Integrated Planning Workshop #2 / 2

November 18, 2025

High DER Proceeding (R.21-06-017)

D.24-10-030 Implementation

California Public
Utilities Commission

Ground Rules and Workshop Logistics

- **Ground Rules:**
  - Raise your hand for questions, both in the room and online
  - Identify yourself and your organization before speaking
  - Do not repeat what another person has already said
  - Stay on topic, be respectful and do not interrupt when others are speaking
- **Workshop Logistics**:
  - **Workshop is being recorded** and will be posted on the CPUC's Distribution Planning webpage along with presentation slides
  - WebEx and phone participants are muted until called on. Please remember to mute yourself when finished speaking.
  - Webex participants type questions/comments in the "chat" and they will be read aloud. You may raise your hand to ask the question yourself or follow up on your question.

Agenda

Integrated Planning Workshop 2/2

Start Time	End Time	Duration	Item
9:00 AM	9:10 AM	10	Introduction
9:10 AM	9:40 AM	30	**SDG&E** - Presentation
9:40 AM	10:00 AM	20	SDG&E Q&A
10:00 AM	10:35 AM	35	**SCE** - Presentation
10:35 AM	10:55 AM	20	SCE Q&A
10:55 AM	11:05 AM	10	Break
11:05 AM	11:40 AM	35	**PG&E** - Presentation
11:40 AM	12:00 PM	20	PG&E Q&A
12:00 PM	12:30 PM	30	Open Discussion / ED Staff Next Steps and Wrap-up*
12:30 PM	1:30 PM	60	Lunch
1:30 PM	2:00 PM	30	(if needed) continue Open Discussion / ED Staff Next Steps and Wrap-up

***May finish by 12:30pm**

Workshop #2 Objectives

- Learn SDG&E, SCE, and PG&E’s (Investor-owned utilities; IOUs) updated Integrated Planning proposals
- IOUs’ address stakeholder questions from the first workshop and obtain additional feedback for further adjustments to help them refine their proposals for the Tier 3 Advice Letter due on December 15, 2025

Integrated Planning (recap)

- Integrated Planning will explore how IOUs can bundle capacity upgrades of distribution infrastructure with other distribution grid workstreams, such as wildfire safety (undergrounding), to **save costs** by avoiding working on the same asset twice
- Risk-based Decision-making Framework (RDF)
  - Requires IOUs to identify, quantify, and prioritize safety and reliability related risks (including wildfire risks), then justify mitigation investments through a cost-benefit analysis.
- General Rate Case (GRC)
  - Work identified through Integrated Planning ultimately will be included as requests in GRCs
- Integrated Planning will not make changes outside of the High DER proceeding

Background

- On October 23, 2024, The CPUC issued Decision (D.)24-10-030. This decision included various orders for Integrated Planning
  - Ordering Paragraph 16: which required IOUs to **consider distribution planning results in other distribution work** and **two workshops** to present their proposals for integrated planning and solicit feedback from stakeholders on issues presented, including cost containment considerations. Workshop #2 must be within 8 weeks after Workshop #1

  - Ordering Paragraph 17: requires the IOUs to submit **a Tier 3 advice letter on December 15, 2025** proposing **a method(s) that calculates and considers whether the increased project costs from the increased sizing of any related assets are less than or equal to the risk-adjusted benefit from avoiding future projects to upgrade grid capacity**. Utilities may propose other factors to be considered towards calculating costs and risk-adjusted benefits. Utilities' proposal shall allow for future evolution of the Distribution Planning and Execution Process and should not become a barrier to future changes in that process

Background

The advice letter shall also answer the following questions:

- (1) How does the proposed method **maintain the flexibility of the distribution planning process**, and allow for that process to develop over time;
- (2) How does the proposed method **estimate the increased costs for current projects**, and how can this estimate change or improve over time? Include increased costs for wildfire mitigation and associated Rulemaking **(R.) 20-07-013 Risk-based Decision-making Framework (RDF) cost benefit ratio data**;
- (3) How does the proposed method incorporate **cost effectiveness and cost efficiencies**?
- (4) How does the proposed method adjust for **risk and potential risk reduction** when considering potential future capacity projects, and how can this adjustment change or improve over time;
- (5) How does the proposed method **estimate cost of future distribution capacity projects**, (including increased costs for wildfire mitigation and associated R.20-07-013 RDF cost benefit ratio data) and how can this estimate change or improve over time; and
- (6) How does the proposed plan **address projects planned in the high fire threat districts** or in areas of wildfire risk, or projects that will require new lines to be built that cross into the high fire threat districts?

San Diego Gas & Electric (SDG&E)

Integrated Planning Workshop 2

November 18, 2025

Agenda

SDG&E's Approach to Integrated Planning

- Recap from Workshop 1
- Ordering Paragraph 17 Responses
- Example Project

Responses to Stakeholder Questions

- Risk Models and Framework Overlaps
- Cost-effectiveness and Bundling
- IGP Scope
- Reporting

SDG&E’s Approach to Integrated Planning

SDG&E's Integrated Planning Proposal

SDG&E proposes to continue using its existing planning processes

- SDG&E's various planning processes identify distribution upgrades that:
  - Accommodate customer load growth (Distribution Planning Process or "DPP")
  - Provide wildfire and PSPS risk reduction
  - Ensure reliability (e.g., aging asset replacement)

- In the unlikely event these upgrades overlap, SDG&E's existing processes "consider," and where necessary "calculate," whether:
  - Cost of upsizing an asset sooner **would be less than or equal to** benefit of avoiding an upgrade later.

SDG&E’s Responses to OP17 Questions

1. Flexibility of the distribution planning process:
   - No changes to SDG&E’s existing planning process are needed to provide distribution planning process flexibility and to allow for future DPP improvements

2. Estimating cost of current projects:
   - No change to SDG&E’s existing planning process is needed to estimate the costs of current assets or to improve the estimation process
   - Current wildfire safety projects, remain subject to RDF benefit-cost analysis

3. Cost effectiveness/cost efficiencies:
   - If least-cost/best-fit solution not obvious, use standard engineering economics

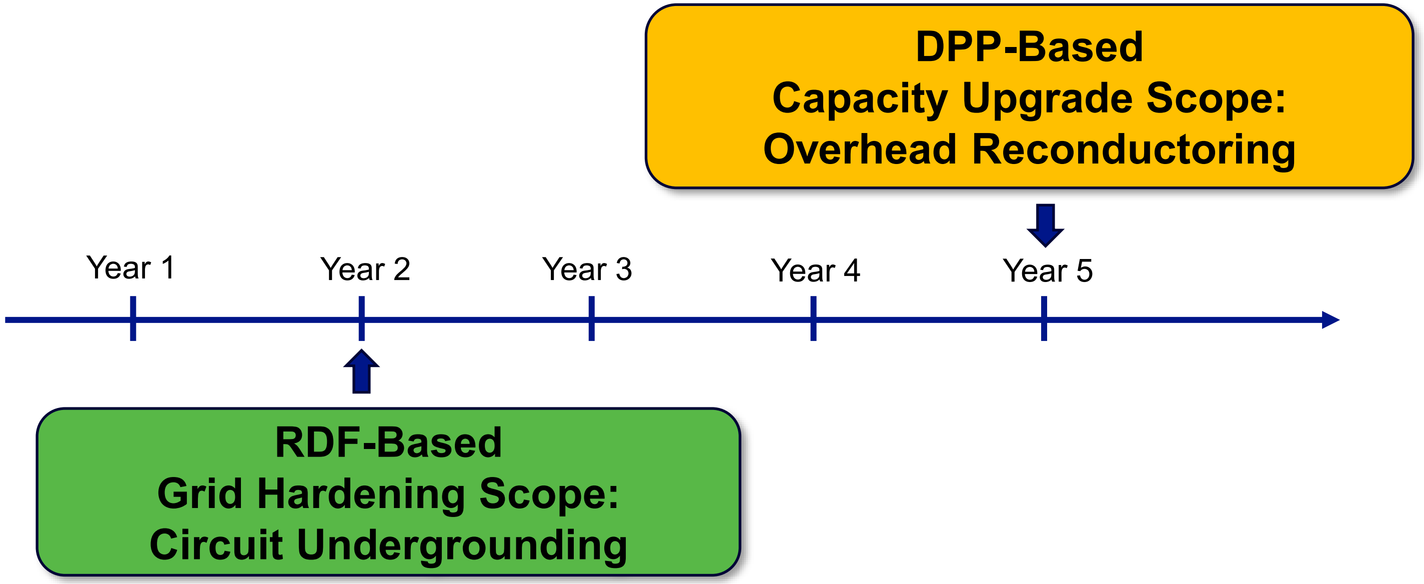
SDG&E's Responses to OP17 Questions (cont.)

