Proposed Topics from the CPUC and Stakeholders for PG&E TPR Process Stakeholder Meeting on February 4, 2026

1. **PG&E Project Planning Strategy / Risk Based Portfolio Planning Framework and Integrated Grid Planning**
   a) Please provide an overview of any updates/refinements to PG&E's RBPPF and IGP framework.
   b) Please explain key inputs and considerations used to develop project rankings.
   c) Please explain whether the criteria PG&E uses to assign an RBPPF score have been modified in 2025/2026.
   d) Please explain if there have been any shifts in project RBPPF rankings since May 2025.
   e) In PG&E's November 1, 2025 TPR Transmittal Letter, Figure 2 "November 2025 TPR PS Actual & Forecasted Expenditures by Primary Purpose" indicates 2025 capital expenditures of $1.5 billion, rising to $3.5 billion by 2028. Please explain in detail how PG&E expects to achieve this expanded capacity of work, given its prioritization initiatives and resource limitations.
2. **Cost/Benefit Analyses (See Data Field 66)**
   a) Please provide an overview of PG&E's perspectives on the value and use of cost/benefit analyses in electric transmission project planning and prioritization.
   b) Please provide an update on PG&E's efforts to secure a consultant and define appropriate scope of work to develop PG&E's cost/benefit analyses.
   c) Please explain how/where PG&E expects to share its TPR project CBR calculation framework and methodology workpaper, to be made available in 2026 Q1 (see PG&E's Response to Data Request TPR-Process_DR_ED_018-Q038), along with whether feedback/formal comments will be accepted.
   d) Please explain in detail how PG&E's investment planning process "leverages CBRs as an input" to investment planning. Please include why PG&E does not rely on CBRs exclusively for making investment planning decisions.
   e) Please describe how PG&E's CBR framework leverages its prioritization models (TCM, WTRM) to establish baseline risk at a structure level to evaluate wildfire and reliability impacts.
   f) Please provide PG&E's timeline for fully populating Field 66 (Cost Benefit Analysis) beyond the limited cost/benefit percentages currently included.
   g) In the February 4th stakeholder meeting, PG&E should walk stakeholders through the Utility Prioritization Ranking – RBPPF score and CBRs for some selected projects for which CBRs are calculated so that parties can better understand the interplay between the two.
   h) Please describe the details of the improvements PG&E has made in the November 2025 TPR submittal. The updates described in the November 2025 TPR submittal letter should be expanded and elaborated. For example, it is not clear how PG&E incorporated an "increase of PoF into future years to highlight changes to risk profile with aging equipment."

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

3. AFUDC and Placing Projects On Hold

a) Please provide an update on how PG&E's "automated hold" process is working, including the names and number of projects that have been placed on hold.

b) Please discuss PG&E's process changes in respect to changes required by FERC's 2025 audit of PG&E.

4. Project Delays

Please provide an overview/update of the three major projects listed below, with specific updates regarding the following:

- POs associated with each T.Dot
- Project drivers
- Timeline to completion
- Current status
- Project risks
- Project dependencies
- Capital expenditures by each respective PO
- Total cost incurred since inception
- Cost incurred by year since project inception
- AFUDC by year since project inception
- Material Cost incurred by year, if any
- If material was purchased, please describe in detail the disposition of such material.
- (If possible, maps or diagrams showing major project segments)

a) T.0000159 -- Egbert 230kV Switching Station

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

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

5. PG&E's Use of AACE Class Cost Estimates

a) Please provide an overview of the AACE Class cost estimating process, along with a description of the variance in each class cost estimate.

b) Please describe PG&E's process/timelines for updating AACE class cost estimates as a project progresses to completion.

6. CWIP Rate Base Incentive Projects

a) For each of the projects noted below, please provide a detailed update on each project's scope, cost, and timeline to completion. Please show all POs included in each T.Dot.
   i. Manning Project: Construction of the Manning 500/230 kV Substation (T.0009194);
   ii. Collinsville Project: Construction of the Collinsville 500/230 kV Substation (T.0009189);

    iii. Newark Project: Construction of the Newark-Northern Receiving Station High-Voltage Direct Current (HVDC) (T.0009168 or its successor); and,
    iv. Metcalf Project: Construction of the Metcalf-San Jose B HVDC (T.0009169)

b) Please provide a map or diagram that includes the major segments of these projects and identify the major segments for which PG&E is responsible and LS Power is responsible. Please highlight how these projects tie to each other and illustrate dependencies to other major projects planned in the South Bay (e.g., San Jose A – Substation Rebuild).

c) Please provide PG&E's current monthly capital expenditure forecast for each of the POs that are part of the above-noted T.Dots.

