Transmission Project Review Process
Stakeholder Meeting

February 4, 2026



Virtual Meeting Safety

Know Your Safety Protocols

Share Your Location in Chat

Assign a 30/30 Lead

Ensure Proper Ergonomics

Know Your Evacuation Plan

Active Shooter “Get Out/ Hide Out/Take Out”

Earthquake “Drop/Cover/Hold”

Psychological Safety

- I’m cared for as a human being
- People have my back
- I know new ideas are safe to try
- I’m not attacked for my ideas

Call the Nurse Care Line for any discomfort at 1-888-449-7787

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
9:10	Steps Taken to Improve PDS
9:15	Asset Strategy
10:40	Break
10:55	Asset Strategy
11:15	Stakeholder requested items
12:10	Lunch
1:00	Stakeholder requested items
2:40	Break
2:55	Stakeholder requested items
4:20	Wrap-up

November 2025 TPR Material

Lorenzo Thompson & Nick Medina - *TPR Team*

TPR Process Calendar (Nov 2025 - April 2026)

November 3	PG&E releases semi-annual Project Spreadsheet, Authorization Documents, and Procedures.
December 16	Due Date for Stakeholders to provide questions and comments related to the Project Spreadsheet provided on November 3.
January 13	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 6	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 3, 2025, 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 (2,551 projects pulled September 10, 2025)
  - 245 Advance Authorizations and Business Cases. 48 documents redacted in the public version
  - The most current version of PG&E's Prioritization Procedures

- Stakeholder questions received by December 16, 2025
  - CPUC (4+42=46)
  - NCPA (27)

- Project updates will be provided in the May 1, 2026, TPR submission.

Steps Taken to Improve the Project Data Spreadsheet

<u>Load Facility Type:</u> PG&E is including Load Facility Type as defined in the Rule 30 application (Application 24-11-007) for large retail load interconnection projects under Data Field 65 Percentage and Value ($000) of Work at the Request of Others (WRO) Passed onto Ratepayers. Load Facility Type 1 is excluded from TPR as these involve non-CAISO controlled assets.

Asset Management Overview

Issam El Ayadi– *Sr. Director, Trans. & Sub. Asset Management*

Asset Risk Framework

Asset Risk Framework

Probability of Failure + **Consequence of Failure**

Probability of Failure

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

Performance
- Outage history

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

Consequence of Failure

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

Controls/ Mitigations	Programs
Condition Monitoring	**Inspection & Preventative Maintenance Programs** **Transmission Line On-line Monitoring Programs** • Tower Sensors • Early Fault Detectors • Distributed Temperature Sensing **Substation On-line Monitoring Programs** • Transformer dissolved gas & partial discharge sensors • Substation Infrared cameras
Repair	Corrective Maintenance and Repair Program
Life Extension	**Transmission Line Programs** • Shunt Splice Program • Tower Coating • Cathodic Protection • Wood Pole Reinforcements **Substation Programs** • Transformer and Circuit Breaker component replacements • Transformer oil dry-out
Replacement & Removal	**Targeted Replacement Programs** • Line conductor, insulator, structure • Substation major and minor equipment **Removal Program** • Idle line management
Emergency Response	**Emergency Material Inventory** • Underground transmission cables • Transformers, Circuit Breakers, Mobiles **Emergency Response Procedures** • 500kV lines • Shoo-fly design/routes for underground lines • EEI 500kV transformers

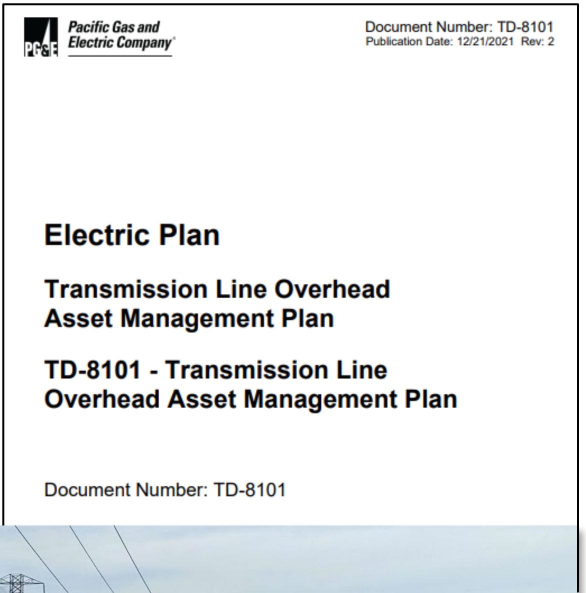
Transmission Line Asset Strategy

John Villalpando, Director – Transmission Line Asset Management

Transmission Line Assets Overview

Overhead Assets (Approximate)	
Voltages	500kV, 230kV, 115kV, 70kV, 60kV
Number of Circuits	1,400 lines; approx. 17,800 circuit miles
Conductors	4 major types (mix of aluminum, copper, steel)
Towers	34,400
Non-wood poles (e.g., Steel)	33,700
Wood Poles	77,500
Insulators	Est. 171,400 structures with insulators; three major types (ceramic, polymer, glass)
Switches	1,950 (39% remote/auto operation capable)

Underground Assets	
Voltages	230kV, 115kV, 70kV, 60kV
Number of Circuits	63 circuits; approx. 182 circuit miles
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

Document Number: TD-8101

Napa-Tulucay 60 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 2025

Risk & Compliance

- Completed an update to the Failure Modes and Effects Analysis (FMEA)
- Maintained steady state compliance with ignition-related HFTD/HFRA maintenance notifications, barring external factors

Asset Health Modeling

- Updated the Transmission Composite Model which included beneficial factors such as asset reinforcement (e.g., splice shunts, cathodic protection), flood hazard for wood poles, and updates to estimated age logic
- The High-Medium-Low risk consequences were updated for Wildfire to reflect the latest model update and for public safety to calibrate with the wildfire levels
- Utilized modeling results for 2026 inspection and targeted mitigation planning

Asset Registry

- Continued the improvement of asset information (e.g., checking for completeness, conformity, consistency) on critical data elements
- Matured data availability with inclusion of engineering-based asset data (e.g., pole loading, corrosion assessments)

Efficiency

- Continued support of Integrated Grid Planning for the 10 year investment plan

System Upgrades

- Birds Landing SS-Contra Costa PP 230 kV - Replaced 4 structures and 1.5 miles of conductor at a major river crossing
- Stanislaus-Melones-Manteca 115 kV Line - Replaced ~10 miles of conductor
- Tidewater-Sobrante 230 kV Line- Replaced 9 steel structures

Transmission Line Asset Risk

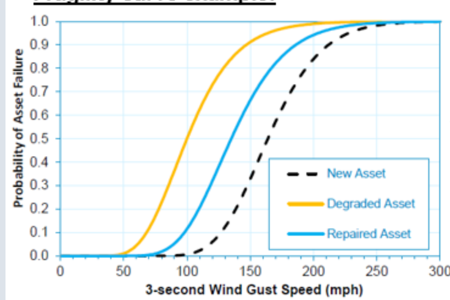
Key Areas of Risk Exposure:

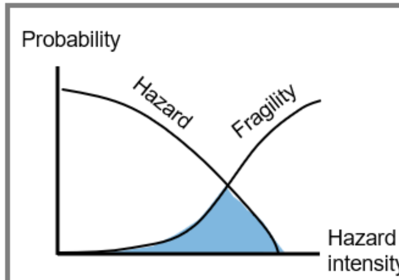
- **Equipment failures and wires down** – continue to better understand the effectiveness of controls/mitigations (i.e., limitations of visual inspections)
- **Wildfire –** updates and improvements to risk model, and expansion of operational mitigations
- **Aging infrastructure** – provide targeted mitigation 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.**
- Validation and feedback loop required to improve modeling accuracy and precision

Fragility curve example:





Composite Annual Pf Results

Hazard	Wind		All Hazards	
Component Grouping	Ave	Max	Ave	Max
Above Grade Hardware	1.44E-002	1.00E+000	1.44E-002	1.00E+000
Below Grade Hardware	3.84E-003	9.47E-001	3.84E-003	9.47E-001
Conductor	6.12E-003	9.98E-001	4.82E-003	9.98E-001
Foundation	5.88E-003	9.39E-001	5.88E-003	9.39E-001
Insulator	7.96E-002	1.00E+000	5.84E-002	1.00E+000
Splice	1.16E-002	9.99E-001	1.16E-002	9.99E-001
Steel Structure	6.29E-003	9.99E-001	5.53E-003	9.99E-001
Wood Pole	2.95E-002	1.00E+000	2.97E-002	1.00E+000

Hazards:
- Wind
- Seismic
- Car pole
- Bird
- Tree
- Balloon
- Gunshot

lic

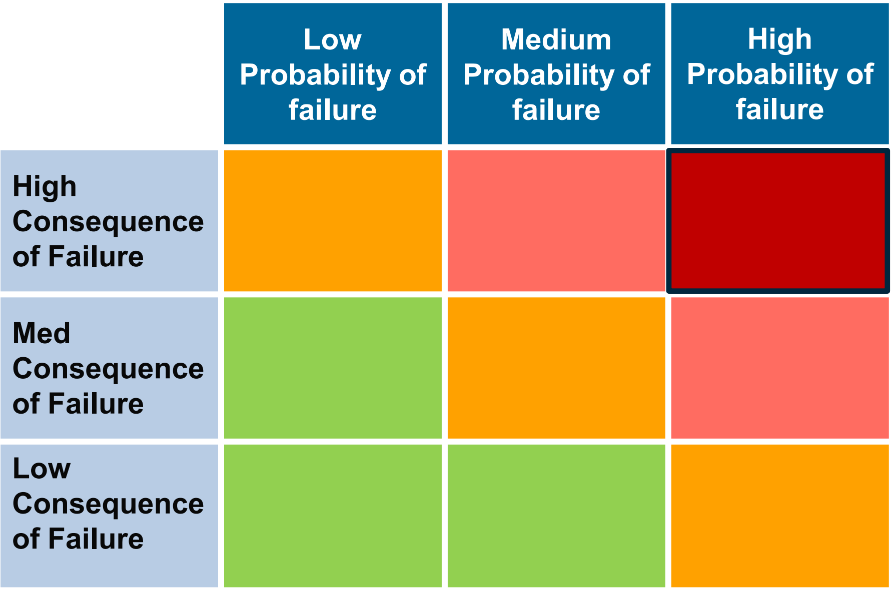
Risk Matrix to Inform Mitigations

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



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

Risk Matrix Example - Shunt Splice Program

SCOPING

Circuit level due to uncertainty in exact locations and number of splices requiring shunting

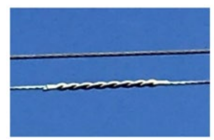
2024 Scoping	Wildfire Consequence		
Annual Prob. of Failure	Low	Medium	High
High	4 circuits	9 circuits	0 circuits
Medium	17 circuits	18 circuits	5 circuits
Low	244 circuits	192 circuits	40 circuits

To reach annual targets for number of circuits (20-25), consider additional boxes from matrix

* Circuit counts are hypothetical numbers but are directionally similar.

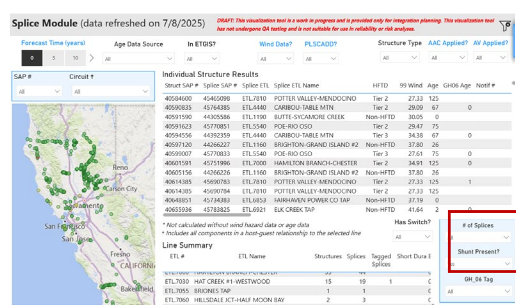
EXECUTE WORK AND DOCUMENT LOCATIONS

Before – Twist Splices

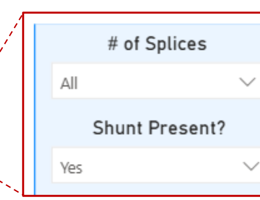


After – Shunts installed over the existing splices

UPDATE TCM



Splice model reduces PF for shunted splices



Update matrix for next year's scoping

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

12. T-Line Emergency & Just In Time (JIT) Replacement Programs

Transmission line emergency and just-in-time replacement programs cover key areas of emergency response (e.g., storm mitigation), GO-95 Rule 18 Level 1 replacement notifications, and just-in-time replacement for urgent risk mitigation.

Work may be identified through field findings, or engineering and risk assessments.

MAT	PO#	Investment	2026 ($M)
92#	5533315	Emergency Replacement (A-priority tags, storm and fire response, etc.)	$20.6
	Misc	Specific units of emergency replacement: Cortina #2 60kV pole, Tesla-Salado-Manteca Tower, and Caribou-Plumas Jct rebuild	$11.5
92#	EX130519	JIT Emergency Replacement	$11.3
92U	5505899	Underground emergency (A-priority tags, etc.)	$0.4
92T	5516801	Third Party Damage – Capital	$5.3

Examples of Just-In-Time work includes:

- **230 kV Polymer Insulator Replacement Program**: Replaces ~500 high risk insulators, after analyzing previous failures
- **JIT Tower Replacement:** Replace towers based on criticality from engineering assessment, typically after short term emergency repairs are made. (Example: Tower relocation due to erosion damage)

Example of a JIT tower replacement due to imminent landslide hazard.

EX113578 -- SWITCH REPLACEMENT PROGRAM
Stakeholder Requested Item #13

Dipo Toriola – *T-Line Asset Strategy*

EX113578 - SWITCH REPLACEMENT PROGRAM

- This program proactively replaces Transmission line switches based on asset health and risk. Capability increases and SCADA may be considered when replacing switches, based on operational need.
- Scope developed in 4/2024 identified **36** switches for proactive replacement within the next 3-5 years (2027-2029).
- Average switch replacement ~$470k (multiple factors can influence cost such as structure rebuild and SCADA installation)

Risk Matrix: Asset Name		**Consequence**		
Version: 1 2024; Refresh 1		**Low** WF Consequence < 20 PS Consequence < 13	**Medium** WF Consequence 20-60 PS Consequence 13-22	**High** WF Consequence > 60 PS Consequence > 22
Probability of Failure	**High** Turner (all), Inertia (all), SEECO (in-line), KPF (MD), Switches with 3+ outages or 3+ repair tags in the past 10 years	None	**High**	**High**
	Medium SEECO (except in-line), KPF (except MD), Switches with 2 outages or 2 repair tags in the past 10 years	None	None	**High**
	Low All others	None	None	None

Work Plan

- Risk Matrix is undergoing continuous refinement to identify switches that merit replacement
- EX 113578 “Switch Replacement Program” dollars will be adjusted accordingly
- High Risk switches are continuously inspected via:
  - Detailed ground and/or aerial inspections
  - Infrared inspections
  - Patrols
  - Switch function testing

Wood-to-Steel Pole Replacement Program
Stakeholder Requested Item #14

Rosalba Mendoza – *T-Line Asset Strategy*

Wood-to-Steel Pole Replacement Program

- The wood to steel replacement program continues to make progress year after year in reducing the number of wood poles in our system.
- Since 2021 when our design standard was revised to incorporate the requirement to replace wood poles with light duty steel poles (LDSPs) we have replaced the following:
  - 2021 ~2,199 poles; average cost per pole ~$70,968
  - 2022 ~2,098 poles; average cost per pole ~$78,539
  - 2023 ~2,494 poles; average cost per pole ~$87,888
  - 2024 ~1,693 poles; average cost per pole ~$93,127
  - 2025 ~1,413 poles; average cost per pole ~$103,810
- Estimated number of wood to steel/FRP poles to be replaced:
  - 2026 ~1,444 poles
  - 2027~ 1,585 poles
  - 2028~ 1,624 poles
- Lessons Learned: locations with limitations to install steel structure result in introducing another material option (composite poles)

Substation Asset Strategy

Alex Wernli– *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	1ph 37
	3ph 129	3ph 18
Voltage Regulators	1ph 0 3ph 21	1ph N/A 3ph 27
Circuit Breakers	3,750 (outdoor) 129 (GIS)	54 (Oil) 18 (SF6) 10 (VAC)
Circuit Switchers	528	23
Motor Operated Air Switch (MOAS)	1126	18
Batteries (Station)	240	12
Reactive Equipment		
Shunt Capacitors	114	25
Shunt Reactors	78	15
STATCOM	1	3
Series Capacitors	41	15/30
Series Reactors	139	14
SVC	6	15
Synchronous Condensers	0	35

*Includes spares

Substation Key Highlights 2025

Asset Life Cycle Planning

- Designed a substation risk composite model including asset health visualization to support substation asset risk assessment for inspections, repairs, and replacements. (Implementation 2026)

Asset Maintenance and Inspection

- Newark area transmission risk mitigations via circuit breaker refurbishment, internal inspection and replacements to reduce significant reliability risks.
- Continued installing online DGA/PD bushing monitor

Climate Change/Resiliency

- SF6 leak reduction work – 25 leak repairs targeted, 25 accomplished
- Installed (14) 70kV and (6) 115kV Vacuum/Clean Air breakers

Grid & Interconnection

- Completed LS Power - Gates 500kV Interconnection Project.