4. Risk reduction:
   - Wildfire Mitigation and PSPS safety projects mitigate specific RAMP risks
   - Upgrades identified in DPP ensure customers are served timely
   - Up-sized asset will allow Wildfire Mitigation and PSPS safety projects to move forward and mitigate RAMP risks, while also ensuring customers are served timely
   - Adjustment Over Time - To further mitigate RAMP risk without future changes or delay:
     - CEC/DPP forecast enhancements will more accurately identify project overlaps and up-sizing
     - Refined Wildfire Mitigation and PSPS safety project plans will also more accurately identify project overlaps

5. Estimating costs of up-sized projects:
   - No change to SDG&E's existing planning process is needed to estimate the costs of up-sized assets or to improve the estimation process going forward
   - An up-sized wildfire safety project, remains subject to RDF benefit-cost analysis

6. DPP upgrades in high fire threat areas
   - SDG&E's existing standards would determine design in high fire threat areas

Example Project



Consideration Factors

- Project Objective
- Time of Need
- Scope Impact

WMP Project: Year 2
Capacity Project: Year 5

Alternative A: Construct WMP Project in year 2 -> Upgrade Overlapping WMP Project in year 5
Alternative B: Construct WMP Project with Upgrade in Year 2

SDG&E Planning Process with IGP Example

Points of Comparison	Alternative A	Alternative B
Capital + O&M	**$4.7 million** (2025$)	**$2.5 million** (2025$)
Time of Project Need	Meets all needs **on time** based on Wildfire safety and DPP results	Meets Wildfire safety needs **on time** Meets capacity needs **ahead of time**
Design, Construction, and Customer Impacts	Would require **two separate rounds** of permitting, design, construction, and customer contact/disconnect-reconnect	Would require **a single round** of permitting, design, construction, and customer contact/disconnect-reconnect
Decision	Conceptual Alternative: Clearly not least-cost/best-fit solution	**Selected Alternative: Clearly least-cost/best-fit solution**

Note: *Values shown are for illustrative purposes only.*

Responses to Stakeholder Questions

Risk Models and Framework Overlaps

- Selection of wildfire and outage program risk mitigation measures is made in accordance with the Commission's directives in the RAMP/GRC proceeding

- Overlap between DPP-identified projects and distribution projects identified in WMP and other SDG&E work streams is **unusual**.
  - None identified for shared years between Wildfire Mitigation Plan and 2025 DUPR.
  - None identified for shared years between other RAMP projects and 2025 DUPR.

- In the unusual event of overlap between DPP-identified upgrades and upgrades identified through RAMP/RDF:
  - *Selection* of the RAMP/RDF project does not change
  - Theoretically, *prioritization* metrics for the RAMP/RDF project could change based on up-sized asset
- Risk Assessments are submitted in next GRC (2028 for SDG&E) for Commission consideration
  - SDG&E pursues DPP-identified project if overlapping RAMP project not pursued

Cost-effectiveness and “Bundling”

- DUPR projects may change due to integrated planning, though this is unlikely
- Upsizing wildfire safety upgrades to meet capacity needs typically adds minimal cost compared to the original wildfire project
- When overlaps occur, SDG&E coordinates across business units to select the least-cost/best-fit solution, usually obvious without detailed analysis
- Benefit-cost analysis will follow standard engineering economics using asset life cycles; end-effects (e.g., a few years on a 30-year asset) are minor if timing difference is a few years
- Historical costs can inform cost-effectiveness analysis, but detailed engineering estimates are generally required due to project uniqueness
- CPUC-authorized Rate of Return is discount rate used to determine present value

IGP Scope

- The role of IGP in emergencies or catastrophic events is uncertain and will depend on recovery timing and urgency; overlap with DPP upgrades is expected to be minimal
- Distribution upgrades are planned based on the circuit-level load growth forecast, which includes both Known and Pending Loads as permitted by the Commission
  - All forecast load growth is treated equally without assigning different certainty levels
  - Hence, IGP implementation is unaffected by the presence of Known and Pending loads

Reporting

- Upsized projects will reduce costs, but SDG&E cannot reliably report time savings, crew dispatch reductions, or outage impacts due to limited data retention on alternatives not pursued
- It is generally not feasible for SDG&E to report how many years a DPP-identified upgrade was advanced when combined with an up-sized distribution upgrade (e.g., wildfire-related), as information on unpursued alternatives is not retained

Summary

Acknowledgement

SDG&E recognizes that where upgrades planned for different objectives (e.g., wildfire safety and load growth) overlap, aligning scope and timing can reduce overall costs and improve efficiency

Current State

SDG&E's portfolio is modest and closely managed

Energization and associated capacity needs remain critical and must not be delayed

Existing practices already include checks for overlaps and efficiencies

Key Considerations

Additional complex processes offer limited benefit at SDG&E's current scale, and may introduce additional costs

There is a risk of diverting emphasis away from urgent energization efforts, affecting service to customers

Commitment

SDG&E's priority is timely execution and delivery for our customers

We will learn from different Integrated Grid Planning approaches. We are most interested in a demonstration of net efficiencies and savings.

Coming Next

Timeline	Action Item/Submittal
Before December 15, 2025	Tier 3 Advice Letter with proposed methodology for IGP decision making

Q&A

Southern California Edition (SCE)

CPUC Integrated Planning Workshop #2

Christina Tan and Rickey Santos

November 18, 2025

Agenda

- Recap of Workshop 1
- SCE's Proposal to Fulfill OP 17
- How Integrated Planning Fits into SCE's Annual Planning Process
- Addressing Questions 1-6 in OP 17

Integrated Planning | Recap and Agenda

Recap of Workshop 1

- Integrated planning will achieve **substantial scoping and execution efficiency** while balancing **affordability**, enhancing **customer experience**, and delivering on **timely customer energization**.
- Integrated Planning is a proactive strategy that determines when a single, integrated solution is optimal to address a collection of grid needs.
- Within High DER Track 1, integrated planning is focused on instances where a known capacity need occurs *after* a non-capacity need.
- Prerequisites for integration include the coexistence of grid needs on the same assets and/or line path

Purpose of today's meeting

- Introduce the role of engineering guidelines in the integration decision-making process
- Show how SCE envisions engineering guidelines to be incorporated into the broader distribution planning and integrated grid planning processes.
- Provide preliminary responses to the enumerated questions within Ordering Paragraph 17
- Seek stakeholder feedback on SCE's proposed approach

Integrated Planning Maximizes the Value of Every Dollar Spent

SCE's integrated planning approach drives greater project scoping and execution efficiencies, while maintaining affordability, improving customer experience, and ensuring timely customer energization.

Customer experience: Minimizes site visits to reduce disruptions and outages.

