PACIFIC GAS AND ELECTRIC COMPANY

ELECTRIC DISTRIBUTION RESOURCES PLAN

JULY 1, 2015

PURSUANT TO PUBLIC UTILITIES CODE 769 AND

CALIFORNIA PUBLIC UTILITIES COMMISSION

ORDER INSTITUTING RULEMAKING 14-08-013

PACIFIC GAS AND ELECTRIC COMPANY
DISTRIBUTION RESOURCES PLAN

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Executive Summary

Executive Summary

Pacific Gas and Electric Company (PG&E) submits its Electric Distribution Resources Plan (DRP) in compliance with the statutory criteria adopted by the California Legislature in Assembly Bill (AB) 327, Public Utilities Code Section 769, and in accordance with the guidance provided pursuant to Rulemaking (R.) 14-08-013 and the Assigned Commissioner's Ruling dated February 6, 2015 (Guidance Ruling). PG&E's DRP is a foundational step in enabling California's environmental and energy policy goals through grid modernization, and PG&E looks forward to participating in this proceeding with other stakeholders under the Commission's leadership.

PG&E's DRP applies the criteria in Public Utilities Code Section 769 to identify optimal locations for the deployment of distributed energy resources (DERs) within PG&E's service area.[1] PG&E has analyzed over 3,000 of its distribution feeders to provide granular information on potential optimal locations for DERs on its electric distribution grid. This is a significant step in enabling increased DER penetration.

Further, PG&E has identified the need for additional investments to integrate cost-effective DERs onto its electric distribution grid, and will request approval of these additional investments in its next General Rate Case (GRC). PG&E's DRP also outlines planned improvements and enhancements to its distribution capacity planning tools and methods. These investments and improvements will further enhance PG&E's industry-leading DER interconnection times.

As the owner and operator of PG&E's electric distribution grid, PG&E provides customers with reliable energy services and enables customer choice through DER program management and industry-leading interconnection. PG&E's DRP reflects customers' expectation of a flexible, resilient and well-maintained grid that allows them to take full advantage of new energy technologies while ensuring that electricity continues to flow safely and reliably as well as

[1] Pursuant to Public Utilities Code Section 769, "distributed energy resources" include distributed renewable generation resources, energy efficiency (EE), energy storage, electric vehicles (EV) and demand response (DR) technologies. Most of these DERs are located on the customer-side of the meter, *e.g.,* "behind the meter." Each of these DERs also has different technical, installation and operating characteristics that affect the methods and processes by which each are integrated with PG&E's electric distribution grid and utility services.

efficiently, conveniently and at affordable cost. Balancing these objectives will be challenging and require an extended time to account for dynamic changes in technology, the entrance of new non-regulated participants behind-the-meter, and to apportion the investments, costs and risks equitably across all of the participants in the energy value chain.

The DRP supports California's major energy policy initiatives for achievement of the State's 2020 and 2050 greenhouse gas (GHG) reduction targets, including recognizing the critical role DERs may play in helping to meet these targets. In particular, PG&E's DRP continues PG&E's Smart Grid, Electric Program Investment Charge (EPIC), and GRC-funded initiatives to modernize its electric distribution system to accommodate two-way flows of energy and energy services, enabling customer choice for new technologies and services and providing new opportunities for new DERs to be integrated onto the grid.

PG&E's DRP also proposes several initiatives to enhance the transparency of its distribution planning and DER interconnection processes, including providing customers and DER developers with additional access to distribution planning data and technical criteria on a geo-spatial level where available distribution capacity exists, and therefore where interconnection of certain types of DERs may be less expensive than in other areas.

The DRP also recognizes that the integration of DERs into PG&E's electric distribution planning process and investments will be an on-going process, spanning multiple years and GRCs. To that end, PG&E proposes a process for implementing PG&E's DRP through PG&E's triennial GRC and EPIC investment proceedings, so that the Commission and all stakeholders can provide continuing oversight and input into the implementation of PG&E's DRP.

In compliance with these overall objectives, PG&E's DRP is organized as follows:

Chapter 1 PG&E's Distribution Resources Plan: Policy and Vision delineates PG&E's long-term vision for the interconnected Grid of Things™, in which the electric grid is the platform that enables continued gains for clean-energy technology, DERs, and customer choice, while ensuring the continued safety, reliability and affordability of the service that PG&E provide to its customers, through operation of the electric distribution grid.

Chapter 2 Distribution Resources Planning details PG&E's methodologies for Integration Capacity Analysis and Optimal Location Benefit Analysis. The purpose of these methodologies is to enhance the integration of DERs interconnected with PG&E's electric distribution grid. Chapter 2 also provides three DER Growth Scenarios based on potential trends for growth of DERs in PG&E's service area over the ten year period 2016-2025.

Chapter 3 Demonstration and Deployment summarizes PG&E's recommended DER Demonstration and Deployment Projects which will test PG&E's enhanced DER integration methodologies for dynamic integrated capacity analysis, optimal location analysis, calculation of DER locational values, distribution operations at high penetrations of DERs, and potential DER dispatch to meet distribution reliability and capacity needs.

Chapter 4 Data Access proposes policies and procedures to expand for the sharing of relevant data among utilities, DER developers and customers to support the transparency and timeliness of DER siting, installation and operation, consistent with customer privacy, electric grid security (including physical and cyber security), and protection of market sensitive and proprietary information.

