
Dipo Toriola — *Electric Standards & Strategy Engineer, T-Line Asset Strategy*

Systemwide Idle Line Removal Update

Actuals/ Forecast Cost (First 3 Years to $85M Disallowance)



2024 Month Cost / Forecast



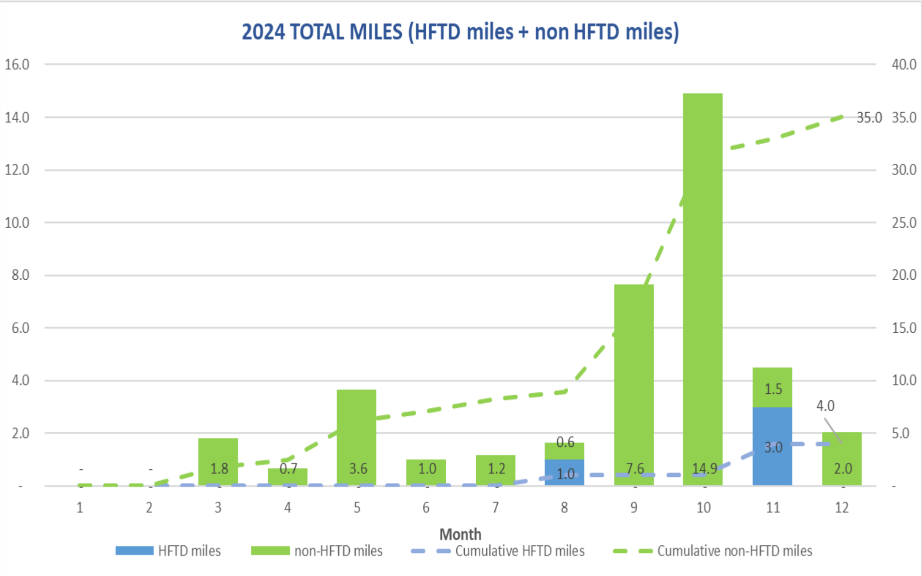
NOTE: - The overall actuals for the 3 years is $89.6M. For the miles of conductor removed, we are still forecasting towards the overall amount.

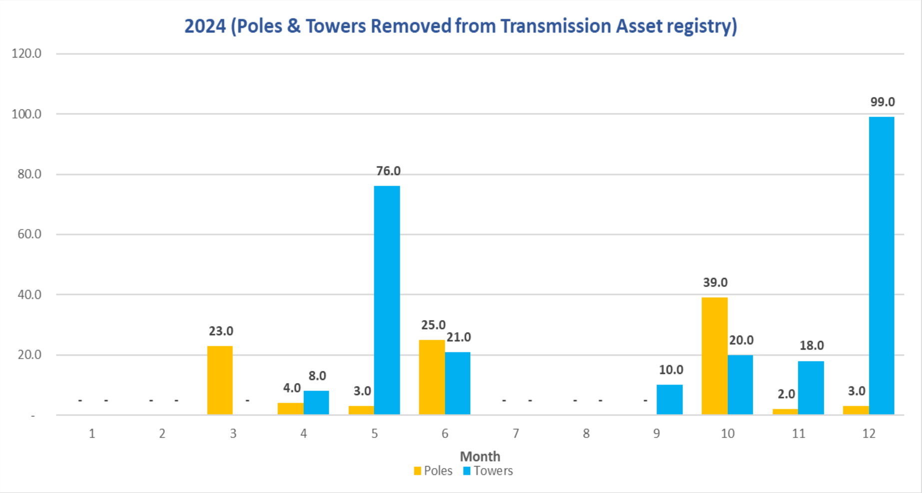
Disallowance YTD Reporting

- December spend = **$3.4M**
- 2024 YTD recorded to OBS order **$33.7M**
  - 2022 YTD recorded to OBS order **$23.4M**
  - 2023 YTD recorded to OBS order $**27.9M**
- ***Note:*** Added tab of pivot of what costs hit orders (excluding credit out to OBS) for reference

- ***Note:*** Per 2/1 meeting, in collaboration with Operations, Accounting, Finance Ops, we will review and start removing orders from auto JE process periodically throughout the year; at that time will true-up any costs that may have incurred that did not get allocated to OBS order

Systemwide Idle Line Removal Update





2024+ Milestones					
Orders	Project Name	Construction Start	OPDAT	Construction Finish	HFTD Miles
74045279	GEYSERS #17 – FULTON_EAGLE ROCK – FULTON-SILVERADO	02-Oct-23	31-Mar-25	31-Mar-25	0.6
31616000	THERMAL ENERGY TAP	22-Apr-25	22-Apr-25	24-Apr-25	
35575474	WESTINGHOUSE TAP	30-Jun-25	30-Jun-25	30-Jun-25	

Beyond the $85M Disallowance

- PO 5510559 Systemwide Idle Line Removal: forecast placeholder for future work beyond the $85M Disallowance. This forecast is subject to reprioritization

2029	2030	2031	2032
$7.5M	$5.7M	$5.7M	$4.9M

- When a given project is implemented, it will receive a unique PO and forecast transferred to that unique PO.

GO 131-D Compliance
Stakeholder Requested Item # 16

Nick Medina – *Sr. Standards & Strategy Engineer, TPR Team*

GO 131-E Section IV

- GO 131-E Rev 1
  - IV.A Annual Reporting: Utilize May TPR PDS
    - Manually add distinct fields for number of circuits, substation/switching station name, and transmission/power line name
  - IV.B Quarterly Reporting: Utilize TPR PDS with milestone/cost updates for off quarter submissions
    - Status quo for existing process with the exception of project inclusion extending expected CPUC permitting filing in the next one year to the next two years

Feedback and Discussion of Next Steps

Lorenzo Thompson, Nick Medina & Nicholas Hsiao

- *TPR Team*

Wrap Up

Lorenzo Thompson, Nick Medina & Nicholas Hsiao

- *TPR Team*