Affordability: Combines multiple mitigations in a location to reduce design and construction costs

Scoping and execution efficiency: Relieves persistent resource constraints by reducing the volume of disparate activities by engineering and field personnel

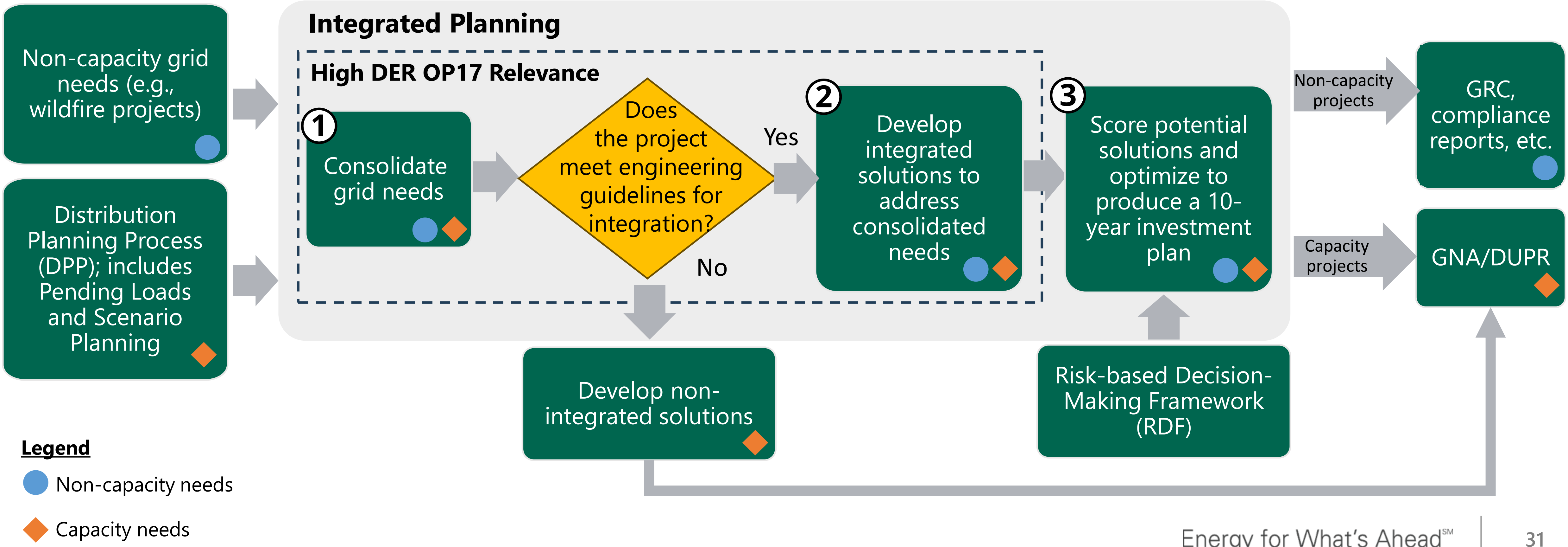
Integrating planning, design, and construction across multiple dimensions facilitates more robust solutions

- SCE defines **integrated planning** as developing a consolidated engineering solution before work order is created for field design and construction.
- It is distinct from SCE's traditional practice of **integrated execution** where work orders are bundled after creation for scheduling and execution.

Dimension	Description	Example
Drivers	Developing a cohesive solution to address multiple needs in a geographical location instead of separate solutions to address each need	Eliminate 4 kV circuitry while performing wildfire mitigation grid hardening to address expected increase in load growth and improve reliability
Voltage Level	Stronger coordination between distribution and transmission upgrades	Identifying capacity constraint for a 115 kV line feeding 12/16 kV distribution circuits with sufficient lead time to implement all necessary upgrades in a timely manner to meet need dates
Time	Evaluating long-term needs and technology solutions while developing near-term scope to identify potential opportunities for avoiding future upgrades	Developing foundational models and analytical capabilities, distribution automation and communication networks to address near term DER-hosting needs while preparing for longer-term electrification needs
Asset Type	Address asset interdependencies into decision-making	Integrate underground structure and switch upgrades with the IR cable installation

Engineering Guidelines Will Assist in Determining When to Integrate

When specific prerequisites are met, engineering guidelines will be applied to guide integration decisions, ensuring the highest priority grid needs are cost-effectively addressed.



SCE's Experience Confirms the Cost-Benefit Analysis Proposed by Staff to Favor Integration

(Increased Cost for Current Project)

is less than

(Probability of Future Grid Need) *multipled by*

(Cost of Potential Distribution Capacity Project, Adjusted via Discount Rate)

This method was provided in the R.21-06-017 High DER Proceeding Track 1 Staff Proposal.

In SCE's experience, if a non-capacity project need date occurs before a capacity need date, the incremental cost to account for the future capacity project is almost always less than the cost of doing a separate project in the future.

Updated Engineering Guidelines Will Reinforce Existing SCE Practices and Provide Insights on When Upsizing for Long-Term Needs is Prudent

- Integration prerequisites: When a non-capacity project is needed *before* a known capacity project, and those needs coexist on the same assets and/or line path
  - Guidelines will be updated to determine whether addressing the capacity need at the time of the non-capacity need is more cost effective than independent projects
  - SCE's experience shows that the cost of sending a crew out to perform work on the same assets a few years later will always be **less** cost-effective than addressing the consolidated needs in one time
- Integration is not synonymous with "upsizing" – it is broader than that. The process of integration may lead to larger conductor in some cases but could also result in a completely different solution.
- With a significant volume of expected load growth, it will be beneficial to:
  - Better understand when upsizing for long-term needs is prudent, especially needs over the latter half of the planning horizon
  - Utilize guidelines to assist in the determination of when to integrate – not rely on a project-by-project analysis.

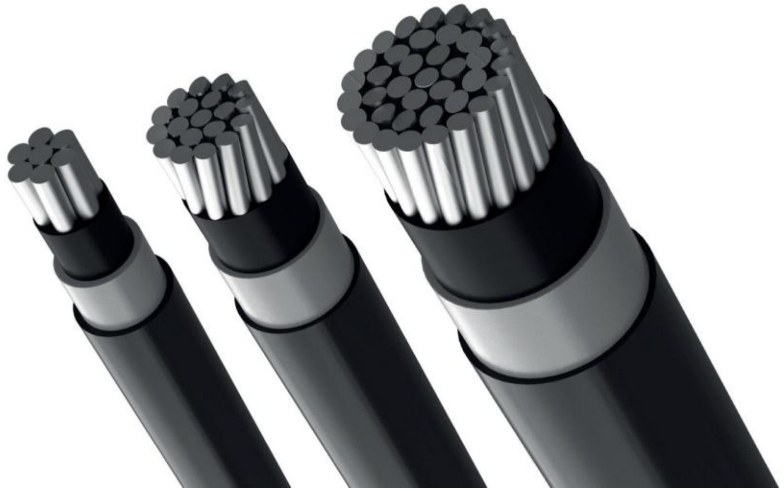
The Guidelines Are a Starting Point and Must Be Complemented With Engineering Judgement

- The guidelines provide a consistent starting point for distribution engineers; however, the guidelines are not a substitute for engineering judgement.
- Consistent with standard engineering practices, if analysis reveals that integration introduces unacceptable risks or complexity, even when the economic case is strong, the projects may proceed separately.
- Conversely, if integration offers significant advantages beyond what the guidelines capture, engineers may recommend integration.

Addressing OP 17 Questions

1. Flexibility of the Distribution Planning Process

- The method does not place any restrictions or constraints on the DPP, because it is applied to the results of the DPP. This allows the DPP to continually evolve.
- The method will make recommendations on whether projects should be integrated, **not** whether projects should be done. This allows SCE to remain responsive to evolving grid needs, especially in wildfire or large load growth areas.



2. Estimating the Increased Cost for Current Projects

- Engineering guidelines are reassessed as needed to identify opportunities for improvement, which may include considerations for more automation and changes to the scenarios considered.
- Wildfire mitigation needs and projects are handled in SCE's Wildfire Mitigation Plan (WMP). The WMP projects are fed into the first step of SCE's integrated planning which consolidates all grid needs. Since wildfire needs are determined through the WMP, the methodology will not result in increased costs due to wildfire mitigation.
- The RDF is narrowly focused on mitigating risks identified in the Risk Assessment Mitigation Phase (RAMP), specifically: safety, reliability, and financial risks.
    - Applying RDF-derived cost-benefit ratios directly within the context of determining whether to integrate or upsize projects, as suggested in OP 17, would be inappropriate. Doing so conflates two fundamentally different definitions of risk, potentially leading to misleading conclusions about project prioritization and integration.

3. Cost Effectiveness and Cost Efficiencies

- In almost all conditions, it is more cost effective to address consolidated grid needs with an integrated solution rather than dispatching work crews to the same location multiple times
- Guidelines provide for a streamlined and efficient decision-making process, which is absolutely essential. Requiring SCE's engineering resources to scope both individual and integrated solutions would result in an overly-burdensome and inefficient process, especially when considered along with the recent incorporation of scenario planning.