Chapter 5 Tariffs and Contracts summarizes existing tariffs and contracts that govern DERs. This chapter also references to other pending proceedings where changes to existing DER tariffs and contracts, including reforms to Net Energy Metering (NEM) tariffs and electricity rate designs, are needed and being considered in order to make the allocation and pricing of DER costs and benefits more equitable and consistent with CPUC ratemaking principles and the cost-effective deployment of DERs.

Chapter 6 Safety Considerations identifies the safety and reliability standards that apply to the expanded integration of DERs into PG&E's electric distribution planning and grid operations. As the volume of DER interconnections increases, PG&E will continue to re-evaluate its existing safety and reliability standards and in some cases, may propose new standards to ensure public and system safety, as well to maintain system reliability.

Chapter 7 Barriers to Deployment reviews potential barriers to DER deployment, including the need for changes to electricity pricing policies in order to ensure cost-effective deployment of

DERs. Where barriers have already been evaluated and addressed in other forums, PG&E does not recommend duplicative consideration in the DRP proceeding.

Chapter 8 DRP Coordination With General Rate Cases provides PG&E's recommendations on next steps to implement its DRP through GRCs and other proceedings as required by Public Utilities Code Section 769, including timing of ratemaking changes to recover the incremental costs of DRP tools, methodologies, processes, and demonstration and deployment projects.

Chapter 9 DRP Coordination With Utility and California Energy Commission Load Forecasting discusses how PG&E's DRP results and DER growth scenarios can be integrated with PG&E's and the California Energy Commission's (CEC) planning processes, as well as the CPUC's Long-Term Procurement Plan (LTPP) and the California Independent System Operator's (CAISO) Transmission Planning Process (TPP).

Chapter 10 Phasing of Next Steps discusses PG&E's next steps towards implementing the new and updated tools and processes in the DRP into distribution system planning, operations and investment.

The DRP marks an important step in enabling its customers and DER providers to play an active, participatory role in the grid. PG&E actively supports this new world and looks forward to continuing to develop the essential, enabling platform for use by existing as well as innovative technologies that will ultimately benefit California's economy, the environment and our customers.

Chapter 1 – PG&E's Distribution Resources Plan:

Policy and Vision

1. PG&E's Distribution Resources Plan: Policy and Vision

1.a. PG&E's Distribution Resources Plan Enables Significant Distributed Energy Resource Integration and Supports California's Clean Energy Vision

PG&E continues to be committed to modernize the electric grid with new technologies that improve electric service and benefit Californians. This DRP outlines improvements to electric distribution planning processes, tools and methodologies so that new DERs can be integrated throughout PG&E's electric grid. These significant improvements yield benefits not only to PG&E's customers, but also to the economy, the environment, and to new energy market participants.

PG&E has demonstrated energy innovation and leadership through numerous accomplishments, including the following:

- Pioneering SmartMeter™ deployment, allowing customers to access granular energy data, and utility planners to better monitor and maintain the electric system, including restoring service much faster during outages.
- Globally recognized for its EE and DR programs, which provide cutting edge tools and financial incentives for customers to manage their energy use more efficiently.
- Investing in leading-edge emerging energy technologies, as detailed in PG&E's Smart Grid Deployment Plan and EPIC plans to modernize and transform PG&E's electric grid, leveraging digital, "self-healing", and "smart" technologies, such as intelligent switches, to improve the safety, reliability and cost-effectiveness of PG&E's utility services. For instance, PG&E is implementing voltage control technology that manages the two-way flow of electricity on the grid to enable the increasing amount of interconnected distributed resources, such as rooftop solar units on our distribution system.
- Delivering record electric grid reliability performance for the sixth consecutive year, reducing both the frequency and duration of customer outages as part of a multi-year grid reliability improvement project. Achieving these high levels of reliability despite strong winter storms and the most powerful earthquake to hit its service area in 25 years.
- As one of the cleanest energy utilities in the nation, PG&E delivered more than 50 percent of its power in 2014 from zero greenhouse gas (GHG) emitting sources.
- In addition, in 2014, 27 percent of the electricity PG&E delivered to customers came from renewable resources, such as solar and wind putting PG&E on track to meet California's Renewables Portfolio Standard (RPS) goals by 2020.

- Interconnecting more than 176,000 solar Photovoltaic (PV) rooftops—more than any other utility in the country by a wide margin. PG&E connects new solar customers to the grid approximately every 11 minutes, and PG&E's territory comprises over 25 percent of the solar rooftop installations in the United States.

- Proposing methods to further electrification of transportation, including the broader adoption of electric vehicles (EVs), such as through PG&E's proposed network of 25,000 EV chargers as well as other programs. PG&E is implementing a major smart-charging pilot program with automaker BMW that pays EV owners for the use of their batteries as tools in stabilizing the grid.

- Developing a Green Tariff community solar program giving customers the choice to cover either 50 percent or 100 percent of their electricity use with power from small and midsize solar projects within PG&E's service area.

These accomplishments and others represent PG&E's strong commitment to enhancing the grid and providing increased benefits to its customers. This forms the foundation for PG&E's DRP to support increased DERs, with the grid as the enabling platform to connect EVs, rooftop solar, microgrids, community and individual energy storage, and many other emerging technologies.

PG&E's Grid of Things™ vision is to integrate new energy devices and technologies to the grid and allow their owners - our customers - to achieve greater value from their energy technology investments – rooftop solar, EVs, storage, DR technologies, etc. - by virtue of their grid connectivity. PG&E is the key builder and enabler of this interconnected and integrated platform that will define California's future energy landscape.

PG&E's DRP facilitates the development of this modern and flexible future grid in several significant, unprecedented ways:

- The enhanced distribution capacity planning process provides a systematic method to integrate DERs, ensure DER compliance with safety and reliability standards, and enable sufficient capacity to deliver electric service to customers under a range of operating conditions.