7. Competitively-Bid Projects Interconnected by PG&E

a) Please provide an update of the work performed by PG&E to interconnect LS Power's Table Mountain, Round Mountain, and Fern Road projects (i.e., T.0006815 -- LSPower Round Mountain Area 500kV Dynami), including timeline for completion, interconnection challenges, and cost changes. Describe any "lessons learned" and explain how PG&E may capture these lessons in the future when interconnecting similar projects.

b) Please describe any "lessons learned" while completing the interconnection of T.0004672 -- Gates: 500 kV Dynamic Voltage Support. Please explain how PG&E may capture these lessons in the future when interconnecting other competitively-bid projects.

c) Please provide an update for the following projects:
    i. Humboldt 500 kV Substation and 500 kV line to Collinsville
    ii. Humboldt to Fern Road 500 kV Line
    iii. San Jose B-NRS 230kV project
        - Please describe why the San Jose B-NRS 230kV project, which was approved by the CAISO in the 2024-2025 TPP, is in the PG&E November 2025 TPR submittal, even though it is subject to competitive solicitation?
        - Please explain whether PG&E's forecasted capital expenditures are for PG&E facilities needed to accommodate the San Jose B-NRS 230 kV project and, if so, describe in detail PG&E's proposed scope of work.
        - Please clarify whether the $1.5 million of the "Current Projected Total or Actual Final Cost" (Field #56) reflects only PG&E-specific cost for this project? If it does, please explain what is represented by the "Original Projected Cost" (Field #54) shown for this project.

8. Major Projects Update

Please provide an overview/update of each of the following major projects, including any project drivers, timelines to completion, current status, project risks, and project dependencies. Please include the POs associated with each T.Dot and provide capital expenditures by the respective PO. Where possible, please include any maps or diagrams showing major project segments.

To the extent a project is part of a CAISO-approved TPP, please provide an overview of PG&E’s role in the CAISO process, who develops power flow analyses, analyzes the alternatives, and selects the project that moves forward.

a) T.0010623 – Salinas Area Reinf Chualar Sub
b) T.0010465 – San Jose A – Substation Rebuild
c) T.0000155 – Lockeford – Lodi Area 230 kV Development
d) T.0010534 – North Dublin-Vineyard Recond Project
e) T.0000156 – Wheeler Ridge Junction Substation
f) T.0000154 – Estrella 230 kV Transmission Substation
g) T.0007072 -- IGNACIO-MARE ISL 115KV (IGN SUB/HWY SUB)
h) T.0004271 -- Morgan Hill-Watsonville 115kV Area Reinforcement
i) T.0011527 -- Pittsburg-San Mateo Bay Towers FOND
j) T.0009719 – Ignacio Area Upgrade
k) T.0010675 -- French Camp Reinforcement
l) EX138970 – SOUTH BAY REINFORCEMENT PROJECT
m) EX138976 -- NORTH OAKLAND REINFORCEMENT PROJECT
    i. In your discussion, please explain whether the Moraga 230 kV Bus Upgrade (T.0006159) project is now a part of this project.
    ii. If it is not, please explain why the Moraga 230 kV Bus Upgrade was removed from the November 2025 TPR, if it was combined with another major project (and identify the project), and provide information on the project’s status and current projected total cost.
n) EX138977 -- SOUTH OAKLAND REINFORCEMENT PROJECT

9. High-Speed Rail Project Update

a) Please provide an update on any activities on this project, including any revised scope, engineering assessments, and schedule.
b) Please explain how the availability of federal funding affects the future activities on this project.
c) Please confirm that no costs for any California High-Speed Rail work has been allocated to ratepayers, pursuant to CPUC Resolution E-4886, Ordering Paragraph #6:

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

10. Large Load Energization Processes & Load and EGI Forecast Placeholders

a) Please provide an update on PG&E’s “Rule 30” application at the CPUC.
b) If acceptance of PG&E’s Rule 30 proposal would impact any projects in the November TPR project spreadsheet, please identify those POs and describe the impacts.
c) PG&E’s Bay Area “cluster study” for new load interconnection projects

i. If work on the previously-discussed “cluster study” is complete, does PG&E anticipate initiating a new “cluster study” in the Bay Area or other areas of its service territory?
ii. Are there any updates from when it was last discussed in the July 29, 2025 TPR Stakeholder Meeting?
iii. Please discuss the cost savings of the cluster study, specifically what caused the savings and whether the savings are estimates or actuals.
iv. How were CAISO TPP-approved projects considered in the cluster study?
v. Please explain how PG&E’s load forecasts for new load may differ from those used by other planning agencies and explain the impacts on planning.

