Transmission Project Review Process
Stakeholder Meeting

July 30, 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

8:00	Welcome
8:05	PDS Summary Interpreting the Project Spreadsheet
8:15	Stakeholder requested items
10:15	Break
10:30	Stakeholder requested items
12:00	Lunch
12:45	Stakeholder requested items
3:10	Break
3:25	Stakeholder requested items
4:50	Wrap-up

May 2026 TPR Material

Lorenzo Thompson, Sakshi Naik & Nick Medina - *TPR Team*

TPR Process Calendar

PG&E TPR Process Schedule: May 2026 – October 2026 (UPDATED 7/2/26)

EVENT	DATE
Data released	May 1
Date by which Stakeholders provide questions and comments	June 15
Last written responses to Stakeholder questions and comments	July 7
Date by which Stakeholders and CPUC provide agenda items for upcoming Stakeholder meeting	July 14
Stakeholder Meeting	July 30*
Stakeholders' questions and comments related to Stakeholder Meeting	August 13
Last written responses to questions and comments related to Stakeholder Meeting	September 4
Last day for Stakeholders to submit project-specific, follow-up questions	September 11
Last written responses to Stakeholder project-specific follow-up questions	September 25
Last day for Stakeholders to submit comments. There is no expectation of written responses.	September 30

*The PG&E TPR Stakeholder Meeting has been rescheduled to this new date: July 30, 2026

You are here!

TPR Material Shared and Questions Submitted

- PG&E's May 1, 2026, 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 (2,671 projects pulled March 10, 2026)
  - 89 approval documents. 30 documents redacted in the public version
  - The most current version of PG&E's Prioritization Procedures

- Stakeholder questions received by June 15, 2026
  - CPUC (74+4=78)
  - NCPA (27)
  - BAMx (11)
  - Cal Advocates (5)

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

Interpreting the Project Spreadsheet

- PG&E does not plan to include CAISO's unique IDs for CAISO-approved projects into the TPR PS as there is no distinct field to provide that data.

- Please refer to Data Field 34 CAISO Year in the May 2026 TPR PS. This field identifies whether a project was CAISO approved or not. Furthermore, in Data Field 39 GIDAP Related, True identifies if it is a queue generation project and False (if a CAISO Year is populated) identifies if it is a TPP project.

- Please refer to Data Field 67 FERC Incentives in the May 2026 TPR PS for all projects that have had CWIP/Abandoned Plant Incentives granted by FERC

Interpreting the Project Spreadsheet

- Stakeholders can find transmission investments associated with large load interconnections by filtering on Data Field 10 Secondary Purpose “Load Interconnection” in the May 2026 TPR PS.
- Load Facility Type 1 projects are non-CAISO and out of scope for TPR
- Projects have NA for Original Planned In-Service Date if they are PG&E Approved projects that have not had an approved Project Charter yet.
- The forecast for an Investment Code is a placeholder and provides funding for the project to kickoff and order long lead materials if necessary. When this project is kicked off, POs will be created and forecasted with a total project cost close to that of the BC0

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 2026.

Annual Investment Planning Process

- New project governance standards require alignment between project forecasts/timelines and investment plans. When projects are actively moving forward, these changes are made during governance reviews.

- The investment planning process is an annual cycle in which project forecasts are refreshed and new projects are identified to support future planning. The plan is subsequently reviewed and refined throughout the year.
  - Nov 2025 TPR based on 2025 Investment Planning Process
  - May 2026 TPR based on 2025 Investment Planning Process
  - Nov 2026 TPR based on 2026 Investment Planning Process
  - May 2027 TPR based on 2026 Investment Planning Process

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

Peter Lee – *Sr. Manager, Risk Management*

Agenda Item

- What is PG&Es methodology that we submitted CBRs for? (subsection d)
- How should stakeholders interpret these values? (subsection b)
- What progress has been made in developing meaningful CBRs? (subsection a, c)
- What is the timeline, status and dependency in delivering these meaningful CBRs (subsection c, d)

TPR Methodology (Transmission Risk)

PG&E TPR methodology and whitepaper is specific to transmission overhead risk and project CBRs. This framework leverages

1. PG&Es prioritization models (TCM, WTRM) to establish baseline risk at a structure level (WF and Rel)

Total Tx Risk = PoF x Rel Conseq + PoF x PoI X WF Conseq

A	B	C	D	E	F	G	H
Project	Structure ID	TCM PoF	Reliability Consequence	**Reliability Risk (Column C x D)**	Wildfire Consequence	**Wildfire Risk (Column C x F)**	**Total Baseline Risk (Column E + G)**
Project 1	Structure 1	0.20	5	$1.0	20	$4.0	$5.0
Project 1	Structure 2	0.10	5	$0.5	0	$0.0	$0.5
Project 1	Structure 3	0.30	2	$0.6	5	$1.5	$2.1
Project 1 Total				$2.1		$5.5	$7.6
Project 2	Structure 4	0.50	2	$1.0	4	$2.0	$3.0
Project 2	Structure 5	0.10	2	$0.2	4	$0.4	$0.6
Project 2 Total				$1.2		$2.4	$3.6

2. Understanding of what structures are tied to a specific investments to define project baseline risk

Project Baseline Risk = Structure 1 (WF + Rel Risk) + Structure 2 (WF + Rel Risk)

3. CBRs accounting for the effectiveness of the measure and total risk reduction benefits over the life of the project

Formula: BCR = $$\frac{\sum_{year=1}^{55} NPV\ (Annual\ Risk\ Reduction)}{NPV\ (Total\ Project\ Cost)} = \frac{\sum_{year=1}^{55} NPV\ (Baseline\ Risk * Effectiveness)}{NPV\ (Total\ Project\ Cost)}$$

TPR Methodology (Transmission Risk)

Total Tx Risk = PoF x Rel Conseq + PoF x PoI X WF Conseq

PoF Reliability
- Defined by TCM

PoF Ignition
- Current no value.
- Workstream in-progress

Reliability Consequence
- Defined by OE Ranking (placeholder)
- This will be superseded by Tx Consequence workstream

WF Consequence
- Defined by WTRM

Risk Scaling
- Risk is scaled to enterprise risk score

Project Baseline Risk = Structure 1 (WF + Rel Risk) + Structure 2 (WF + Rel Risk) + ...

Project definition
- Projects defined by engineering and asset strategy
- For each project (Investment PO) is defined by specific structures
- These structures have an assigned risk in our asset level models

Data Gaps
- The streamlining of defining projects is a critical step in delivering timely CBRs requiring change management and management of change.

Formula: CBR = $\frac{\sum_{year=1}^{55} NPV\ (Annual\ Risk\ Reduction)}{NPV\ (Total\ Project\ Cost)} = \frac{\sum_{year=1}^{55} NPV\ (Baseline\ Risk * Effectiveness)}{NPV\ (Total\ Project\ Cost)}$

Other Modeling Assumptions

Risk Trajectory
- TCM PoF increases as assets age to reflect changing risk profile

Effectiveness:
- Based on TCM analysis that reset asset age for conductor and structure replacement by MAT code

NPV Risk and Cost:
- Benefits realized at project completion
- Cost are normalized into NPV dollars on when risk reduction is achieved and cost incurred

Value and Use of CBR

The current TPR methodology provides a baseline framework to directionally determine transmission project benefits, based on effectiveness and costs. CBRs have never been intended to be used as the sole decision point on how to prioritize investments. The current cost-benefit ratios remain appropriate for their intended purpose.

At the same time, we are continuing to improve the methodology to provide an even more targeted and useful representation of costs and benefits. This reflects normal program maturation and continuous improvement rather than a determination that the existing approach is incorrect

Refinements in current methodology

- Account for substation assets or protection devices
- Accounts for connectivity between asset failure and consequence
- Accounts for reliability consequence

Progress and Timelines

PG&E is making progress on its T&S model and has defined the project into 6 workstreams. More details are included on the following slides.

The model is scheduled to be completed by the end of the year and PG&E plans to use the outputs of the updated model to evaluate CBRs for T&S projects for its May 2027 TPR Submittal.

- PG&E plans to conduct a stakeholder CBR methodology meeting in Q2 of 2027, following the May 2027 TPR submittal. PG&E will provide a workpaper of the T&S methodology in advance of this meeting

Progress and Timelines

- **Workstream 1: Substation Asset-Level Modeling (On Target)**
  - PoF assessment of substation assets
  - Dependencies: Reasonableness of CBR model is dependent on appropriateness of PoF assessment.
- **Workstream 2: T&S Consequence of Failure (On Target)**
  - Consequence assessment for T&S asset failure
  - Dependencies: Reasonableness of CBR model is dependent on appropriateness of consequence assessment.
- **Workstream 3: Develop CBRs (On Target)**
  - Integrate PoF with CoF for specific projects

AFUDC Policies and Practices
Stakeholder Requested Item #3

Nikki Rose Apura – *Capital Advice*

George Kataoka – *Capital Recovery*

Kim Erdmann – *T&S Program Management*

Bhavana Jalote – *Project Management*

AFUDC Policies and Practices (1 of 4)

a) Please explain whether PG&E has placed any projects in "Deferred" or "SAP Status 21" status since December 2025. If not, please explain why not.

b) For POs/Work Orders subject to PG&E's "automated pause" process, please explain the basis for continuing to accrue AFUDC during the period before the suspension is triggered.

c) Please explain PG&E's policy basis for treating accounting adjustments as activity that resumes or resets the automatic AFUDC suspension trigger. Please include the types of accounting adjustments that qualify for this treatment, how PG&E determines that such adjustments are associated with eligible construction activity, and the controls in place to prevent non-construction or administrative accounting entries from extending AFUDC accrual.

<u>PG&E Responses</u>:

a) As of June 2026, PG&E only put 1 ET PO in SAP Deferred Status: PO 5800044 Panoche Sub: Install 230 kV breaker (5/7/26).

b) The basis for continuing to accrue AFUDC during the period before the automatic AFUDC suspension is triggered includes PG&E's AFUDC policies (i.e., SAP Deferral and Automated AFUDC Pause processes), benchmarking with other utilities (see subpart a.iv below), and alignment with FERC regulations, including the Uniform System of Accounts and FERC Accounting Release No. 5. (TPR-Process_DR_ED_022-Q007)

c) Accounting adjustments reflect necessary transactions on the capital work orders, such as costs for labor, materials, contract costs, and overhead construction costs. PG&E excludes transactions that should not trigger the unpausing of AFUDC (excluded: I. PG&E's PowerPlan system has been configured to ensure these charges do not trigger the pausing or unpausing of AFUDC. (TPR-Process_DR_ED_022-Q007)

AFUDC Policies and Practices (2 of 4)

d) Please explain how accounting adjustments that resume AFUDC for a project constitute a resumption of construction activities, how they correspond to meaningful construction activity, or how they advance the asset to its intended use.

e) Please explain how PG&E defines a substantive resumption of construction activities and the types of activities it considers substantive.

f) Please explain how PG&E's policy of continuing AFUDC until the automatic pause is triggered after six consecutive months is consistent with Accounting Standards Codes 835-20-25-3 and 835-20-25-4. Please include how PG&E determines whether activities necessary to prepare the asset for its intended use are ongoing, temporarily interrupted, or intentionally deferred during the six-month period prior to AFUDC suspension.

<u>PG&E Responses</u>:

d) Accounting adjustments can reflect all types of non-removal capital expenditures, including labor, materials, contract costs, and overhead construction costs. Such costs represent necessary costs for the assets to become used and useful. (TPR-Process_DR_ED_022-Q007)

e) PG&E's policy is aligned with FERC Accounting Release No. 5 and focuses on whether activities necessary for its intended use are in progress. FERC Accounting Release No. 5 expressly states that such activities should be construed broadly. As such, PG&E does not utilize the definition of “substantive". AFUDC begins accruing again when a qualifying direct charge or accounting adjustment is recorded to the capital order. Examples of qualifying direct charges include labor, materials, and contract costs. (TPR-Process_DR_ED_022-Q007)

f) PG&E's AFUDC policy is consistent with ASC 835-20-25-3 and ASC 835-20-25-4 as AFUDC that accrues is directly related to construction activities that remain active, and AFUDC is suspended when projects exhibit sustained inactivity or meet the criteria for formal deferred status. PG&E does not treat every temporary slowdown, reprioritization, or scheduling delay as evidence that construction activities have ceased. Instead, PG&E distinguishes between (1) temporary interruptions during normal construction process and (2) projects experiencing extended interruptions that warrant suspension of AFUDC. The six-month automated pause process and the separate SAP deferred status requirements are the controls that PG&E uses to make those distinctions. (TPR-Process_DR_ED_022-Q008)

AFUDC Policies and Practices (3 of 4)

g) PG&E indicated in response to Data Request TPR-Process_ED_017-Q004, subpart e, that "demobilization, remobilizations, and escalation costs are included in total project costs for reprioritized and delayed projects…" and that they are "necessary to safely and effectively pause and resume a project." Please explain in detail the decision leading to the need for demobilization and remobilization of the projects shown in the May 2026 TPR PS that began construction in 2020 or 2021 and were subsequently paused, including whether the decision to pause the construction stemmed from a management-initiated decision or a condition that was externally imposed.

h) Please explain PG&E's process for determining if a project that has been subject to the automated pause or "deferred" will proceed to completion or be cancelled.

<u>PG&E Responses</u>:

g) Please refer to TPR-Process_DR_ED_022-Q009

h) As a part of PG&E's annual investment planning process, projects in deferred or on automated pause are reassessed to ensure they are still needed. Once the planning process has determined the viability of the project, the functional area will be responsible to either continue with the deferral, restart the paused/deferred project or process the cancellation.

AFUDC Policies and Practices (4 of 4)

i) T.0000590 – Hunters Point Substation is now delayed to 2039. Please explain what value the $35.3 million in capital expenditures to date will have to a project that is not planned to be in service for another 13 years.

PG&E Responses:

i) The Hunters Point Substation project has been restarted from hold status, and the ultimate in-service date will be reevaluated as the project scope is aligned with current Transmission Planning needs.

The capital expenditures incurred to date have advanced critical project development activities, including engineering design, geotechnical investigations, environmental and land studies, community outreach, permitting efforts, and material procurement. This work establishes the technical, environmental, regulatory, and stakeholder foundations needed to support future project execution and will reduce redevelopment effort as the project scope and schedule are refined.