- PG&E's dynamic Integration Capacity Analysis is performed for over 3,000 distribution feeders on multiple nodes in each line section, which provide information on available capacity for DERs on the distribution system.

- The DRP's Optimal Location Benefit Analysis methodology quantifies a DER's impact at specific locations on the grid and translates that impact into identification of potential avoided or increased costs associated with the DER's type and location.

- The DER Growth Scenarios provide the ability to identify trends in DER growth on a geo-spatial, granular level, so that PG&E's distribution planning can take into account the growth of DERs at the feeder level, and down to each line section as necessary.

1.b. PG&E's Role as Central Integrator, Grid Owner and Operator Is Essential to Achieving California's Goals for Safe, Clean, Affordable, Reliable and Resilient Energy

The electric grid is a complex, highly technical system that is one of the greatest engineering feats of humankind. The grid must operate not only within safety, reliability and affordability standards but also must provide essential services in order to power the needs of PG&E's customers. These services include: high power quality, sufficient capacity, start-up power, back-up power, steady state voltage, balanced transmission, distribution and grid-edge power and operating in an always on continuous mode during all potential conditions ranging from winter storms, to peak hot summer days, and during both weather and non-weather related emergencies. The distribution grid is complex, and has been engineered for one-way, reliable power flow. Transitioning the grid to accommodate two-way power flow in a distributed and potentially more intermittent energy environment is complex. Further, the transition must be done in an orderly manner over time to maintain safety, reliability and affordability objectives.

In order to balance utility infrastructure investments and ensure unnecessary risks are not inappropriately imposed on PG&E or its customers, PG&E and DER providers also must commit to proper planning and funding of the necessary technical, operational, safety and reliability investments that will enable a strong, optimally functioning grid and provide enhanced benefits to customers. As examples, in a high DER-penetration world, PG&E has identified that the following types of requirements are essential for both customer-side investments and utility-side grid investments for a safe, reliable and affordable grid for all customers:

Distribution Capacity and Control Requirements: DERs should help reduce the net loading on specific distribution infrastructure when an operational need is identified. DERs should also have interoperable automated control systems which could include pricing signals or other control mechanisms.

Steady-State Voltage: DERs should provide voltage management services, such as voltage regulation, that can mitigate voltage fluctuations as well as support PG&E's voltage conservation investments and strategies which enable less use of energy and reduce GHG emissions.

Power Quality: DERs should provide dynamic transient voltage and/or power harmonics mitigation service in coordination with utility voltage control and protection schemes to ensure grid stability, safety and reliability is maintained.

Reliability/Resilience: DERs should be capable of minimizing electric service disruptions and improving the ability to restore electric service following routine outages, as well as major or catastrophic events (*e.g.*, earthquakes, wildfires, flooding).

Physical and Cyber Security: DERs should comply with industry standards and best practices in protecting the grid from threats to the physical security and cyber-security of the grid. This also requires that DERs implement security enhancements and improvements as industry security standards evolve to meet new and advanced threats.

In a high penetration DER world, the need for coordination between DER providers and PG&E, central owner and operator of the grid, is necessary for several important reasons. First, PG&E is obligated to serve all customers including in areas where DERs do not have an economic incentive to provide services. Second, PG&E, in coordination with the CAISO, the Federal Energy Regulatory Commission (FERC), and other entities must support the safety, stability and reliability of power throughout California and the Western United States. The safe and reliable operation of the electric distribution and transmission grids, as well as the entire Western bulk power system, is a requirement of utilities. Third, PG&E must ensure reliable power that integrates DERs and also provides power when DERs are offline, experiencing intermittency, power fluctuations or generating insufficient power during peak periods. Fourth, PG&E is obligated to plan and mitigate for situations ranging from daily operational needs to larger emergency or even catastrophic issues and provide for the safety of the public, its employees, and the electric system overall.

Finally, to ensure compliance with state and federal regulatory commitments, while enabling the increasing penetration of DERs which are not subject to the same regulatory oversight, PG&E needs to maintain the appropriate visibility, operator, control, and coordinating role.

1.c. Achieving the Long Term DRP Vision Requires Significant and Coordinated Electricity Pricing Reform

Implementing the DRP vision requires equitable, cost-based pricing and cost recovery structures. Both DER providers and the utilities should be actively engaged in the regulatory and policy dialogue and be provided the appropriate cost-effective incentives and compensation mechanisms commensurate with their respective service responsibilities, guarantees and obligations. Significant investments will be needed to continue to modernize the grid as well as to achieve California's clean energy vision. It is essential that all stakeholders in the energy value chain contribute their equitable share of the costs as well as mitigate the risk the utility incurs to enable and provide energy services.

The transformation of the electricity grid must ensure that electricity remains affordable to the millions of utility customers; at the same time the future transformed grid will need to recognize the differentiated needs of customers and their right to choose these differentiated services. In other proceedings before the CPUC (namely, Residential Rate Design Reform and NEM 2.0), PG&E has outlined proposed reforms to California's residential electricity rate design to enable grid modernization and the DRP. Further DER pricing reforms are needed to ensure equitable pricing, protect customers from inequitable cost-shifting, and also allow for the future investments needed to achieve California's clean energy goals. Without the CPUC's adoption of these reforms, cost-effective grid investments are compromised and many customers will be faced with disproportionately higher, inequitable bills. The need for electricity pricing reform is underscored here due to the critical role of equitable electricity rates in achieving the DRP vision.