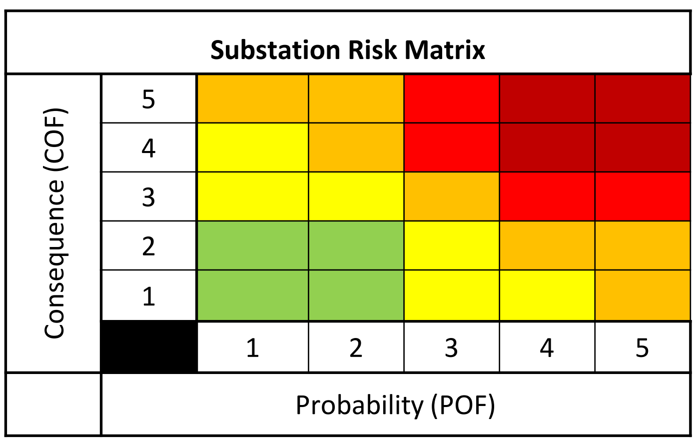
Substation Risk Matrix to Inform Mitigations

Probability of Failure (POF)

- Asset Condition (Inspection, Testing, On-line Monitoring)
- Maintenance History
- Failure History
- Industry Information
- Age

Consequence of Failure (COF)

- Safety
- Customer Impact
- Transmission Grid Reliability



Long-term mitigations

- Planned asset replacements
- Long Lead Materials (LLM) bulk ordering strategy and process

Short-term controls/mitigations to minimize in-service failures

1. Condition assessment (inspection, preventative & corrective programs, on-line monitoring)
2. High-Risk Targeted Equipment Replacement Program (High impact/low-cost minor equipment and other targeted breaker and transformer replacements)
3. Life Extension Programs
4. Emergency Response
5. Increase Maintenance Repairs

Risk Mitigation	**Negligible**	**Minor**	**Moderate**	**Significant**	**Critical**

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
GIS	115,230kV	2 to 2.5 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

Going forward, substation asset strategy will focus on improvement in the following areas:

Data collection	• Connect asset data from APM to Foundry, making it available for risk models • Integration of online transformer monitoring into TOA
Risk	• Continue building risk models with Probability and Consequence of Failure • Link assets in matrices to programs and funding categories
Technology/Pilot Programs	• Long term planning with Integrated Grid Planning (IGP) • Circuit breaker online monitoring

Emergency Replacement Programs and Just-in-Time Replacements Stakeholder Requested Item #12

Alex Wernli – *Manager, Substation Asset Strategy*

Yen Ha – *Program Manager*

PG&E's Emergency & Just-In-Time Replacement Strategy

- PG&E develops replacement forecasts using a three-year historical spending average plus expected increases in replacement volumes and unit costs.

- PG&E maintains a dedicated inventory of **CEM transformers** to support emergency replacement work because procurement lead times can be **up to 5 years**.
    - This stocking strategy ensures PG&E has sufficient CEM units available to **address urgent failures** and **mitigate high-risk conditions** without delay

<u>**Transmission circuit breaker replacements**</u>

- Forecast for **EX139131** (Emergency Transmission Circuit Breaker Replacement of Failed and JIT) is based on **three-year historical spend trends**.

- Forecast for **EX113779** (Purchase CEM breakers for anticipated failures) includes a bulk transformer order (OBS 9753641) with deliveries 2027–2029.

Transmission transformer replacements

- Forecast for **EX139253** reflects **planned transformer replacements** at six banks per year starting in 2029.
- Investment codes in table represent **individual transformer orders** to maintain emergency stock and **support high-risk replacements**.
  - Forecasts for **EX139130** and **EX139162** were developed by extrapolating stock-transformer costs from historical spending average, as reflected in the table, to estimate remaining forecast needs.

Planning Order/ Investment Code	Project Name	Current Projected Total or Actual Final Cost ($000)
EX139130	Emergency Transmission Xfmr non-500kV Banks Replacement	190,541
EX113712	CEM Forecast failure 2025, 3 Phase, 115/(60x70)kV, 200 MVA	7,000
EX113710	CEM Forecast failure 2025, 3 Phase, 230/115kV, 420 MVA	7,000
EX113711	CEM Forecast failure 2025, 3 Phase, 230/(60x70)kV, 200 MVA	7,000
EX113714	CEM Forecast failure 2027, 3 Phase, 230/115kV, 420 MVA	7,000
EX113715	CEM Forecast failure 2027, 3 Phase, 230/(60x70)kV, 200 MVA	7,000
EX113716	CEM Forecast failure 2027, 3 Phase, 115/(60x70)kV, 200 MVA	7,000
EX113769	CEM Forecast failure 2026, 3 Phase, 230/115kV, 420 MVA	7,000
EX113770	CEM Forecast failure 2026, 3 Phase, 115/(60x70)kV, 200 MVA	7,000
EX113774	CEM Forecast failure 2026, 3 Phase, 230/(60x70)kV, 200 MVA	7,000

Planning Order/ Investment Code	Project Name	Current Projected Total or Actual Final Cost ($000)
EX139162	Emergency Transmission Xfmr 500kV Banks Replacement	76,200
EX113709	CEM Forecast failure 2025, 3 Phase, 500/230kV, 374 MVA, 2 tanks	7,000
EX113713	CEM Forecast failure 2027, 3 Phase, 500/230kV, 374 MVA, 2 tanks	7,000
EX113768	CEM Forecast failure 2026, 3 Phase, 500/230kV, 374 MVA, 2 tanks	7,000
EX114013	CEM Forecast failure 2029 3 Phase, 500/230kV, 374 MVA, 2 tanks	7,000
EX139159	CEM 500/230kV, 374 MVA, 1PH T-500-230-01	7,000
EX139160	CEM 500/230kV, 374 MVA, 1PH T-500-230-03	7,000
EX139161	CEM 500/230kV, 374 MVA, 1PH T-500-230-02	7,000

2026 Transmission Substation MWC 65 (Emergency Tranche 1,2,3)

DET Allocation - MWC 65	$62,000,000	
1 and 2 Total Need	$78,734,091	% to Ttl Portfolio
1 Deductions - Carryover (MAT 65 C, D, E)	$42,749,091	54%
2 Forecasted Emerg + JIT +Materials (Tranche 1 & 2 and LLM)	$35,985,000	46%
$ LLM)†	$6,100,000	
$ INSF CB (Tranche 1)	$1,200,000	5 unis
$ INSF non-500kV Xfmr (Tranche 1)	$450,000	1 unit
$ JIT CB (Tranche 2)	$960,000	4 units
$ JIT non-500kV Xfmr (Tranche 2)	$450,000	1 unit
Other (Minor equipment 65F)[1]	$26,000,000	
STM Bay Meadows Battery Charger rplcmt	$825,000	
Over prescribed amount (not including Tranche 3)	($16,734,091)	

Comments
† Committed funds
[1] MAT 65F= Target + 2026 PRJ (Average 3-yr historical trend '22-'24)

3 New Work - Targeted High Risk (Tranche 3)	$20,385,000	
Work Activity	Dollars (2026 in- year spend)	Units
Online Monitoring (Xfmr) MAT 65F	$1,800,000	12
Online Monitoring (T-CB) MAT 65F	$600,000	4
Battery charger	$825,000	11
Transformer	$5,400,000	6
Circuit Breakers	$5,760,000	24
Targeted Minor Equip (CT/PT) MAT 65F	$6,000,000	12

T.0010949 - Moraga: EM Repl CB 642 & 712

CB 712

- Construction: In progress
- Clearance Start: 11/3/25
- Test Date/Release to Operations: 2/22/26

CB 642

- Construction – Not started/on track
- Clearance Start: 2/25/26
- Test Date/Release to Operations: 5/31/26

- An emergency transmission breaker replacement is estimated to cost approximately $2.80M and require 3–6 months to complete.
- A planned transmission breaker replacement is expected to cost about $2.50M with a completion timeline of 36–42 months.
- CB 642 & 712 planned replacements were initiated under 2019 transmission breaker replacement program, formally kicked off in 2020, and was expected to be placed in service by July 2024 before being put on hold in 2023.

Overdutied Circuit Breakers

- Overdutied (also referred to as overstressed) circuit breakers are identified in an annual process in coordination with Protection and Transmission Planning, following NERC TPL-001-5.1
  - Study identifies circuit breakers that will become overdutied in years 0, 2, 5, and 10
- Per NERC requirements, all transmission circuit breakers that will become overdutied in years 0-5 must have a corrective action plan
  - A planned project is initiated if the project can replace the circuit breaker before the expected overdutied date
  - Other mitigations are considered: bus reactors, protection schemes, and operational mitigations can be utilized in some cases
  - If the overdutied breaker cannot be replaced or otherwise mitigated before the expected overdutied date, a Just-in-time replacement is initiated

Back at 10:55

BREAK

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 EMS Environments comprised of over 175 Servers and over 250 Workstations
	    • Phasor Applications – Transmits and analyze synchrophasor data internally and to CAISO
	    • DDLR - AAR applications
	• **RAS:** 59 total schemes (39 BES RASs and 20 non-BES RASs) jointly maintained by Grid Ops and System Protection
	  • 57 of which are implemented at the substation level
	  • The remaining 2 (PACI RAS and SF RAS) are centralized in the VGCC and RGCC
	• EGMP – from RT SCADA to EMS
	  • Have built 2200+ EMS display screens to prepare for the transtions from RT SCADA to EMS

Protection	• **Relays**: 30,089 units* • **Synchrophasors**: 200 PMUs, 30 data concentrators • **RAS:** 59 total schemes (39 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 145 installations in 110 substations (~10K relays installed)

Pacific Gas and Electric Company

Document Number: TD-8104
Publication Date: 04/04/2024 Effective Date: 06/04/2024 Rev: 3

Electric Plan

Operational Assets and Systems

Document Number: TD-8104

April 4th, 2023

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 2025

Grid Operations / Business Applications: MWC 63

- EMS 3.4 Upgrade Infrastructure - FAT/SAT
- SFGO Circuit Rerouting
- FERC Order 881 – Dynamic Line Rating Implementation
- Initiated Phase 2 of the SFGO RAS Relocation Project
- CAISO PMU Bellota

System Protection: MWC 3F

- Implemented 12 EPSS terminals.
- Installed new relays for Diablo Tie Line
- Working on moving relays on to the risk register as a Primary component
- Worked on ComAPS 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

- Project in progress to Lifecyle EMS Servers and upgrade Windows and EMS application software to GE EMS 3.4/latest version, deployed in phases:
  - Phase A cut-over planned Q2 2026
  - Phase B Q4 2026
  - Phase C Q4 2027
  - Phase D Q4 2028
- Lifecycle replacement for all EMS Workstations in 2025/2026

Dynamic Line Rating Tool Enhancements

- Enhance 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 Enhancements –
  - Lifecycle replacements/software upgrades for servers transmitting synchrophasor data from field PMU/PDCs for utilization by PG&E analysis tools and CAISO.
  - Employ new application functions utilizing Synchrophasor Data
  - Expand TOSTL (phasor applications experimentation lab)
- Control Room A/V and Video Wall replacements in Vacaville and Rocklin

Electric Grid Modernization Program Key Highlights

EGMP Key Accomplishments

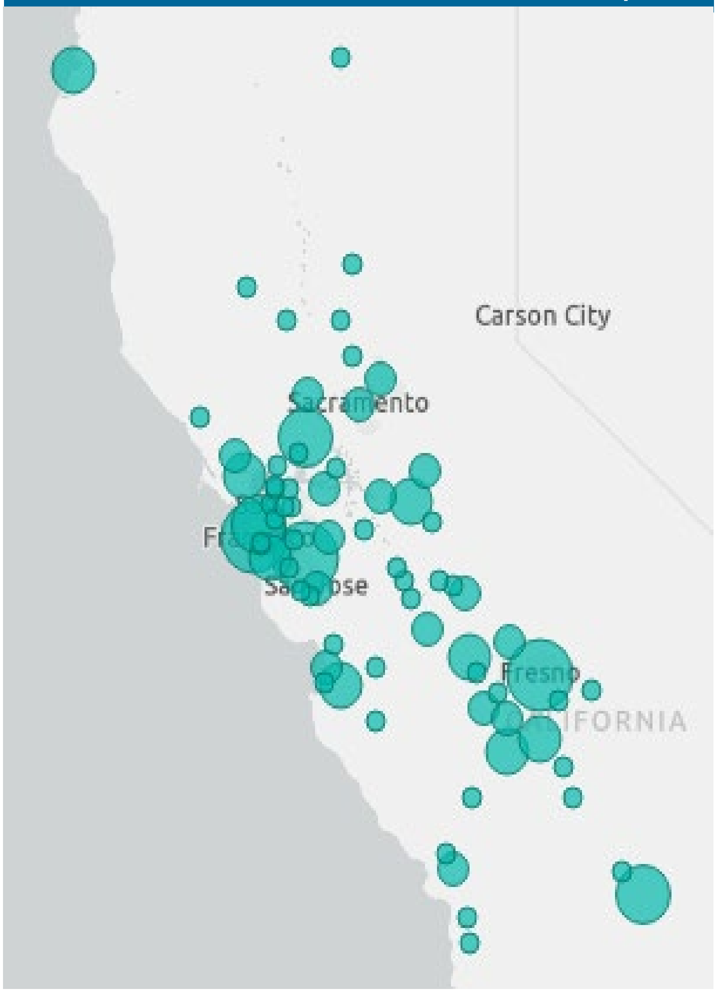
- Completed Proof of Concept and development of Automation Framework tool to accelerate the validation and virtual cutover of SCADA communication in Control Centers from RT SCADA to EMS
- Completed RFP selection process for an Engineer, Procure, and Construct (EPC) vendor
- Plans developed for testing critical sites across 4 remaining regions (66 target sites)
- Have built 2200+ EMS display screens to prepare for operations cutover to EMS

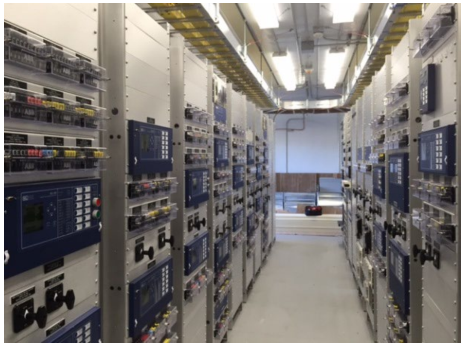
EGMP Upcoming Milestones

- Q4 ‘26 - Complete Phase 1 critical site testing & virtual cutover to EMS for South Valley Region

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.

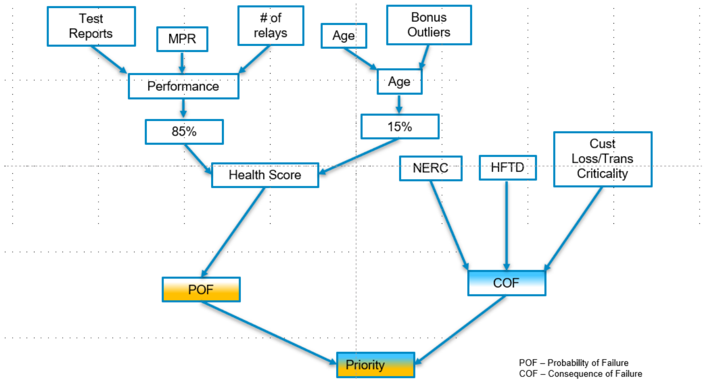
Asset Strategy Plan for System Protection Assets

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

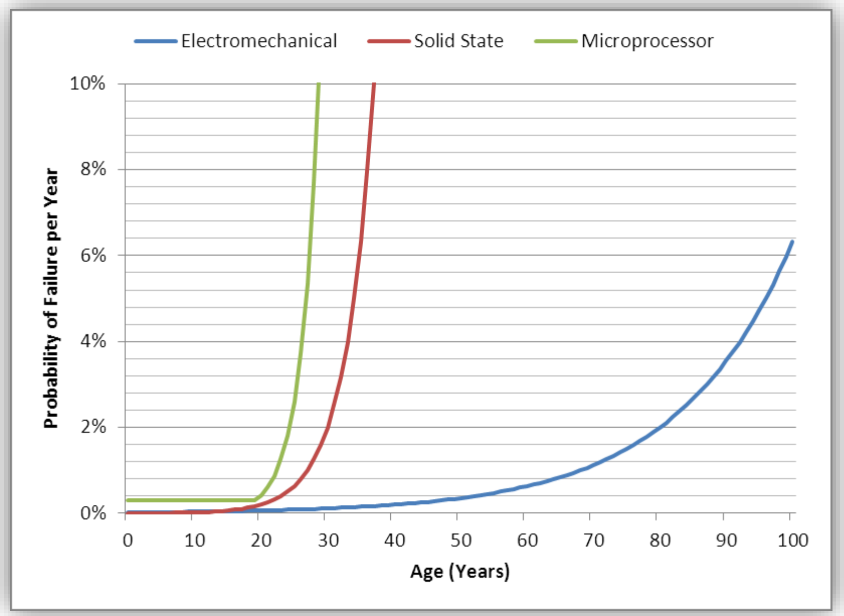


NERC compliance purposes (PRC-004, PRC-005, PRC-012-R5, etc.),

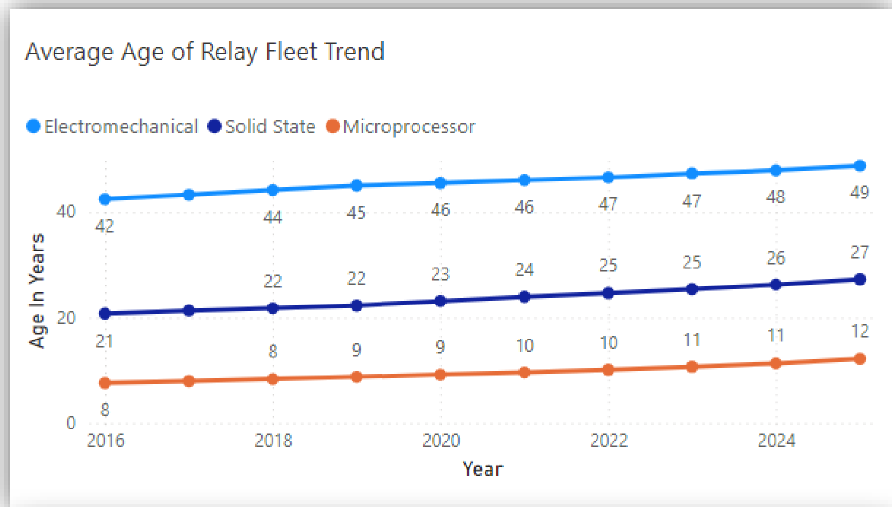
- System Protection group is responsible for evaluation of each of the five components of a Protection System.
  - Protective relays which respond to electrical quantities,
  - Communications systems necessary for correct operation of protective functions
  - Voltage and current sensing devices providing 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.