4. Adjusting for Risk and Risk Reduction

- In most situations, the risk of missing or delaying customer energization is fully mitigated by upsizing to meet capacity needs, especially in years 1-5.
- Capacity needs identified in the DPP beyond year 6 are informed by the distribution planning process, which includes soon-to-be Commission-adopted Pending Loads and Scenario Planning practices. These concepts already incorporate the confidence that load will materialize and ensure proactive planning and risk are appropriately balanced.
- Risk is appropriately considered in non-capacity grid needs such as through the robust RAMP and WMP processes.

5. Estimating the Cost of Future Distribution Capacity Projects

- When the decision to integrate is made, the scope of the integrated project will be different than the non-capacity project alone, however, cost estimating practices will remain unchanged
  - For example, conductor size and miles, number and size of poles and unit costs will be utilized to produce a total project cost estimate
- Wildfire mitigation needs and projects are handled in SCE’s Wildfire Mitigation Plan (WMP). The WMP projects are fed into the first step of SCE’s integrated planning which consolidates all grid needs. Since wildfire needs are determined through the WMP, the methodology will not result in increased costs due to wildfire mitigation.

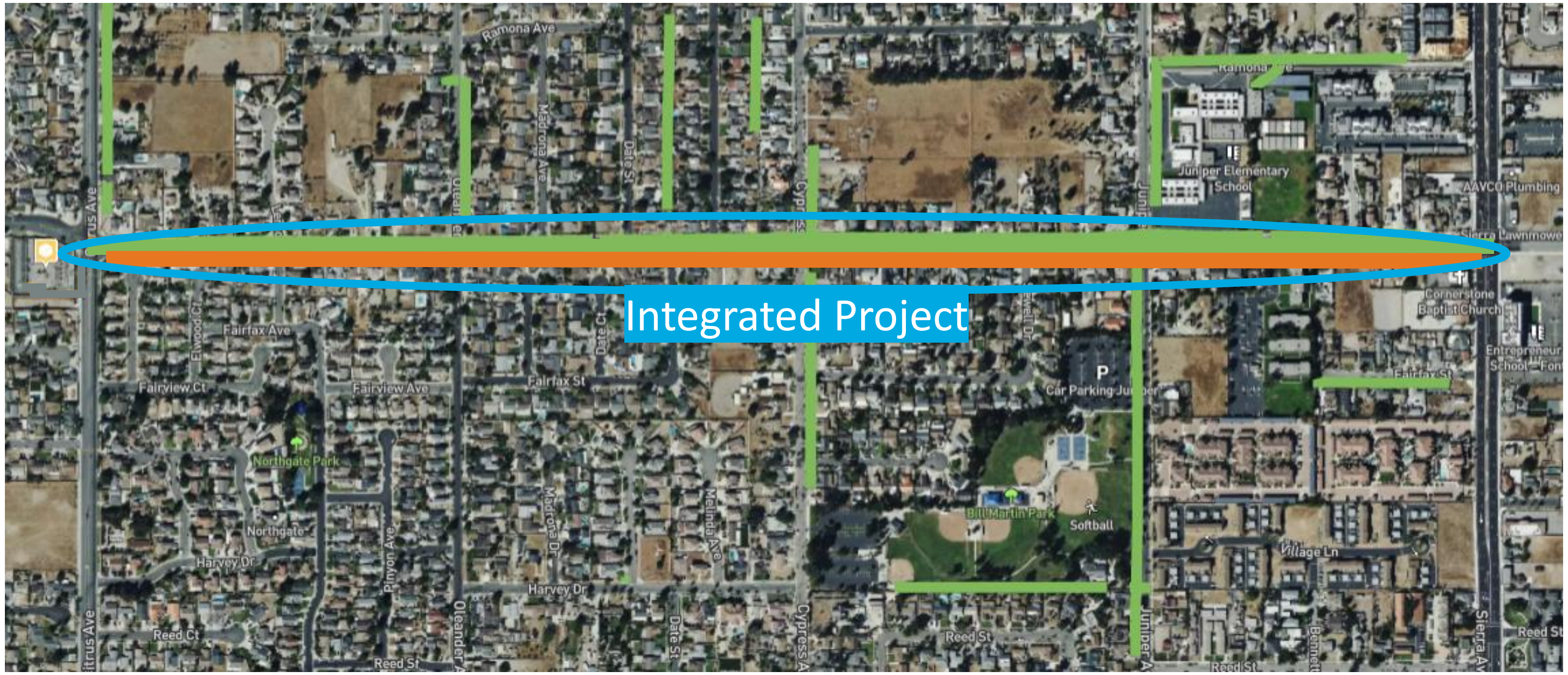
6. Specific Considerations for Projects in Wildfire Risk Areas

- When new or upgraded lines must be built in regions subject to wildfire risk, SCE will design infrastructure solutions that effectively mitigate wildfire hazards, applying appropriate design standards as needed.
- Considerations include, but are not limited to, undergrounding and covered conductor installation.

Appendix

Integrated Planning Example for Time and Drivers
(Step 1 and Step 2)

For illustrative purposes only



Legend

- Safety and reliability need in Year 3
- Capacity need in Year 6
- Substation
- Integrated Project

Method	Project	Driver	Need Year	Scope Description	Impact
Non-Integrated	A	Reduce frequency of wire down to address public safety and reliability risks	Year 3	Upsize conductor from 1/0 bare to 1/0 covered	• Twice amount of material, labor, and planned outages • Assets (wire) not utilized to their full useful lifespan
	B	Increase capacity to meet demand growth	Year 6	Upsize conductor from 1/0 covered to 336 covered	
Integrated (Future)	C	Integration of the above drivers	Year 3	Upsize conductor from 1/0 bare to 336 covered	• Accelerate capacity mitigation to support timely customer energization • Single amount of material, labor, and planned outages

Guidelines are currently being developed to determine whether to integrate projects or not. This will save time and effort by preventing engineering teams from duplicate scoping and cost estimating (once for non-integrated and again for integrated).

SCE Q&A

10 Min Break

Pacific Gas and Electric Company (PG&E)

High DER Workshop 2

Review of PG&E's Distribution Capacity Planning Process
and integration into Integrated Grid Planning processes

Agenda

- Upsizing opportunities by project type
- Asset upsizing approaches
- Standards-based sizing methodology
- Economic criteria
- Exception cases & limits of application
- Q&A / Discussion

Distribution Planning Process (DPP) Overview

The current **Distribution Planning Process** is an **annual**, **dynamic process** that identifies projected **distribution capacity** deficiencies and determines mitigation plans to address those projected deficiencies.

Dynamic Inputs (e.g., Load Requests, Project Developments, Customer Input)

Forecast Development

Establish baseline assumptions

- Historical load data
- Known load applications
- Spatial growth up to IEPR cap
  - Future load growth and loading profiles
  - Distributed Energy Resources

Determine Grid Requirements

Assess forecasted distribution grid deficiencies

- Overload
- Undervoltage
- Overvoltage

Evaluate Mitigation Options

Find cost-optimal solution to address grid need

- Transfer load
- Asset replacement(s)
- New asset(s)
- Flexible service connection
- Non-wires alternatives