d) Please discuss any TNU work in the PS on which current or anticipated large load energization applications are dependent and, to the extent possible, describe the connections between said work and dependent projects. Please describe how TPR PS Field 8 is being used to illuminate these connections for Stakeholders.
e) PO 5555047 – 82N DET PLAN – Load
    i. Please walk through the forecast and assumptions used to develop these capital expenditures, including the active, cluster, and non-cluster projects. Please specifically detail which elements are CAISO- and non-CAISO jurisdictional.
    ii. Please describe PG&E’s process for developing load-specific planning orders for the work captured in this forecast placeholder.
    iii. Please identify any “exceptional case filings” that have been submitted by PG&E to the CPUC.
f) PO 5554999 - 82W DET Plan – EGI
    i. Please walk through the forecast and assumptions used to develop the capital expenditure forecast.
    ii. Please explain whether these costs represent 100% of the forecast electric generator interconnection costs. Please indicate whether some of the forecast cost may be borne by electric generators, rather than electric transmission ratepayers.

11. Supply Chain Issues

a) Please provide an update on supply chain issues for transformers, circuit breakers, and other critical transmission-related infrastructure that PG&E is facing. If it is, please explain them and describe PG&E’s plans to address.
b) Please provide an update on PG&E’s advance procurement of transformers and circuit breakers, both for emergency inventory and known projects. Please include estimated delivery timelines and the process for transferring any charges from the “other balance sheet” (OBS) to actual planning orders.
c) Please describe how new or proposed tariffs are affecting the cost and availability of transformers, circuit breakers, and other critical transmission-related infrastructure.

12. Emergency Replacement Programs and Just-in-Time Replacements

a) In the November 2025 TPR, PG&E introduced a plethora of Emergency Replacement and Just-in-Time Replacement Programs. These include, but are not limited to, EX139131 -- EMERGENCY TRANSMISSION CIRCUIT BREAKER REPLACEMENT OF FAILED AND JIT, EX113779 -- -- Purchase CEM breakers for anticipated failures, Emergency Transmission Xfmr 500kV Banks Replacement, Emergency Transmission Transformer Non-500 kV Banks Replacements (multiple POs and investment codes), and EX139253 -- Transmission Xfmr Non 500kV Banks (6 Banks) Planned Replacement. Please identify all programs associated with emergency replacements and just-in-time replacements and describe PG&E's overarching strategy in creating these initiatives.
b) Please provide a diagram detailing the numerous programs created for emergency replacements and just-in-time replacements. The diagram should include the scope of work under each program, authorized budget, units anticipated to be replaced, cost per unit to be replaced, and any other pertinent details.
c) Long-delayed proactive replacement of circuit breakers is now being supplanted by emergency replacements of the equipment. Using T.0010949 -- Moraga: EM Repl CB 642 & 712 as an example, please walk through PG&E's timeline for initiating the replacement, executing the replacement, costs incurred, and cost differentials associated with replacing the circuit breakers on an emergency basis.
d) Please provide PG&E's strategy on when "overdutied" circuit breakers are replaced proactively or on an emergency basis and whether any interim mitigation measures are implemented to relieve "overdutied" breakers. Please include whether being "overdutied" is determined on a forecast basis or on existing conditions.

13. **EX113578 -- SWITCH REPLACEMENT PROGRAM**
    a) Please provide an overview of the goals and reasons for this program, along with a summary of the work completed to date and to be performed under this program. Please include the average switch replacement cost, along with the number of switches to be replaced.
    b) Please provide the workplan for 2026, 2027, and 2028.

14. **Wood-to-Steel Pole Replacement Program**
    a) Please provide a summary of the work completed to date, along with average cost per pole replacement and describe any issues encountered.
    b) Please provide the workplan for 2026, 2027, and 2028.
    c) Please share any "lessons learned" from implementing this program and how PG&E is applying these lessons as it continues to replace poles throughout its system.

15. **Tower Coating**
    a) Please provide a summary of the work completed to date, along with average cost per tower and issues encountered.
    b) Please provide the workplan for 2026, 2027, and 2028.

c) Please share any “lessons learned” from implementing this program and how PG&E is applying these lessons as it continues to coat towers throughout its system.

16. Cathodic Protection

a) Please provide a summary of the work completed to date, along with average cost per tower, estimated per tower filed inspection cost, and issues encountered.
b) Please provide the workplan for 2026, 2027, and 2028.
c) Please explain whether PG&E has a process to revisit whether additional cathodic protection initiatives are needed once the current program is completed.