California High-Speed Rail Project Update
(T.0000005 and T.0000006)
Stakeholder Requested Item #10

Paul Krum – *Large Load Program Management*

High Speed Rail Update

- PG&E is working on revised technical studies to assess the impact and upgrades required to support the California High-Speed Rail project based upon the updated applications received in December of 2025. Preliminary results have been shared with California High-Speed Rail and the final study reports are expected to be provided by the end of the year

- Given the California High Speed Rail project is still at the technical 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.

Load Interconnection Processes
Stakeholder Requested Item #11

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

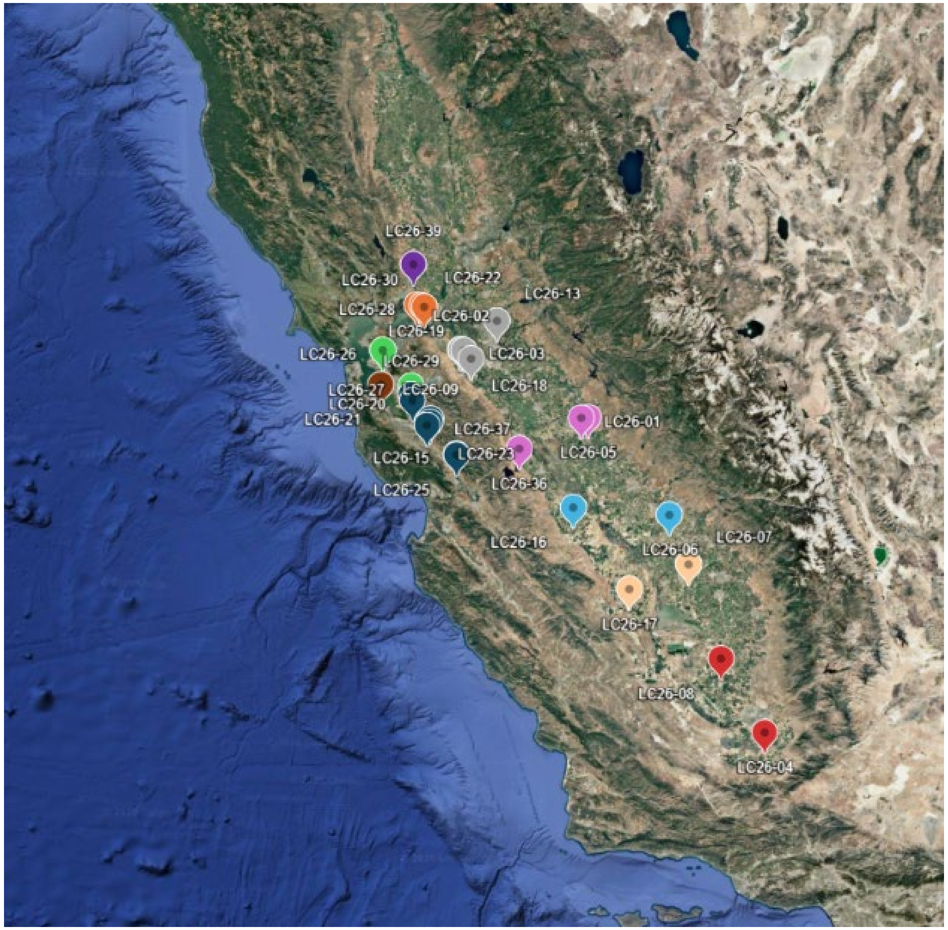
Rule 30 – Application Updates

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 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.
- **On February 13, 2026,** PG&E filed supplemental testimony to address three issues: revised minimum demand methodology, revised applicant build terms, and revisions to the proposed Rule 30 Form Agreement.
- **On April 6, 2026,** PG&E filed rebuttal testimony to address the ALJ's questions on several topics.
- **On April 14, 2026**, PG&E filed an errata to its April 6, 2026, rebuttal testimony.

Large Load Map

- Please provide a map showing the expected new load interconnection projects by "Load Interconnection Facility Type. "



- This map identifies the location of the 28 transmission applications participating in the 2026 Load Cluster Study

- Facility types associated with each application have not been fully scoped

Large Load Cost Allocation Methodology

Please provide PG&E's current process or methodology for determining electric transmission ratepayer cost responsibility and interconnection customer cost responsibility for large load interconnections and describe how this process may change under the Rule 30 Application.

PG&E's Current Process:

- PG&E conducts a Preliminary Engineering Study (PES) to identify the interconnection facilities and system upgrades required to interconnect a large load customer and provide full capacity.
- Based on the results of the PES, PG&E determines preliminary cost responsibility for required facilities and upgrades by applying existing Commission-approved Electric Rules and tariffs, while also considering cost responsibility principles proposed in the ongoing Electric Rule 30 proceeding where appropriate.
- The preliminary cost responsibilities are documented in the PES report and further refined through discussions with the interconnection customer.
- PG&E and the customer execute one or more construction agreements that specify the scope of work and the associated cost responsibilities.
- Because certain large load interconnections may not fit within the framework of existing Commission-approved tariffs and rules, PG&E currently files a Tier 3 Advice Letter with the California Public Utilities Commission (CPUC) requesting approval of the construction agreement(s) as an exceptional case when deviations from existing rules are required.
- The CPUC reviews the filing and may approve, modify, or reject the proposed cost responsibility treatment.

Large Load Cost Allocation Methodology

Please provide PG&E's current process or methodology for determining electric transmission ratepayer cost responsibility and interconnection customer cost responsibility for large load interconnections and describe how this process may change under the Rule 30 Application.

Expected Process Under Rule 30:

- If the CPUC adopts PG&E's proposed Electric Rule 30 framework, the methodology for determining transmission ratepayer and interconnection customer cost responsibility would be governed directly by the provisions of Rule 30.

- PG&E would continue to perform engineering studies to identify required facilities and upgrades; however, cost responsibility would be assigned pursuant to the approved Rule 30 provisions rather than through exceptional case treatment.

- As a result, PG&E anticipates that Tier 3 Advice Letter filings seeking approval of customer-specific cost responsibility arrangements that deviate from existing electric rules would generally no longer be necessary, as the Rule 30 framework would provide a standardized tariff-based process for allocating costs.

Upfront Financing

- The Interconnection is the Private Load Interconnection project (MWC 82) that the customer finances 100% upfront.
- The Capacity Upgrade is CAISO Concurred capacity project (MWC 60/61) that PG&E finances 100% upfront.

CAISO 2025-2026 Transmission Plan		TPR Column 27	TPR Column 26	
Project	**Interconnection Scope and Capacity Upgrade**	**Utility Unique ID #2 (Less Specific)**	**Utility Unique ID #1 (Most Specific)**	**Upfront Financing (Yes/No)**
LC24-2	**Interconnection:** • Add (1) 115 kV circuit breaker at Lockheed #1 Substation and associated 115 kV service line	5813904	T.0010873	Yes
	Capacity Upgrade: Lockheed loop project • Convert Lockheed 115 kV double tap to Lockheed loop configuration • Reconductor Lockheed #1 and #2 115 kV taps • Remove substation limiting elements and upgrade protection	5816523/ 5816522/ 5816521	T.0011626	No

Docket EL26-71

- Stakeholder Requested Item: Please describe the key elements of PG&E's response to FERC's Order to Show Cause in Docket EL26-71 on large load interconnection.

- Response: PG&E is working diligently internally and with external stakeholders, including the CAISO, to fully respond by FERC's deadline(s). We are not in a position to preview that filing at this time.

Betterment
Stakeholder Requested Item #21

Art McAuley – *Reg Tariffs & Advice Ltrs*

Betterment

- Please explain how PG&E considers betterment when scoping projects.
  - The term "Betterment" is used and defined in Electric Rule 15.
  - The concept of Betterment as related to transmission service falls under the pending Rule 30 tariff, which is pending resolution at the CPUC.
  - PG&E is unable to provide further information on Betterment until the Rule 30 proceeding is resolved.

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

Jamie Salazer – *T-Line Asset Strategy*

Wood-to-Steel/FRP 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) or Fiber-Reinforced Polymer (FRP) poles, we have replaced the following:

Year	Approximate Count	Average cost per pole
2021	2,199	$ 70,968
2022	2,098	$ 78,539
2023	2,494	$ 87,888
2024	1,693	$ 93,127
2025	1,431	$ 104,974
2026 YTD*	581	$ 92,997

*Note all tags have been mapped in our system and are not reflected in this count. Average cost may change by end year.

- 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 (FRP)

Shunt Splice Replacement Program
Stakeholder Requested Item #17

Chandini Prasad – *T-Line Asset Strategy*

Saveesna Baskaran – *Interim Program Manager*

Douglass Qualls – *WMP Program Manager*

Shunt Splice Program

Please provide a summary of the work completed to date, along with average cost per tower, estimated per tower field inspection cost, and issues encountered.

- Work Completed to date: 846 splices shunted YTD (2026)
- Average Cost per structure: $12,276
- Estimated per structure field inspection cost: $1,300
- Issues Encountered: Minimal. Access issues to the splice, clearance, outage windows

Shunt Splice Program

Please provide the workplan for 2026, 2027, and 2028 and explain why PG&E reduced its shunt splice replacement work in 2025.

- Workplan:

Year	WMP Shunt Splice Target
2025	25 circuits
2026	250 splices
2027	250 splices
2028	250 splices

Please provide the workplan for 2026, 2027, and 2028 and explain why PG&E reduced its shunt splice replacement work in 2025 (contd...)

- Targets were redefined, moving from # of circuits to # of splices:
  - Brings us in line with other Investor-Owned Utilities
  - Reduces the risk of confusion – citing # of circuits could wrongly suggest that shunts are installed on every splice across the entire line, whereas the work is often focused on select splices instead.

Shunt Splice Program

Please explain whether any of the shunt splice replacements recently added or that will be added in the next five years will be replaced as part of known planned reconductoring projects

- 2026:
  - Colgate-Challenge (ETL.6480) has a reconductoring project (T.0005895) but its status is deferred.
  - Hat Creek #1 – Westwood (ETL.7030) has a conductor segment replacement project (T.0009921) with FISD on 12/31/2027.

- 2027 & beyond:
  - Scope to be determined.
  - The shunt splice program scope is created on an annual basis.

Back at 10:30

BREAK

Material Supply Chain Overview

Demand
Growing infrastructure development

Lead Times extending
2–4year lead time

Costs increasing
Higher initial costs

Stringent regulations

Risk Mitigation

- Long Term Supplier Contracts
- Diversifying Supplier Pool by finding new sources
- Strengthening Supplier Relationships
- Increasing Strategic Inventory Levels

Power Transformer Market & Strategic Initiatives

Summary

Power transformers are critical grid assets ranging from 2 MVA to 420 MVA. PG&E's transmission-class transformers (115 kV to 500 kV) support long-distance bulk power delivery, while distribution-class transformers (60 kV to 230 kV) reduce voltage for commercial, industrial, agricultural, and residential customers.

Transformer procurement and manufacturing involve a complex, multi-year process that includes supplier qualification, competitive sourcing, procurement of specialized raw materials and components, and coordination of heavy-haul transportation due to the size and weight of the equipment.

Key Market Observations

- Global demand for power transformers continues to exceed available manufacturing capacity, driven by infrastructure replacement, grid expansion, renewable energy integration, electrification, data center growth, and increasing industrial load.
- Industry lead times have expanded from approximately one year to as much as two to four years, with strong demand expected to persist throughout the next decade.
- Transformer pricing has increased significantly due to sustained demand, inflationary pressures, and higher costs for raw materials and critical components.
- Available factory capacity can be reserved quickly, limiting supplier participation in competitive solicitations and reducing the number of proposals received.

Strategic Initiatives

- PG&E continues to diversify and expand its supplier base to improve supply resiliency and mitigate long lead times. The company is actively evaluating new manufacturers, with six emerging suppliers currently participating in pilot programs.
- To support future system needs, PG&E plans to competitively source approximately 120 power transformers through a bundled procurement strategy designed to secure production capacity and address forecasted demand.
- PG&E is collaborating with key suppliers to establish long-term production slot agreements, providing additional flexibility to meet needs that may arise beyond the current five-year planning horizon.

Circuit Breakers Market and Strategic Initiatives

Summary

Circuit Breakers are used to aid interrupting the current flow of electricity and prevent damage brough about by short circuit or overcurrent. Circuit breakers are critical to any electric distribution networks. Circuit breakers have a longer lead time of about 150 weeks, which requires PG&E to forecast its demand 2-3 years out in advance of circuit breakers. CARB regulations are also requiring specific circuit breaks to be Sulfur Hexaflouride (SF6) free. PG&E uses circuit breakers with voltage from 72.5 kV to 500 kV. Circuit breakers have one approved vendor, 3 conditionally approved vendors, and one approved in development.

Key Market Observations

- Circuit Breakers are a $10.4B market that is projected to grow 8.5% - 10% by 2031; the top consumer and manufacturer of circuit breakers are within the Asia Pacific region[1]
- Grid modernization is needed now more than ever to 1) extend networks into remote regions and 2) create SF6 free products that align with CARB regulations[2]
- Under current administration, Section 232 creates a 35%-50% tariff on steel, aluminum and copper – all important raw materials that are imported for circuit breakers[3]

Strategic Initiatives

- PG&E is focusing on strengthening supplier relationships through long term contracts and committing future slots to preferred suppliers to increase visibility from both sides
- When possible, circuit breaker category leads work with other long lead time category leads (ex. transformers, STATCOM) to propose a bundled pricing to suppliers to create cost savings
- With the help of engineering, circuit breakers have standardized specifications to ensure customizations are low and the circuit breakers are easy to maintain for the front line

1. Beroe Analysis – Circuit Breakers April 2026
2. Sulfur Hexaflouride Basics from the US Environmental Protection Agency
3. FAQ of Section 232 Tariffs from the U.S. Customs and Border Protection

Tariff Environment: Cost Pressure and Uncertainty Managed Through Proactive Procurement

MARKET DRIVERS		POTENTIAL IMPACTS		PG&E RESPONSE
Expanded tariff coverage on steel, aluminum, copper and transformer-core steel Evolving trade policies and supplier sourcing adjustments Ongoing uncertainty regarding tariff applicability and pass-through practices	→	Inflationary pressure on transformers, switchgear, circuit breakers and substation equipment Indirect cost impacts from domestic suppliers using imported inputs Pricing volatility and commercial uncertainty	→	Long-term supplier agreements to secure capacity Supplier diversification and qualification of new manufacturers Competitive sourcing, bundled buys and advance procurement

KEY MESSAGE: Tariffs continue to create inflationary pressure and uncertainty across utility supply chains. While exact impacts remain dependent on evolving trade policy and supplier actions, PG&E is actively mitigating risk through strategic sourcing, supplier diversification, and long-term procurement planning.