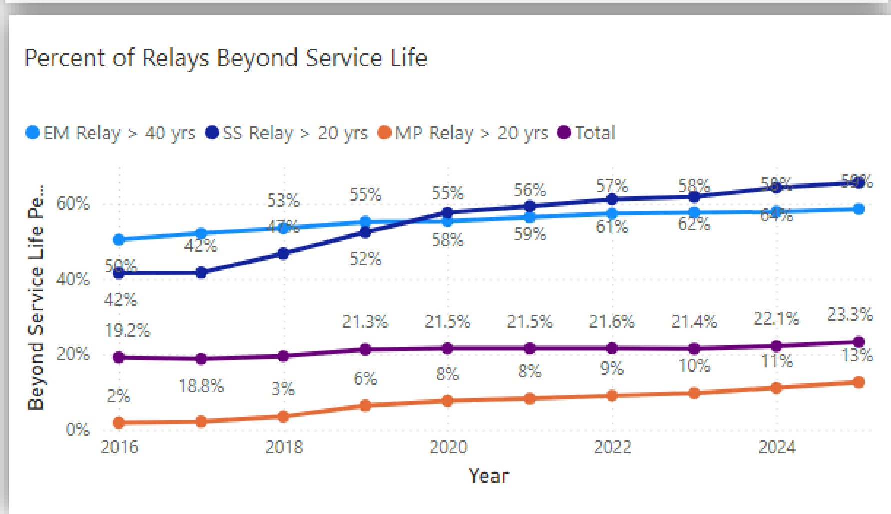


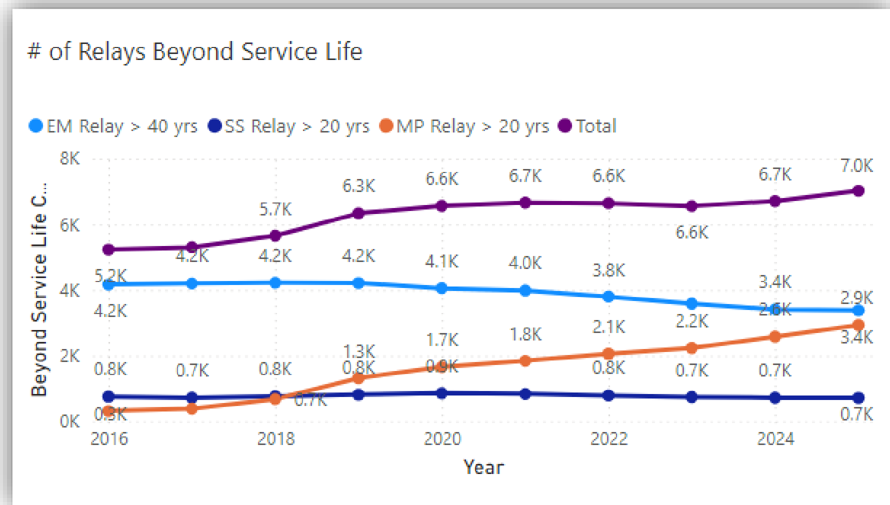
Number of Relays Beyond Expected Service Life



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.

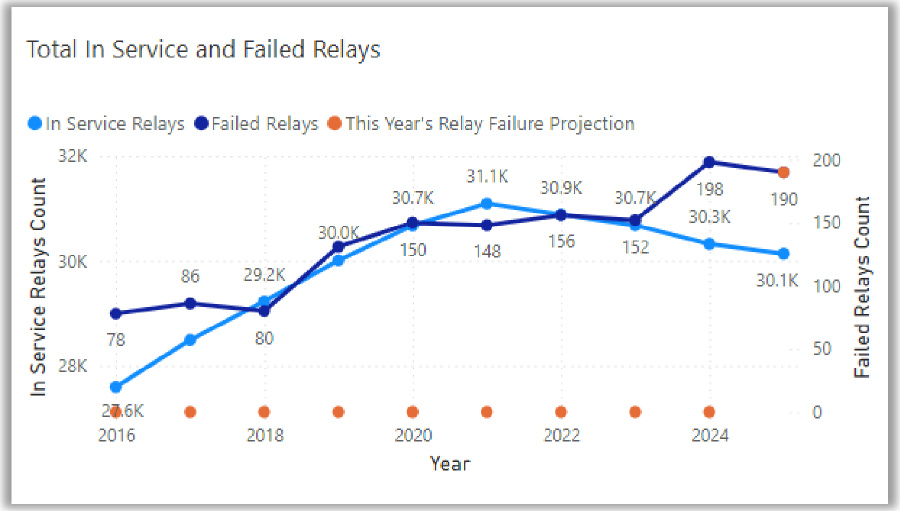
- We are not keeping up with the replacement of the aging MP relays

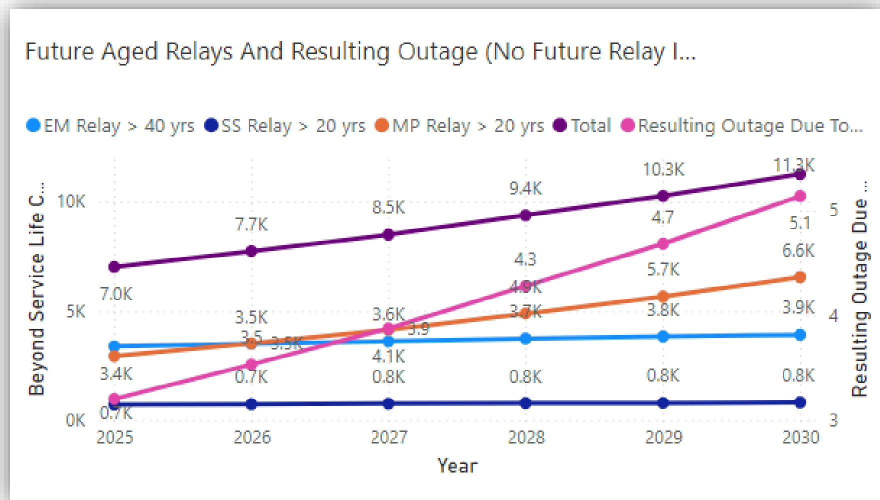




- You can see that even though the number of EM relays beyond 40 years is decreasing, the percent of relays beyond 40 years is increasing for those relays that are left. The same is true for SS relays.

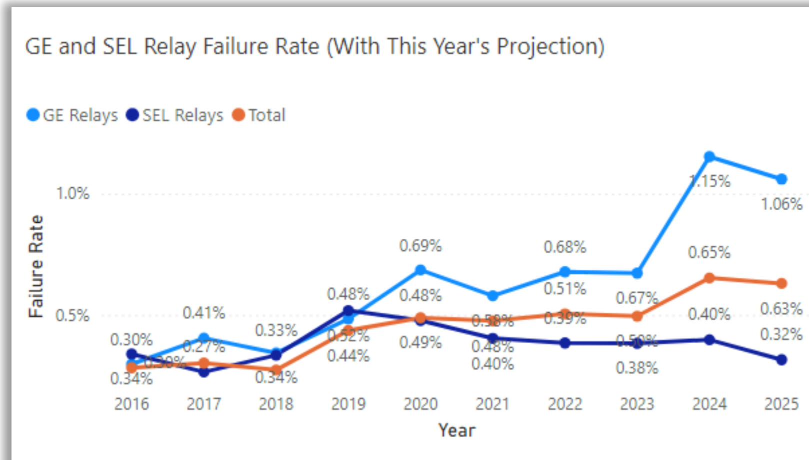
Relay Failure Totals by Year





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.

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

Ryan Blake, *Director, Investment Planning*

RBPPF/IGP Update

- There are no updates/refinements to PG&E's RBPPF and IGP framework.
- The criteria PG&E's uses to assign an RBPPF score has not been modified in 2025/2026.

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 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.

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

Within-Funding Tier Prioritization

	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.

How PG&E Will Execute 5 Year Plan

- T&S command center in Dublin driving on time delivery using Lean methodologies
- Cross-functional operations reviews monitor action items and catch-back plans to meet project timelines
- Readiness metrics for multi-year projects are tracked to enable portfolio ramp up
- Project Development process is improving speed to market with earlier planning and implementation strategies during project lifecycle

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

Peter Lee – *Sr. Manager, Risk Management*

Ryan Blake – *Director, Investment Planning*

Value and Use of CBR

Question a)

Please provide an overview of PG&E's perspectives on the value and use of cost/benefit analyses in electric transmission project planning and prioritization.

Use of CBR methodology in project planning and prioritization

- PG&E is maturing its asset level risk modeling to best represent and inform the risk reduction element in the RBPPF process. A better understanding of the consequences associated with multiple failures and catastrophic outages is required.
- This impacts the overall risk value assigned to structures. A change in this consequence profile can significantly impact the risk profile and generate dissimilar results from what is currently being provided as part of the TPR requirement.

Value of CBA/CBR Analysis - RDF Framework

- The RDF framework and cost benefit analysis is a means to evaluate the benefits of investments across the enterprise, within a risk, and between projects. RDF is maturing and there are other factors that are not quantified in the risk framework to evaluate overall benefits of a project.
- Risk is one value amongst six value categories in our RBPPF process (Risk, Reliability, Compliance, TNS, Capacity, Business Continuity) PG&E evaluates in its prioritization project.
- A CBR value is not the sole justification to move forward with a project or program.

.

Consultant Scope of Work

Question b)

Please provide an update on PG&E's efforts to secure a consultant and define appropriate scope of work to develop PG&E's cost/benefit analyses.

PGE Response

- Internal and external resources will be leveraged to deliver an MVP for transmission and substation asset level models by the end of 2026. Meaningful CBRs would be targeted for March TPR 2027.
- The following work will be completed over the next year

- ❑ Workstream 1: PoF assessment for
  - Relays (i.e., microprocessor, electromechanical, and solid state)
  - Substation assets (e.g., ground grid, batteries, transformers, circuit breakers)
- ❑ Workstream 2: Substation Contingency work
  - Define substation failure modes for individual substations across the system
  - Define consequence associated with substation failure modes
- ❑ Workstream 3: Transmission/Substation consequence modeling
  - Define transmission/substation failure modes system-wide that could lead to catastrophic failure
- ❑ Workstream 4: Build Model and Develop CBRs
  - Combine workstream initiatives to develop asset level model and develop project related CBRs

CBR Calculation Workpaper

Question c)

Please explain how/where PG&E expects to share its TPR project CBR calculation framework and methodology workpaper, to be made available in 2026 Q1 (see PG&E's Response to Data Request TPR- Process_DR_ED_018-Q038), along with whether feedback/formal comments will be accepted.

PGE Responses

- The TPR project CBR calculation framework and methodology workpaper has been drafted and feedback from subject matter experts is being collected. PG&E will send the PDF copy of the white paper to TPR stakeholders when it is available.

Risk Input into RPBBF Process

Question d)

Please explain in detail how PG&E's investment planning process "leverages CBRs as an input" to investment planning. Please include why PG&E does not rely on CBRs exclusively for making investment planning decisions.

PGE Responses

- Risk is one value amongst six value categories in our RBPPF process (Risk, Reliability, Compliance, TNS, Capacity, Business Continuity) PG&E evaluates in its prioritization project.
- A CBR value is not the sole justification to move forward with a project nor is it the only reason a project should be invested in.
- RBBPF framework includes other value streams that have equal value in the prioritization process. Prioritization decisions should not be made in vacuum that only includes a risk lens.

Use TCM/WTRM to Establish Baseline Risk

Question e)

Please describe how PG&E's CBR framework leverages its prioritization models (TCM, WTRM) to establish baseline risk at a structure level to evaluate wildfire and reliability impacts.

PGE Responses

- PG&E's transmission 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
- *See details in TPR project CBR calculation framework and methodology workpaper.

From February 2025 Stakeholder Meeting

	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

Timeline for Full Population of CBR

Question f)

Please provide PG&E's timeline for fully populating Field 66 (Cost Benefit Analysis) beyond the limited cost/benefit percentages currently included.

PGE Responses

MWC	Completion Date	Reason
60	TBD	PG&E currently is not planning to develop CBR frameworks for capacity projects. Capacity projects pose no enterprise risk since an interconnection will not occur if the system design does not address this constraint.
61	TBD	PG&E currently is not planning to develop CBR frameworks for capacity projects. Capacity projects pose no enterprise risk since an interconnection will not occur if the system design does not address this constraint.
63	N/A	This MAT code supports control system upgrades (i.e. ADMS, SCADA, EMS) and are considered foundational programs. They do not reduce risk and thus CBRs will not be calculated.
64	Plan March 2027	PG&E is initiating its substation asset level models and plans to have an MVP by end of 2026
65	N/A	PG&E will not develop CBRs for emergency work as part of the TPR process. Location of emergency work is not known in advance and cannot be realistically forecasted to estimate CBRs.
66	Plan March 2027	PG&E is initiating its substation asset level models and plans to have an MVP by end of 2026
67	Plan March 2027	PG&E is initiating its system protection models and plans to have an MVP by end of 2026.

Timeline for Full Population of CBR

PGE Responses (Con’d)

MWC	Completion Date	Reason
68	Plan March 2027	PG&E is initiating its substation asset level models and plans to have an MVP by end of 2026
70*	May 2026 TPR PS	PG&E is developing a CBR framework for T-line projects under the MWC 70.
71	N/A	These projects do not have risk reduction impact but have indirect benefits through replacing boardwalks, constructing roads, and creating ROW access.
72	TBD	PG&E cannot provide CBRs for Underground Transmission Line programs until these assets are included in their Transmission Composite Models. Currently the inclusion of TUNGD assets is not planned for the TCM.
82	N/A	PG&E currently is not planning to develop CBR frameworks for generation/load interconnection projects.
92	N/A	PG&E will not develop CBRs for emergency work as part of the TPR process. Location of emergency work is not known in advance and cannot be realistically forecasted to estimate CBRs.
93*	May 2026 TPR PS	PG&E is developing a CBR framework for T-line projects under the MWC 93
94A/L	November 2026 TPR PS	PG&E is developing a CBR framework for MAT 94A (SCADA Switch Program) and MAT 94L (Targeted Reliability)
94B/D	Plan March 2027	PG&E is initiating its substation and system protection models and plans to have an MVP by end of 2026.
3F	Plan March 2027	PG&E is initiating its system protection models and plans to have an MVP by end of 2026.

*PG&E currently is not planning to develop CBR for in-flight projects with an in-service date in the current year, programmatic work where projects are not defined, On Hold projects where scope is not defined yet, and Operational projects.

Sample Projects – RBFFF score and CBR

Question g)

PG&E should walk stakeholders through the Utility Prioritization Ranking – RBPPF score and CBRs for some selected projects for which CBRs are calculated so that parties can better understand the interplay between the two.

PGE Responses

RPBBF Overview

- RBPPF Process includes scoring investments six value categories between 1-5
- This scoring is intended to give higher score to proposed investments that have higher value/impact/urgency across multiple value categories

Value Categories			
1	Risk	4	Reliability
2	Compliance	5	Other TNS Objectives
3	Capacity	6	Business Continuity

Key takeaways of RBPPF:
- 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

Within-Funding Tier Prioritization

	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
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	5	3	3	0	0	0	5.33000
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- 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.

November 2025 Improvements

Question h)

Please describe the details of the improvements PG&E has made in the November 2025 TPR submittal. The updates described in the November 2025 TPR submittal letter should be expanded and elaborated. For example, it is not clear how PG&E incorporated an "increase of PoF into future years to highlight changes to risk profile with aging equipment."

PGE Responses

Enhancements

1. Refreshing TPR models with updated TCM/WTRM outputs that included better assumptions on asset age and PoF
    - TCM models are refreshed annually and TPR models were updated accordingly
    - Major update in 2025 TCM was improving asset age estimates
    - This parameter is a primary driver in defining PoF, leveraging fragility curves
2. Incorporated an increase of PoF into future years to highlight changes to risk profile with aging equipment
    - TCM uses age of assets and fragility curves to understand PoF of assets over time
    - Updated TPR accounted for these escalated PoFs into future years from the TCM mode
3. Scaled risk values with our updated Enterprise Bowtie risk that includes "next failure" contingency
    - TPR models are scaled to enterprise models, where the bowtie was updated with a "next failure" contingency to better account for overall transmission risk as an engineering solution to reliability consequence is being developed
4. Updated reliability consequence profile with a qualitative assessment
    - Inclusion of an improved placeholder for a reliability consequence profile based on a SME assessment that assigns risk based on criticality
5. Updated program effectiveness values for conductor and structure replacement program
    - Program effectiveness values were enhanced leveraging a TCM analysis that reset asset age for conductor and structure replacement by MAT code

Changes in CBRs

Question i)

For the November 2025 TPR submittal, PG&E included CBR assessments for 62 projects, including a refresh of the 2024 TPR CBRs and new projects. Some CBA values differ significantly from those in the May 2025 submittal. i). Please walk through some examples to illustrate the drivers of these changes in CBA values.

PGE Responses

- PG&E would like to re-iterate that the TPR assessment is demonstrating a “framework” and CBR values should not be viewed as values to drive prioritization or decision-making
- Additionally, the model is not final and there are still missing elements before a meaningful comparison can be made
- Acknowledging the above, the following would be drivers to changes in CBRs
  1. Cost
     - Project information could have been updated with updated forecast information
  2. Project Definition
     - Project information could have been updated with a refined scope
  3. Risk Profile
     - TCM was updated with better age estimates that changed the profile of risk
     - Consequence profile was updated leveraging a qualitative assessment on tx asset criticality
     - Updated TPR accounted for PoF of assets into future years

Grid Enhancing Technologies
Stakeholder Requested Item #17

Raji Shah – *Principal, Grid Innovation Engineer, Transmission Asset Management*

Ambient Adjusted Ratings

Technology: Ambient Adjusted Ratings (AAR)

Description: 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.