17. Grid Enhancing Technologies

a) Please provide any updates on Grid Enhancing Technologies (GETs) PG&E is evaluating (e.g., Ambient Adjusted Ratings (AAR) and Dynamic Line Rating (DLR)), if any GETs projects have been in coordination with the CAISO, and how deployment of these technologies have enhanced grid operation and congestion/constraint mitigation timelines.
b) Please provide an update on PG&E’s AAR implementation that it indicated previously was planned by July 2025. Please explain whether the costs associated with the planned AAR implementation are captured in PG&E’s TPR. If so, please identify the PO. If not, please explain.
c) Please provide an overview of any pilot programs that have deployed GETs and provide any next steps in their evaluation.
a) Please identify any projects that are greater than $15 million that PG&E has placed on hold using its manual process since June 2025.

18. Generator Interconnection Network Upgrades and CAISO TPP Reliability and Policy-Driven Projects Through CAISO TPP

a) Please provide an update on projects at or greater than 1MW that are interconnecting to PG&E’s electric transmission system. Please identify the updates to those included in the January 2025 CAISO Transmission Development Forum (TDF).
b) Please identify the type and amounts (MW and MWh) of generation that will interconnect to the electric grid.
a) Diablo Canyon Area 230 kV High Voltage Mitigation: This reliability-driven project was approved by the CAISO in the 2023-2024 Transmission Plan.[1] Why isn’t it being included in the Project Spreadsheet?
b) Collinsville 230 kV Reactor: All projects approved as policy-driven by the CAISO in the 2023-2024 Transmission Plan, except for this project involving the addition of 20-ohm reactors on the Collinsville – Pittsburg 230 kV line, were included in the Project Spreadsheet (PS). Please explain why this project is missing.[2]
c) Please provide a timeline for the projects approved in the CAISO 2024-2025 Transmission Plan to be included in the PS.

19. 2024-2025 CAISO TPP Projects

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[1] CAISO 2023-2024 Transmission Plan, May 23, 2024, p.5.
[2] CAISO 2023-2024 Transmission Plan, May 23, 2024, p.6.

a) Most projects approved in the 2024-2025 TPP have dramatically different current projected cost (Field 56) and the original projected cost (Field 54), as shown in the table below. Please explain the discrepancies between Field 56 and Field 54 for all projects approved in the 2024-2025 CAISO TPP.
b) Why are the current projects typically so much less than the original projections?
c) Why is the Pittsburg-Kirker 115kV Line Section Limiting Elements Upgrade currently estimated to exceed the CAISO estimate?
d) Why is the Jefferson-Stanford Cable Replacement currently estimated to exceed the CAISO estimate?

Data Field 2	**Data Field 27**	**Data Field 54**	**Data Field 56**
Project Name(s)	**Utility Unique ID #2 (Less Specific)**	**Original Projected Cost or Cost Range ($000)**	**Current Projected Total or Actual Final Cost ($000)**
Gold Hill-El Dorado Reinforcement Project	T.0011182	$ 127,000	$ 19,050
North Oakland Reinforcement Project	T.0011287	$ 1,127,000	$ 222,000
South Oakland Reinforcement Project	T.0011294	$ 250,000	$ 69,131
Sobrante 230kV Bus Upgrade	T.0011324	$ 15,000	$ 1,500
Metcalf Substation 500/230kV Transformer Bank Addition	T.0011326	$ 182,000	$ 1,400
Ames Distribution – Palo Alto 115 kV transmission line	T.0011327	$ 84,000	$ 7,000
Eagle Rock-Fulton-Silverado 115kV Recon	T.0011334	$ 92,900	$ 16,000
San Miguel New 70 kV Line Project	T.0011337	$ 30,000	$ 2,500
GWF-Kingsburg 115 kV Line reconductoring	T.0011378	$ 81,600	$ 2,100
South Bay Reinforcement Project	T.0011380	$ 434,000	$ 131,299
Greater Bay Area 500 kV Transmission Reinforcement	TBD	$ 700,000	$ 1,000
Moraga 230/115kV Transformer Bank Addition	TBD	$ 40,000	$ 2,000
Helm 230/70 kV Transformer Bank Addition project	TBD	$ 115,000	$ 3,000
Pittsburg-Kirker 115kV Line Section Limiting Elements Upgrade	TBD	$ 200	$ 2,000
San Jose B - NRS 230 kV line	TBD	$ 200,000	$ 1,500
San Mateo 230/115 kV Transformer Bank Addition Project	TBD	$ 110,000	$ 1,500

West Fresno 115 kV Voltage Support Project	TBD	$ 60,000	$ 9,000
Jefferson-Stanford Cable Replacement	T.0010604	$ 40,000	$ 42,295
Cortina #3 60 kV Reconductoring Project	T.0011146	$ 55,500	$ 13,500
Konocti-Eagle Rock 60 kV Reconductoring Project	T.0011250	$ 32,500	$ 22,007
CORTINA #3 MERIDIAN SUB LINE TERM	T.0011146	$ 55,500	$ 4,675