OBS Advanced Procurement

- Please provide an update on PG&E's advance procurement of transformers and circuit breakers, both for emergency inventory and known projects. Please include quantities ordered, estimated delivery timelines and the process for transferring any charges from the "other balance sheet" (OBS) to actual planning orders. Please identify any associated Planning Orders to which these costs are or will be recorded.

Type	2025	2026	2027	2028	2029	2030	Grand Total
Circuit Breakers	10	26	15	4	2		57
Transformers	2	18	46	34	2	3	105
Grand Total	**12**	**44**	**61**	**38**	**4**	**3**	**162**

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 7/27/26
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.

Spare Equipment Ratemaking

Q: Please explain how “spare” equipment is treated from a ratemaking perspective. For example, if a spare transformer is ordered, is it added to inventory and reserved for future use or is it treated as a new capital addition, even though it has not been placed in service.

PG&E Response:

- In general, spare equipment (with exception to CEM) is initially included in Materials and Supplies Inventory balances, which are included in rate base within TO21 Formula Model, Schedule 13 (Working Capital).
  - Once equipment is taken from a warehouse or distribution center to be used for a project, the original costs are included in the respective capital or expense work order and the same amount is reduced from the Materials and Supplies balance.
  - Equipment used in capital work orders are only included as capital additions once the project is operative or if set up as operative-as-installed work.
- Separately, PG&E procures Capitalized Emergency Materials (CEM) to aid in emergency work and critical events. These capital expenditures are recorded directly to a capital order supporting the specific emergency work.
  - These costs are not recorded to Materials and Supplies balances.

Generator Interconnection Network Upgrades and CAISO TPP Reliability and Policy-Driven Projects Through CAISO 2025-2026 TPP Stakeholder Requested Item #20

David Corzilius – *Contract Specialist*

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

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

Total Proj Count and Gen Amounts (MW) by Interconnection Phase		
Phase	**Proj Count**	**Gen Amt (MW)**
Study in Progress	54	14,050
Parked	0	0
IA in Progress	5	509
Implementation (includes Suspended projects)	92	19,766
In Service	8	931
Commercial	50	5,918
Totals	**209**	**41,173**

Project Counts by Interconnection Phase and Generator Type
(Projects >= 1 MW, Connecting to PG&E Transmission System)

Generator Type	Study In Progress	Parked	IA In Progress	Implementation +Suspended	In Service	Commercial	Totals / Gen Type
Cogeneration					1		**1**
Energy Storage	22		1	32	1	15	**71**
Engine	1			1			**2**
Hybrid: Engine / Energy Storage				1			**1**
Hybrid: Hydroelectic / Pumped Storage							**0**
Hybrid: Solar PV / Energy Storage	24		2	39	3	17	**85**
Hybrid: Solar PV / Wind / Energy Storage				1			**1**
Hybrid: Solar Thermal / Energy Storage							**0**
Hybrid: Synchronous Engine / Energy Storage							**0**
Hybrid: Turbine / Energy Storage				4			**4**
Hybrid: Wind / Energy Storage				3	1		**4**
Hybrid: Wind / Solar PV / Energy Storage							**0**
Hydroelectric	1			1			**2**
Solar PV	3			4		13	**20**
Synchronous Engine						1	**1**
Turbine	2					2	**4**
Wind	1		2	6	2	2	**13**
Totals	**54**	**0**	**5**	**92**	**8**	**50**	**209**

Gen Amounts (MW) by Interconnection Phase and Gen Type
(Projects >= 1 MW, Connecting to PG&E Transmission System)

Generator Type	Study In Progress	Parked	IA In Progress	Implementation +Suspended	In Service	Commercial	Totals / Gen Type
Cogeneration					10		**10**
Energy Storage	4,932		28	7,802	10	2,037	**14,809**
Engine	35			20			**55**
Hybrid: Engine / Energy Storage				120			**120**
Hybrid: Hydroelectic / Pumped Storage							**-**
Hybrid: Solar PV / Energy Storage	8,190		290	7,741	640	2,243	**19,105**
Hybrid: Solar PV / Wind / Energy Storage				400			**400**
Hybrid: Solar Thermal / Energy Storage							**-**
Hybrid: Synchronous Engine / Energy Stora							**-**
Hybrid: Turbine / Energy Storage				390			**390**
Hybrid: Wind / Energy Storage				1,616	104		**1,720**
Hybrid: Wind / Solar PV / Energy Storage							**-**
Hydroelectric	5			5			**10**
Solar PV	718			415		1,449	**2,581**
Synchronous Engine						18	**18**
Turbine	65					26	**91**
Wind	105		191	1,257	167	145	**1,865**
Totals	**14,050**	**-**	**509**	**19,766**	**931**	**5,918**	**41,173**

Generation Interconnection Projects in the CAISO Transmission Development Forum (TDF)

- The TDF Network Upgrade (NU) workbook & TPR PS 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

2025-2026 CAISO TPP Projects

- CAISO 2025-2026 Transmission Plan
  - All newly approved projects will be included in November 2026 TPR PS as unique POs or Investment Codes

Circuit Breaker Replacement vs. Uprating
Stakeholder Requested Item #13

Alex Wernli – *Manager, Substation Asset Strategy*

Circuit Breaker Replacement vs. Uprating

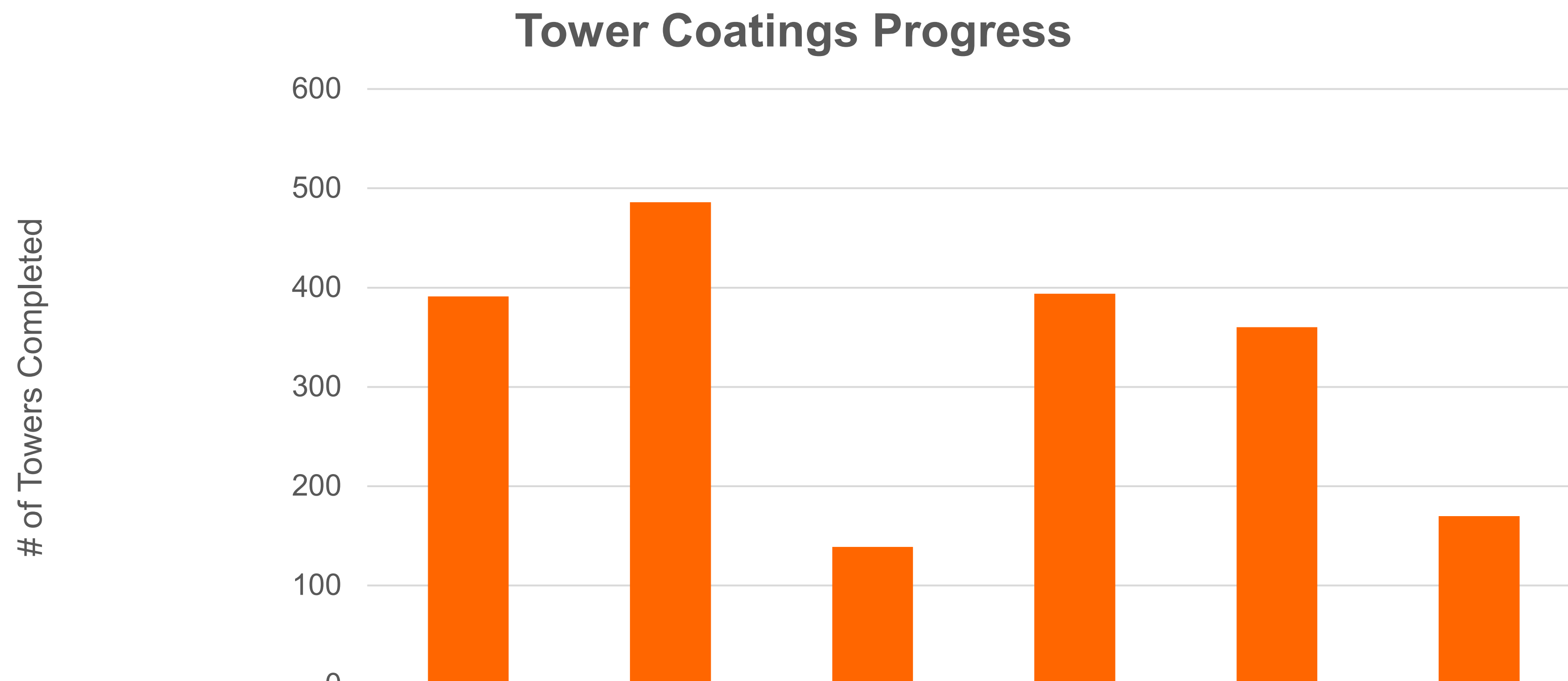
- Uprating can be to increase the circuit breaker interrupting current, IC rating. It can be to increase the continuous current, CC, rating.
- Depending on project needs this can be accomplished by replacement of the circuit breaker interrupter, mechanism, and bushings.
- Circuit breaker uprating evaluation is performed on a project-by-project basis during scoping (PG&E has no program to uprate circuit breakers). Several factors like CB health, manufacturer, CT thermal rating factors all determine if CB is a good candidate for uprating instead of replacement.
- A circuit breaker uprating tends to be cheaper, and quicker turnaround than a full circuit breaker replacement.
  - No change in foundations, conduits, bus work, etc.
  - No long construction clearances. Breaker is uprated in place.
  - Lead times tend to be much shorter than compared to full circuit breaker replacement.

Tower Coating
Stakeholder Requested Item #15

Shivani Nigam *(Program Manager)*, Sean Clesen, and Nick Narup

Transmission Line Tower Insulation and Coating

Tower Coatings Progress



	2021	2022	2023	2024	2025	2026
# of Towers Completed	391	486	139	394	360	170

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. 2026 YTD unit cost approx. $71.1K

**2026 YTD June units shown in the graph.*

Tower Coatings Work Plan (2027 – 2029)

	2027	2028	2029
# of Towers*	425	347	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

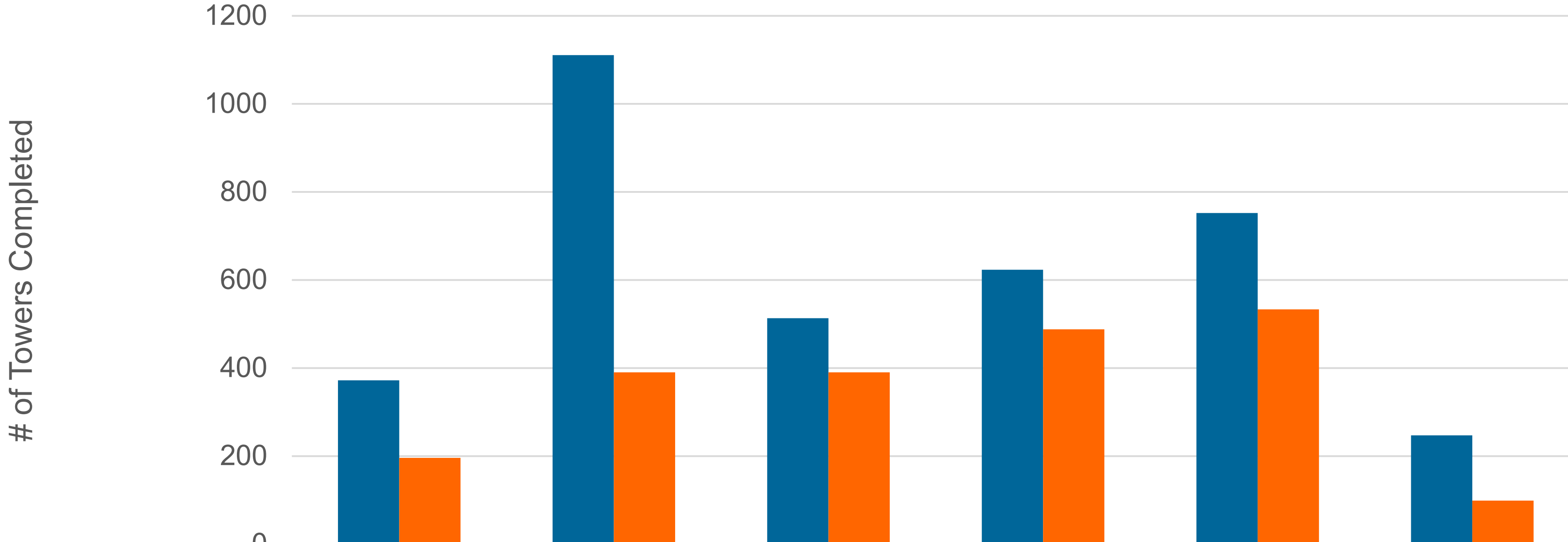
Cathodic Protection
Stakeholder Requested Item #16

Shivani Nigam *(Program Manager)*, Sean Clesen, and Nick Narup

Transmission Line Tower Insulation and Coating

Cathodic Protection (CP) Progress

Field Investigations vs CP Install



	2021	2022	2023	2024	2025	2026
Field Investigations	372	1111	513	623	752	247
CP Install	196	390	390	488	533	99

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. 2026 YTD unit cost approx. $15.5K

**2026 YTD June units shown in the graph.*

CP Work Plan (2027 – 2029)

Year	Field Investigations	CP Installs
2027	525	500*
2028	525	500*
2029	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

Project Delays
Stakeholder Requested Item #12

Andre Williams – *Project Manager*

June Yu – *Project Manager*

Rich Neumann– *Digital Substation Program Manager*

T.0003456 – Tesla 230kV MPAC

- Project Status: Construction
- Costs
  - Inception to Date: $31M
  - Estimate at Completion: $135M
- Milestones
  - Kickoff: 6/12/20
  - Engineering Start: 6/15/20
  - Engineering End: 2/22/26
  - Construction Start: 12/10/25
  - FISD: 10/24/30
- Scope Delays:
  - During the kickoff and walkdown the project team primarily focused on all 230kV breakers there are associated with the Bus. During detailed design, the engineering team identified conflicts with the 230kV transformer banks and the 115kV transformer banks.
  - While the relays for these transformers are not installed in the new MPAC buildings, the equipment is tied to the 230kV Bus therefore additional circuits needed to be connected to and tied into the equipment.
  - Upon further investigation during detailed design our internal protection team suggested that the relays for this equipment should be replaced to better align with and communicated with the relays that are being installed in the MPAC Buildings.
  - This deign change required a project scope change that included the installation of new relay for 500kV Banks 2, 4, & 6 as well led to a significant delay in the project design phases.