Current Status:

- PG&E has partnered with GE to develop a tool in order to optimize and automate the AAR calculation process.
- Updates applied to existing Asset and GIS tools as well as EMS enhancements
- Costs associated with FERC Order 881 Phase 1 implementation are captured in the TPR PDS worksheet under the following POs: 5555924 Enterprise FERC 881 and 5800498 FERC Order 881
- Costs associated with FERC Order 881 Phase 2 implementation are captured in the TPR PDS worksheet under the following PO: 5555502

Next Steps:

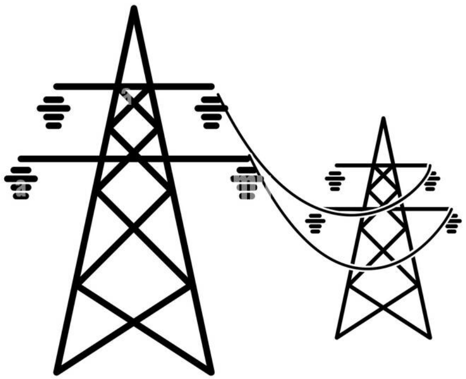
- FERC 881 requirement for CAISO has been extended until December 17,2026
- Requirements applicable to PTO's have been extended to October 15,2027
- PG&E is on track to meet the compliance requirements by the due date

Dynamic Line Ratings

Technology: Dynamic Line Ratings (DLRs):

Description:

- 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.



Current Status:

- PG&E is exploring dynamic line rating technology through the EPIC program. We have identified 4 vendors; 1 vendor is a software-based application while the other 3 are hardware-based applications
- Current pilots deployed on 3 circuits

Next Steps:

- Partnering with EPRI for acceptance testing 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.

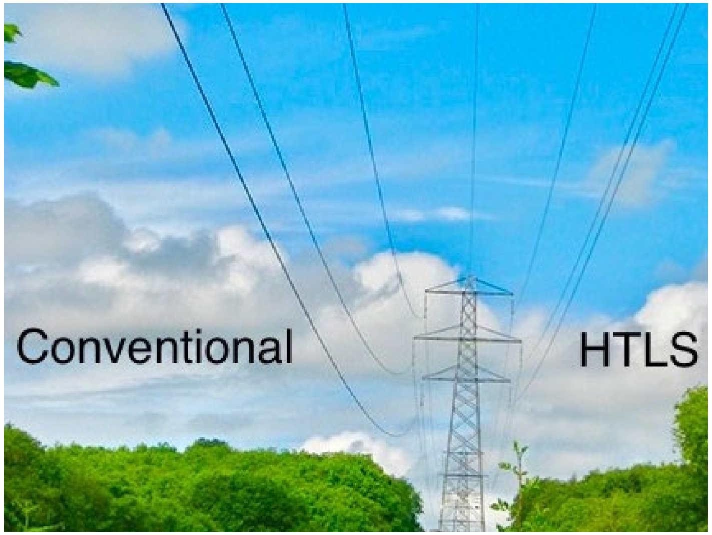
High Temperature Low Sag Conductors

Technology: High Temperature Low Sag (HTLS)

Description: Conductors designed to operate efficiently at high temperatures without significant loss of:

1. Mechanical strength
2. Minimizing sag under thermal stress
3. Allowing for increased capacity
4. Improved reliability

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.
- Implemented a company-wide process to evaluate use of advance conductors on all reconductoring projects.

Next Steps:

- Considering utilizing HTLS for all reconductoring where 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 April 2026.

Next Steps:

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

Back at 1:00

LUNCH BREAK

Major Projects Update
Stakeholder Requested Item #8

Lorenzo Thompson, TPR Team

Various Project Managers*, Major Projects*

Ashwini Mani, Sr. *Manager, Transmission Planning*

8 - PO Expenditures

PM Assigned Major Projects

T.Dot	Project	Status	Construction Start	ISD	Total Actuals	EAC
T.0010623	Salinas Area Reinf	Engineering	6/7/27	12/31/32	$1M	$417M
T.0010465	San Jose A – Substation Rebuild	Engineering	10/30/26	11/17/28	$12M	$167M
T.0000155	Lockeford – Lodi Area 230 kV Development*	Engineering	11/5/29	6/30/31	$24M	$198M
T.0010534	North Dublin-Vineyard Recond Project	Planning	8/2/28	9/2/34	$0.1M	$233M
T.0000156	Wheeler Ridge Junction Substation	Engineering	3/7/30	5/1/34	25M	$380M
T.0000154	Estrella 230 kV Transmission Substation	Construction	11/13/25	3/30/29	$52M	$147
T.0007072	IGNACIO-MARE ISL 115KV (IGN SUB/HWY SUB)**	Operational	10/19/22	12/13/24	$52M	$52M
T.0004271	Morgan Hill-Watsonville 115kV Area Reinforcement	Engineering	08/03/26	12/29/28	$13M	$171M
T.0011527	Pittsburg-San Mateo Bay Towers FOND	Engineering	4/13/26	10/30/26	$0.2M	$24M
T.0009719	Ignacio Area Upgrade	Engineering	1/4/28	12/31/30	$1M	$159M
T.0010675	French Camp Reinforcement	Planning	5/1/29	5/1/30	$0.4M	$138M

*Schedule and cost are estimates pending CPCN approval

**Phase 4 (T.0011035), Phase 4 (T.0011035), & Phase 6 (T.0011037) have been reclassified as routine programmatic work and is no longer part of the major project

Initiating Major Projects

T.Dot	Project	Status	Kickoff	Construction Start	ISD	Total Actuals	EAC
T.0011380	SOUTH BAY REINFORCEMENT PROJECT	Planning	March 2026	5/1/31	5/1/34	$0.05M	$434M
T.0011287	NORTH OAKLAND REINFORCEMENT PROJECT	Planning	Feb 2026	5/1/29	5/1/32	$0.03M	$1.127B
T.0011294	SOUTH OAKLAND REINFORCEMENT PROJECT	Planning	Feb 2026	5/1/29	5/1/32	$0.04M	$250M

- Moraga 230 kV Bus Upgrade (T.0006159) is now under T.0011323
- T.0011323 was included in Nov 2025 TPR PS

PG&E Transmission Plan Role in CAISO TPP

- PG&E is registered with NERC as a Transmission Planner and as such PG&E must demonstrate that its transmission system complies with all applicable reliability planning standards.
- PG&E is also required to participate in the CAISO's transmission planning stakeholder process
- PG&E's responsibilities among others include maintenance of transmission system models, collection of required information for planning purposes, building power flow models for the CAISO TPP per the agreed upon Unified Planning Assumptions and Study Plan.
- PG&E also assesses its system and proposes mitigation to identified issues, but ultimately the CAISO decides on the transmission plan.

Competitively-Bid Projects Interconnected by PG&E
Stakeholder Requested Item #7

Cait Ribeiro – *Project Manager, Sr Consulting*

Ashwini Mani, Sr. *Manager, Transmission Planning*

T.0006815 - LSPower Round Mountain Area 500kV Dynamic

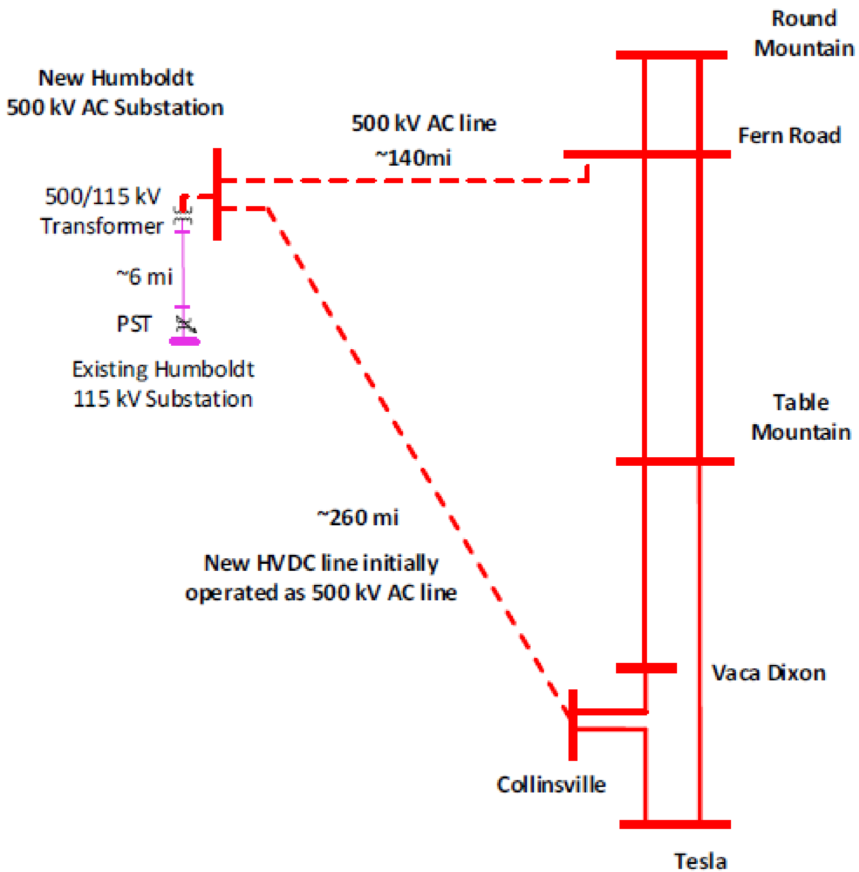
- Project Status: Construction
- Costs
  - Inception to Date: $116M
  - Estimate at Completion: $121M
- Milestones
  - Kickoff: 6/2/21
  - Engineering Start: 5/3/21
  - Engineering End: 12/8/25
  - Construction Start: 2/15/23
  - FISD: 12/15/26
- Scope
  - Interconnect new Transmission Owner (TO) LS Power Grid California's Fern Road Substation STATCOM Facility to the Round Mountain-Table Mountain 500kV line. Reduce RM 500 kV Series Cap Banks 3&4 reactance. Increase TM 500 kV Series Cap Banks 1&2 reactance
- Challenges:
  - Contractor performance challenges with Fixed Series Capacitor (SC) commissioning
  - Design changes driven by assorted operational and system studies results (Seismic, Harmonic, TRV, MOV, RTDS, etc)
  - Third party Utility LSPower collaboration and coordinated commissioning sequencing across three locations
- Lessons Learned:
  - Perform system impact operational studies during the initiation phase of the project, before project team is assigned, to allow for comprehensive scope development

T.0004672 - Gates: 500 kV Dynamic Voltage Support

- Project Status: Operational
- Costs
  - Inception to Date: $84M
  - Estimate at Completion: $84M
- Milestones
  - Kickoff: 1/19/21
  - Engineering Start: 9/1/21
  - Engineering End: 5/30/24
  - Construction Start: 4/3/23
  - FISD: 1/28/25
- Scope
  - Interconnect new Transmission Owner (TO) LS Power Grid California's Orchard Substation STATCOM Facility to Gates 500kV Bus
- Challenges (realized):
  - Implementation of many newer technologies : GIB (Gas Insulated Bus), DTS (Distributed Temperature Sensing) Fiber, XLPE (Underground 500kV line)
- Lessons Learned
  - Allow schedule float to accommodate the learning curves of newer technologies and the field applications

Humboldt Project Update

- Please provide an update for the following two projects:
  - Humboldt 500 kV Substation and 500 kV line to Collinsville
  - Humboldt to Fern Road 500 kV Line
- California ISO approved these transmission upgrades as part of its 2023-2024 transmission plan to support offshore wind development in the Humboldt Wind Energy Area. ISD for the projects is June 2034.
- On May 16, 2025, the California ISO announced selection of Viridon as the approved project sponsor who will finance, build, own and operate both projects. PG&E is responsible for the local 115 kV connection.
- Viridon and PG&E have initiated preliminary discussions regarding the 115 kV interconnection.
- As the project progresses, PG&E, Viridon, LS Power, and CAISO will need to coordinate on any other system impact studies related to the interconnection of the transmission projects.



San Jose B-NRS 230kV Update

- Even if competitive, the San Jose B-NRS 230kV project will require interconnection facilities at PG&E's San Jose B 230 kV substation that need to be planned.
- PG&E's scope of work for the interconnection at San Jose B 230 kV:
  - PG&E will be responsible for installing the new transmission line segments from the San Jose B 230 kV bus up to a point near the San Jose B 230 kV Substation property line.
  - Installing other substation bus and protection equipment required to interconnect the new 230 kV line. Scope details will be finalized once PG&E is able to work with the approved project sponsor, after CAISO awards the project.
- $1.5M was the initial funding to get project kicked off and is not representative of the total project cost. Project forecasts will be updated once PMs assigned and project kicks off.

CWIP Rate Base Incentive Projects
Stakeholder Requested Item 6

Jason Castellanos, *Project Manager*

Cait Ribeiro, *Project Manager, Sr Consulting*

Tim Criner, *Project Manager*

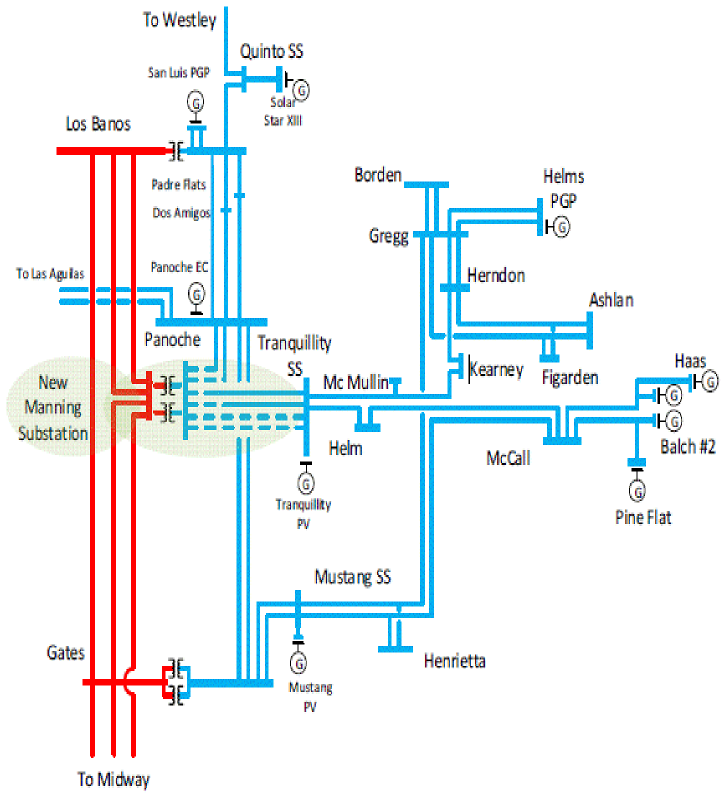
Creed Young, *Project Manager*

6 - Monthly Forecast

T.0009194 Manning New 500kV Sub Connection

Scope:

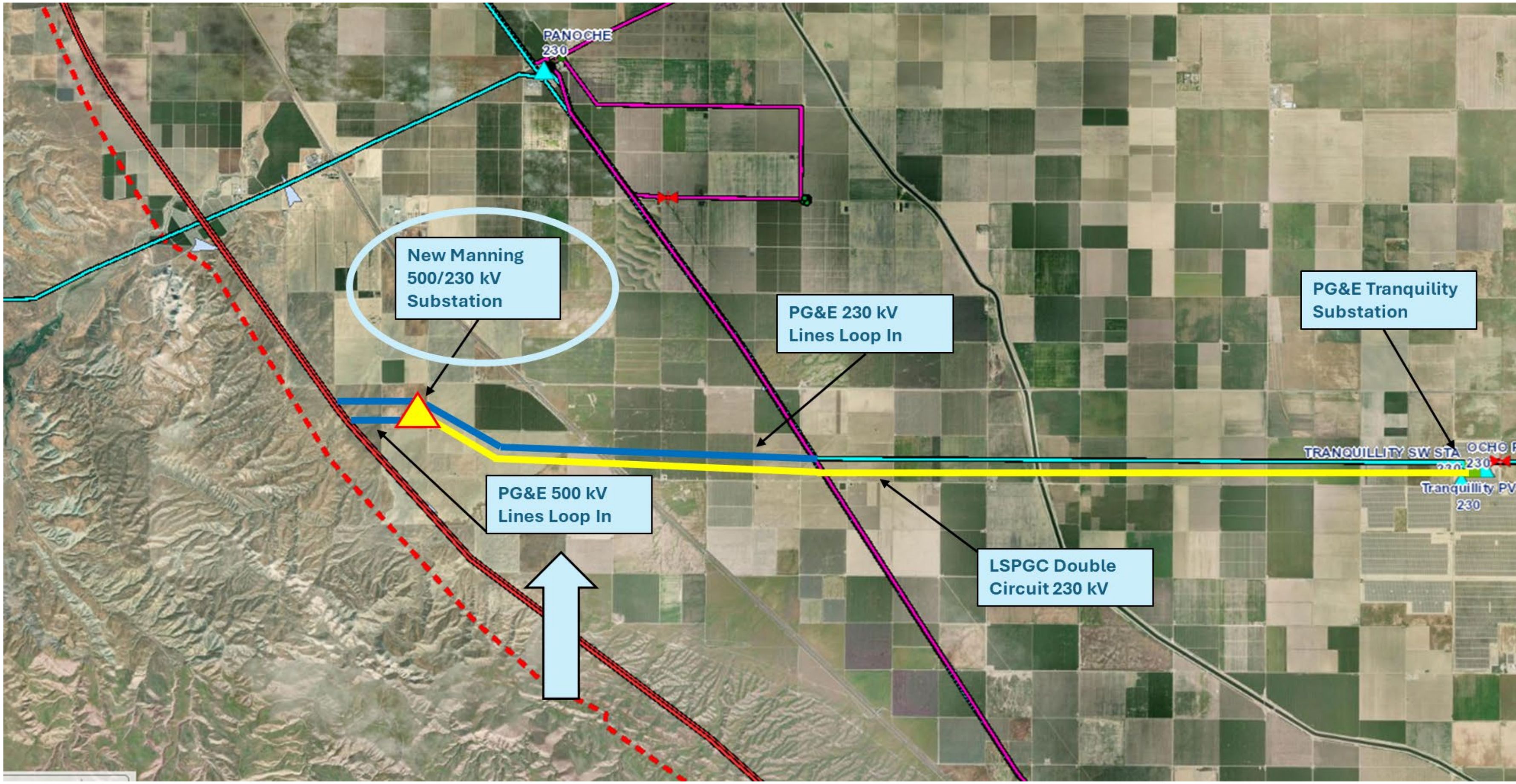
- LS Power to construct a new 500kV/230kV Substation.
- LS Power to construct 2 new 230kV transmission lines between Manning substation and Tranquility SW Sta.
- PG&E to loop the Los Banos – Gates No.1 500kV line and the Los Banos – Midway No. 2 500kV line
- PG&E to modify 500kV Transposition structure locations on the Los Banos – Gates No.1 500kV line and the Los Banos – Midway No. 2 500kV line
- PG&E to loop the two existing Panoche – Tranquility 230kV lines into the new 500kV Manning substation
- PG&E to reconductor the two Manning – Tranquility 230kV lines from loop in point to Tranquillity SW Sta.
- 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, replace all overstressed breakers in 230kV Bus Section E, replace all overstressed 115kV breakers. Build Telecom yard and install Telecom enclosure at Manning Substation to facilitate monitoring the status of Manning substation. Build 230kV BAAH bays 4 & 6 at Tranquillity Switching Station to accommodate two new 230kV lines from Manning Substation to Tranquillity Switching Station, replace and extend main bus 1 & 2 from BAAH bay 4 to bay 6. Upgrade 500kV line protection at Los Banos and Gates Substations. Install 500kV line disconnect switches at Los Banos and Midway Substations.