1.d. Building the Future Grid – PG&E's Strategy for Achieving the Goals of Its Electric Distribution Resources Plan

Along with other stakeholders and as demonstrated in its DRP, PG&E has an important role in building and enabling the new energy platform envisioned for California. The DRP is an important element of PG&E's Grid of Things™ vision to bring benefits to California, foster innovation and DER integration, and enable collaboration in a world of rapid change.

PG&E's DRP outlines the principles and specific enhancements to electric distribution planning and operations that PG&E recommends to enable this transformation of the electric grid. These are summarized below:

- Interconnection and Integration Efficiency: PG&E will continue to provide industry leading interconnection service and transparent information to customers to efficiently interconnect and integrate DERs. PG&E's Integration Capacity methodology and tools described in Chapter 2 of the DRP will further improve the integration of DERs in the future.

- Transparent Locational Benefits and Costs Evaluation: PG&E's Locational Value Methodology described in Chapter 2 uses objective and transparent criteria for evaluating the locational benefits and costs of customer-owned or operated DERs, including methods for quantifying financial benefits and costs attributable to local integration of DERs. The Demonstration and Deployment Projects described in Chapter 3 will demonstrate the application of PG&E's enhanced DER integration methodologies for dynamic integrated capacity analysis; optimal location benefit analysis; calculation of DER locational benefits; enabling distribution operations at high penetration of DERs; and greater DER dispatch to meet reliability needs. The criteria and demonstration projects will assist customers, DER developers and PG&E in identifying locations where DERs can provide local, objectively-quantified benefit to reduce costs and improve grid reliability and safety.

- Consistent Scenarios of Distribution Capacity and Resources: The DRP provides long-term and short-term scenarios of electric distribution capacity needs, costs, and benefits using the best information available, building on specific geo-spatial scenarios and trending of DER growth as described in the DER Growth Scenarios discussed in Chapter 2.

- Effectively-Managed Overlapping Initiatives: As described in Chapters 5, 6, 8 and 9, PG&E's electric distribution planning aligns with its on-going business strategy, initiatives and proceedings, including the GRC, LTPP, customer rates and tariffs including NEM tariffs and retail electric rates, the Smart Grid Deployment Plan, EV programs and tariffs, and electric distribution operations.

- Fair and Transparent Processes for DER Deployment and Integration: As described in Chapters 2 and 7, PG&E will establish fair and transparent processes to evaluate DER alternatives to conventional distribution system services or capacity investments. PG&E plans to also establish tools to inform DER service providers about locations on the distribution system where it may be more cost effective to integrate DERs to provide distribution capacity and related services.

CONCLUSION

PG&E sees tremendous opportunity for customers to have increased choice to manage their energy usage while PG&E enables a safe, reliable, affordable and clean energy future.

California and its utilities have shown a strong commitment to leadership on energy innovation and clean energy goals. This will require that PG&E continue working in concert with regulatory and policy stakeholders as well as DER providers to create a 21st-century electric grid. From renewables and energy storage to electric vehicles and smart homes and appliances, the utility grid is the platform for integrating and optimizing a growing array of new technologies. As such, ongoing innovation and investment in utility infrastructure under equitable electricity pricing policies is critical to California's ability to achieve its environmental, energy affordability and energy reliability goals.

The following chapters of PG&E's DRP provide a detailed discussion of PG&E's proposed plans, initiatives, projects and activities to enable the Grid of Things™ and implement the foundational DRP policy principles discussed above.

Chapter 2 –

Distribution Resources Planning

2. Distribution Resources Planning

INTRODUCTION

The Guidance Ruling directs PG&E, Southern California Edison Company (SCE) and San Diego Gas & Electric Company (SDG&E) (together the Investor Owned Utilities or IOUs) to develop three analytical frameworks to better integrate the capacity of DERs into the distribution planning process, including quantifying DER locational net benefits and taking into account future growth of DERs. The three analytical frameworks are: (**1) Integration Capacity Analysis; (2) Optimal Location Benefit Analysis; and (3) DER Growth Scenarios**. These three analytical frameworks are intended to create tools that detail how much DER can potentially be deployed under a business as usual distribution grid investment trajectory, and build the capabilities to compare portfolios of DERs as alternatives to traditional grid infrastructure.

This Chapter describes how PG&E's DRP complies with the Guidance Ruling and is organized as follows:

Section 2.a. PG&E's Distribution Planning Process: This section provides an overview of PG&E's electric Distribution Planning Process (DPP), including foundational concepts of safety, reliability and affordability, and the primary objectives of distribution planning. Having a basic understanding of the distribution planning process is essential to determine the potential levels at which DERs can be deployed on PG&E's distribution grid.

Section 2.b. Integration Capacity Analysis: This section provides PG&E's analysis of estimated DER integration (or hosting) capacity that may be available on PG&E's distribution system using an initial Integration Capacity methodology comparable to the methodology used by SCE and SDG&E. The IOUs have collaborated to coordinate on a common methodology. At a high level the commonalities are obtained through: (1) utilizing dynamic planning tools for circuit modeling and analysis; (2) analysis of similar power system criteria; and (3) performing analysis and retrieving line section results. PG&E's recent investments in advanced power flow analysis and load analysis tools have allowed the Company to analyze a multitude of line sections across its 3,000+ distribution feeders at multiple nodes based on hourly feeder load and DER profiles.[2]

Section 2.c. Optimal Location Benefit Analysis: This section describes PG&E's methodology for analyzing the benefits and costs associated with DERs to determine optimal locations for DERs. First, PG&E identifies components of locational value associated with DERs. In doing so, PG&E adapts the Energy + Environmental Economics (E3) calculator as well as the Commission's additional value components identified in the Guidance Ruling. Second, PG&E describes its method for calculating a DER's potential locational net benefit for each value component. Third, PG&E describes its proposed method for considering locational net benefits when identifying optimal locations. As requested by the Guidance Ruling, this framework for analyzing the benefits and costs of DERs has been developed in coordination with SCE and SDG&E.