- MPAC Program Funding: Project is approved to be fully funded. Only part of the project shows as funded in the TPR PS. The expectation is that this project is to proceed to meet the current in-service date and funding to be allocated annually via the Investment Planning Process.

T.0011178 – Monta Vista: Install 115kV MPAC

- Project Status: Planning
- Costs*
  - Inception to Date: $0.4M
  - Estimate at Completion: $40M
- Milestones*
  - Kickoff: 8/21/25
  - Engineering Start: 11/2/26
  - Engineering End: 11/8/26
  - Construction Start: 5/15/28
  - FISD: 6/1/29

- Project Justification: Project scope is not complete. Monta Vista Substation in Cupertino is a critical substation that provides power to Silicon Valley as well as the San Francisco Peninsula. The driver of the Monta Vista 115 kV and 60 kV MPAC replacement project is to proactively replacing the aging legacy relaying assets to address the escalated protection failures and deficiencies on the 115 kV and 60 kV system that has reduced the reliability of the station. This includes upgrades of impacted equipment at all interconnected substations at the remote-end of Monta Vista substation. This project will improve system reliability and grid resilience.

*Note this project is still in the early stages of development. Scope is not complete. All details provided are estimates and will change as project progresses

Why Digital Substation?

- Context: Today, PG&E provides Protection, Automation, and Control (PAC) at substations via the Sustainable Modular Protection (SMP) standard. SMP currently provides safe and effective PAC. However, deploying this PAC standard is costly and time consuming. Once deployed, SMP is difficult to maintain.
- Challenge: With the forecast increase in grid demand and associated need to expand substation capacity, PG&E must develop a strategy to deploy substation PAC more rapidly, more cost effectively, and more maintainable than our current SMP PAC standard allows.
- To meet this challenge: PG&E will proactively transition PAC standard to state-of-the-art Digital Substation (DSS) technology based upon the IEC 61850 standard.

Benefits of Digital Substation:

Deploying PAC to the IEC 61850 standard will:

- Reduce construction costs (e.g. reduction in copper wiring and control enclosure footprint)
- Reduce cycle time associated with design, installation, and commissioning of PAC systems
- Improve scalability when implementing expansion to existing PAC schemes
- Enhanced interoperability and cybersecurity of PAC schemes
- Predictive maintenance rather than fixed intervals through continuous monitoring

Deployment Strategy:

Transitioning from current PAC to Digital Substation is complex. Protection and control of our substations is critical. There can be zero tolerance for Protection Systems failure. To assure an effective transition from current PAC standard to Digital Substation PG&E will:

- Phase 1: Develop laboratory to understand the IEC 61850 standard and how it should be applied to PG&E's substations. Lab activated Q4, 2025.
- Phase 2: Deploy IEC 61850 PAC at two proof-of-concept substations (French Camp and Jarvis) to inform PG&E's new DSS standard.
- Phase 3: Change management
  - Update roles and responsibilities to reflect DSS requirements
  - Create intro and role specific training materials, train impacted stakeholders
  - Create training infrastructure and curriculum supporting hands-on stakeholder instruction
- Deploy
  - Publish DSS Standard including guidance of when to leverage IEC 61850
  - Begin transition period (deployment at scale.) Targeted for 2028.

Affect on MPAC:

As the Digital Substation program progresses through the three phases described on the previous slide, there will be no change to the MPAC program. For those MPAC projects that will enter their scoping phase in 2028 and beyond, the project team will begin transitioning the PAC standard specified for the MPAC project from the current SMP standard to our new IEC 61850 PAC standard.

Digital Substation Active Projects:

From the Capital Projects perspective, the DSS program is currently in Phase 2 with active projects and forecasts as shown in the table below.

Planning Order	Scope	Expected Cost	Contingency	Total Forecast (Expected + Contingency)	Comments/Notes
5814821	Digital Sub Phase 2 – French Camp	$10,900,000	$1,000,000	$11,900,000	Scoping and schematic level design complete. Contingency ~10%
5814822	Digital Sub Phase 2 – Jarvis	$8,500,000	$3,500,000	$12,000,000	Scoping not complete, preliminary parametric estimate only (AACE class 4) ~40% contingency

“High Impact” Transmission Projects from 2026 SB 1174 Transmission System Assessment Stakeholder Requested Item 9

Raul Sanchez, *Project Manager*

Ali Ghonji, *Project Manager*

Arnaldi Rustandi, *Substation Asset Mgmt*

Darrin Yoxtheimer, *Principal*

T.0007056 – Borden-Gregg 230kV Lines 1 & 2 Reconduct Project

- Project Status: Construction
- Costs
  - Inception to Date: $6.45M
  - Estimate at Completion: $36.10M
- Milestones
  - Kickoff: 12/03/2018
  - Engineering Start: 04/03/2019
  - Engineering End: 09/25/2025
  - Construction Start: 1/20/2027
  - FISD: 07/2/2027
- Scope: Upgrade 795 ACSR with 958 ACCR conductor on 6.25-mile line section between Borden and Gregg Substations, install new 72 count OPGW and static wire on peaks, install 15 new Tubular Steel Poles within line section, expand easement width to 75 feet, and reroute both circuits from Avenue 11 to Borden Substation to support landowner's future development project.
- Land Rights/Acquisitions: 100% of land rights acquired.
- Challenges: Acquisition of land rights, material lead times, and finalizing Joint Utility Agreement with CA High Speed Rail.

T.0010881 – Tesla 230kV & 500kV Mitigation

- Project Status: Engineering
- Costs
  - Inception to Date: $0.5M
  - Estimate at Completion: TBD (pending final scope)
- Milestones
  - Kickoff: 11/13/2025
  - Engineering Start: Q2 2027
  - Engineering End: Q4 2028
  - Construction Start: Q2 2029
  - FISD: 04/18/2031
- Scope:
  - Expand Tesla Sub to a new yard north of the existing substation, within existing property. The initial build includes two (2) 500kV BAAH bay as new bus section E (ultimate 6 BAAH bays), one (1) 230kV BAAH Bay as new bus section F (ultimate up to 12 BAAH Bays, with 6 per section)
  - Install a 500/230kV transformer bank 7
  - Loop in the new 500kV bus section E into existing Vaca Dixon – Tesla 500kV line
  - Relocate Tesla – Tracy 230kV Line #2 from existing 230kV bus section D to new bus section F
  - Install a new MPAC building (300' control building) for 500 kV yard (6 bay ultimate)
- Challenges: Active Fault Zone (Midway fault) – see next slide for more details
- Permitting: Project will continue with permitting/environmental review once conceptual alternatives are available.

T.0010881 – Tesla 230kV & 500kV Mitigation

- **Question**: PG&E's notes on this project indicate that there is a "Seismic impact to expansion area" and that PG&E is "evaluating options". Please explain this issue and any impacts it may have on the proposed ISD for these projects? Additionally, what is the current permitting status for these projects and are there any known delays

- **Response**: The proposed substation site is intersected by the Midway fault in the Altamont Hills of California, with uncertainty about its exact location and potential ground displacement during earthquakes. The project team is currently working on alternative arrangements considering the fault issue, including both AIS and GIS options and cost comparison. Also, PG&E brought in a contractor (LCI) doing study on the fault line (in 2 phases).
  - Phase 1 Midway Fault Desktop Geologic Mapping Study identified a primary fault line crossing the property, with additional offshoots affecting usable space.
  - Phase 2 trenching is expected to:
    - Surface fault rupture trenching study to be performed on the Midway fault, in the Altamont Hills of California at key locations identified from Phase 1 results.
    - Refine fault boundaries
    - Potentially reduce setback zones
    - Improve usable area on the property (particularly west side)

T.0010881 – Tesla 230kV & 500kV Mitigation

- Project team continues developing AIS layout as primary path and maintains GIS as contingency if grading/seismic constraints become prohibitive

- As Project is waiting for Phase 2 results, project team is working on rough order-of-magnitude estimates (ROM) to support decision-making between AIS and GIS options

- Project will continue with permitting/environmental review once conceptual alternatives are available.

- The proposed ISD for the project is currently in 2031 with the likelihood it will be adjusted once the selection of the GIS versus AIS solution is decided given there are different timelines between those options.

T.0010880 – PITTSBURG 230KV BUS OVERSTRESS

- **Project Status:**
  - Initiating (Kickoff in May 2027)
  - Current ISD: 8/14/29
  - Original ISD: 3/31/30
  - Bundling Dependencies is not listed as Reason for Delay in May 2026 TPR

- **Scope:**
  - Install 230kV bus reactors between Bus D and Bus E to reduce fault duty and equipment overstress.

- **Project Driver:**
  - BESS (500 MW) interconnection to Tesla Substation
  - Interconnection studies identified that new generation projects will increase fault duty at Pittsburg 230kV

- **Costs:**
  - Inception to Date: $0.03M
  - Estimate at Completion: $26.8M

2026 SB1174

- SB1174 does identify Bundling Dependencies as a catch all for delays/constraints to schedules in the construction phases. This includes preconstruction, dependency alignments, and construction sequencing for phases of project work. PG&E mitigates delays to generation as much as possible by sequencing work components as early as possible impacting external commitments where it makes the most sense.
- SB1174 does identify Project Design as a key impact to delays for Generation. PG&E mitigates delays in design prioritization of assigning resources to the work, funding to advance the projects, and milestone development. Designs can be phased on projects to prioritize critical dependency work first. Scoping and design on complex projects tends to lengthen timelines of projects when PG&E coordinates the full impact of the work.
- Project Sponsors, Operations Management, Project Construction Groups, Tests / Inspections Groups, and Engineering / Protection groups all play a part of ensuring the right project phases are executed safely and prioritized accurately.
- PG&E utilizes customer required operative dates to determine when specific work is needed to be placed in service. PG&E is constantly monitoring and evaluating any changes in commitments to best prioritize projects. PG&E prioritizes first signed and ready operative dates to backfeed customers and then prioritizes capacity, reliability, and deliverability dependencies when there arises conflicts in priorities.

Back at 12:45

LUNCH BREAK

CWIP Rate Base Incentive Projects
Stakeholder Requested Item 4

Jason Castellanos, *Project Manager*

Eyob Embaye, *Project Manager, Sr Consulting*

Tim Criner, *Project Manager*

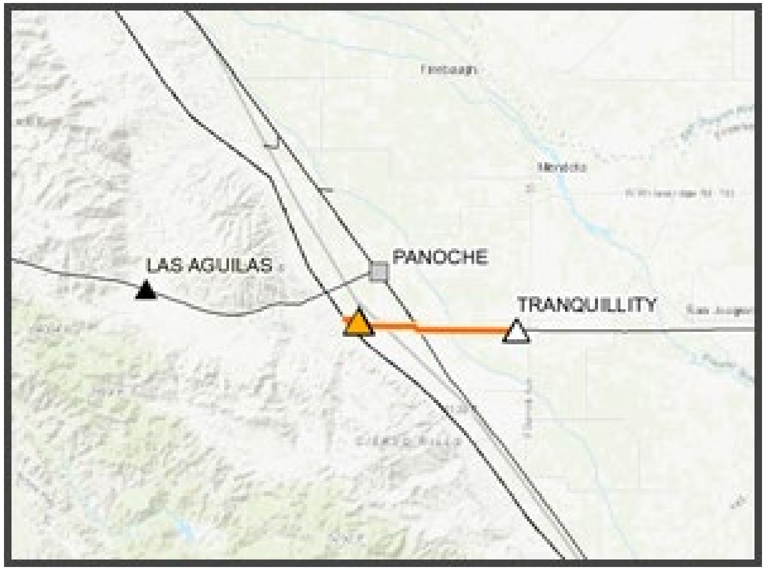
Margarethe Pena*, Project Manager*

Renardo Wilson*, Regulatory Relations Advocacy, Chief*

T.0009194 Manning New 500kV Sub Connection

- Project Status: Construction
- Costs
  - Inception to Date: $43M
  - Estimate at Completion: $265M
- Scope:
  - 3rd Party Scope:
    - Construct a new 500kV/230kV Substation.
    - Construct (2) new 230kV transmission lines between Manning Substation and Tranquillity Switching Station.
  - PG&E Scope:
    - Loop Los Banos-Gates #1 500kV line and Los Banos-Midway #2 500kV line into Manning Substation.
    - Loop (2) existing Panoche-Tranquillity 230kV lines into the new 500kV Manning substation, reconductor the (2) Manning-Tranquillity 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.
- Challenges:
  - Land acquisition and easement delays
  - Material delays

- Milestones
  - Kickoff: 7/31/23
  - Engineering Start: 8/1/23
  - Engineering End: 10/12/26
  - Construction Start: 3/30/26
  - FISD: 4/1/28



T.0009189 Loop Vaca Dixon-Tesla in Collinsville

- **Project Status:** Engineering/Design
- **Costs**
  - Inception to Date: $7.5M
  - Estimate at Completion: $115M
- **Project Scope:**

  - LS Power:

  - Install new 500kV substation in the town of Collinsville
  - Install two new 230kV lines from Collinsville to Pittsburg substations

  - PG&E:

  - Tap into existing 500kV line to loop in & out of the new Collinsville substation including installation of IT yard adjacent to substation
  - Replace remote end relays at Vaca Dixion & Tesla substations
  - Modify existing series capacitor bank at Vaca Dixion substation
  - Install two new 230kV line breaker positions & 115kV reactor at Pittsburg substation
- **Challenges/Risks:**

  - Permitting: CPUC approval is currently anticipated in Oct/Nov 2026. Approval delay could potentially jeopardize LS Power's planned construction in January 2027.

  - **Land Acquisition**: New substation location is not yet secured. LS Power is currently negotiating with landowner to purchase the property.