Publish Distribution Plan

Investment Planning

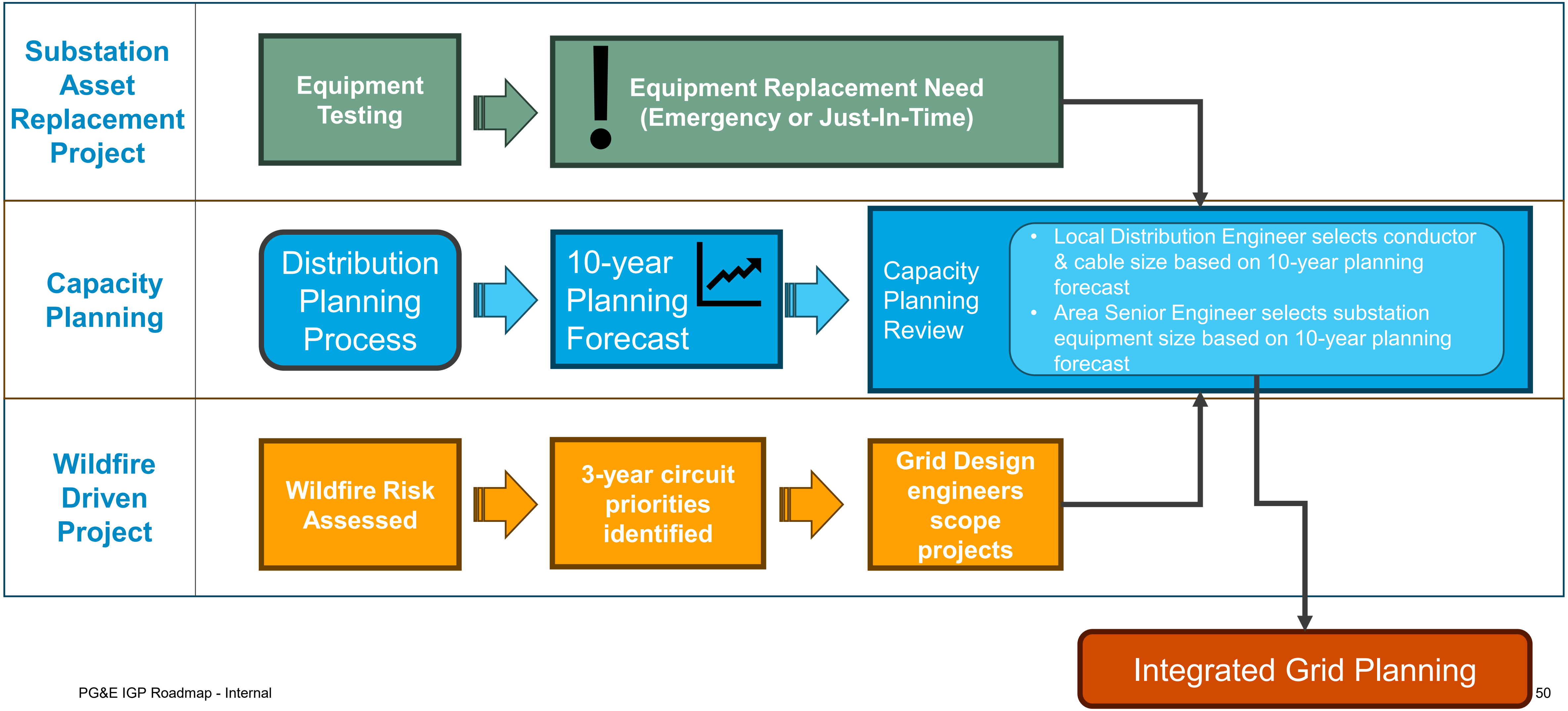
General Rate Case

Revisit and adjust plans annually and as needed

Dynamic Inputs (e.g., Load Requests, Project Developments, Customer Input)

Cross-Functional Capacity Planning

Engineers with local knowledge



Approaches to upsizing

Decisions to upsize equipment on non-capacity projects is generally based on standard engineering practice and is not solely a financial consideration

- Because PG&E works with standardized equipment, there is a limited range of opportunities to upsize
- In many cases, upsizing has a minimal impact on project scope and cost
- In other cases, factors beyond solely economics must be considered
- Engineers leverage planning standards in designing and upsizing equipment

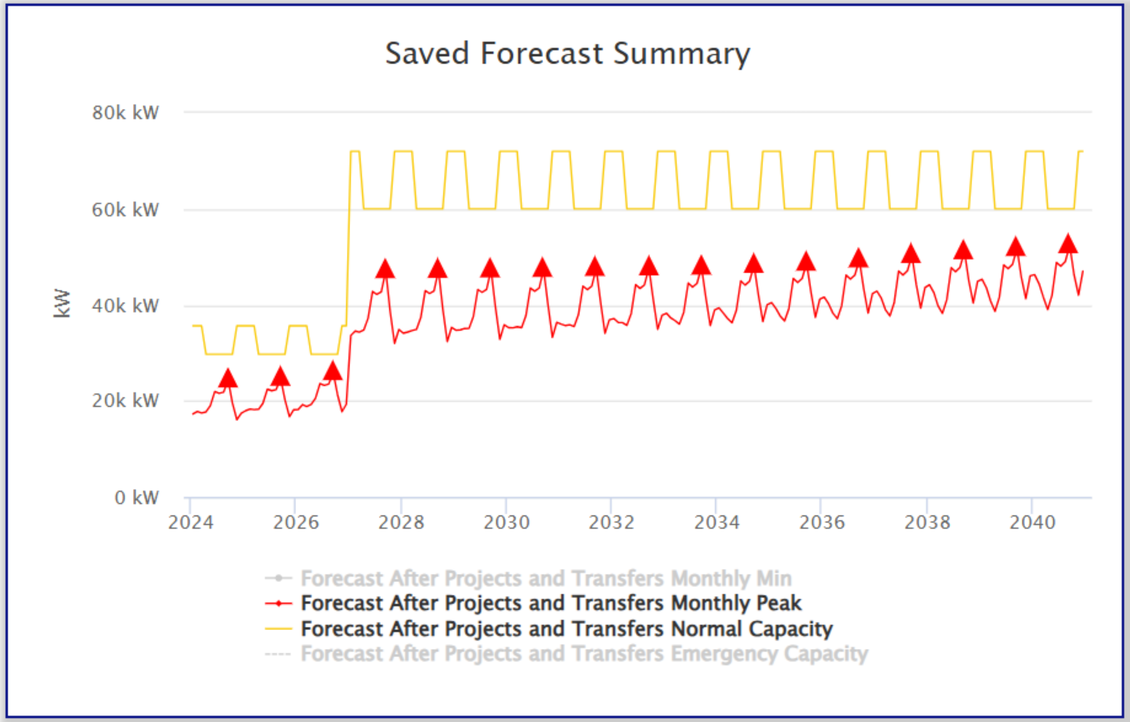
Project Type	Size Options	Impact of Upsizing	Approach to upsizing
Undergrounding tap line	1/0 in 4” conduit	n/a	n/a
Undergrounding main line	600Al in 6” conduit 1,100Al in 6” conduit	Mostly material cost (10-20% impact on project cost)	Upsize if needed for growth
Hardening overhead	1/0 (interior only) #2 (coastal only) 397Al 715Al	Larger wire triggers larger poles, more poles, and more guying, impacting project right-of-way needs, constructability, and schedule	Engineering evaluation of financial and non-financial factors
Replacing substation transformer	3.5-7MVA (1-phase) 5-75MVA (3-phase)	If there is space for the larger bank and the feeders it will ultimately serve, the impact is mostly material cost.	No-regrets: upsize if needed for growth and/or ultimate design
		If there is not space, the larger transformer triggers significant additional work.	Engineering evaluation of financial and non-financial factors

Asset sizing

Load forecasting and area planning ensure that distribution engineers size assets to address the risk of future overloads

- **Load & Planning Forecast Review**
  - 16-year load forecast
  - 10-year planning forecast and area plan
  - 5-year bank & feeder project plan
  - 3-year line section project plan
- **If approved, Pending Loads & Scenario Planning will enable more holistic area planning**
  - Upsizing decisions will consider low, base, and high scenarios, separating pending loads by level of confidence
- **Decisions requiring engineering evaluation:**
  - Preliminary design & cost estimate
  - Constructability
  - Timing
  - Permitting
  - Level of confidence in load growth
- **Additional for substation: Ultimate Design review**
  - Ultimate Design defines total # of banks & feeders that substation can serve if fully built out
  - Defined by parcel size and high-side voltage

LoadSEER 16yr Forecast



- *Bank & feeder level load forecast*
- *Planning forecast:*
  - *Years 1-5: **initiate** projects to address overloads*
  - *Years 6-10: **identify** projects to address overloads*

Powering Progress: How PG&E Engineers Tailor Capacity Sizing for Every Project

- **Standard Guidance as Foundation**
- PG&E provides clear standards and planning guidelines for capacity sizing, including forecasting, asset evaluation, and reliability requirements. Distribution Engineers use tools like LoadSEER for 10-year planning forecast (16-year load forecast) and apply company-wide protocols for asset sizing and deficiency analysis.
- **Project-Specific Engineering Analysis**
- Each project is evaluated individually, considering unique characteristics such as geography, load profiles, and operational needs. Distribution Engineers analyze historical and projected loads, identify deficiencies, and recommend corrective actions tailored to local conditions.
- **Role of Senior Engineers**
- Senior Engineers lead the asset planning framework, integrating information from various sources and specialties to resolve complex problems
- They approve final load growth regression models and oversee the application of standards, ensuring consistency and technical rigor.