T.0009194 Manning New 500kV Sub Connection

Planning Order	Order Description	MWC	T.Dot	EAC	ITD	Construction Start	FISD
5809641	PANOCHE-EXCELSIOR SW STA #1 & #2 115KV	60	T.0009194	$ 2,647	$ 140	9/1/2026	5/31/2028
5809640	MANNING PANOCHE SHOOFLY	60	T.0009194	$ 2,342	$ 244	9/14/2027	6/1/2028
5809639	MANNING GATES-PANOCHE #1 & #2 230KV	60	T.0009194	$ 5,666	$ 267	3/16/2026	6/1/2028
5809623	MANNING TRANQ POCO MAN-TRANQ#3	60	T.0009194	$ 1,629	$ 72	3/2/2027	5/31/2028
5804811	RECONDUCTOR 230KV MANNING - TRANQUILITY#1	60	T.0009194	$ 55,090	$ 1,540	6/4/2026	5/31/2028
5804801	LOOP 2 PANOCHE-TRANQ LINES IN MANNING	60	T.0009194	$ 17,735	$ 83	5/12/2027	5/31/2028
5804800	LOOP LOS BAN-GATES#1 & LOS BANO-MID#2	60	T.0009194	$ 28,003	$ 1,025	10/22/2026	6/1/2028
5560999	MANNING SUB_LAND RIGHTS	60	T.0009194	$ 4,710	$ 127	N/A	2/2/2027
5809978	MANNING SUB - LAS AGUILAS SW SUB	61	T.0009194	$ 1,980	$ 308	3/6/2028	4/28/2028
5809028	MANNING SUB: MANNING TELECOM & TESTING	61	T.0009194	$ 10,576	$ 893	7/17/2026	5/26/2028
5808684	MANNING: PANOCHE SUB REPLACE CB 102, 132	61	T.0009194	$ 6,294	$ 174	1/8/2027	5/1/2028
5804878	MANNING SUB: GATES PROTECTION UPGRADE	61	T.0009194	$ 2,938	$ 606	11/4/2027	4/28/2028
5804813	MANNING SUB: TRANQUILITY BAAH	61	T.0009194	$ 22,733	$ 1,808	5/1/2026	4/27/2028
5804806	MANNING SUB: PANOCHE BAAH	61	T.0009194	$ 77,624	$ 7,208	7/9/2026	4/27/2028
5804805	MANNING SUB: MIDWAY PROTECTION UPGRADE	61	T.0009194	$ 1,970	$ 320	1/7/2027	4/30/2027
5804804	MANNING SUB: LOS BANOS PROTECTION UPGRAD	61	T.0009194	$ 6,136	$ 599	1/11/2027	5/1/2028

PG&E vs. LS Power Mapping



LS Power 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 Scope:

- Loop the Los Banos – Gates No.1 500kV line and the Los Banos – Midway No. 2 500kV line into Manning Substation.
- Loop the two existing Panoche – Tranquility 230kV lines into the new 500kV Manning substation, reconductor the two Manning – Tranquility 230kV lines to higher capacity.
- Replace 500kV Transposition structures on Los Banos – Gates No.1 500kV line and the Los Banos – Midway No. 2 500kV lines.

T.0009189 Loop Vaca Dixon-Tesla in Collinsville

Planning Order	Order Description	MWC	T.Dot	EAC	ITD	Construction Start	FISD
5804858	LOOP VACA DIXON-TESLA IN COLLINSVILLE	60	T.0009189	$ 36,206	$ 2,113	8/18/2027	5/30/2028
5804803	PITTSBURG CONNECT 2 230 & INST BUS REAC	61	T.0009189	$ 26,933	$ 2,444	6/29/2027	5/26/2028
5804802	TESLA UPGRADE SYSTEM PROTECTION	61	T.0009189	$ 7,612	$ 461	8/18/2027	5/30/2028
5804724	VACADIXON SUB 500KV SERIES CP BK2 MOD	61	T.0009189	$ 27,590	$ 920	6/1/2027	5/30/2028

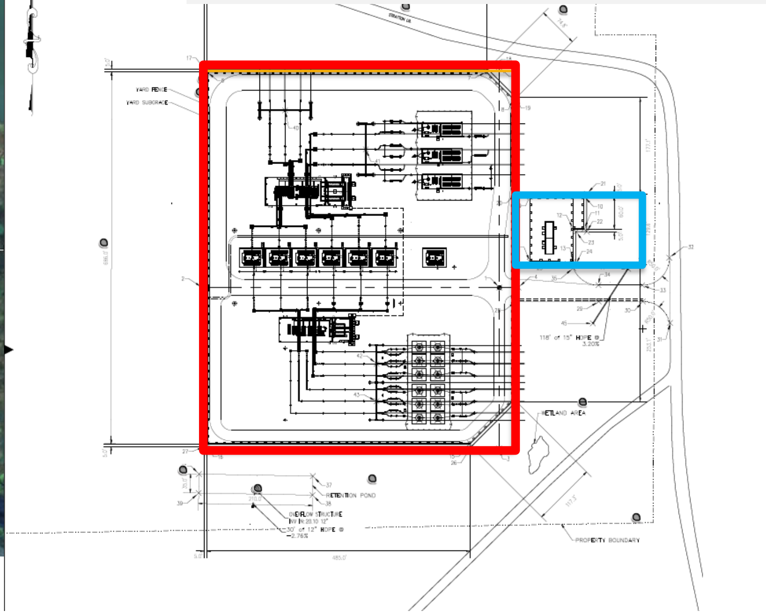
- **Scope:** LS Power to install a new 500kV substation in the town of Collinsville. PG&E to tap into existing 500kV line to loop in and out of the new substation. PG&E to replace remote end relays at Vaca Dixion and Tesla substations and install IT yard adjacent to new substation. Furthermore, modify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

- **Status:** The Project Team is currently collaborating with the CPUC and LS Power to address public comments solicited in December 2025 after the publication of the CPUC's Draft Environmental Impact Report (DEIR). Note the Transmission Line design is on hold because LS Power's substation location may be impacted by the findings in the DEIR. Remote End Substation designs are in progress anticipated to be complete by Q4-2026.

PG&E vs. LS Power Mapping

T.0009189 Loop Vaca Dixon-Tesla in Collinsville

Collinsville Substation & PG&E Communications Yard

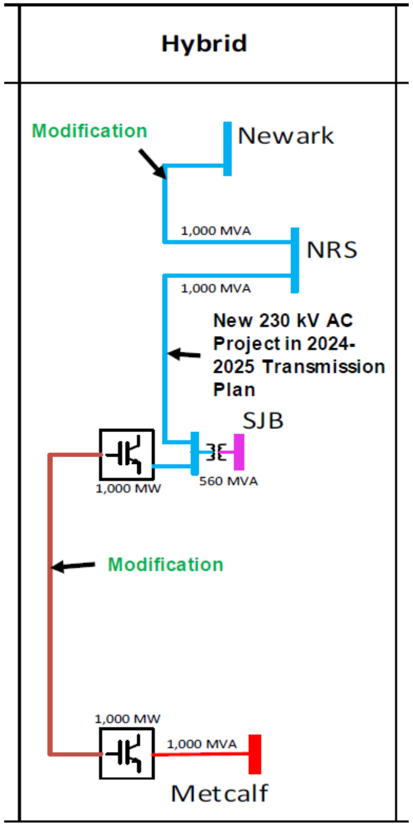


T.0009168 Newark – NRS 230 kV Project

Planning Order	Order Description	MWC	T.Dot	EAC	ITD	Construction Start	FISD
5806599	NEWARK - HVDC CONNECTION - TLINE	60	T.0009168	$ 1,500	$ 82	12/2/2026	5/28/2027
5804787	NEWARK - HVDC CONNECTION	61	T.0009168	$ 22,750	$ 5,876	9/2/2026	5/28/2027

Scope:

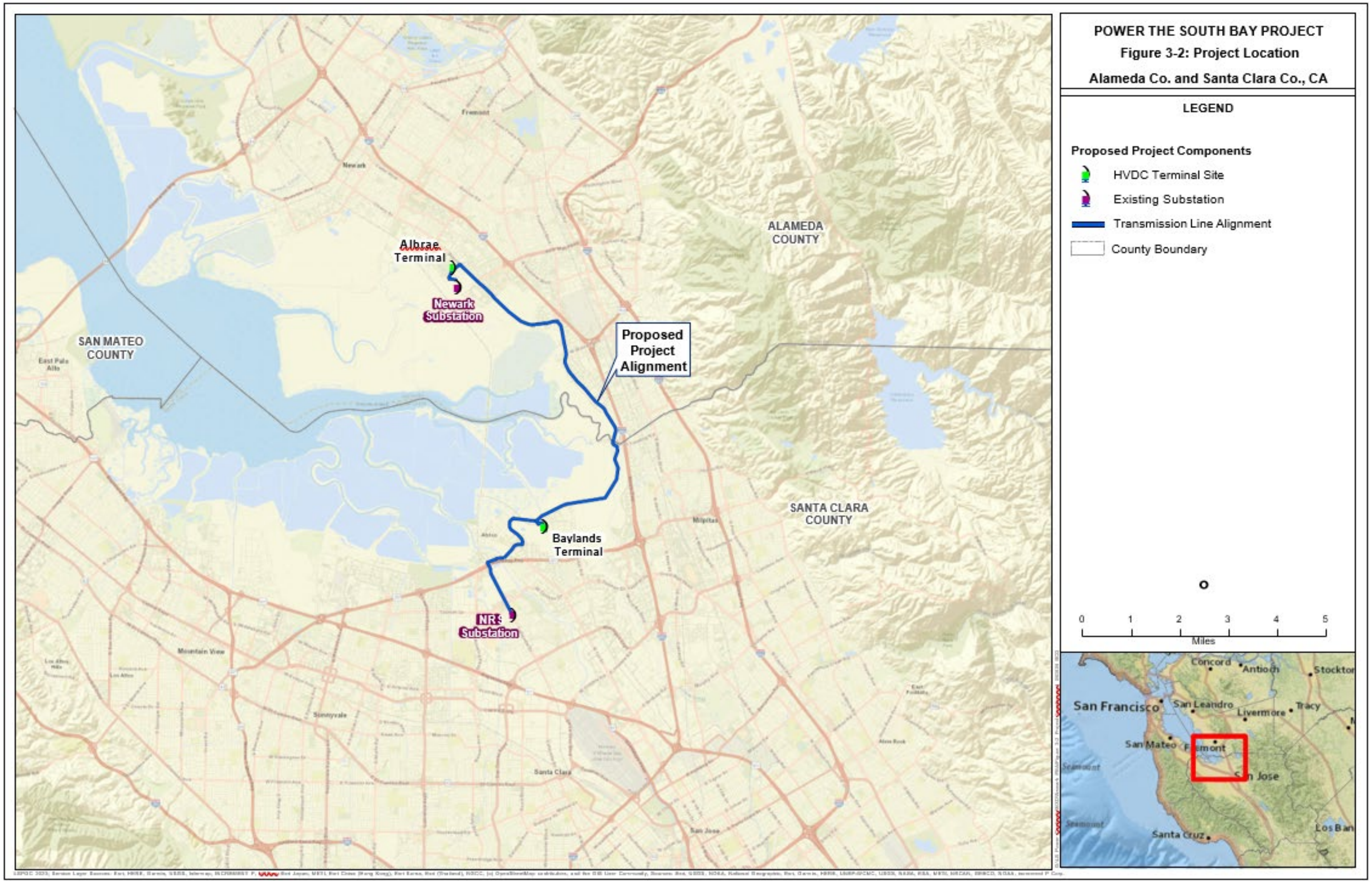
- PG&E's responsibility includes upgrades within Newark Substation and transmission line from Newark to the point of interconnections to connect with LS Power. PG&E scope includes
  - Install one (1) 230kV 4000A breaker complete with new structure and all associated switches at Newark. Breaker to be install in DBSB configuration. New 230kV NRS-Newark Line to be designed for 4000A rating.
  - Modify protection scheme, upgrade grounding and grading as required.
  - Construct a 230kV transmission line from Newark Substation to the LS Power POCO location.
  - Newark 230kV bus will be upgraded to 4000A rating. Upgrade existing CB810/CB820 and CB200/800 to 4000A rating.
- LS Power responsibility includes transmission line between Northern Receiving Station (NRS) and Newark Substation. Based on November 2024 decision by CAISO, the HVDC Terminal Sites (Albrae and Baylands) are not required since the entire transmission line between NRS and Newark Substations was changed to an AC circuit.



Status:

- PG&E scope is currently in design phase.
- PG&E is coordinating with LS Power and Silicon Valley Power (SVP), who owns and operates the NRS Substation regarding the CAISO scope changes (1,000 MVA 230 kV AC connection between Newark and NRS) and interconnection details.

T.0009168 Newark - PG&E vs. LS Power Mapping



Note: HVDC Terminal Sites (Albrae and Baylands) are not required based on November 2024 CAISO decision.

Reference: LS Power Certificate of Public Convenience and Necessity (CPCN) application and Proponent's Environmental Assessment (PEA) for Power the South Bay Project, May 17, 2024

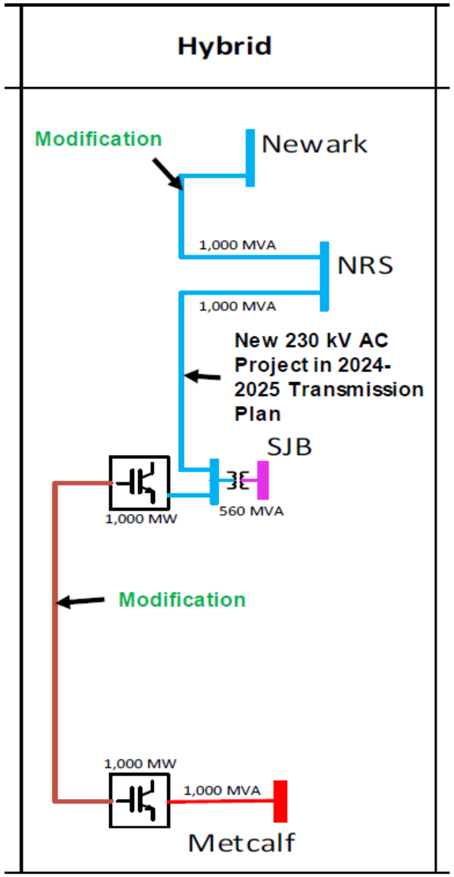
T.0009169 Metcalf - HVDC Connection

Scope:

- PG&E's scope includes upgrades at the Metcalf and San Jose B Substations. In addition, PG&E will install the transmission lines from Metcalf and San Jose B Substations to the point of interconnections to connect with LS Power HVDC.
- PG&E will be completing the project in two phases
  - Phase 1: Upgrade 500 kV at Metcalf substation; rebuild 115kV San Jose B substation including one 560MVA 230/115kV autotransformer; transmission line connections at Metcalf and SJB to LS Power POCO location.
  - Phase 2: Addition of a new 230kV GIS switchyard at San Jose B substation and one 560MVA 230/115kV autotransformer.
- LS Power responsibility includes the Skyline and Grove HVDC (converter station) Terminal sites and the transmission lines (Skyline-Grove, Grove-Metcalf Substation and Skyline-San Jose B Substation).