- **Milestones**
  - Kickoff: 7/24/23
  - Engineering Start: 7/25/23
  - Engineering End: 6/24/27
  - Construction Start: 5/7/27
  - FISD: Nov/Dec 2028

•PG&E Scope

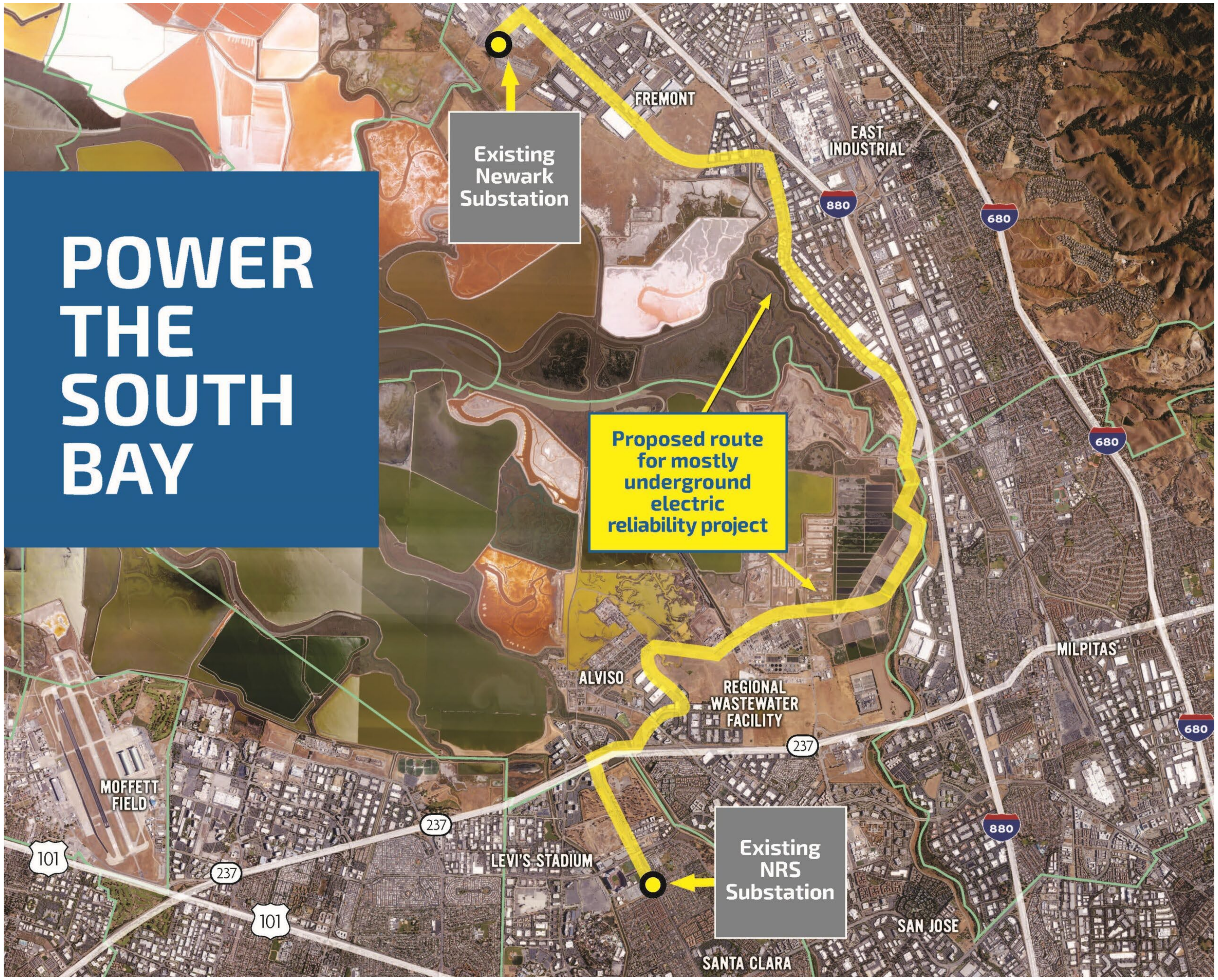
LS Power Scope

T.0009168 Newark NRS LS Power Interconnection

- Project Status: PG&E scope is currently in design phase.
- Costs
  - Inception to Date: $9M
  - Estimate at Completion: $45M
- Scope:
  - **PG&E's scope** includes upgrades within Newark Substation and transmission line from Newark to the point of interconnections to connect with LS Power.
    - Install breakers complete with new structure and all associated switches at Newark. 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 circuit breakers to 4000A rating.
  - **LS Power scope** 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.
- Challenges:
  - PG&E is coordinating with LS Power and Silicon Valley Power (SVP), who owns and operates the NRS Substation regarding the CAISO scope changes (230kV AC connection between Newark and NRS) and interconnection details.

- Milestones
  - Kickoff: 7/12/23
  - Engineering Start: 7/13/23
  - Engineering End: 10/13/26
  - Construction Start: 10/21/26
  - FISD: 12/30/27

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



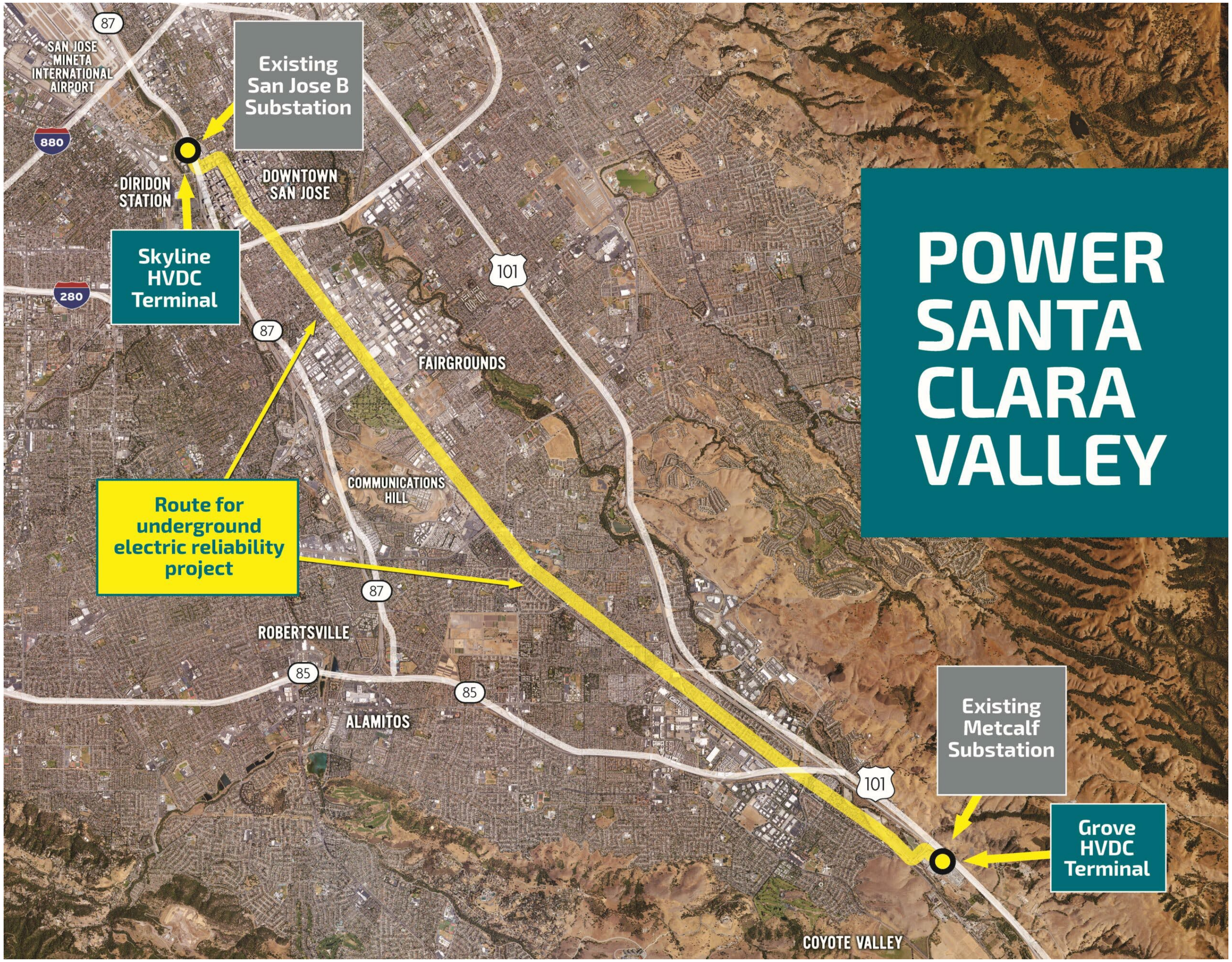
Reference: LS Power About the Projects – Power The Bay (https://powerthebay.com/en/about-the-projects/#projects) - accessed 7/24/26

T.0009169 Metcalf - HVDC Interconnection

- Project Status:
  - **Metcalf:** PG&E is currently in construction phase for substation upgrades. Relocation of PG&E facilities (to accommodate the LS Power Grove converter station adjacent to Metcalf substation) and land acquisition to move PG&E facilities have started.
  - **San Jose B:** PG&E is currently in construction phase for substation upgrades and for relocation of distribution lines. Temporary relocation of a transmission line was completed.
- Costs
  - Inception to Date: $103M
  - Estimate at Completion: $528M
- Scope:
  - **PG&E's scope** includes upgrades at Metcalf and San Jose B Substations.
  - 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 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 230/115kV autotransformer.
  - **LS Power scope** 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).
- Challenges:
  - PG&E is coordinating with LS Power regarding interconnection details and regarding land acquisition at San Jose B and Metcalf.

- Milestones
  - Kickoff: 7/12/23
  - Engineering Start: 7/12/23
  - Engineering End: 5/17/28
  - Construction Start: 11/6/26
  - FISD:
    - 12/31/27 (Phase 1)
    - 6/28/30 (Phase 2)

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



Reference: LS Power [About the Projects – Power The Bay](https://powerthebay.com/en/about-the-projects/#projects) (https://powerthebay.com/en/about-the-projects/#projects) - accessed 7/24/26

Abandoned Plant and CWIP Incentive Ratemaking at FERC

- PG&E evaluates transmission projects for potential CWIP and Abandoned Plant incentive treatment on a case-by-case basis to determine whether a project meets the requirements of Section 219 of the Federal Power Act, FERC Order No. 679, and subsequent Commission precedent.

- As part of this process, PG&E reviews transmission projects identified through the CAISO planning process and evaluates whether those projects satisfy the applicable eligibility, nexus, risk, and customer-benefit considerations.

Newly-Added CWIP Incentive Projects
Stakeholder Requested Item 5

Various PMs, *Project Manager*

T.0011287 North Oakland Reinforcement Project

- Project Status: Engineering
- Costs
  - Inception to Date: $ 0.381 M
  - Estimate at Completion: $ 847M
- Milestones
  - Kickoff: 11/12/25
  - Engineering Start: 01/26/26
  - Engineering End: 04/04/28
  - Construction Start: 05/02/28
  - FISD: 5/1/32
- Scope
  - Rebuild existing two Sobrante-Grizzly-Claremont #1 and #2 115 kV lines into four lines. Two of the four lines will bypass Claremont Substation and connect to Oakland D and Oakland L Substations through new underground (UG) cable sections.
  - Build a new UG cable to connect one of the new rebuilt lines to Oakland D
  - Build a new UG cable to connect one of the new rebuilt lines to Oakland L
  - Reroute the Moraga-Oakland X #4 line to bypass the Oakland X Substation. Build a new UG cable section to connect the Moraga-Oakland#4 115 kV line to Oakland C
  - Convert Oakland C to GIS.
  - Replace the Oakland C-X#2 115 kV underground cable with larger size cable
  - Disconnect existing Oakland D-Oakland L 115 kV cable.
- Challenges:
  - Complex routing between Claremont (Oakland K) and Oakland D substations
- Permitting:
  - Sobrante-Claremont-Oakland D/L: a PTC application will be submitted to the CPUC in Q4 2027
  - Oakland C-X and new GIS at C: strategy TBD

T.0011380 South Bay Reinforcement Project

- Project Status: Planning
- Costs
  - Inception to Date: $0.6M
  - Estimate at Completion: $415M
- Milestones
  - Kickoff: 8/3/26
  - Engineering Start: 8/3/26
  - Engineering End: 3/14/28
  - Construction Start: 4/8/27
  - FISD: 5/1/32
- Scope:
  A. Reconductor the line drop at San Jose A and at El Patio between the El Patio and San Jose A Substation on the El Patio – San Jose A 115kV line
  B. Reconductor the Trimble – San Jose B 115 kV Line.
  C. Reconductor the Mountain View – Monta Vista 115 kV Line
  D. Reconductor the Whisman – Monta Vista 115 kV Line
  E. Remove the limiting elements at the Metcalf Substation on the Los Esteros – Metcalf 230kV line
  F. Not required. This line will be rebuilt as UG in the Tesla – Trimble – Metcalf 230 kV corridor expansion project.
  G. Swap the connections of the Newark-Trimble and Trimble-FMC 115 kV lines at the tower line. Additionally, rebuild the KRS-Trimble section using double 795 ACSS conductors over a length of approximately 3 miles. (ON HOLD)
  H. Construct an underground (UG) line from Ringwood to Montague. The conductor must be capable of handling at least 1500 Amps during summer emergency conditions. Disconnect the Los Esteros-Montague 115 kV line and use the available connection point at Montague to connect the new Ringwood-Montague 115 kV line. Additionally, a new 115 kV connection will be required at the Ringwood substation.
- Challenges:
  - Contracting and material resources
  - Permitting and land rights
  - Construction and clearance sequencing
- Permitting: Permitting strategy and timeline to be determined

T.0011294 South Oakland Reinforcement Project

- Project Status: Engineering
- Costs
  - Inception to Date: $0.4M
  - Estimate at Completion: $313M
- Scope
  - Rebuild five lines:
    1. Moraga-San Leandro #1,
    2. Moraga-San Leandro #2,
    3. Moraga-San Leandro #3,
    4. Moraga-Oakland J,
    5. San Leandro-Oakland J
  - Upgrade line and substation limiting components to achieve full conductor capacity at Moraga, San Leandro, Oakland J
- Challenges:
  - Clearance sequencing
- Permitting:
  - Strategy and timeline to be determined
  - Project is in stage 1 and the CEQA permit (FEIN) is the primary permit to address

- Milestones
  - Kickoff: 11/12/25
  - Engineering Start: 4/7/26
  - Engineering End: 5/12/28
  - Construction Start: 12/18/28
  - FISD: 5/3/32

T.0011209 Metcalf 500/230 kV Transformer Bank Addition Project

- **Project Status:**
  - Project Initiated
  - Kick off in 2026
- **Scope:**
  - Install new 500/230 KV bank at Metcalf Substation
  - Install 500 KV breaker and associated protection system
- **Project Driver:**
  - Increased demand from EV, data centers and large load
  - Estimated Completion 5/1/2034
- **Costs:**
  - Total estimated cost: $160M - $240M
  - Total Actuals: $0.068M

T.0011182 Gold Hill-El Dorado Reinforcement Project

- Project Status: Engineering
- Costs
  - Inception to Date: $0.137M
  - Estimate at Completion: $127M
- Milestones
  - Kickoff: 5/26
  - Engineering Start: 6/1/26
  - Engineering End: 2/8/29
  - Construction Start: 11/5/30
  - FISD: 5/1/32

- Scope: Serve Diamond Springs 115 kV Substation from Missouri Flat – Gold Hill #1 115 kV Line. Convert Shingle Springs Substation 115 kV bus to BAAH. Reconductor ~8.8 circuit miles between El Dorado and 008/062 of the El Dorado – Missouri Flat #2 115 kV Line with larger conductor to achieve minimum 577 Amps of summer emergency rating. Remove any limiting components as necessary to achieve full conductor capacity

- Challenges: Scope yet to be finalized, constructability complexity (need for temporary shoofly arrangements, multiple clearances, and tie-ins), physical site constraints (substation footprint expansion would trigger permitting)

T.0011984 San Mateo 230/115 kV Transformer Bank Addition Project

- Project Status: Planning
- Costs
  - Inception to Date: $0
  - Estimate at Completion: $110M
- Scope: Add an additional 560MVA Transformer 230/115kV. Plus, any bus and SCADA work needed. This project is to mitigate thermal overloads and voltage violations under the NERC Reliability Standard TPL 001 5.
- Challenges: Physical space in substation and connection difficulties to 230 kV and 115 kV bus.