Section 2.d. DER Growth Scenarios: As required by the Guidance Ruling, this section describes three 10-year scenarios for potential DER growth through 2025. PG&E summarizes the methods used to develop these DER growth scenarios for the following types of DERs listed in the Guidance Ruling: EE, DR, Retail Distributed Generation (DG), EVs, Wholesale DG, Large-Scale Combined Heat and Power (CHP), and Wholesale Storage. The scenarios provide relevant data for PG&E's DPP to help determine geographic areas of potential future DER growth that may result in additional distribution capacity investments to enable DERs, while helping identify other areas where this growth may result in deferred distribution capacity investments.

2.a. PG&E's Distribution Planning Process

PG&E's DPP ensures the availability of sufficient capacity and operating flexibility for the distribution grid to maintain a reliable and safe electric system. PG&E engineers accomplish this by: (1) forecasting load and peak demand; (2) using power-flow modeling tools to simulate electric grid performance under projected conditions to forecast distribution capacity

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[2] PG&E has approximately 3,200 distribution feeders, but around 200 of these feeders are classified as tie, single customer/dedicated, and network feeders. These feeders were declared not necessary or not applicable to perform integration capacity analysis.

requirements; and (3) identifying and developing distribution capacity additions that meet forecasted conditions that address identified distribution capacity requirements, including safety and reliability deficiencies.

PG&E's distribution system must be planned to include sufficient transmission, substation and circuit capability that ensures:

A. Substation and distribution facilities are not loaded beyond safe operating limits;

B. Voltage supplied to the customer is within limits as required by CPUC Rule 2 and industry electric system reliability standards; and

C. The reliability of continuous customer service is maintained in accordance with best industry practices and customer expectations for system reliability.[3]

PG&E currently maintains visibility and control of the distribution system via Supervisory Control and Data Acquisition (SCADA) and other systems which are necessary to ensure these grid safety, voltage and reliability operating requirements are met. DERs must meet the same technical and operating standards as the rest of the distribution system such that when DERs are interconnected, they do not impact the safety and reliability of the distribution grid.[4] Visibility and control of interconnected DERs is also necessary to ensure overall grid safety, voltage and reliability operating requirements are met.

Table 2-1 below provides a summary of some of these technical and operating standards that DERs and distribution capacity additions must meet under PG&E's DPP.

[3] As of 2014, PG&E maintains a reliability of customer service within 99.9 percent across the entire service territory based on CPUC-reported System Average Interruption Duration Index (SAIDI) numbers: http://www.pge.com/includes/docs/pdfs/myhome/outages/outage/reliability/AnnualElectricDistributionReliabilityReport.pdf

[4] PG&E's GRCs include PG&E's evaluation and forecast of future necessary distribution capacity additions.

TABLE 2-1 PG&E ELECTRIC DISTRIBUTION SERVICE REQUIREMENTS

Service	Description	DER Functional Requirements	DER Technical Requirements	Examples of Utility “Wires” Equipment That Support Providing Service
Distribution Capacity	Load modifying or supply service capable of reliably and consistently reducing net loading on desired distribution infrastructure	Resource or aggregated set of resources that are able to demonstratively reduce the net loading on specific distribution infrastructure coincident with the identified operational need in response to an economic (e.g., dynamic rate or price) or control signal. Firm service is characterized by direct (not human interface) control system interface with an individual DER or aggregator’s control system.	• Response time • Performance measurement data reporting • Measurement granularity • Interface Protocols for measurement and control system • Cybersecurity requirements • Communications bandwidth and latency requirements • Other	• Service Transformer • Substation Transformer • Overhead Line Conductors • Underground Conductor • SCADA • SmartMeter™
Steady-State Voltage	Feeder level dynamic voltage management service	Feeder level voltage management service provided by an individual resource and/or aggregated resources capable of dynamically and demonstrably responding to excursions outside voltage limits as requested by utility as well as supporting conservation voltage strategies in coordination with utility voltage/reactive power control systems.	• Response time • Performance measurement data reporting • Measurement granularity • Interface Protocols for measurement and control system • Cybersecurity requirements • Communications bandwidth and latency requirements • Other	• Fixed or Switchable Capacitors (including controllers) • Fixed and Variable Voltage Regulator (including controllers) • SCADA • SmartMeter™ • Overhead Conductor • Underground Conductor • Substation Load Tap Changer • Reactor

TABLE 2-1
PG&E ELECTRIC DISTRIBUTION SERVICE REQUIREMENTS (CONT.)