Status:

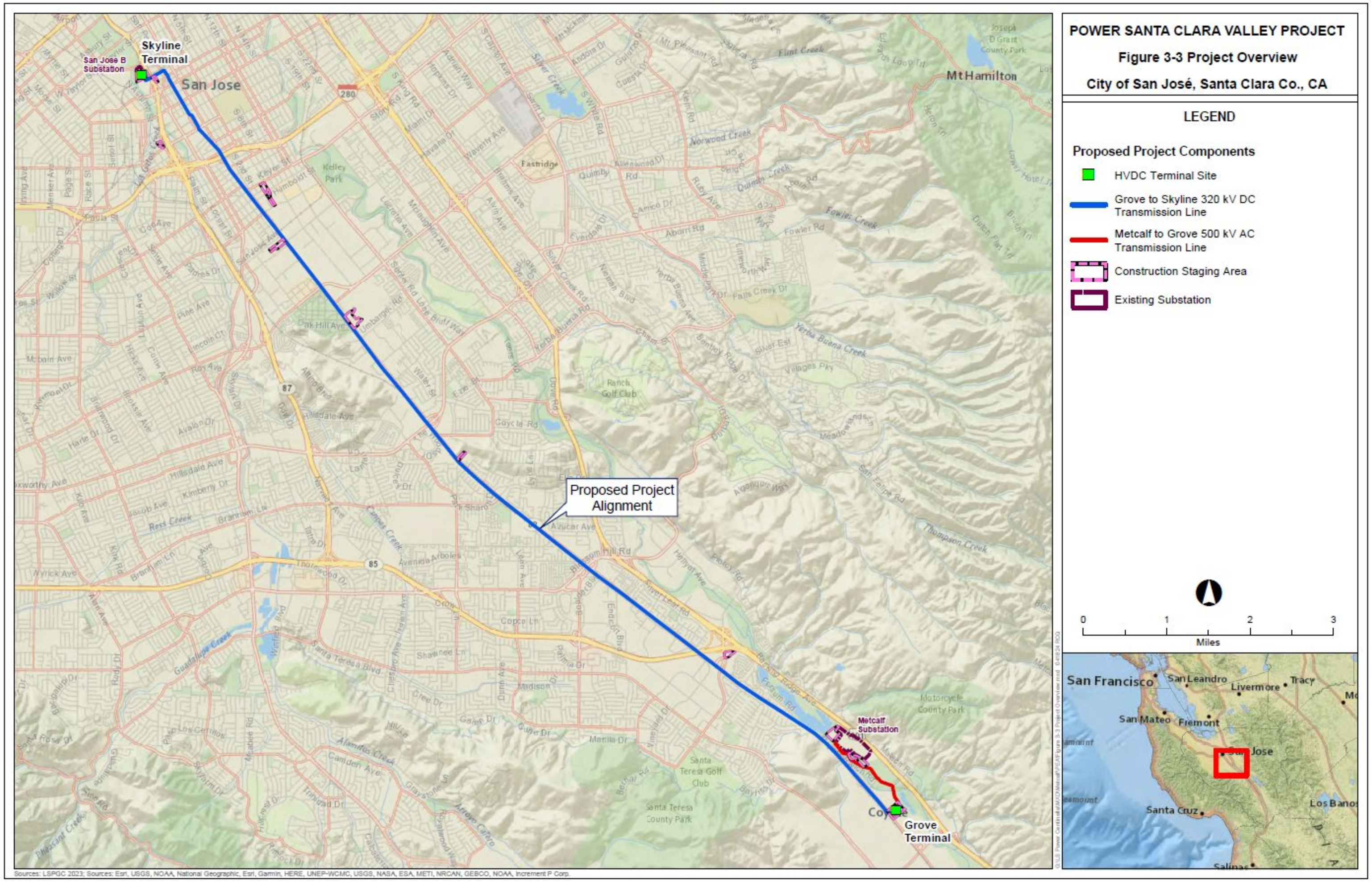
- Metcalf: PG&E is currently in design phase for substation upgrades. Relocation of PG&E GC yard facilities (to accommodate the LS Power Grove converter station adjacent to Metcalf substation) and land acquisition to move the GC yard facilities have started.
- San Jose B: Construction has started for relocation of distribution lines, substation site grading and temporary relocation of a transmission line. The remainder of the work at San Jose B is in design phase.
- PG&E is coordinating with LS Power regarding interconnection details and regarding land acquisition at San Jose B and Metcalf.



T.0009169 Metcalf - HVDC Connection

Planning Order	Order Description	MWC	T.Dot	EAC	ITD	Construction Start	FISD
5806625	SAN JOSE B - HVDC CONNECTION - TLINE	60	T.0009169	$ 7,877	$ 221	2/23/2027	12/30/2027
5815774	METCALF -MORGAN HILL SECURITY FENCE	61	T.0009169	$ 3,373	$ 2,183	N/A	2/27/2026
5813144	SAN JOSE B 230KV GIS	61	T.0009169	$ 169,696	$ 181	7/24/2029	6/28/2030
5807758	SAN JOSE B - HVDC - SAN JOSE A RE	61	T.0009169	$ 1,685	$ 85	11/1/2027	12/30/2027
5807739	SAN JOSE B - HVDC - TRIMBLE RE	61	T.0009169	$ 2,185	$ 60	6/30/2027	12/30/2027
5804789	SAN JOSE B - HVDC CONNECTION	61	T.0009169	$ 219,153	$ 30,546	4/23/2027	12/30/2027
5804788	METCALF - 500KV HVDC CONNECTION	61	T.0009169	$ 71,580	$ 3,419	6/4/2027	12/30/2027
5561666	METCALF GC YARD RELOCATION LAND ACQUISIT	61	T.0009169	$ 28,871	$ 16,871	N/A	N/A
5559139	SAN JOSE B HVDC LAND ACQ	61	T.0009169	$ 4,800		N/A	N/A
5555161	SAN JOSE B - HVDC - SOUTH TRANSITION RE	61	T.0009169	$ 458	$ 12	5/17/2027	12/30/2027
5555160	SAN JOSE B - HVDC - NORTH TRANSITION RE	61	T.0009169	$ 401	$ 14	4/20/2027	12/30/2027

T.0009169 Metcalf - PG&E vs. LS Power Mapping

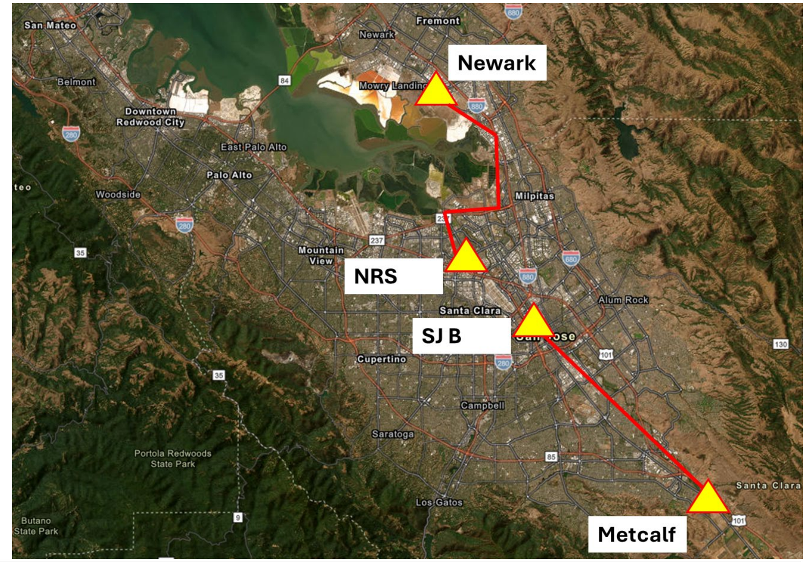


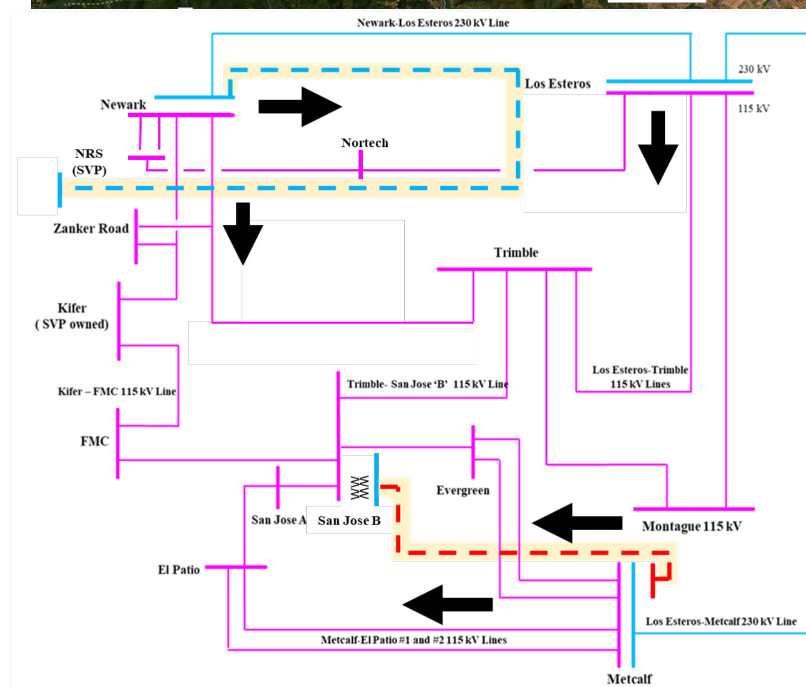
Note: The location of Grove terminal has been updated to be adjacent to PG&E Metcalf substation..

Reference: LS Power Certificate of Public Convenience and Necessity (CPCN) application and Proponent's Environmental Assessment (PEA) for Power the Santa Clara Valley Project, April 29, 2024

LS Power Project Relations

- Metcalf, Newark, Los Esteros supply 230 kV power to a network system of 115 kV and 60 kV lines, serving several transmission and distribution stations in the South Bay Area
- The new LS Power lines will be interconnected with the existing grid and will support the area's load growth
- By 2030 the San Jose B-NRS 230 kV line is expected to be added to San Jose B Substation
- Data centers located in the area will connect across the 115 kV network and will rely on these and others capacity upgrades – coordinated between large load interconnection process and TPP





Project Delays
Stakeholder Requested Item #4

Andre Williams – *Project Manager*

Mamie Yuen – *Project Manager*

Alain Billot – *Project Manager*

4 - Costs Since Inception

T.0000159 Egbert 230kV Switching Station

- Scope: Construct a new 230kV switching station near, but not adjacent to, Martin Substation.
- Project Driver: CAISO TPP
- Project Status: Engineering
- Construction Start: 8/1/26 (Tentatively)
- FISD: 10/27/28
- EAC: $294M
- ITD: $105M
- Risks: Project risk includes changes to design standards that would delay the project timeframe and increase project cost.
- Project Dependencies: T.0008764 Martin-Hunters Point Shoofly Project
- Material Purchased: Long lead material such as series and shunt reactors, and Gas Insulated Substation equipment.

T.0000159 Egbert 230kV Switching Station

Planning Order	Order Description	MWC	T.Dot	EAC	ITD	Construction Start	FISD
5767217	REROUTE JEFFERSON_MARTIN 230KV LINE	60	T.0000159	$ 72,306	$ 31,775	6/29/2027	10/27/2028
5767213	LOOP EMBARCADERO & MARTIN	60	T.0000159	$ 31,837	$ 3,947	2/3/2028	10/12/2028
5551310	EGBERT T-LINE - VISITACION AVE EASEMENT	60	T.0000159	$ 24	$ 24	N/A	3/31/2026
5767648	MARTIN BUS EXT: SF RAS MODIFICATIONS @ C	61	T.0000159	$ 3,438	$ 26	5/26/2028	10/26/2028
5767647	MARTIN BUS EXT: EMBARCADERO PROT UPGRADE	61	T.0000159	$ 2,274	$ 122	6/27/2028	10/27/2028
5767646	MARTIN BUS EXT: JEFFERSON PROT UPGRADES	61	T.0000159	$ 2,722	$ 88	5/26/2028	10/26/2028
5767645	MARTIN BUS EXT: MARTIN SUB PROT UPGRADES	61	T.0000159	$ 2,867	$ 346	5/26/2028	10/12/2028
5767214	Egbert Greenfield Substation	61	T.0000159	$ 82,181	$ 49,305	2/2/2027	10/12/2028

T.0008698 - Los Esteros-Nortech 115kV Series Reactor

- Scope: Add Smart Wires' series compensation devices on the Los Esteros-Nortech 115kV line to insert 2.76 ohm, which will increase the impedance of the line to avoid thermal overloading concerns
- Project Driver: CAISO TPP
- Project Status: Construction
- Construction Start: 1/20/26 FISD: 5/1/26
- ITD: $11.756M EAC: $23.802M
- Risks: This is a pilot project for a vendor and technology that is new to PG&E, so there are more unknowns that can impact the cost, scope, and schedule. Getting clearances on the Los Esteros-Nortech line can be challenging, and any outage can impact sensitive customers. Wet weather and the water table can impact the schedule for civil construction.
- Project Dependencies: None
- Material Purchased: All major materials have been purchased including (3) V-switch disconnect switches, (3) sets of SmartValves.

T.0008698 -- Los Esteros-Nortech 115kV Series Reactor

Planning Order	Order Description	MWC	T.Dot	EAC	ITD	Construction Start	FISD
5808477	LOS ESTEROS T-LINE REMOTE END	60	T.0008698	$ 948	$ 161	3/31/2026	4/16/2026
5808476	NORTECH LOS ESTEROS LINE UPGRADE	61	T.0008698	$ 2,937	$ 446	1/20/2026	5/1/2026
5802781	LOS ESTEROS-NORTECH 115KV SERIES REACTOR	61	T.0008698	$ 19,918	$ 11,148	1/20/2026	5/1/2026

T.0000603 - Seismic Upgrade: Potrero to Mission/Lark

- Scope: This project will build three new seismically resilient cables: two cables from Potrero to Mission and Larkin and one cable from Mission to Larkin.
- Project Driver: CAISO TPP
- Project Status: Engineering
- Construction Start: 4/27/28
- FISD: 11/8/30
- EAC: $239M
- ITD: $11M
- Risks: CPUC Permit to Construct V. Notice of Construction: Add 2+ years to FISD
- Project Dependencies: None at this time
- Material Purchased: None to date

T.0000603 -- Seismic Upgrade: Potrero to Mission/Lark

Planning Order	Order Description	MWC	T.Dot	EAC	ITD	Construction Start	FISD
5801473	LARKIN X-Y #2 TERMINATION	61	T.0000603	$ 1,085	$ 25	7/9/2029	11/6/2029
5801472	MISSION X-Y #2 TERMINATION	61	T.0000603	$ 1,069	$ 8	7/9/2029	11/6/2029
5801471	POTRERO A-Y #3 TERMINATION	61	T.0000603	$ 1,208	$ 70	7/11/2030	11/8/2030
5798621	LARKIN A-Y #3 TERMINATION	61	T.0000603	$ 1,157	$ 28	7/11/2030	11/8/2030
5798620	MISSION A-X #2 TERMINATION	61	T.0000603	$ 1,020	$ 27	4/27/2028	8/28/2028
5798619	POTRERO A-X #2 TERMINATION	61	T.0000603	$ 1,044	$ 51	4/27/2028	8/28/2028
5765141	POTRERO-MISSION #2 (A-X2) SEISMIC UPGRAD	93	T.0000603	$ 95,979	$ 4,064	9/1/2028	9/30/2030
5765140	MISSION-LARKIN #2 (X-Y2) SEISMIC UPGRADE	93	T.0000603	$ 35,619	$ 3,138	9/1/2028	9/30/2030
5765139	POTRERO-LARKIN #3 (A-Y3) SEISMIC UPGRADE	93	T.0000603	$ 100,507	$ 3,648	11/7/2028	9/30/2030

AFUDC and Placing Projects on Hold
Stakeholder Requested Item #3

George Kataoka – *Capital Recovery*

AFUDC and Placing Projects On Hold

- There are no updates or changes to PG&E's automated hold process. The process is working as intended alongside the manual SAP Deferred status process.
  - For more information regarding PG&E's AFUDC standard and timing of deferrals, please refer to PG&E's responses to **DR_ED_017-Q001** and **Q004**.
- For transmission work orders currently placed On Hold via the automated hold process, please refer to PG&E's response to **DR_ED_018-Q025.**
- There are no transmission work orders in SAP Deferred status as of Dec 2025.
- AFUDC process changes per FERC Audit (*Docket No. FA23-8-000, p.44-47*):
  - PG&E has completed the remediation of these recommendations:
    - Corrected AFUDC Rate: Including the use of calendar year-end book balances for Long-Term Debt, Preferred Stock, and Common Equity. Additionally, other items include exclusion of non-eligible balances and appropriate calculation of Long-Term Debt.
  - Audit findings state that PG&E did not over accrue AFUDC during the audit period

PG&E's Use of AACE Class Cost Estimates
Stakeholder Requested Item #5

Kim Erdmann – Program Manager, T&S Project Management

AACE Class Cost Estimates

Each AACE Class of cost estimate has a specific purpose. As the degree of the project definition increases, the estimate progresses from Planning (AACE Class 5) to full project to start of construction (AACE Class 2 or 1).

- Class 5 estimate should be used for long term planning and future year budgeting decisions. Class 5 project estimates correspond to projects in the early concept and Planning Stage, often before a project team has been assigned. Class 5 estimates are prepared based on limited information (e.g., a very high-level investment objective provided by a sponsor) and subsequently have a wide range of potential outcomes.
- Class 4 estimates are based on a selected asset alternative and are prepared with limited scope information and have a wide range of potential outcomes. Strategy alternatives (e.g., routing/siting, contracting strategy) are typically not yet selected.
- Class 3 estimate may be prepared and used at the indoor and outdoor developing engineering design review to make decisions on scope-freeze as well as decisions on whether to proceed with the project. Class 3 estimates are based on a detailed scope of work, execution strategy, and preliminary engineering design. A Class 3 estimate can help facilitate constructability review.
- Class 2 or 1 estimate is required to proceed with construction and should be used as the baseline by which to measure project performance during construction. Class 2 estimates are based on detailed engineering designs and execution plans. A Class 1 estimate represents the highest level of estimating certainty.