- Milestones
  - Kickoff: TBD 8/2026
  - Engineering Start: 8/2026
  - Engineering End: TBD
  - Construction Start: TBD
  - FISD: 5/1/32

T.0009536 Metcalf-Piercy & Swift and Newark-Dixon Landing 115 kV Project

- Project Status: Engineering and scope development
- Costs:
  - ITD: $3.17M
  - EAC: $191.11M
- Milestones
  - Kickoff: 10/31/2024
  - Engineering Start: 12/22/2025
  - Engineering End: Q4 2028
  - Construction Start: Q4, 2028
  - FISD: 12/31/2030

- Scope: Rebuild and reconductor approximately18.3 miles of four 115kV transmission lines in the East San Jose area (McKee-Piercy, Piercy-Metcalf, Swift-Metcalf & Newark-Dixon Landing) to support the increased forecasted load demand using advanced conductors (ACCC) with a summer emergency of 3000 amp or higher. The scope also includes some upgrades at six substations (Metcalf, Piercy, Swift, Newark, Dixon Landing and McKee).

- Challenges: The Project area includes a mix of urban/developed land uses and protected parks and open space in the East San Jose Area. In urban areas, there will be temporary construction-related impacts to traffic, parking, and noise in residential, commercial, and developed park areas. Similarly, in undeveloped areas, there will be impacts associated with temporary construction-related disturbances to sensitive biological habitats.

- Permitting: The 3000 Amps requirement turns the reconductoring into a full rebuild, usually needing extra rights of way and an extensive environmental assessment plus a CPUC Permit to Construct. PTC may be required for some segments of the Tline. Environmental Team is currently working on routing and siting study.

T.0009536 Metcalf-Piercy & Swift and Newark-Dixon Landing 115 kV Project

- Project dependencies:
  - Large Load project (another project is reconductoring Metcalf- Evergreen #1 and #2 lines to support) interconnection into Hellyer [formerly known as Silver Creek] switching station, which is also looping into Swift- Metcalf and Piercy- Metcalf 115 kV Lines. LC24-13 and LC24-14

  - Large Load Interconnection project is dependent on Swift - Metcalf Reconductoring portion of this project to meet customer load demand.

T.0011327 Ames Distribution – Palo Alto 115 kV Transmission Line Project

- Project Status: Engineering
- Costs
  - Inception to Date: $0.2M
  - Estimate at Completion: $126M
- Scope
  - Install a new 4 miles long Ames Distribution-Palo Alto 115kV line with a minimum capacity of 3000 Amps of summer emergency rating.
  - Install 3 breakers at Ames Distribution and convert existing 115kV Loop into a Ring Bus
  - Install new MPAC & Battery Enclosure at Ames Distribution
  - Expand Ames Distribution yard
  - Install a Breaker And-A Half (BAAH) bay for new Ames Distribution-Palo Alto 115kV new Line at Palo Alto Switching Station
  - Reconductor 0.1 Miles of Ames –Ames Distribution 115kV line
- Challenges: None at this time

- Milestones
  - Kickoff: 4/28/26
  - Engineering Start: May 2026
  - Engineering End: September 2028
  - Construction Start: January 2030
  - FISD: May 2034

T.0011327 Ames Distribution – Palo Alto 115 kV Transmission Line Project

T.0011878 West Fresno 115 kV Voltage Support Project

- Project Status: Feasibility / Initial Engineering
  - Inception to Date: $0.05M
  - Estimate at Completion: $47M
- Milestones
  - Kickoff: 8/31/26
  - Engineering Start: 10/31/26
  - Engineering End: 11/07/28
  - Construction Start: 11/08/28
  - FISD: 5/31/31
- Scope
  - Voltages fell below lower operating limit of 109 kV. With growing distribution level forecast, low voltages at West Fresno are expected to continue and worsen if not mitigated.
  - Install 75 MVar voltage support at West Fresno Substation
  - Expand West Fresno 115 kV bus as needed for voltage support interconnection
- Challenges:
  - There is limited space at West Fresno substation to install additional equipment.
  - High side bus may need to be converted to ring bus.
  - Analysis needed to determine spacing requirements for both Capacitor bank or STATCOM
  - Long lead time material will not be known until the decision between STATCOM and Capacitor is made.

T.0011146 Cortina #3 60 kV Reconductoring Project

- Project Status: Engineering
- Costs:
  - Inception to Date: $0.15M
  - Estimate at Completion: $49M
- Scope:
  - Substation Work:
    - Install a 15 MVAR shunt capacitor at Meridian 60 kV Substation in two steps (7.5 MVAR each and associated equipment).
  - T-Line Work:
    - Reconductoring about 9.0 miles of the Cortina #3 line between the Cortina Substation and Williams Substation
- Challenges:
  - Area load growth. PG&E & CAISO will continue monitoring the area growth within the CAISO Transmission Planning Process.

- Milestones
  - Kickoff: 11/4/25
  - Engineering Start: 11/4/25
  - Engineering End: 9/22/28
  - Construction Start: 8/13/29
  - FISD: 12/31/31

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

Cait Ribeiro – *Project Manager, Sr Consulting*

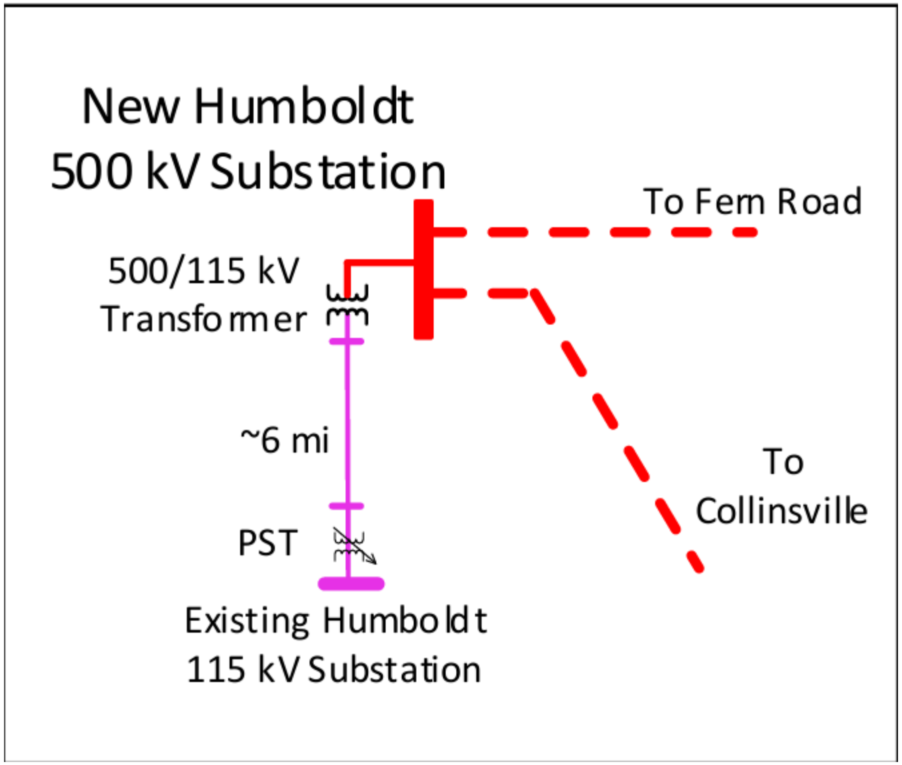
Ashwini Mani, Sr. *Manager, Transmission Planning*

T.0006815 - LSPower Round Mountain Area 500kV Dynamic

- **Project Status:** Construction
- **Costs**
  - Inception to Date: $140.6M
  - Estimate at Completion: $169.2M
- **Milestones**
  - Kickoff: 6/2/21
  - Engineering Start: 5/3/21
  - Engineering End: 12/8/25
  - Construction Start: 2/15/23
  - FISD: 7/1/26 (Fern Rd), 07/15/27
- **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 (SC) 3&4 reactance. Increase TM 500 kV Series Cap Banks 1&2 reactance. Install transposition towers at three locations on the Fern Rd-Round Mountain 500kV line.
- **Successes:**
  - Release to Operations of :
    - Fern Rd Substation 500kV GIS
    - Round Mtn – Fern Rd 500kV #2 Line
    - Fern Rd – Table Mtn 500kV #2 Line
    - Table Mtn SC1
    - Table Mtn SC2
    - Fern – VGCC PACIRAS
- **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

Humboldt Project Update

- Please provide an update for the following two projects:
  - Humboldt 500 kV Substation
  - Humboldt to Collinsville 500 kV Line
  - Humboldt to Fern Road 500 kV Line
- The CAISO 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 CAISO 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.



Major Projects Update
Stakeholder Requested Item #8

Various Project Managers, *Major Projects*

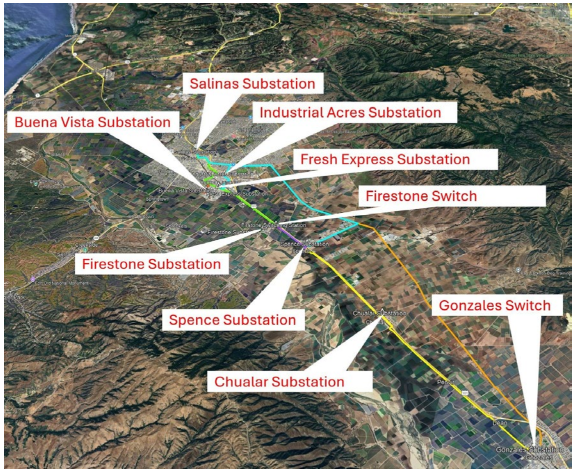
T.0010623 – Salinas Area Reinforcement

- Project Status: Engineering
- Costs
  - Inception to Date: $1M
  - Estimate at Completion: $452M
- Project Drivers: The Salinas Area Reinforcement project strengthens grid reliability and expands capacity to support future customer and regional growth. Key investments include two new substations, major substation upgrades and conversion of approximately 28 miles of existing 60kV transmission line to 115kV transmission line.
- Project Risks: The project’s primary near-term risk remains permitting, including Proponents of Environmental Assessment (PEA) development, California Environmental Quality Act (CEQA) review and Notice to Proceed (NTP) issuance. Extended regulatory review timelines or additional environmental study requirements could impact key schedule milestones and construction readiness.
- Project Dependencies: Potential clearance coordination with Crazy Horse-Salinas-Soledad #1 and #2 (Operative Date = 2030)

Milestones

- Kickoff: 2/25/25
- Engineering Start: 7/1/25
- Engineering End: 12/4/28
- Construction Start: 4/4/28*
- FISD: 12/31/32

*Note: Multiple concurrent projects



T.0000155 – Lockeford – Lodi Area 230 kV Development

- Project Status:
  - CPUC Permitting phase closed: on 07/21
  - Entered Design phase and Land Acquisition
- Costs
  - Inception to Date: $25.4M
  - Estimate at Completion: $199M
- Milestones
  - Kickoff: 7/18/18
  - Engineering Start: 7/19/18
  - CPCN Final Decision: 07/16/26
  - Engineering End: 9/4/29
  - Construction Start: 11/1/29
  - FISD: 6/30/31
- Project Drivers : Address reliability issues in the area and provide additional transmission capacity
- Project Risks : Land Rights and Long Lead Material
- Project Dependencies: New 230kV Substation to be built by the City of Lodi
- Permitting: The CPUC issued a proposed decision for the CPCN permit on 6/12/26, which was approved on 7/16/26. PG&E received the final CPCN decision on 7/21/26, granting approval to construct the Northern San Joaquin 230 kV Transmission Project.