PG&E Asset Sizing Standards

PG&E standards specifies that the local electric distribution engineer to consider load growth when sizing equipment

4.1 Basic Criteria

Distribution system capital investments, including DER deployments will be made so that forecast loads or added generation can be supplied without:

A. loading any substation or distribution facilities beyond their normal capability during normal conditions or emergency capability during emergency conditions, and

B. allowing the voltage on the non-express portion of any feeder to deviate from the applicable voltage limits under either normal or emergency conditions, as per the Distribution System Voltage Regulation Drawing 027653 and Electric Rule 2, and

C. risking interruptions to service that would be unreasonable in their frequency, extent and/or duration.

PG&E Electric Planning Manual, Ch. 2

Before designing a main-line system, the electric distribution engineer must incorporate the specific information listed below.

A. The locations of new and future loads relative to existing substations and circuits.

B. The maximum normal and emergency demands of the load area.

C. The main-line route plan for the affected substation and other available circuit routes.

D. Changes in area load patterns and/or other developments that could affect the area being served.

PG&E Electric Design Manual, Ch. 2

Design Guideline 023068: Guide for Economical Selection of Distribution Conductors

General Information

1. "Economical conductor size" is defined as the size of conductor providing the lowest present annual cost of investment and loss. Electric Distribution Planning Engineers may need to select the next larger economical conductor size listed due to other considered factors i.e. area load growth, reliability, voltage issues.
2. Consult with local electric planning personnel to ensure consistency when selecting the most economical conductor or cable and when sizing facilities based on emergency use.

PG&E Electric Design Manual, Ch. 16

The electric distribution engineer evaluates voltage and power factor when determining main line conductor size and adapts the design by adding voltage regulators or reducing main line conductor size, as necessary.

Project Specific Considerations in Capacity Grid Sizing

Project Timing
- Timely upgrades prevent overloads and deficiencies.
- Schedules must match forecasted growth and deadlines.
- Early planning adds flexibility and reduces risks.

Permitting Needs
- Permitting can drive schedules and add uncertainty.
- Multiple agencies, each with unique requirements.
- Early engagement helps avoid delays.

Forecasted Growth
- Sizing considers known and anticipated growth.
- Scenario planning maintains flexibility for future needs.
- Engineers balance risks of over- and underbuilding.

Zoning
- Zoning affects siting, design, and construction.
- Restrictions may require design changes.
- Early coordination streamlines approvals.

Material Lead Times
- Critical materials may have long lead times.
- Early procurement and contingency planning help avoid delays.

Operational Flexibility
- Extra assets may be added for flexibility and future growth.
- Flexibility helps the grid adapt to changing conditions.
- Additional infrastructure may be recommended.

Economics
- Generally done within distribution engineer scope rather than a separate analysis
- In edge cases, requires a specific economic analysis (described on next slides)

Economic Assessment (when needed)

Quantifiable cost factors

- A preliminary design is available
  - Feet of conductor/cable can be estimated
  - Preliminary device counts: switches, protective devices, regulators, capacitors
- Unit costs
  - Regional: bay, non-bay
  - OH vs UG
  - New trench vs existing spares
  - Not cable or conductor size dependent

Other cost factors: constructability

- Detailed designs are not available yet
  - This will occur once scope is finalized and project is approved, kicked off, and estimated
- Cost risks depend on a constructability review incorporating many factors, for example:
  - Access and working space
  - Age & health of existing poles
  - Daytime vs overtime work
  - Pole spacing (note: this is dependent on conductor size)

Detailed Economic Assessment (when needed)

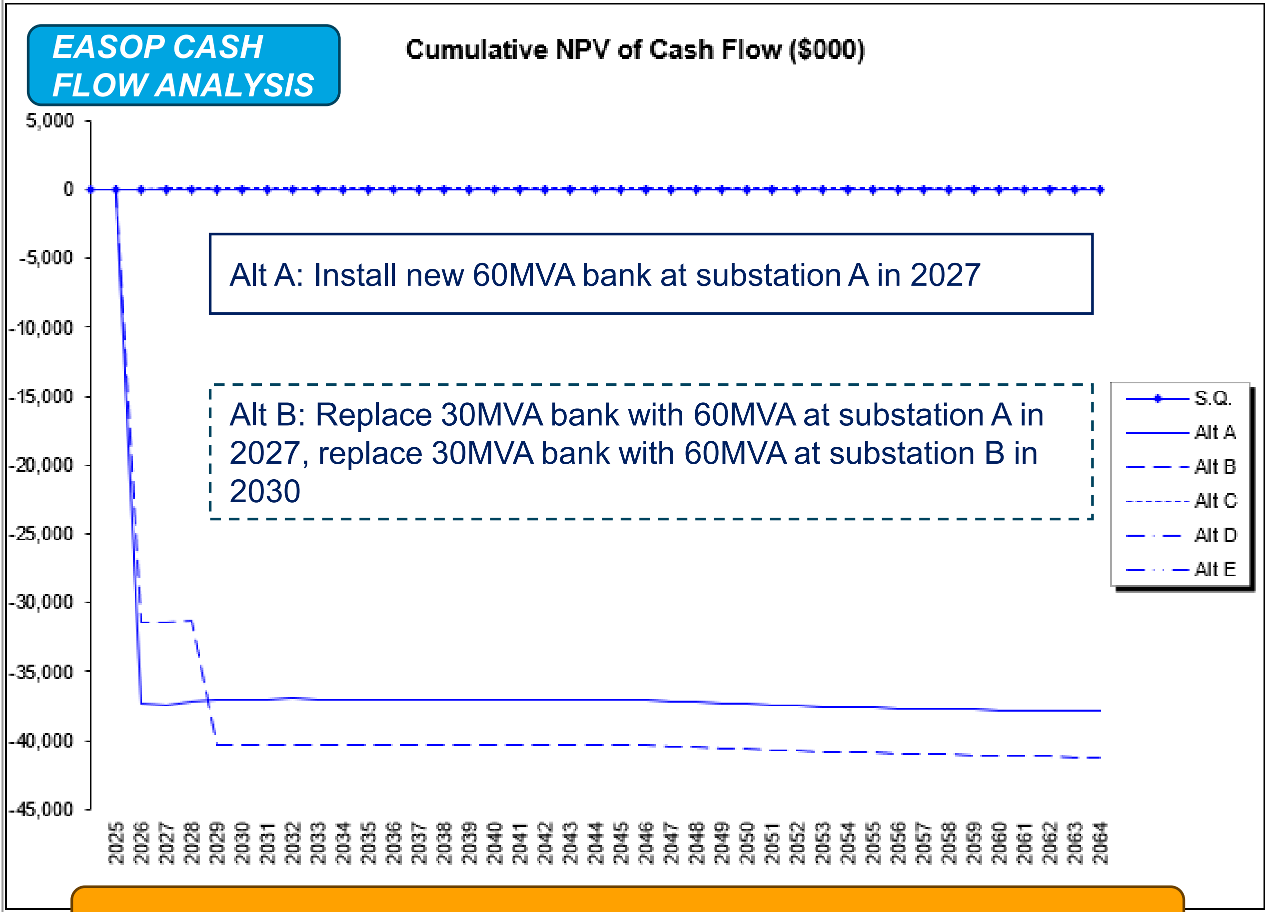
Engineers have tools to perform detailed net-present cost analysis (when needed)

EASOP tool:

- **PG&E internal Economic Analysis tool**
- **Integrates PG&E's most recent authorized cost of capital**
- **Facilitates net-present cost comparison of capital and expense components**
- **Base Case analysis includes only "hard" costs and benefits**
- **Expected Case analysis includes "soft" costs and benefits weighted by likelihood**

When it would be used:

- **Used in exceptional cases as one input—not the sole determinant—within a broader engineering framework.**
- **If upsizing will be expensive but will mitigate a significant future investment need**
- **There are numerous significant costs and benefits to weigh**
- **Different alternatives have significantly different long-term maintenance expense needs (rare)**



In this example, a higher upfront investment reduces long term costs

Engineering Standards & Expertise with Economic Analysis as one Input

Prioritizing Engineering Expertise with Economic Analysis as Input

For non-capacity projects with forecasted capacity needs in future years:

- Engineering decisions are grounded in established standards and professional expertise to ensure safe, reliable, and efficient outcomes.
- Distribution and Senior Engineers have the responsibility and authority to make decisions that reflect technical integrity, operational reliability, and customer needs
- Long-term forecasts—such as a 16-year horizon—serve as critical inputs for planning and prioritization.