Service	`Description	DER Functional Requirements	DER Technical Requirements	Examples of Utility "Wires" Equipment That Support Providing Service
Power Quality	Transient voltage and/or power harmonics mitigation service	Feeder level transient voltage and/or power harmonics mitigation service capable of dynamically and demonstrably responding to unacceptable fast transients and harmonic components as requested and in coordination with utility voltage control and protection schemes.	• Response time • Performance measurement data reporting • Measurement granularity • Interface Protocols for measurement and control system • Cybersecurity requirements • Communications bandwidth and latency requirements • Other	• Fixed or Switchable Capacitors (including controllers) • Overhead Conductor • Underground Conductor • SCADA • SmartMeter™
Reliability + Resilience	Load modifying or supply service capable of improving local distribution reliability and/or resiliency	Substation or feeder level firm dispatchable resource and/or aggregated resources as required to address reliability needs based on real-time operational conditions. Resource or aggregator's control system must be capable of receiving and confirming utility dispatch signal as well as continuously providing discrete measurement of resource response during operation.	• Response time • Performance measurement data reporting • Measurement granularity • Interface Protocols for measurement and control system • Cybersecurity requirements • Communications bandwidth and latency requirements • Other	• Breaker and Relay • Fuse • Recloser and Recloser Controller • Switches • Sectionalizer • Fault Interrupter • SCADA • Fault Location, Isolation and Service Restoration • SmartMeter™

PG&E's annual distribution capacity planning process ensures that the distribution grid and PG&E's utility services meet the reliability and safety standards and also takes into account recorded and expected DERs that may impose additional costs or provide incremental benefits to the distribution grid.

PG&E's Distribution Capacity Program cost-effectively addresses: (1) capacity expansion necessary to meet customer demand growth; (2) expected equipment overload conditions; (3) voltage and power factor compliance requirements and (4) electrical protection coordination.[5] Each year, PG&E analyzes the peak demand or loads by comparing future load forecasts against available capacity, then develops specific capacity projects for the following year, and identifies additional work that the forecast indicates is necessary in future years. In developing this plan, the Capacity Program management process allows PG&E to: (1) apply uniform planning standards and guidelines to distribution capacity capital projects; (2) consistently manage the risk of equipment failure due to overload conditions and prioritize projects system-wide; (3) manage resources more efficiently; (4) make adjustments as conditions change throughout the year; and (5) forecast future expenditures and manage overall spending.

The Capacity Program management process involves six general steps:

2.a.i. Identify Need

PG&E's service territory consists of over 3,000 feeders and 1,300 distribution banks under the responsibility of 12 local area planning groups. Each year, the planning groups prepare load growth / forecasting studies, identify area and equipment overloads and quantify capacity deficiencies.[6] Using uniform capacity planning guidelines and engineering standards, the area planning groups identify solutions that address these deficiencies. The planning groups also prepare detailed forecasts for the subsequent two years and provisional forecasts for the larger individual capacity projects (such as substation transformers, distribution circuit or other large

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[5] This description of PG&E's Distribution Capacity Program is consistent with PG&E's prepared testimony in its 2014 GRC application, A.12-11-009.

[6] PG&E's LoadSEER is a load forecasting program that forecasts at the feeder and bank level, which is rolled up to the Distribution Planning Area (DPA) level.

projects to increase capacity) for the next five years. The current forecast incorporates the effect of DERs to the extent these items are reflected in historical peak loads.

2.a.ii. Evaluate Project Alternatives

Evaluate project alternatives, which include installing new or upgrading existing electric distribution facilities and/or deploying programs that reduce peak demand by DERs that can address electric capacity deficiencies.

2.a.iii. Estimate Project Costs

The area planning groups then develop project cost estimates. For most projects, the area planners develop costs using either estimates of specific equipment and work required unit costs, or historical costs from completed projects.

2.a.iv. Project Consolidation

Projects from the local planning area groups are consolidated for evaluation and prioritization. With input from staff engineers and other managers, one of the lead engineers reviews each project and examines the historic spending trends of the smaller recurring projects. The lead engineer assesses projects based on the overload or deficiency forecast, as well as costs, then makes preliminary budgeting recommendations for both large projects (*e.g.*, substation transformers and distribution feeders) and smaller recurring projects (*e.g.*, voltage, conductor upgrade and distribution line transformer related projects).

2.a.v. Finalize Funding Plan

After further evaluation of the preliminary plan and new information from the local planning groups, the lead engineer develops a funding plan for the subsequent two years and a provisional plan for the next five years. This plan is then provided to the work execution teams for implementation.

2.a.vi. Ongoing Evaluation

The funding plan is re-prioritized as required throughout the year to: (1) ensure completion of high priority work; (2) maintain an accurate forecast of year-end expenditures; and (3) monitor spending.

PG&E's DRP describes new processes to be used in its electric Distribution Capacity Planning Program to evaluate potential DER alternatives that, if technically and economically feasible, could meet projected distribution capacity and reliability needs.[7] PG&E has developed an enhanced utility planning standard for assessing DER alternatives to traditional distribution capacity additions as a part of ongoing electric distribution capacity planning (DER Alternative Standard). This DER Alternative Standard expands the scope of PG&E's original *mobile generation* standard to include all DERs that meet the technical and operating standards needed to maintain the safety and reliability of the distribution grid.

PG&E has decades of experience with the complexities of the distribution and transmission grid system. Planning for the electric distribution grid is a complex and thoughtful process that has been performed and refined for many years. Electricity is essential to customers' everyday lives, including the need for 24 × 7, on-demand availability under both normal and unusual operating conditions. Proper planning to meet the multi-faceted needs of the electric grid on a day to day basis is extremely important and is becoming even more important to serve the increasingly differentiated needs of consumers—including consumers who both consume and produce energy—in the future. PG&E's DRP is an important step to integrating DERs, but new processes, systems and technologies also will be required, especially at higher DER penetration levels to maintain dynamically coordinated, safe and reliable operations into the future.
The DRP is one of many steps that must be taken to ensure proper DER integration while still providing the same level of quality and reliable service to customers.