T.0010534 – North Dublin-Vineyard Recond Project

- Project Status: Project is at Initiate stage. Substation engineering is working on completing scoping and preliminary (30%) design. T-Line engineering is working on issuing the contract for the engineering consultant to start preliminary design and scoping.
- Costs
  - Inception to Date: $0.5M
  - Estimate at Completion: $233.0M
- Project Drivers: This project is driven by the need to mitigate CAISO-identified reliability overloads, support future generation deliverability, including offshore wind integration, and maintain NERC compliance by increasing the North Dublin–Vineyard 230 kV line capacity.
- Project Risks: Clearance availability, Environmental restrictions, If engineering evaluations necessitate replacing the existing OH structures.
- Project Dependencies: None identified.
- Milestones
  - Kickoff: 1/20/26
  - Engineering Start: September 26
  - Engineering End: December 27
  - Construction Start: November 28
  - FISD: May 34

T.0000156 – Wheeler Ridge Junction Substation

- Project Status: Engineering
- Costs
  - Inception to Date: $27M
  - Estimate at Completion: $328M
- Milestones
  - Kickoff: 1/5/15
  - Engineering Start: 11/1/24
  - Engineering End: 7/5/29
  - Construction Start: 3/7/30
  - FISD: 5/1/34
- Scope: This project will construct a new 230/115 kV transmission substation in the Bakersfield area to provide additional transmission capacity to serve electric customers in Kern County. The 230 kV and 115 kV buses will be constructed to a breaker-and-a-half (BAAH) configuration.
- Project Driver: The electric demand in the unincorporated area of Kern County is expected to continuing growing in the area. The project protects against NERC P1, P2, P6, and P7 contingencies, which may result in thermal overloads and voltage issues on transmission lines
- Risks: Permitting timeline, operational restrictions on clearances / construction windows, long lead material
- Project Dependencies: Permit approval, potential land acquisition, Wheeler Ridge Substation Tesla distribution bank project

T.0000154 – Estrella 230 kV Transmission Substation

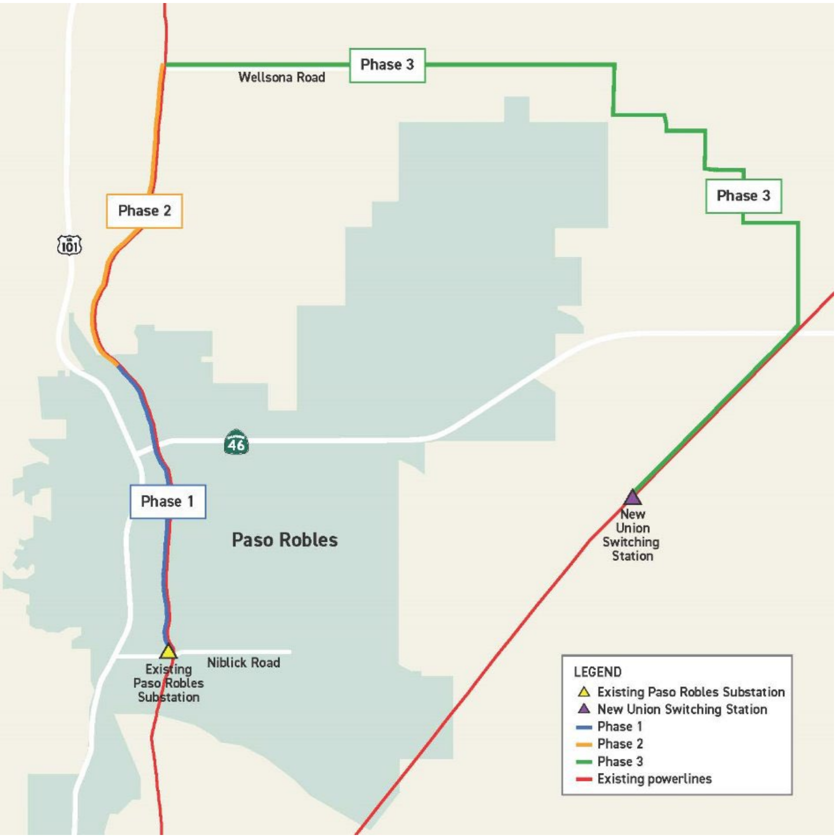
- Project Status: Engineering/Construction
- Costs
  - Inception to Date: $65M
  - Estimate at Completion: $175M
- Project Drivers
  - This project will interconnect a new 3rd Party 230kV Substation.
- Project Risks
  - Land acquisition delays
  - Material delays
- Project Dependencies – none at this time
- Scope:

Phase 1:
- Upgrading 3 miles of existing powerlines between Niblick Rd and Barolo Ln, replacing wood poles with Galvanized steel poles

Phase 2:
- Upgrading 3 miles of existing powerlines between Barolo Ln and Wellsona Rd, replacing wood poles with galvanized steel poles

Phase 3:
- Construct a 10.5-mile, 70 kV powerline from Wellsona to the new 70kV Union Substation
- Construct the new 70 kV Union Substation off Union Rd

- Milestones
  - Kickoff: 2/3/15
  - Engineering Start: 5/19/15
  - Engineering End: 6/30/27
  - Construction Start: 11/13/25
  - FISD: 3/29/29



T.0007072 – IGNACIO-MARE ISL 115KV (IGN SUB/HWY SUB) + Phases 4-8

T Dot	T dot Description	Project Status	Forecast at Completion	Total Actuals	Kickoff	Eng Start	Eng End	Construction Start	FISD
T.0007072	IGNACIO-MARE ISL 115KV (IGN SUB/HWY SUB)	Closed	$ 51,861	$ 51,861	11/01/21	01/10/22	8/27/24	10/19/22	12/13/24
T.0011035	IGNACIO - MARE ISLD TWR REP PHASE 4	In Service	$ 48,112	$ 47,588	07/15/24	07/17/24	08/27/25	11/12/25	12/19/25
T.0011036	IGNACIO - MARE ISLAND TWR REPL PHASE 5	Engineering	$ 33,801	$ 1,698	01/15/25	01/17/25	08/31/26	09/17/26	02/19/27
T.0011037	IGNACIO - MARE ISLAND TWR REPL PHASE 6	Engineering	$ 27,415	$ 23	04/01/26	04/01/26	08/31/27	09/01/27	01/14/28
T.0011092	IGNACIO - MARE ISLAND TWR REPL PHASE 7	Engineering	$ 29,500	$ 22	04/01/26	04/01/26	06/30/28	09/01/28	01/12/29
T.0011090	IGNACIO - MARE ISLAND TWR REPL PHASE 8	Engineering	$ 14,774	$ 9	04/01/26	04/01/26	02/02/29	06/01/29	08/31/29

- Scope
  - Original: Replace 34 deteriorated towers along the Ignacio-Mare Island #1 and #2 115 kV transmission line.
  - Revised: Replace 6 deteriorated towers along the Ignacio-Mare Island #1 and #2 115 kV transmission line.
- Project Status: This project (T.0007072) is completed and closed out. Remaining structures in the original scope have moved to routine programmatic work
- Costs
  - Inception to Date: $51.86M
  - Estimate at Completion (EAC): $51.86M
- Project Drivers: Replacement of the towers in scope addressed NERC non-compliances from Ignacio Substation to Highway Substation and improved the overall safety and reliability of the system due to the conditions of these towers.
- Project Risks: Construction is completed and all risks have been mitigated.
- Project Dependencies: No dependencies on other projects.

T.0004271 – Morgan Hill-Watsonville 115kV Area Reinforcement

- Project Status: Morgan Hill Substation Engineering has achieved 60% design maturity with the recent release of the Constructability Review submittal. For Tline Engineering, targeting NOC submittal for mid-August 2026, 95% in 09/2026 and IFC 11/2026
- Costs
  - Inception to Date: $29M
  - Estimate at Completion: $161.7M
- Project Drivers: Address growing reliability, capacity and resiliency needs by reinforcing the Morgan Hill-Watsonville transmission line grid and upgrading the existing Substation configuration to Breaker-and-a-Half.
- Project Risks: Submitting the NOC may trigger agency review comments, additional study requirements, or stakeholder concerns that could result in scope changes, schedule delays and increased project costs.
- Project Dependencies: AWS SFO69: Llagas Remote End, Metcalf Install 230kV MPAC, AWS SFO69 Morgan Hill Remote End

Milestones

- Kickoff: 12/15/24 (re-kickoff)
- Engineering Start: 12/15/24
- Engineering End: 5/27/27
- Construction Start: 3/18/27
- FISD: 12/29/28

T.0011527 – Pittsburg-San Mateo Bay Towers FOND

- Project Status: Construction
- Costs
  - Inception to Date: $5M
  - Estimate at Completion: $24M
- Milestones
  - Kickoff: 7/28/25
  - Engineering Start: 11/12/25
  - Construction Start: 5/15/26
  - FISD: 1/31/27
- Project Drivers
  - Foundations rehabilitation due to corrosion and deterioration
- Project Risks
  - Potential delays due to weather
- Project Dependencies
  - N/A

T.0009719 – Ignacio Area Upgrade

- Project Status: Engineering
- Costs
  - Inception to Date: $2.7M
  - Estimate at Completion: $154M
- Project Drivers
  - System Capacity
- Project Risks
  - Material Delays
  - Permitting Delays
- Project Dependencies
  - NA
- Milestones
  - Kickoff: 11/2024
  - Engineering Start: 11/2025
  - Engineering End: 2/2028
  - Construction Start: 11/2027
  - FISD: 12/31/2030

T.0000159 – Egbert 230kV Switching Station

- Project Status: Engineering

- Costs
  - Inception to Date: $90M
  - Estimate at Completion: $369M

- Project Drivers
  - System reliability

- Project Risks
  - Project has been internally on hold since 2022, associated risk are changing design standards, potential redesign cost, and increased construction cost.

- Project Dependencies
  - The Jefferson Bus Reliability project (T.0004805) and the Egbert Large Load Interconnection Project (T.0009133).

- Milestones
  - Kickoff: 12/30/16
  - Engineering Start: 12/22/15
  - Engineering End: 5/3/28
  - Construction Start: 4/11/28
  - FISD: 12/6/29

T.0010675 – French Camp Reinforcement

- Project Status: Engineering, Siting & Permitting
- Costs
  - Inception to Date: $1M
  - Estimate at Completion: $137M
- Milestones
  - Kickoff: 2/27/2025
  - Engineering Start: 3/15/2025
  - Engineering End: 11/15/2028
  - Construction Start: 1/1/2029
  - FISD: 5/1/2030
- Project Drivers: French Camp is currently served from Weber Substation. In the 2023-2024 TPP assessment studies P1 contingency overloads were observed on Weber 60 kV lines. In addition, significant distribution load requests have come in this area. Replacing existing 60 kV French Camp Substation with a new 230 kV substation looped into the Bellota - Tesla 230 kV Line No. 2 would serve the existing and requested load.
- Project Risks: PTC permit could get delayed if CPUC does not support the proposed project or requests an alternative that was not studied. Land acquisition could get delayed if complexities arise with the property owner negotiations.
- Project Dependencies: In 2028/2029 replace Stockton A Bank 5 with 60MVA and add two new feeders to support the loads until the new French Camp Substation can be completed.

T.0010637 – Martin-Millbrae 60kV Area Reinforcement

- Project Status: Engineering
- Costs
  - Inception to Date: $0.5M
  - Estimate at Completion: $70M
- Milestones
  - Kickoff: 9/11/25
  - Engineering Start: 9/12/25
  - Engineering End: 9/8/27
  - Construction Start: 3/7/28
  - FISD: 5/31/30
- Project Drivers: The section of line is seeing load growth in the areas that is exceeding the capacity of the conductors is one station is to go down. Conductor size needs to be upgraded to prevent Overload to the system in the area and prevent Blackouts.
- Project Risks: Permitting timeline and acquisition, operational restrictions on clearances that work with construction windows, Existing supports not able to accommodate a larger Conductor size
- Project Dependencies: None identified at this time do complete the project

T.0001650 – Midway 230kV Bus Upgrade Section D

- Project Status: Construction
- Costs
  - Inception to Date: $112M
  - Estimate at Completion: $153M
- Milestones
  - Kickoff: 4/6/17
  - Engineering Start: 9/1/17
  - Engineering End: 1/31/22
  - Construction Start: 4/7/21
  - FISD: 2/7/29
- Project Drivers:
  - Enterprise Risk
    - Substation Failure: Failure of substation assets may result in public or employee safety issues, property damage, environmental damage, disruption of major generation sources and inability to deliver energy.
    - This project will mitigate this risk by improving system reliability, maintenance and operational flexibility by upgrading aging equipment to PG&E's current design and operational standards.
  - Compliance Risk:
    - Protects against NERC reliability standard violations (defined as an event resulting in the loss of a single element).
- Project Risks:
  - Clearance Conflicts and Constraints
    - Several lines that will be relocated into the new us Section D are 3rd party lines and clearances need to be coordinated between PG&E and these partners.
    - Material delays: TSP's, Breakers, Switches, and Steel are experiencing long lead times and delays.
- Project Dependencies
  - N/A

Back at 3:25

BREAK

2025-26 CAISO Transmission Plan Concurred for Large Load Interconnection Stakeholder Requested Item #6

Ashwini Mani, *Sr Mgr. Elec. Transmission Planning*

Jason Castellanos, *Project Manager, Senior Consulting*

Fadie Masri, *Manager, Electric Project Management*

Jonathan Cardoza, *Manager, Electric Project Management*

Arnaldi Rustandi, *Mgr, Elec. Transmission Asset Implementation*

CAISO TP vs. Concurred Projects

Customer-specific facilities

Large-load driven transmission projects are customer-specific facilities developed to serve individual load interconnection requests. They are not CAISO TPP projects for regional reliability, economic, or policy needs.

CAISO concurrence role

CAISO reviews proposed upgrades and provides concurrence that facilities are technically acceptable and compatible with operation of the CAISO-controlled grid.

TPP approval threshold

CAISO approval through the TPP is reserved for projects CAISO identifies as needed to address system-wide reliability, economic, or policy objectives.

T.0010465 San Jose A Substation Relocation

Project Status

- Project status: Engineering

Costs

$20M
Inception to date

$179M
Estimate at completion

Milestones

Milestone	Date
Kickoff	10/2024
Engineering Start	01/2026
Engineering End	03/2027
Construction Start	01/2028
FISD	11/2028

Project Driver

- Capacity upgrades for PG&E to serve new load in downtown San Jose including data centers and ongoing load growth.

Dependencies

- San Jose A Substation Relocation must be completed to interconnect with data centers and complete the San Jose A – San Jose B Interconnection project.

Key Risks

- Land acquisition required for substation relocation
- Long lead material timeframes and cost increase

T.0010903 Private Load Interconnection

Project Status

- Project status: Engineering
- Signed PES Report and Engineering Agreement

Costs

$6M
Inception to date

$230M
Estimate at completion

Milestones

Milestone	Date
Kickoff	03/2025
Engineering Start	03/2025
Engineering End	09/2027
Construction Start	07/2029
FISD	03/2030

Project Driver

- Large load interconnection

Dependencies

- This project is not dependent on another project to be energized.

Key Risks

- Land acquisition required for substation relocation
- Long lead material timeframes and cost increase
- Customer readiness
- Clearance sequencing

T.0011286 San Jose A-San Jose B 115kV T-Line

Project Status

- Project status: Engineering

Costs

$1.2M
Inception to date

$70.1M
Estimate at completion

Milestones

Kickoff	10/2025
Engineering Start	10/2025
Engineering End	03/2027
Construction Start	08/2027
FISD	10/2028

Project Driver

- Increase operational flexibility, load serving capability, customer reliability, and address potential contingency overloads.