Engineering decisions are essential and based in standards:

- Each project is unique, and engineering decisions are essential to address operational nuances and site-specific consideration. A structured economic analysis can provide one input to a data-driven foundation for evaluating upgrade options when appropriate.
    - Tools like EASOP may be used in exceptional cases as one input—not the sole determinant—within a broader engineering framework.
    - Engineers are trained to assess and perform economic analyses as part of their decision-making process, applying these evaluations when needed to support project outcomes.
    - Even when EASOP suggests a preferred option, engineers may select a different course based on standards, risk assessment, and holistic considerations.

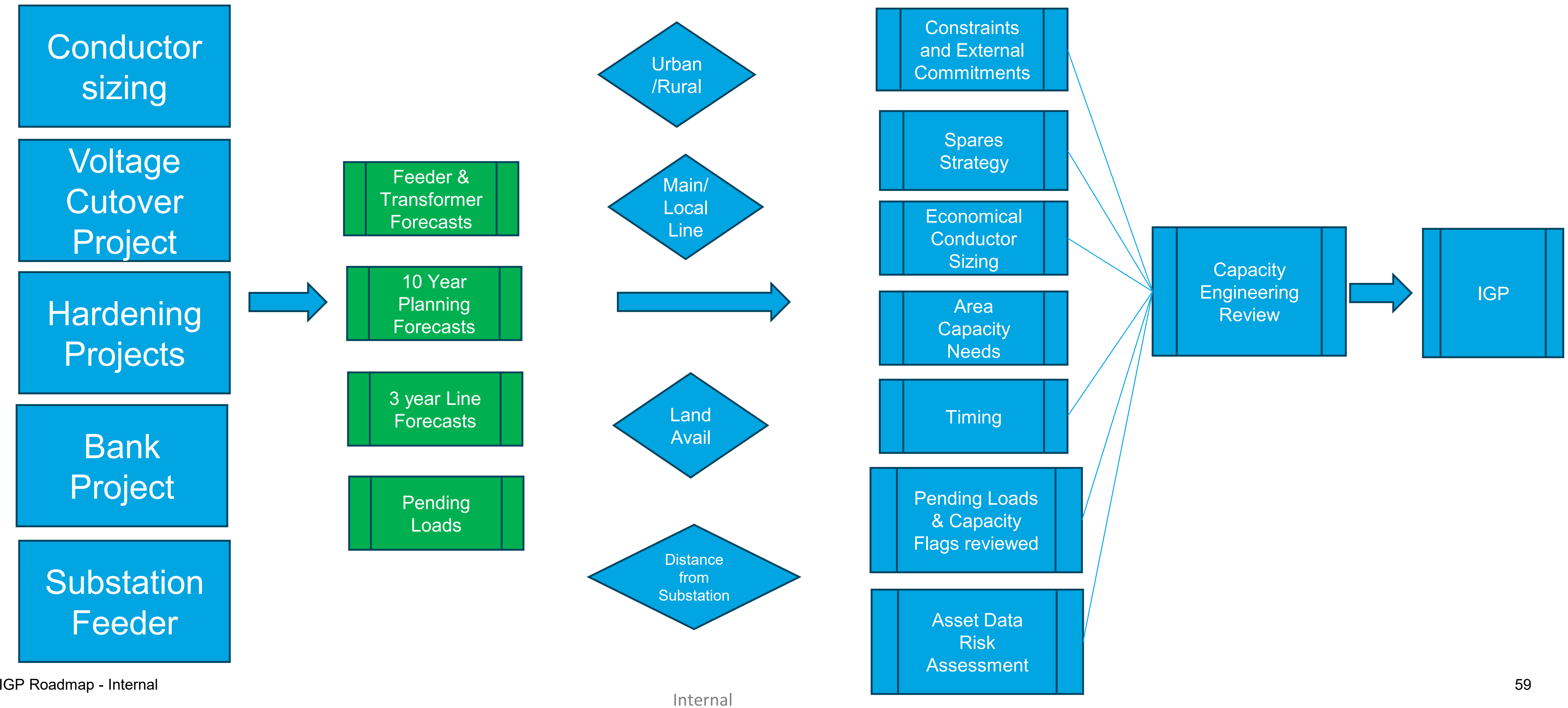
Bottom Line:

- Analytical rigor is balanced with the flexibility and insight of experienced engineers, ensuring every project receives the most appropriate and responsible solution.

Powering Progress: How PG&E Engineers Tailor Capacity Sizing for Every Project

Distribution and Senior Engineers Review

Project Type | **Forecasts** | **Project Specifics** | **Engineering Evaluations**



Smart Sizing in Action: PG&E's Project-Specific Approach to Grid Capacity

Collaboration and Oversight

- Substation feeder sizing and other key decisions are made collaboratively between Area Senior Engineers and local Distribution Engineers, applying both standard principles and project-specific judgment. Supervisors review and approve proposed projects, ensuring that all relevant alternatives and updates have been considered.

Engineering Upsizing Decisions

- While standard guidance informs the process, the final call on upsizing assets rests with the engineers, who weigh cost/benefit tradeoffs, timing, uncertainty, and operational flexibility.
- The "de minimis principle" is applied: upsizing is pursued if the incremental cost and complexity are minimal compared to long-term benefits.

Affordability and Customer Impact

- Engineers are responsible for ensuring that solutions maintain affordability for customers, balancing investment costs with reliability and future growth needs
- Affordability metrics and customer impact are considered in prioritizing and justifying projects.

Exception Cases

Engineers need the ability to override purely financial guidance in consideration of non-financial factors

Types of exception cases:

- Upsizing conductor will enhance transfer capabilities in the area
- Knowledge of area indicates potential future needs beyond forecast
  - Example: vacant lot zoned for development
- Other planned or likely work in the area will address the capacity need
  - Example: adjacent substation bank is aging and may need replacement soon
- Increased scope will impact the timing of the project
  - Example: larger substation transformer requires relocation of equipment
  - Example: larger conductor requires more and larger poles, increasing guying requirements and right-of-way needs

Limits of Economic Analysis framework

Apply only to instances where a non-capacity project replaces an asset with a later capacity need

- Other design standards inform capacity project sizing, example:
  - Economical conductor sizing
  - Electric design manual informs spares strategy
  - Electric planning manual defines minimum area & substation bank and feeder capacity
- Does not determine non-sizing design guidelines
  - Substation bus arrangement
  - Spares
  - Feeder routing

Appendix

Economical Selection of OH Distribution Conductors

023068: Guide for Economical Selection of Overhead Distribution Conductors

1. "Economical conductor size" is defined as the size of conductor providing the lowest present annual cost of investment and loss. Electric Distribution Planning Engineers may need to select the next larger economical conductor size listed due to other considered factors i.e. area load growth, reliability, voltage issues.

Table 1 Overhead Primary, Short-Span Urban Construction, Light Loading District

Conductor Type	Conductor Size (AWG or kcmil)	Economic Load Limit (Amperes) [1]			
		Annual Load Factor			
		0-40%	41-60%	61-80%	81-100%
Copper	#2–7 [2]	105	80	65	45
ACSR	#2–7/1 [3]	85	60	50	40
Aluminum	4/0	215	155	125	105
	397.5	370	270	215	180
	715.5	Thermal Limit	Thermal Limit	Thermal Limit	Thermal Limit

Additional tables for:

- Overhead Primary, Rural Construction, Light Loading District
- Overhead Primary, Rural Construction, Intermediate/Heavy Loading District

Selection of conductors for overhead hardening

15.6. Conductors in HFTD and HFRA Areas

Level 1 Hardening does not permit the installation of covered conductor/tree wire for any work.