Estimate Class Accuracy Ranges

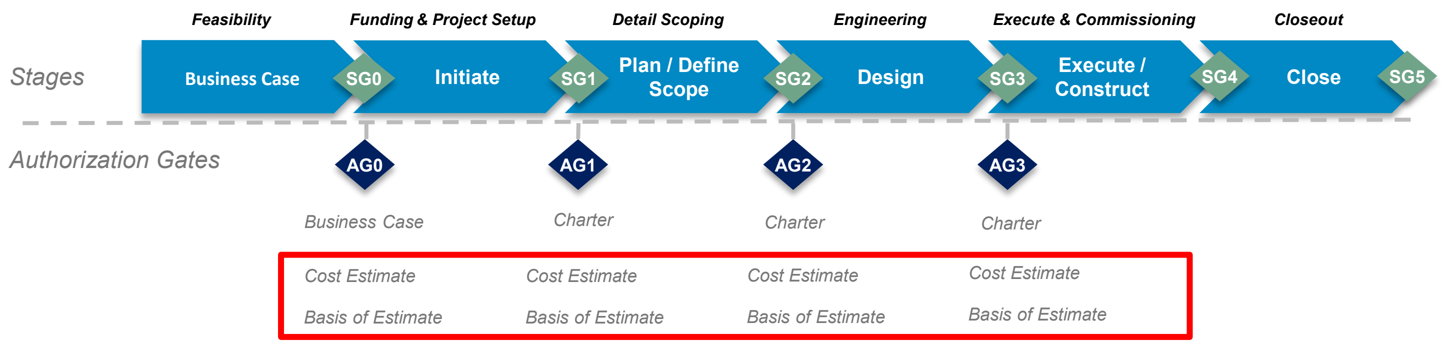
Estimate Ranges

AACE Estimate Class	Class 5	Class 4	Class 3	Class 2	Class1
Expected Accuracy Range	+100% to -50%	+50% to -30%	+30% to -20%	+20% to -15%	+15% to - 10%

AACE Cost Management and Project Lifecycle

Legend

- Project Stage-gate (#)
- Project Authorization:
  - Business Case (BC)
  - Charter (CH)



Stage Gate	AACE Class
0	5
1	4
2	4
3	3
	2
After 3, Reauthorizations	1

AACE in TPR

- PG&E will update AACE in the May 2026 TPR PDS to the following:

AACE Class	Project Status
5	Planning
4	Eng < 50%
3	Eng > 50%
2	Construction
1	Operational
NA	Programmatic Work

Back at 2:40

BREAK

General Economic Outlook / 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 ~ $42.5 billion by 2032
  Regional Dominance: Asia Pacific leads with a 40% market share

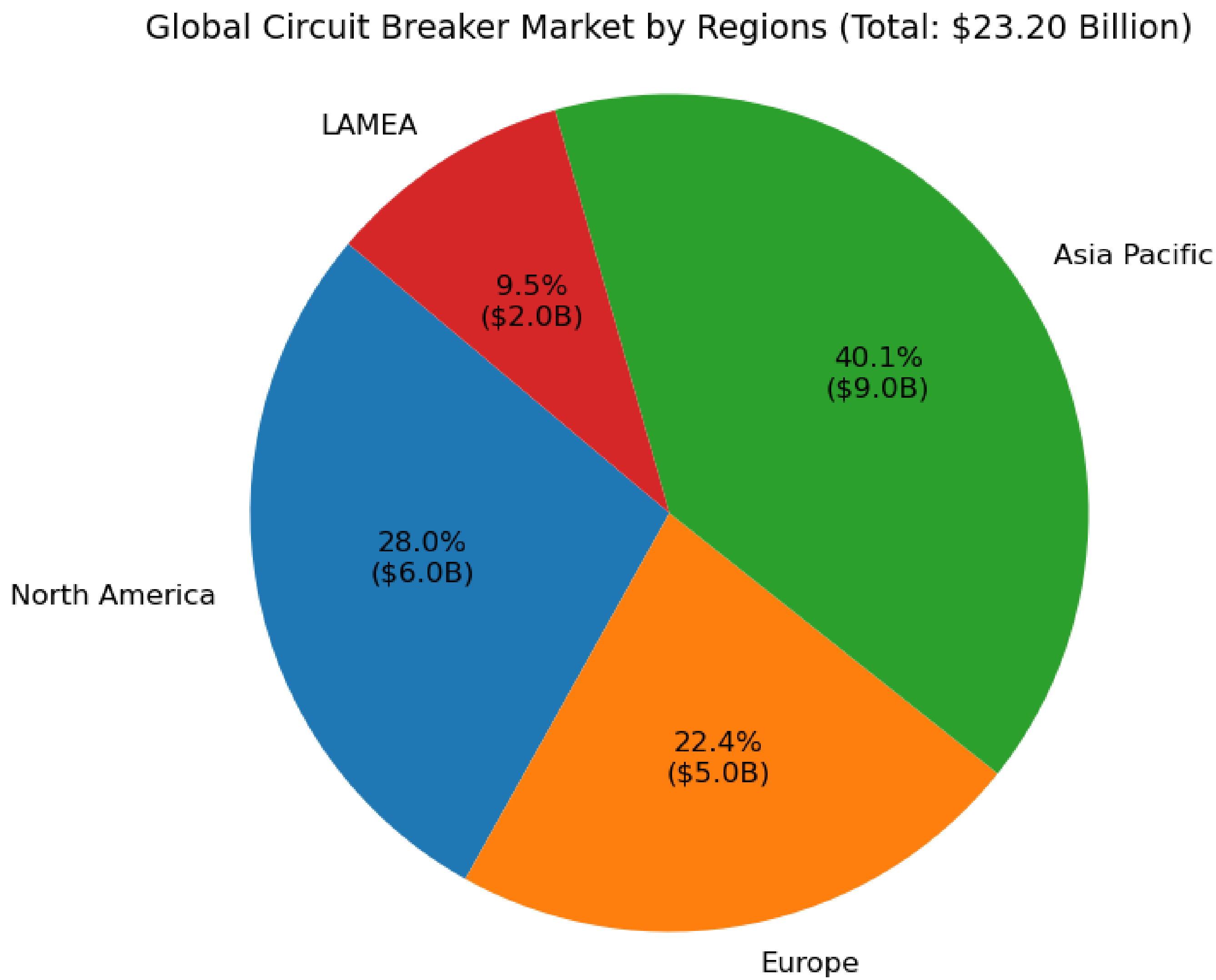
- **Challenges**
  High Initial Costs: The high initial cost of advanced circuit breakers, component shortages and logistics delays, regulatory Complexity: Varying standards across regions

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

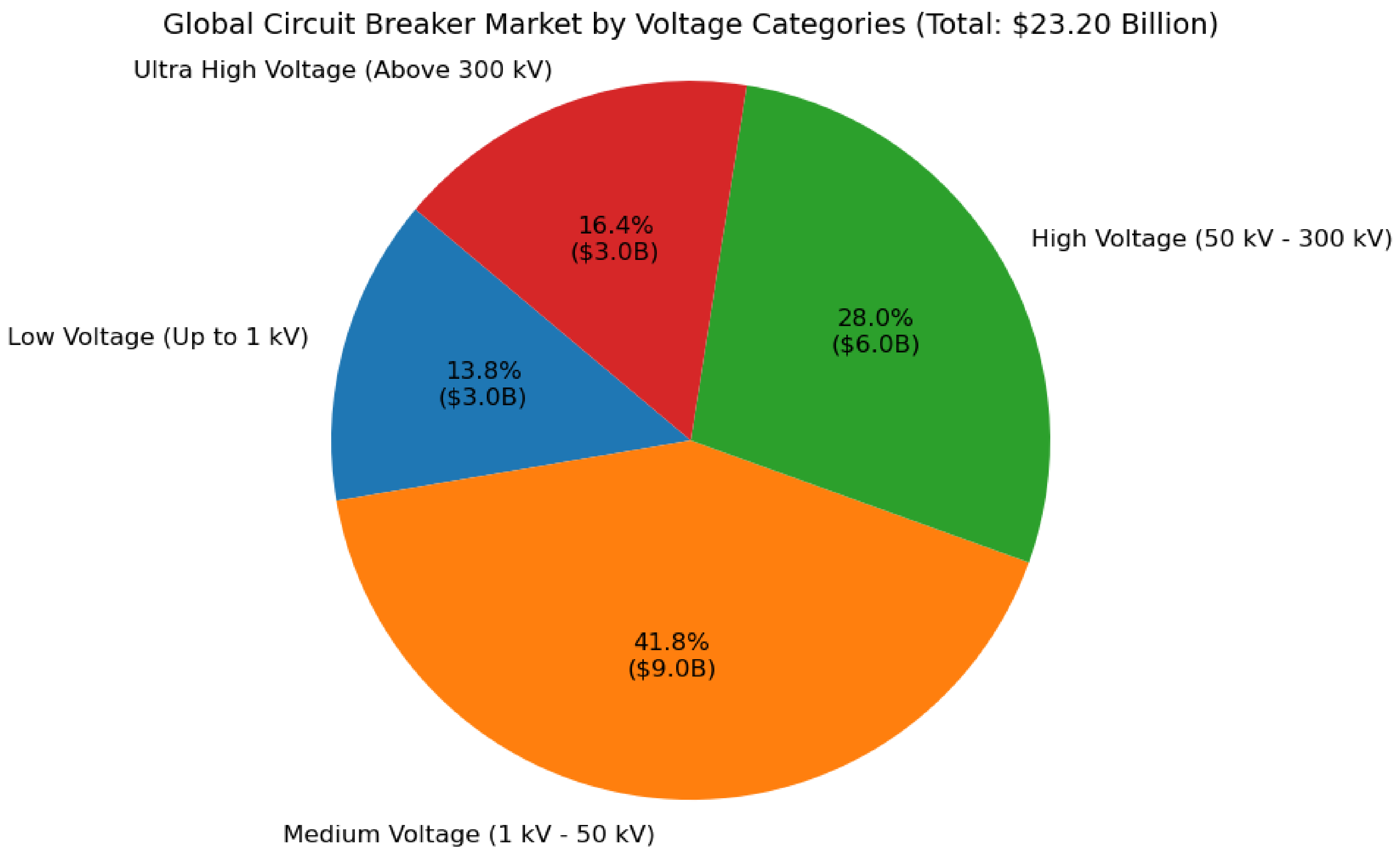
- **Lead Times**
  Supply Chain Disruptions: Initial disruptions due to labor and component shortages
  Manufacturing Hubs: Asia Pacific remains a key manufacturing hub

- **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 (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

- **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. Five developing suppliers have active pilot awards
- PG&E is working on updating our five-year demand forecast in effort to support projected demand, secure slots, bundle awards, 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

Load Interconnection Processes
Stakeholder Requested Item #10

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

Mike Colborn – *Sr. Manager, Electric Program Management*

Ashwini Mani, Sr. *Manager, Transmission Planning*

Nick Medina – *Sr. Engineer, TPR Team*

Rule 30 – Application Updates

Please provide an update on PG&E's "Rule 30" application at the CPUC.

- On November 21, 2024, PG&E submitted proposed Electric Rule 30 application to the CPUC (Application 24-11-007). Electric Rule 30 addresses the interconnection of electric retail load customers interconnecting at transmission level voltages (e.g., data centers, EV charging, etc.).
- On January 24, 2025, PG&E filed a motion requesting the CPUC to approve interim implementation or Rule 30 until final ruling is made.
- On March 11, 2025, the Administrative Law Judge (ALJ) issued a scoping memo identifying the issues and schedule for the proceeding.
- On March 21, 2025, PG&E filed its supplemental testimony.
- On June 20, 2025, the ALJ issued a proposed decision (PD) for interim implementation in response to PG&E's motion. The PD recognized the increased number of retail transmission applications and found it reasonable to grant PG&E's request with modifications. The CPUC is scheduled to vote on the PD July 24, 2025.
- **On July 24, 2025,** the CPUC approved Interim Implementation which partly grants and partly denies PG&E's motion for interim implementation of Rule 30. Approves interim implementation of Electric Rule 30 for transmission-level customers, but delays a decision on refunds for Type 1-3 transmission facilities, repayment of pre-funded loans (Type 4 facilities), and interest provisions.
- **On November 21, 2025,** the Administrative Law Judge suspended the proceeding.
- **On January 9, 2026,** the Administrative Law Judge issued a new ruling requesting additional testimony focused on cost responsibility for Type 4 facilities and cost allocation scenarios for Facility Types 1-3.

Rule 30 Impact on TPR Projects

Large Retail Load Projects in Nov 2025 TPR PS

Utility Unique ID 2	T Project Name
T.0000005	CHSR Interconnections, Sites 4-7
T.0000006	CHSR Interconnections, Sites 8-13
T.0005903	Private Load Interconnection Project
T.0006960	Private Load Interconnection Project
T.0007676	Private Load Interconnection Project
T.0008046	Private Load Interconnection Project
T.0008309	FMC: VTA 115kV Interconnect
T.0009031	Private Load Interconnection Project
T.0009133	Private Load Interconnection Project
T.0009652	Private Load Interconnection Project
T.0010081	Private Load Interconnection Project
T.0010100	Private Load Interconnection Project
T.0010142	Private Load Interconnection Project
T.0010517	Private Load Interconnection Project
T.0010520	Private Load Interconnection Project
T.0010809	L0006_BRITTON-MONTA VISTA & NEWARK-APPLIED
T.0010873	LC24-2 Private Load Interconnection Project
T.0010874	LC24-26 Private Load Interconnection Project
T.0010875	LC24-27 Private Load Interconnection Project
T.0010876	LC24-28 Private Load Interconnection Project
T.0010902	LC24-1 Private Load Interconnection Project
T.0010903	Private Load Interconnection Project
T.0010908	Private Load Interconnection Project
T.0011156	Private Load Interconnection Project

- Rule 30 is not expected to have a final decision until Q3 2026.
- The impact of Rule 30 approval on Projects in the November 2026 TPR cannot be determined at this time.
- Filter for “Load Interconnection” for Data Field 10 Secondary Purpose to find these projects. Work under MWC 82

Cluster Study Update

- PG&E conducted its first transmission cluster study in 2024 which was limited to data centers located in Santa Clara and Alameda counties.
- In 2025, PG&E conducted its second transmission cluster study limited to data centers but expanded to include all of PG&E's service territory.
- PG&E will soon launch its third cluster study for 2026.

2025 Cluster Study

- Expanded the 2025 Cluster Study to include all of PG&E's service territory
- The application window closed April 30th and reports were issued October 31st
- 29 initial applications:
  - 24 unique customers
  - 7,472 MWs of requested load
- 20 preliminary engineering study (PES) reports issued totaling 3,772 MWs
- 12 projects proceeding to final design
  - 2,429 MWs (compared to 940 MWs from the 2024 Cluster Study)

Cluster Study Findings

- Customers who participated in the 2024 Cluster Study noticed improvements year over year including organization, communication, and report delivery
- The $200M in projected customer savings from the 2024 Cluster Study is based on interconnection scope estimated costs. It is driven by shared costs between the interconnection customers such as shared switching stations and sharing the cost of reconfiguring existing substations.
- Participants in the 2025 Cluster Study provided high praise for the effort, with a **median 8 out of 10 score**
- Improvements for 2026 include providing customers more time to review the reports before making a decision to proceed

Cluster Study Update: TPP Projects

- How were CAISO TPP-approved projects considered in the cluster study?
  - CAISO TPP-approved projects are modeled in the cluster study. Load Process identifies additional capacity needs to support the load growth and requests
- Please explain how PG&E's load forecasts for new load may differ from those used by other planning agencies and explain the impacts on planning.
  - PG&E load interconnection process models customer forecast or request
  - CEC has added data center forecast in the IPER process since 2024-2025 cycles and use confidence level and utilization level to scale down data center forecast.
  - Discussion is ongoing on how to model committed DS loads in future load interconnection studies

PO 5555047 – 82N DET PLAN – Load

YEAR		2025	2026	2027	2028	2029	2030
Active Projects							
Project Management's List (SI Portion Only) + DWR		$ 2,312,295	$ 18,587,044	$ 27,905,361	$ 105,366,423	$ 128,828,931	$ 52,625,949
Large Load		$ 2,312,295	$ 17,587,044	$ 12,769,117	$ 5,196,111	$ 2,802,746	$ 7,258,199
Active Projects Total		**$ 4,624,590**	**$ 36,174,087**	**$ 40,674,478**	**$ 110,562,534**	**$ 131,631,676**	**$ 59,884,148**
Cluster Projects [4]	**# Projects**						
2024	10	$ 40,532,110	$ 101,676,353	$ 130,337,579	$ 135,285,500	$ 128,308,000	$ 60,942,000
2025	18		$ 72,957,799	$ 183,017,435	$ 234,607,643	$ 270,571,000	$ 256,616,000
2026	20			$ 81,064,221	$ 203,352,706	$ 260,675,159	$ 300,634,444
2027	20				$ 81,064,221	$ 203,352,706	$ 260,675,159
2028	20					$ 81,064,221	$ 203,352,706
2029	20						$ 81,064,221
2030	20						
Cluster Projects Total		**$ 40,532,110**	**$ 174,634,152**	**$ 394,419,235**	**$ 654,310,070**	**$ 943,971,085**	**$ 1,163,284,530**
Non Cluster Projects [5]	**# Projects**						
2025	6	$ 20,000,000	$ 60,000,000	$ 240,000,000	$ 80,000,000	$ 26,312,800	$ 26,312,800
2026	4		$ 4,395,971	$ 9,175,039	$ 14,752,857	$ 28,582,930	$ 29,638,004
2027	3			$ 3,296,978	$ 6,881,279	$ 11,064,643	$ 21,437,197
2028	3				$ 3,296,978	$ 6,881,279	$ 11,064,643
2029	3					$ 3,296,978	$ 6,881,279
2030	3						$ 3,296,978
Non Cluster Projects Total		**$ 20,000,000**	**$ 64,395,971**	**$ 252,472,017**	**$ 104,931,114**	**$ 76,138,630**	**$ 98,630,901**
TOTAL		**$ 65,156,701**	**$ 275,204,210**	**$ 687,565,730**	**$ 869,803,718**	**$ 1,151,741,391**	**$ 1,321,799,579**

	2026 Allocated Funding	2027 Allocated Funding	2028 Allocated Funding	2029 Allocated Funding	2030 Allocated Funding
Management Approved Large Load Program Forecast	**$ 165,630**	**$ 169,925**	**$ 213,775**	**$ 219,328**	**$ 188,926**
Nov 2025 TPR Project Forecast	$ 261,447	$ 89,497	$ 204,771	$ 89,221	$ 123,354
PO 5555047 - 82N DET Plan – Load Forecast	$ -	$ 80,428	$ 9,004	$ 130,107	$ 65,573

PO 5555047 – 82N DET PLAN – Load

- Large Load Interconnection program forecast is not solely under PO 5555047 -- 82N DET PLAN – Load but rather all projects with a Secondary Purpose of Load Interconnection.
- PO 5555047 - 82N DET PLAN – Load forecast is the delta between management approved forecast for the Large Load Interconnection program and the forecast for defined projects in Nov 2025 TPR PS.
- The management approved forecast for the Large Load Interconnection program is significantly less than that in TPR Process_DR_ED_018-Q033-Atch01.
- Approved forecast aligned to funding forecast from completed 2024 cluster study in 2027+ timeframe with reduction in 2026 to account for expectations of project ramp up not hitting the full forecast.
- 2025 expected cluster study forecast was partially funded to account for project ramp up and uncertainty of required timing for the projects.
- Future cluster study forecasts were logged and tracked as “flex-in” funding. Flex-in funding is used to track additional investment opportunities

PO 5555047 – 82N DET PLAN – Load

- Project specific planning orders are created after the customer signs a Preliminary Engineering Study (PES) report, expressing their intent to move the project to the implementation phase
- Exceptional case filings that have been submitted by PG&E to the CPUC:
  - Google Advice 7785-E
  - Microsoft Advice 7635-E
  - Genentech Advice 7814-E
  - STACK Advice 7569-E
  - Menlo Equities Advice 7667-E

PO 5554999 - 82W DET Plan – EGI

	2026 Allocated Funding	2027 Allocated Funding	2028 Allocated Funding	2029 Allocated Funding	2030 Allocated Funding
Management Approved EGI Program Forecast	$ 154,351	$ 224,464	$ 244,968	$ 257,602	$ 238,016
Nov 2025 TPR Project Forecast	$ 256,480	$ 188,548	$ 46,349	$ 203,065	$ 47,211
PO 5554999 - 82W DET Plan – EGI Forecast	$ -	$ 35,916	$ 198,620	$ 54,537	$ 190,805

- PO 5554999 is the carrying variance of the Management Approved EGI Program Forecast and the Nov 2025 TPR Project Forecast
- The November 2025 TPR Project Forecast is the sum of all the individual projects in-flight at the time the forecast is captured. It does not include emergent work.
- The Management Approved EGI Program Forecast reported included active Queue interconnection requests for Clusters up through a hand-full of new Cluster 14 projects at the time the November 2025 TPR information was reported. For details about cluster projects and their interconnections, please see the CAISO public Queue data and filter for the PG&E Utility data in Column W. publicqueuereport.xlsx.
- These costs are 100% Network Upgrades which will be borne by electric transmission ratepayers
- More details included in CPUC ED 18 Q34

High-Speed Rail Project Update
Stakeholder Requested Item #9

Paul Krum – *South Bay PMO*

High Speed Rail Update

- The technical studies delivered in 2024, based upon the applications received in 2023, have expired.
- The High Speed Rail Authority submitted a new application for transmission level service with revised project parameters.
- New technical studies will have to be performed before the California High Speed Rail project can move forward to assess impacts to PG&E's transmission system, upgrades required to support the projects, etc.
- 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.
- The availability of federal funding and its impact on future project activities are unknown at this time.