2.b. Integration Capacity Analysis

The Guidance Ruling requires PG&E to analyze how much DER hosting capacity may be available on its distribution network. To implement this analysis, PG&E is required to include seven elements in its DRP discussed below. PG&E's recent investments in its advanced distribution planning tools and underlying datasets have allowed PG&E to analyze DER integration capacity on its distribution feeders on multiple points (*i.e.*, nodes) in each line section based on detailed distribution circuit models and hourly feeder load and DER profiles.

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[7] As the Guidance Ruling notes, the use of DERs to traditional transmission capacity additions requires further coordination and collaboration with the CAISO and other bulk power system operators throughout California and the West.

For this Plan, PG&E analyzed approximately 500,000 nodes across 102,000 line sections for its 3,000 + distribution feeders.[8]

Section 2.b.i provides an overview of PG&E's Integration Capacity Analysis methodology that analyzes how much potential, point-in-time DER integration capacity may be available on any distribution feeder using an Integration Capacity Analysis methodology comparable to SCE and SDG&E. Section 2.b.ii.1-7 addresses the specific elements required by the Guidance Ruling to demonstrate how PG&E implemented its analysis.

2.b.i. Overview of Integration Capacity Analysis Methodology

At a high level, PG&E's Integration Capacity Analysis methodology takes the components of a detailed interconnection study process to develop a streamlined approach to identifying available capacity. PG&E's streamlined Integration Capacity Analysis provides faster results than a detailed interconnection study along with a higher level of accuracy than a Fast Track screen.[9] PG&E's approach is similar to the Electric Power and Research Institute (EPRI) streamlined hosting capacity for PV Interconnection. Like EPRI, PG&E's framework provides a methodology that can be regularly applied to analyze its entire service territory.[10]

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[8] PG&E has approximately 3,200 distribution feeders, but around 200 of these feeders are classified as tie, single customer/dedicated, and network feeders. For PG&E's initial Integration Capacity Analysis, calculations were limited to three phase line segments only. Interconnections on two and single phase line segments should consult PG&E's Pre-Application Process.

[9] Fast Track Screens are a set of technical screening questions in the California Rule 21 Interconnection Tariff and FERC Wholesale Distribution Tariff that are meant to determine if detailed study is needed using a basic set of engineering data.

[10] See EPRI published report "A New Method for Characterizing Distribution System Hosting Capacity for Distributed Energy Resources: A Streamlined Approach for Solar Photovoltaics." http://www.epri.com/abstracts/Pages/ProductAbstract.aspx?productId=000000003002003278.

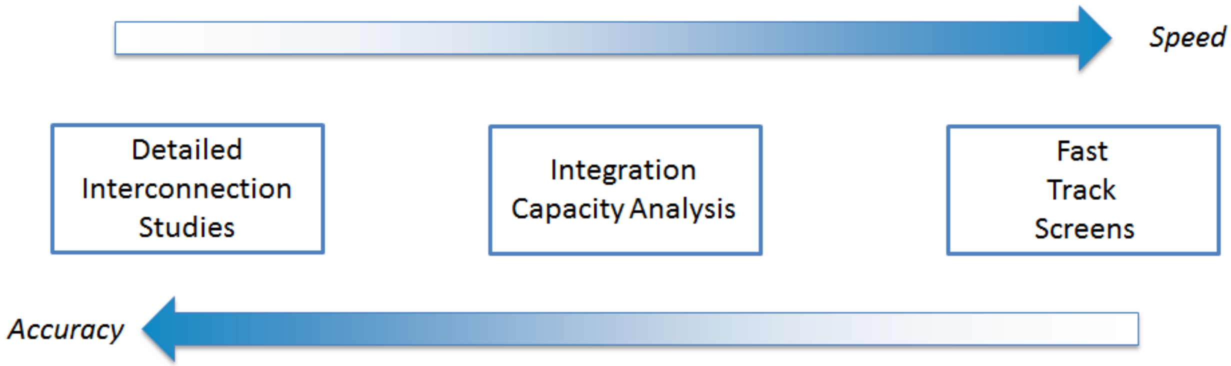


FIGURE 2-1: BALANCE OF SPEED AND ACCURACY BETWEEN DIFFERENT APPROACHES

PG&E's Integration Capacity Analysis methodology has three general steps: (1) establish distribution system level of granularity; (2) model and extract power system data; and (3) evaluate power system criteria to determine DER capacity. The three steps are explained in further detail below.

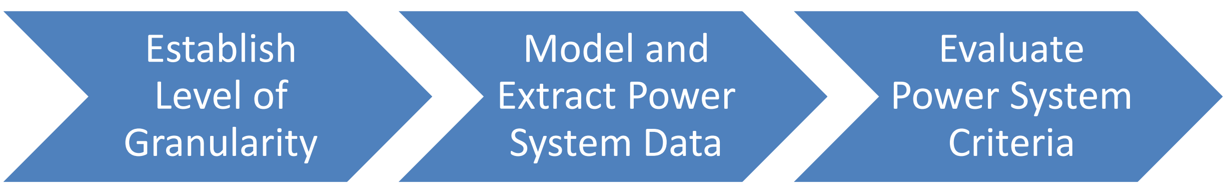


FIGURE 2-2: INTEGRATION CAPACITY ANALYSIS STEPS

2.b.i.1. Establish Distribution System Level of Granularity at the Line Section Level

The first step in PG&E's Integration Capacity Analysis methodology is to determine the distribution system level of granularity at the line section level. As part of PG&E's line section level analysis, PG&E further increased the level of granularity by analyzing selected line segments and nodes within each line section.