For all Level 2 Hardening work, the following are PG&E standard conductor sizes allowed in Tier 2 and Tier 3 fire areas (installing of new bare overhead primary conductor is not permitted):

- 1/0 Aluminum Conductor Steel-Reinforced (ACSR) tree wire
- 397 All Aluminum Conductor (AAC) tree wire
- 715 AAC tree wire

For Moderate and Severe corrosion/coastal areas use:

- #2 copper (Cu) tree wire
- 397 AAC tree wire
- 715 AAC tree wire

Covered XLPE Tree Wire

Table 18 Primary Aluminum ACSR and Copper XLPE Tree Wire
Reference PG&E Engineering Material Spec. # 83

Conductor Size AWG or kcmil [2]	Str.	Nominal OD over Bare Conductor (inches)	Nominal Covering Thickness (mils)			Nominal outside Diameter over Outer Layer (inches)	Maximum Rated Strength (lbs.)	Weight (lbs./ 1000 feet) [1]	Standard Reel Length (feet)	Code
			Conductor Shield	Inner Layer	Outer Layer					
#2 HD Cu	7	0.292	25	75	75	0.642	2,240	324	5,000	M290432
1/0 ACSR	6/1	0.398				0.748	4,160	294	5,000	M301616
397.5	19	0.723				1.074	6,754	612	3,500	M290430
715.5	37	0.974		80	80	1.344	12,160	992	2,500	M290431

[1] Weight is slightly different among approved manufactures. Weight must not exceed value shown in this table.
[2] Hard Drawn (HD); Aluminum Conductor Steel Reinforced (ACSR); All Aluminum Conductor (AAC).

Selection of conductors for undergrounding

Electric Design Manual, Chapter 2: “General Design Criteria for Primary Underground and Overhead”

2.5.6. Underground Main-Line Design

A. New underground main line is three-phase with either 600-kcmil Al or 1,100-kcmil Al conductor in a 6-inch conduit with 600-Amp terminations.

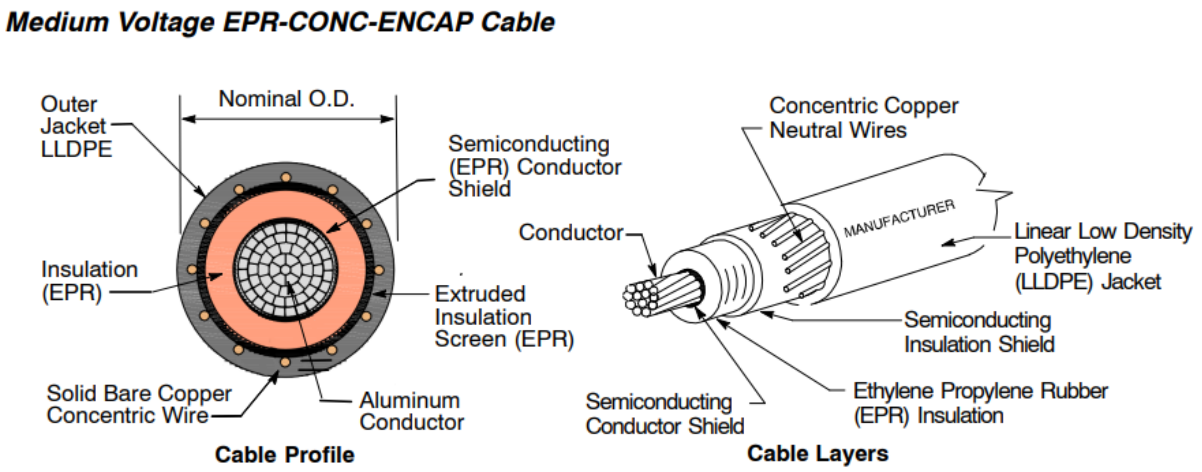


Figure 1
15–35 kV EPR-CONC-Encap LLDPE Cable

Cable		Nominal OD Over Conductor (inches)	Nominal OD Over Insulation (inches)	Nominal OD Over Jacket (inches)
Size	Rating			
#2 [1, 4]	15 kV	0.280	0.770	1.080
1/0 – 1/C [1]	25 kV	0.357	0.923	1.224
1/0 – 2/C [1]		–	–	2.448
1/0 – 3/C [1]		–	–	2.637
600 – 1/C [2]		0.814	1.408	1.745
600 – 3/C [2]		–	–	3.759
1,100 –1/C [2]		1.100	1.698	2.071
1,100 –3/C [2]		–	–	4.385 [3]
1/0 – 1/C [1]	35 kV	0.357	1.110	1.45
350 – 1/C [1]		0.622	1.376	1.703
1,100 – 1/C [2]		1.100	1.876	2.249

Unit Costs: Line Equipment, by Region

Refreshed in each GRC filing: Workpaper Chapter 17, Table 27

Description	Unit Cost[1]	Per
Non-Bay		
OH New	$160	Foot
OH Reconductor	$160	Foot
OH Capacitor (Cap)	$46,500	Capacitor
OH Switch	$51,000	Switch
OH Regulator	$285,000	3 Regulator Bank including material
OH Recloser	$101,000	Recloser
OH Fuse/Disconnect	$12,500	Fuse/Disconnect
Autotransformer	$1,700,000	Autotransformer
UG New w/trench	$490	Foot
UG New no trench	$295	Foot
UG Switch	$115,000	Switch
UG Interrupter	$155,000	Interrupter

(1) Unit Costs are derived from recorded costs of similar work

Description	Unit Cost[1]	Per
Bay		
OH New	$505	Foot
OH Reconductor	$505	Foot
OH Capacitor (Cap)	$46,500	Capacitor
OH Switch	$51,000	Switch
OH Regulator	$285,000	3 Regulator Bank including material
OH Recloser	$101,000	Recloser
OH Fuse/Disconnect	$12,500	Fuse/Disconnect
Autotransformer	$1,700,000	Autotransformer
UG New w/trench	$1,055	Foot
UG New no trench	$480	Foot
UG Switch	$115,000	Switch
UG Interrupter	$155,000	Interrupter

(1) Unit Costs are derived from recorded costs of similar work

Selection of Substation Transformers

Table 5.6 Single-Phase Transformer Ratings

Available MVA	Available Primary kV	Available Secondary kV	Percent Impedance
2.8/3.5 MVA	60, 70, 115	12, 17	8.0
3.33/4.167 MVA	60, 70, 115	12, 17	8.0
5.25/7.0 MVA	60, 70, 115	12, 17	8.0

Table 5.4 Preferred Ratings of Three-Phase Transformers

MVA	Primary kV	Secondary kV
5	60	12
10/12.5	60[e], 70[e]	12
12/16	60[e], 70[e], 115	12, 17[f], 21
18/24/30	60[e], 70[e], 115, 230	12, 17[f], 21
27/36/45	60[e], 70[e], 115, 230	12, 17[f], 21
36/48/60[g]	115, 230	12, 17[f]
45/60/75[g]	115, 230	21

Unit Costs (Substation)

Refreshed in each GRC filing: Workpaper Chapter 17, Table 27

Description		Unit Cost[1]		Per
New Substation Total		$28,750,000		Substation
Construction		$20,350,000[2]		Substation
Regulatory		$6,000,000		Substation
Land		$2,400,000		5 Acre Parcel
Substation Transformers		$14,550,000		Transformer, = < 45 MVA with Switchgear
		$10,650,000		Transformer, = < 45 MVA Outdoor Bus, Install
		$7,650,000		Transformer, = < 45 MVA Outdoor Bus, Replace
		$1,100,000		Cost adder for transformer > 45 MVA
Transmission Voltage Circuit Switcher or Breaker		$2,650,000		High Side Circuit Switcher or Circuit Breaker
Distribution Voltage Breakers		$1,400,000		Low Side Circuit Breaker
Recable SF Circuit outlet in indoor substations		$1,100		Foot

(1) Unit Costs are derived from recorded costs of similar work

(2) New Substation unit cost excludes MWC 60/61 equipment (transmission voltage equipment upstream of banks)

PG&E Q&A

Open Discussion and Next Steps

Next Steps

- Workshops have concluded
- Submit questions and comments to the High DER Proceeding (R.21-06-017) Service List by Tuesday, December 2 for IOUs to consider in their Advice Letter
- IOU Tier 3 Advice Letters due by Monday, December 15, 2025
- Energy Division will submit a resolution in Q1 2026

1-Hour Lunch

12:30 PM – 1:30 PM

(if needed) Continue Open Discussion and Next Steps