Generator Interconnection Network Upgrades and CAISO TPP Reliability and Policy-Driven Projects Through CAISO TPP
Stakeholder Requested Item #18

David Corzilius – *Contract Specialist*

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

Count and Generation Amounts (MW) of Projects ≥ 1MW Interconnecting to PG&E Transmission System

Phase	Proj Count	Gen Amt (MW)
Study in Progress	47	12,594
Parked	24	5,740
IA in Progress	15	1,323
Implementation (includes Suspended projects)	191	41,030
In Service	7	558
Commercial	51	5,618
Totals	**335**	**66,862**

Project Counts by Interconnection Phase and Generator Type

Generator Type	Study In Progress	Parked	IA In Progress	Implementation +Suspended	In Service	Commercial	Totals / Gen Type
Battery Storage			1			1	2
ration					1		1
Energy Storage	16	16	6	66	2	14	120
Hybrid: Gas Turbine / Energy Storage				1			1
Hybrid: Hydroelectic / Pumped Storage	1						1
Solar PV / Energy Storage	22	8	4	74	2	8	118
Solar PV / Wind / Energy Storage				1			1
Hybrid: Solar Thermal / Energy Storage				1			1
Hybrid: Steam Turbine / Energy Storage				3			3
Hybrid: Synchronous Engine / Energy Storage				1			1
Hybrid: Wind / Energy Storage				5			5
Hybrid: Wind / Solar PV / Energy Storage				1			1
Hydroelectric				2			2
Solar PV	5			20	1	22	48
Steam Turbine	1		1				2
ınous Engine			1			1	2
Turbine						2	2
Wind	2		2	16	1	3	24
Totals	47	24	15	191	7	51	335

Generation Amounts (MW) by Interconnection Phase and Gen Type

Generator Type	Study In Progress	Parked	IA In Progress	Implementation +Suspended	In Service	Commercial	Totals / Gen Type
Battery Storage			28			24	52
ion					10		10
Energy Storage	3,922	3,175	546	15,568	107	1,930	25,248
Hybrid: Gas Turbine / Energy Storage				120			120
Hybrid: Hydroelectric / Pumped Storage	67						67
ar PV / Energy Storage	7,650	2,565	470	16,394	100	1,371	28,550
ar PV / Wind / Energy Storage				400			400
Hybrid: Solar Thermal / Energy Storage				100			100
Hybrid: Steam Turbine / Energy Storage				270			270
Hybrid: Synchronous Engine / Energy Storage				120			120
Hybrid: Wind / Energy Storage				1,823			1,823
Hybrid: Wind / Solar PV / Energy Storage				400			400
Hydroelectric				5			5
Solar PV	742			2,764	250	2,006	5,761
Steam Turbine	12		53				65
us Engine			35			18	53
Turbine						26	26
Wind	201		191	3,066	91	244	3,793
Totals	12,594	5,740	1,323	41,030	558	5,618	66,862

Generation Interconnection Projects in TDF

- The TDF NU workbook & TPR PDS serve different purposes and audiences:
  - TDF projects are Network Upgrades. Generation Interconnection projects are not included in TDF.
  - TPR projects are at the PO level, with all work scopes under each T.dot project. Generation Interconnection projects are included in TPR
    - Network Upgrades can be a subset of generation interconnection projects or part of other maintenance/capacity projects

CAISO TPP Projects Not in TPR

- Diablo Canyon Area 230 kV High Voltage Mitigation:
  - This project is included in the November 2025 TPR PS under T.0010474 Mesa: Install 115kV Shunt Reactors
- Collinsville 230 kV Reactor:
  - This is not included in the November 2025 TPR PS because it is an LS Power project and not a PG&E project
- CAISO 2024-2025 Transmission Plan
  - All newly approved projects are included in November 2025 TPR PS as unique POs or Investment Codes

2024-2025 CAISO TPP Projects
Stakeholder Requested Item #19

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

2024-2025 CAISO TPP Projects

- Data Field 56 (PG&E) > Data Field 54 (CAISO)
  - EX138981 Pittsburg-Kirker 115kV Line Section Limiting Elements Upgrade
    - PG&E forecast of $2M exceeds CAISO estimate of $0.2M due to the forecast being a placeholder factoring in risk.
    - Forecast is pending scoping of limiting elements.
    - Project forecasts will be updated once PMs assigned and project kicks off
  - T.0010604 Jefferson-Stanford Cable Replacement
    - PM assigned project.
    - $42M exceeds CAISO estimate of $40M due to project team scoping and updating forecasts.
    - Current forecast is $37M.

2024-2025 CAISO TPP Projects

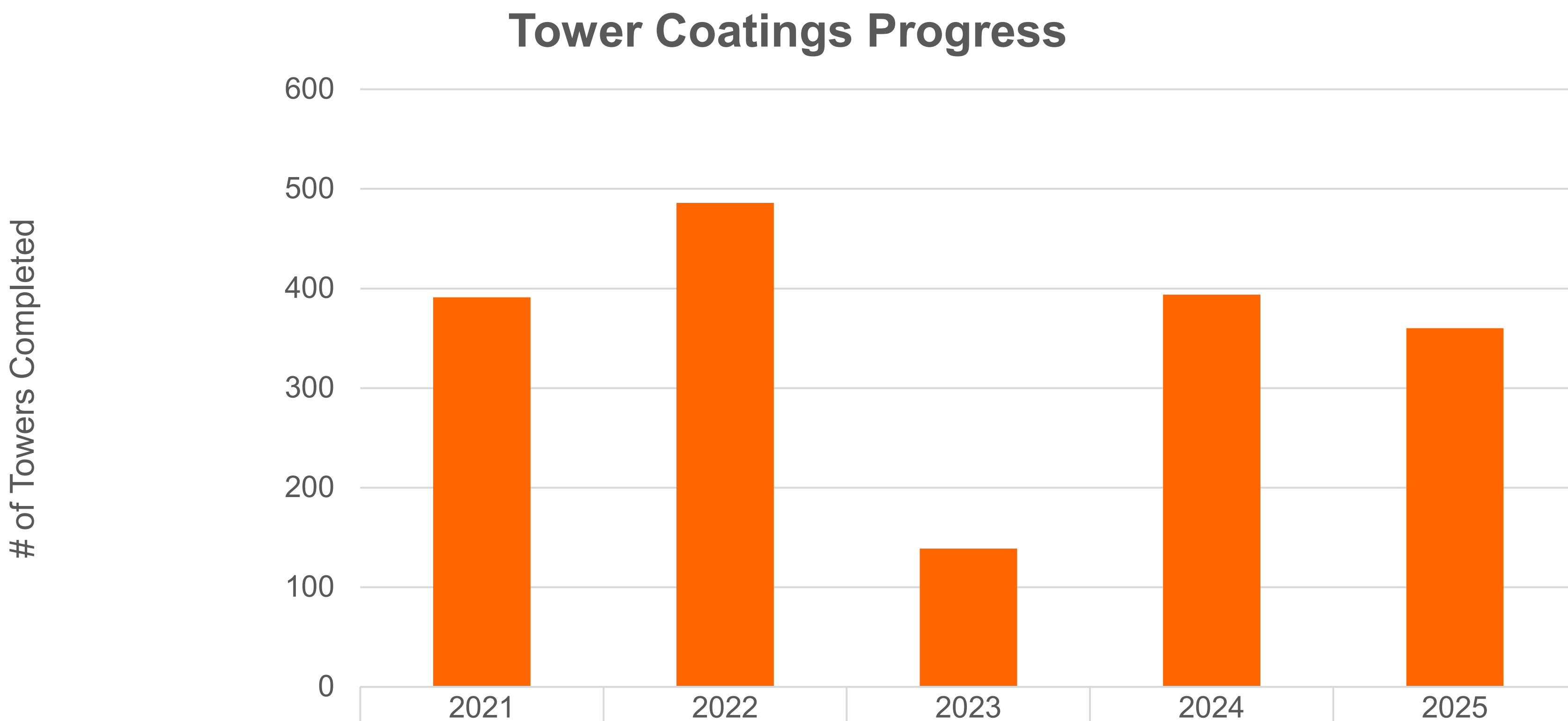
- Data Field 56 (PG&E) < Data Field 54 (CAISO)
  - Accounting in process of being set up at time of TPR pull
  - Forecast provided in Data Field 56 reflects initial funding to kick project off & is not representative of total project cost
  - EX113287 Placeholder Emergent Need in MWC 60/61 includes forecast that will eventually be allocated to these projects
  - Refer to Data Field 54 for total project cost at time of CAISO TP approval for Nov 2025 TPR pull
  - Cost estimates in CAISO TP are also at AACE Class 5
  - Project forecasts will be updated once PMs assigned and project kicks off
  - May 2026 TPR PS total project cost will be closer to that of CAISO approval

Tower Coating
Stakeholder Requested Item #15

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

Transmission Line Tower Insulation and Coating

Tower Coatings Progress



	2021	2022	2023	2024	2025
# of Towers Completed	391	486	139	394	360

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. Program received limited funding from investment plan thus reducing the execution scope for 2023.
4. 2025 YTD unit cost approx. $62.9K

Tower Coatings Work Plan (2026 – 2028)

	2026	2027	2028
# of Towers*	450	425	347

*Units may vary based on approved funding for 2026-2028 and based on draft investment plan

Program Challenges

- Prioritization of work
- Inclement weather in Q1 and Q4 historically impact execution of tower coatings.
- Delay of work due to safety stand downs
- Environmental constraints and Permit lead times
- Execution of tower coating in rice fields –timing constraints
- 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.

Lessons Learned

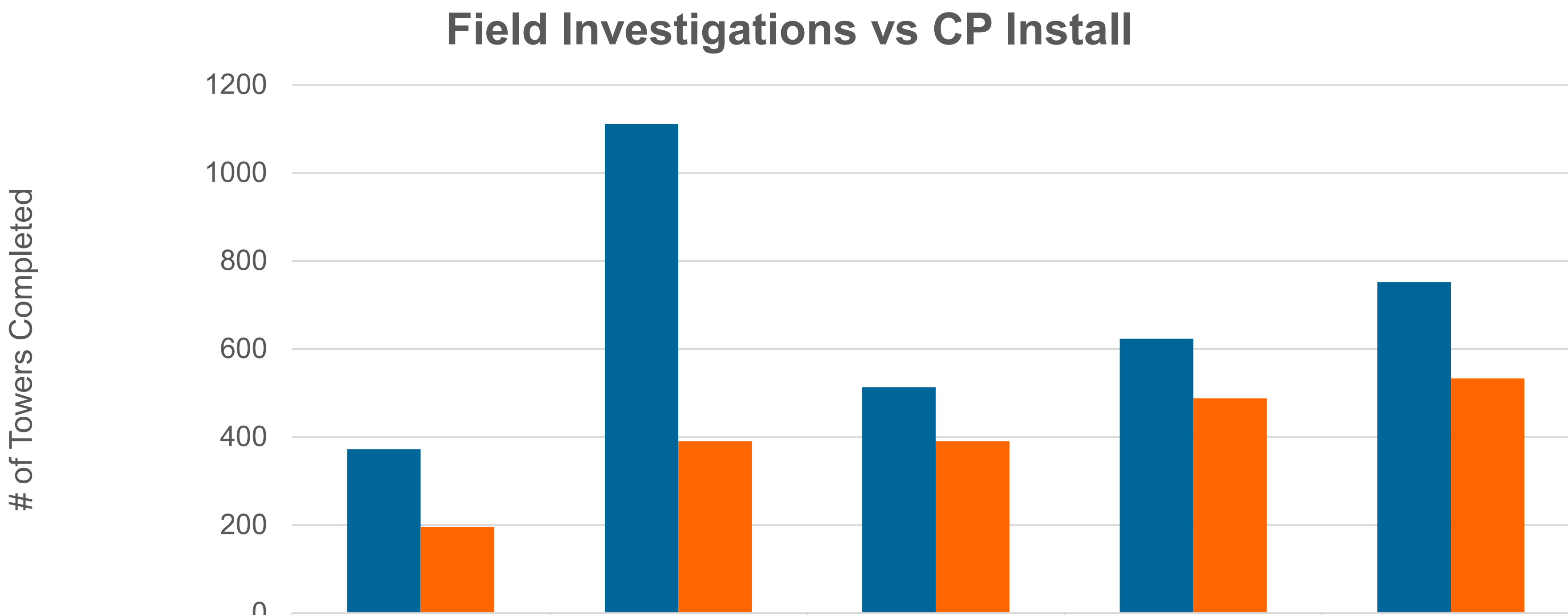
- Minimal towers planned in Q1 and Q4 due to inclement weather
- Special consideration in terms of schedule and coordination with farmers on towers located in rice fields
- Planning work kicking off earlier to accommodate long lead time for permits.
- Additional planning for any water towers due to time constraints and environmental constraints

Cathodic Protection
Stakeholder Requested Item #16

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

Transmission Line Tower Insulation and Coating

Cathodic Protection (CP) Progress



	2021	2022	2023	2024	2025
Field Investigations	372	1111	513	623	752
CP Install	196	390	390	488	533

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. 2025 YTD unit cost approx. $12.5K

CP Work Plan (2026 – 2028)

Year	Field Investigations	CP Installs
2026	677	483*
2027	525	500*
2028	525	500*

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

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
- Execution in rice fields –timing constraints
- Environmental constraints and Permit lead times

Additional CP Initiatives

- Please explain whether PG&E has a process to revisit whether additional cathodic protection initiatives are needed once the current program is completed.

- Operate & Maintain for the CP installed long term plan (expense work)
  - Annual CP testing program
  - Trouble shooting and corrective actions for testing results
  - Remote Monitoring pilot in 2026

Feedback and Discussion of Next Steps

Lorenzo Thompson, Nick Medina & Nicholas Hsiao

- *TPR Team*

Wrap Up

Lorenzo Thompson, Nick Medina & Nicholas Hsiao

- *TPR Team*

Closing Message

Renardo Wilson – *Chief, Regulatory Relations*

Appendix

Project Lifecycle Authorization Gates

New Stage 0 - Business Case

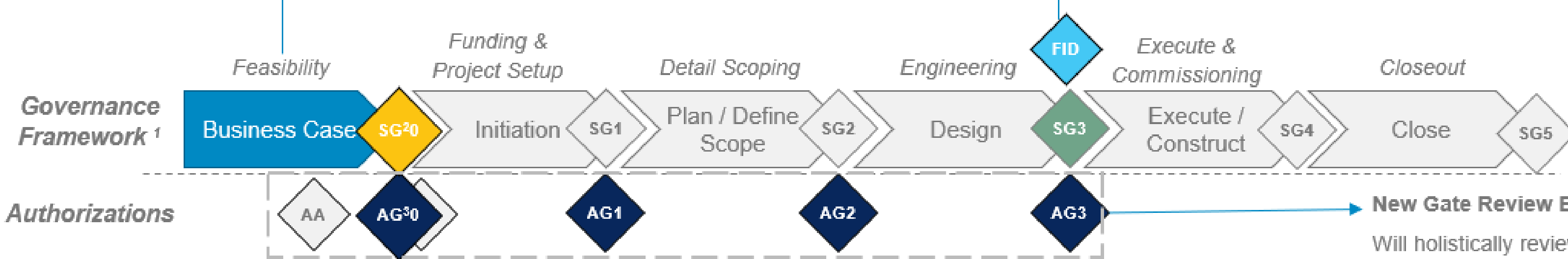
Feasibility to establish the need for a project and get it into BPD.

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.