Dependencies

- T.0010465 – San Jose A Substation Relocation
- T.0009169 – Metcalf HVDC Interconnection

Key Risks

- Environmental compliance associated with work adjacent to Guadalupe River
- Poor geology, liquefaction risk
- Land acquisition required for substation relocation

T.0010902 Private Load Interconnection

Project Status

- Project status: Engineering
- Signed PES Report and Engineering Agreement

Costs

$1M Inception to date

$28.8M Estimate at completion

Milestones

Milestone	Date
Kickoff	03/2025
Engineering Start	03/2025
Engineering End	03/2028
Construction Start	05/2028
FISD	10/2029

Project Driver

- Interconnection of a third-party customer.

Dependencies

- T.0007676 – Private Load Interconnection Project

Key Risks

- Land acquisition and permitting
- Long lead material timeframes and cost increase
- Customer readiness
- Clearance sequencing

T.0011276 Morgan Hill-Llagas 115kV Reconductor

Project Status

- Project status: Engineering

Costs

$0.7M
Inception to date

$70M
Estimate at completion

Milestones

Milestone	Date
Kickoff	09/2025
Engineering Start	01/2026
Engineering End	04/2027
Construction Start	06/2028
FISD	12/2028

Project Driver

- Increase transmission capacity and operational flexibility on the Morgan Hill–Llagas 115kV corridor to meet forecasted load growth in the South Bay region.

Dependencies

- T.0004271 – Morgan Hill-Watsonville 115kV Area

Key Risks

- Permitting and environmental approvals
- Contract and material lead times
- Clearance sequencing

T.0010873 Private Load Interconnection

Project Status

- Project status: Engineering
- Interconnection Agreement submitted to CPUC

Costs

$2.8M
Inception to date

$65.5M
Estimate at completion

Milestones

Milestone	Date
Kickoff	03/2025
Engineering Start	05/2025
Engineering End	10/2026
Construction Start	10/2026
FISD	09/2027

Project Driver

- Large load interconnection.

Dependencies

- This project is not dependent on another project to be energized.

Key Risks

- Permitting and environmental approvals
- Contract and material lead times
- Customer readiness
- Clearance sequencing

T.0011626 DeAnza T-line Capacity Upgrades

Project Status

- Project status: Engineering

Costs

$1M Inception to date

$81.3M Estimate at completion

Milestones

Milestone	Date
Kickoff	03/2026
Engineering Start	03/2026
Engineering End	12/2026
Construction Start	11/2027
FISD	12/2028

Project Driver

- Large load interconnection.

Dependencies

- This project is not dependent on another project to be energized.

Key Risks

- Permitting and environmental approvals
- Contract and material lead times
- Clearance sequencing

T.0011290 Hellyer-Metcalf 115kV Reconductor

Project Status

- Project status: Engineering

Costs

$0.5M
Inception to date

$35M
Estimate at completion

Milestones

Kickoff	09/2025
Engineering Start	01/2026
Engineering End	02/2027
Construction Start	09/2027
FISD	12/2028

Project Driver

- Increase operational flexibility, load serving capability, customer reliability, and address potential contingency overloads.

Dependencies

- T.0010903 – L17 Private Load Interconnection

Key Risks

- Permitting and environmental approvals
- Contract and material lead times
- Clearance sequencing

T.0011274 Montague-Trimble 115kV

Project Status

- Project status: Engineering

Costs

$0.3M
Inception to date

$7M
Estimate at completion

Milestones

Milestone	Date
Kickoff	09/2025
Engineering Start	09/2025
Engineering End	02/2027
Construction Start	10/2028
FISD	12/2028

Project Driver

- Increase operational flexibility, load serving capability, customer reliability, and address potential contingency overloads.

Dependencies

- This project is not dependent on another project to be energized.

Key Risks

- Permitting and environmental approvals
- Contract and material lead times
- Clearance sequencing

T.0011288 San Jose B-Evergreen 115kV Reconductor

Project Status

- Project status: Engineering

Costs

$0.2M
Inception to date

$22M
Estimate at completion

Milestones

Kickoff	10/2025
Engineering Start	10/2025
Engineering End	02/2027
Construction Start	09/2027
FISD	12/2028

Project Driver

- Increase operational flexibility, load serving capability, customer reliability, and address potential contingency overloads.

Dependencies

- This project is not dependent on another project to be energized.

Key Risks

- Permitting and environmental approvals
- Contract and material lead times
- Clearance sequencing

T.0010908 Private Load Interconnection

Project Status

- Project status: Engineering

Costs

$3.6M Inception to date

$174M Estimate at completion

Milestones

Milestone	Date
Kickoff	03/2025
Engineering Start	03/2025
Engineering End	01/2028
Construction Start	08/2028
FISD	03/2030

Project Driver

- Large load interconnection.

Dependencies

- This project is not dependent on another project to be energized.

Key Risks

- Permitting and environmental approvals
- Contract and material lead times
- Clearance sequencing
- Customer readiness

T.0010891 Private Load Interconnection

Project Status

- Project status: Engineering
- Signed PES Report and Engineering Agreement

Costs

$1M
Inception to date

$150M
Estimate at completion

Milestones

Kickoff	10/2025
Engineering Start	10/2025
Engineering End	12/2027
Construction Start	09/2028
FISD	10/2030

Project Driver

- Large load interconnection.

Dependencies

- T.0012882 – Eastshore 230kV Bank 3
- T.0012617 Eastshore Area Reinforcement

Key Risks

- Permitting and environmental approvals
- Contract and material lead times
- Clearance sequencing
- Customer readiness

EX138957 Trimble 230 kV/115 kV Substation expansion looping onto NRS-San Jose B 230 kV Line

Project Status

- Project status: Project Development
- Estimated initiation by end of 2026

Costs

TBD
Inception to date

TBD
Estimate at completion

Milestones

Milestone	Date
Kickoff	TBD
Engineering Start	TBD
Engineering End	TBD
Construction Start	TBD
FISD	TBD

Project Driver

- Large load interconnection.

Dependencies

- This project is not dependent on another project to be energized.

Key Risks

- Permitting and environmental approvals
- Contract and material lead times
- Clearance sequencing
- Third party coordination

T.0012882 Partial 230 kV BAAH bay at Eastshore 230 kV and a third 230 kV/115 kV transformer

Project Status

- Project status: Engineering

Costs

$0.2M Inception to date

$22M Estimate at completion

Milestones

Kickoff	TBD
Engineering Start	TBD
Engineering End	TBD
Construction Start	TBD
FISD	TBD

Project Driver

- Increase operational flexibility, load serving capability, customer reliability, and address potential contingency overloads.

Dependencies

- T.0012617 Eastshore Area Reinforcement

Key Risks

- Permitting and environmental approvals
- Contract and material lead times
- Clearance sequencing

Grid Enhancing Technologies Stakeholder Requested Item #19

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 hourly temperature 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 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
- Phase 2 implementation is still in progress, current efforts include:
  - 4 seasons implementation
  - Updates to exceptions list
  - Revisions to external-facing documentation
- Costs associated with FERC Order 881 Phase 2 implementation are captured in the TPR PDS worksheet under the following PO: 5555502 FERC 881 Phase 2A

Next Steps:

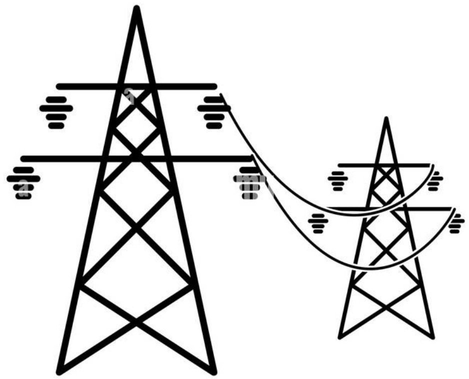
- FERC 881 requirement for CAISO has been extended until December 17, 2026
- Requirements applicable to PTO's have been extended to October 15, 2027
- PG&E is on track to meet the compliance requirements by the due date

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
- Pilots deployed on 3 circuits
- Pilot installation, calibration, and multiple field corrections completed for all vendors and circuits
- Data capture and analysis ongoing
- EPRI executing acceptance testing and validation

Next Steps:

- In addition to the DLR benefits for these chosen vendors, the asset health monitoring capabilities will also be assessed at the selected locations.
- EPIC vendor demonstration and integration feasibility/opportunities being explored
- GE digital DLR demonstration initiated

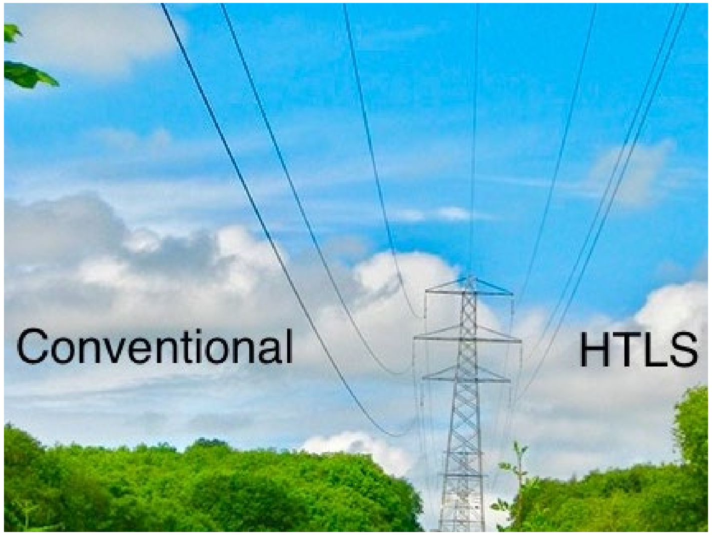
High Temperature Low Sag Conductors

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 initial deployment and is apart of analysis for future deployment opportunities.
- Implemented a company-wide process to evaluate use of advance conductors on all reconductoring projects.

Next Steps:

- Monitor existing locations for performance.
- Evaluating manufactures for smarter conductor technologies and identifying deployment opportunities.

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 December 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.

Pilot GETs Question

Question: Outside of any CAISO joint development, please provide an overview of any new pilot programs that have deployed GETs and provide any next steps in their evaluation.

Response: No new pilot programs have deployed GETs outside of any CAISO joint development.

Feedback and Discussion of Next Steps

Lorenzo Thompson, Nick Medina & Nicholas Hsiao

- *TPR Team*

Wrap Up

Lorenzo Thompson, Nick Medina & Nicholas Hsiao

- *TPR Team*

Appendix

Project Lifecycle Authorization Gates

New Stage 0 - Business Case

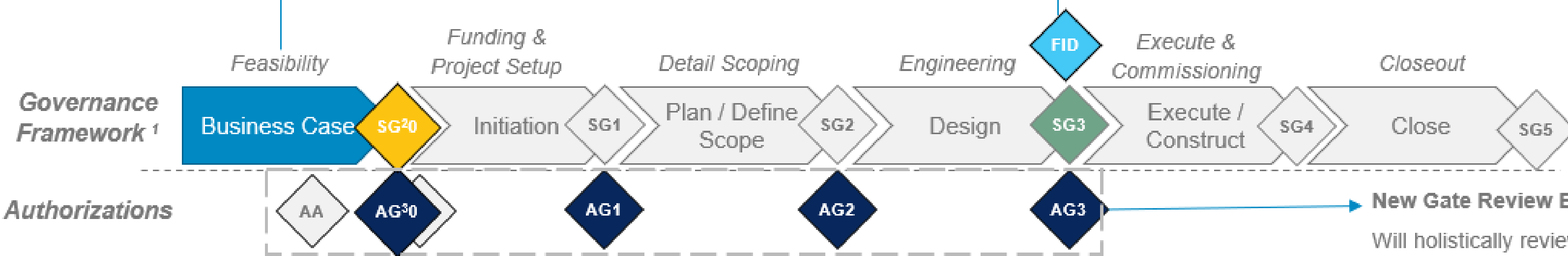
Feasibility to establish the need for a project and get it into BPD.

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.

70 Data Fields in TPR Process Data Sheet

- **Project Description Data Fields**
  1. Row/Line Number
  2. Project Name
  3. Location 1 (Lat/Long)
  4. Location 2 (City/County)
  5. Project Description
  6. Project Description – What?
  7. Project Description – Action Taken
  8. Related Projects
  9. NERC/WECC/CAISO Standard/Requirement/Contingency
  10. Primary Purpose
  11. Secondary Purpose
  12. Last Inspection Date
  13. Age of Asset
  14. Types of Analyses Performed
  15. Alternative Solutions and Costs
  16. Fire Threat Zone Rating
  17. Wildfire Related
  18. RAMP
  19. Other Environmental Factors
  20. Project Manager
  21. Transmission Project Size (Length)
  22. Substation Project Footprint (Acres)
  23. Transmission Voltage Level
  24. Substation or Transformer Capacity
  25. Utility Prioritization Ranking
  26. Utility Unique ID #1 (PO)
  27. Utility Unique ID #2 (T.dot)
  28. Utility Unique ID #3 (MWC)
  29. Changes In Unique ID
- **Utility/CAISO Approval and FERC Rate Cases Data Fields**
  30. Utility Approval
  31. Year of Internal Utility Approval
  32. Process(es) for Utility Approval
  33. Long term Transmission Investment Plan Inclusion
  34. CAISO Year
  35. Transmission Planning Process ("TPP") Phase 3
  36. Year(s) considered in CAISO TPP
  37. Year when expected to be considered in CAISO TPP
  38. Link to TPP where project has been considered, approved, and/or expected to be considered
  39. Generator Interconnection and Deliverability Allocation Procedures (GIDAP) Related
- **CPUC Permit Status Data Fields**
  40. CEQA Status
  41. CEQA/NEPA Document Type
  42. CEQA/NEPA Lead Agency
  43. CPUC Filing Type
  44. CPUC Date Filed
  45. CPUC Status
  46. CPUC Status: Year
- **Project Status Data Fields**
  47. Project Status
  48. AACE Class
  49. Construction Start Date
  50. Original Planned In-Service Date
  51. Current Projected or Actual In-Service Date
  52. Reason for Change in In-Service Date
  53. In-Flight Projects
- **Costs Data Fields**
  54. Original Projected Cost or Range
  55. Cost Cap
  56. Current Projected or Actual Cost
  57. Actual Capital Expenditures
  58. Projected Capital Expenditures
  59. CWIP Expenditures
  60. Accrued Overhead
  61. Accrued AFUDC
  62. FERC: Year(s)
  63. FERC Dollars in Rate Base
  64. % of Bid
  65. % of WRO Passed to Ratepayers
  66. Cost Benefit Analysis
  67. FERC Incentives
  68. % Cost in High Voltage TAC
  69. % Cost in Low Voltage TAC
- **Notes**
  70. Notes