Figure 2-3 illustrates the three different components on distribution power lines. The next figure, Figure 2-4, represents these three components as they relate to a substation. PG&E's selection of its line segments and nodes within each line section is explained in more detail below.

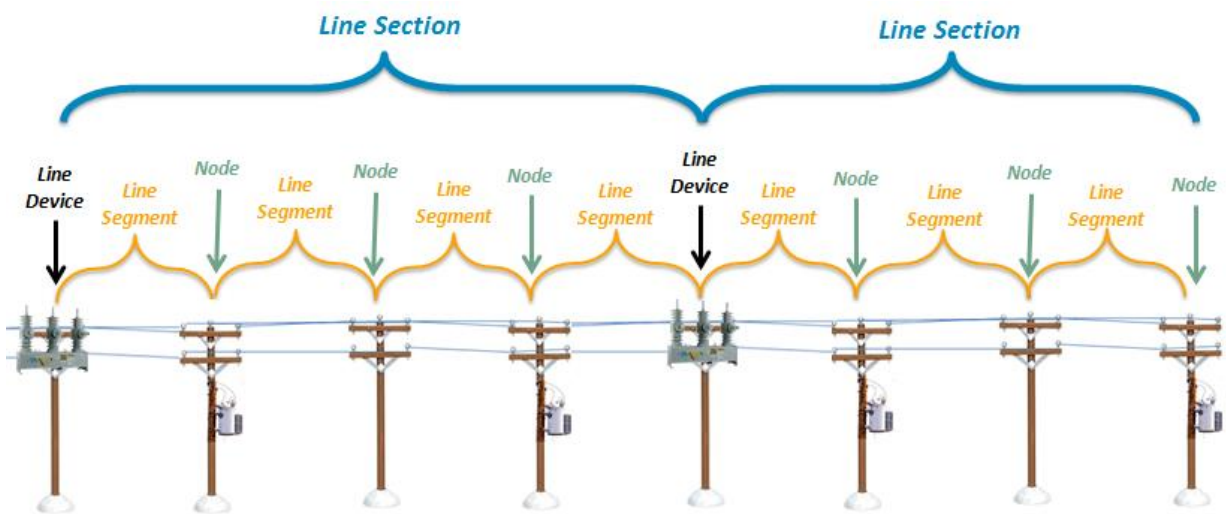


FIGURE 2-3: ANALOGY OF NODES, LINE SEGMENTS, AND LINE SECTIONS

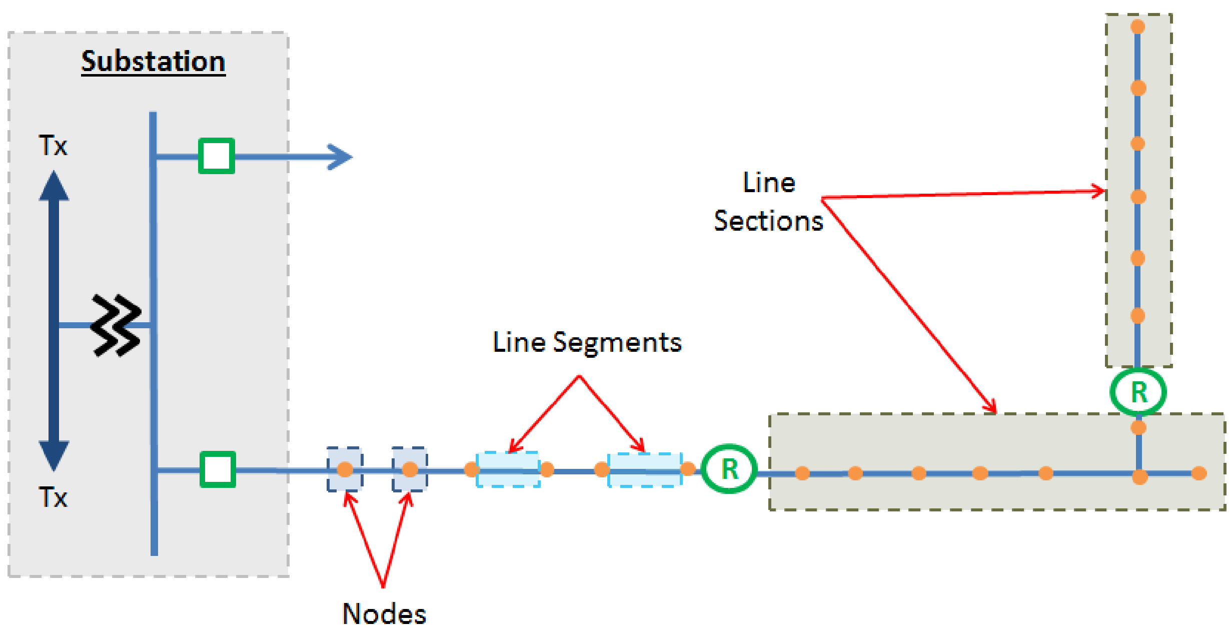


FIGURE 2-4: REPRESENTATION OF NODES, LINE SEGMENTS, AND LINE SECTIONS

Determining Line Sections

To determine line sections, PG&E identified line devices that would be most affected by changes in load or new DERs. Table 2-2 describes the selected line devices used in PG&E's analysis.

TABLE 2-2
LINE DEVICES USED FOR INTEGRATION CAPACITY LINE SECTION DELINEATION

Line Section Device	Description
Circuit Breaker:	Main circuit protection device that is the first device that distinguishes the beginning of the circuit
Line Recloser:	Line section protection device that protects a subset of the circuit
Sectionalizer:	Line section protection device that protects a subset of the circuit
Interrupter:	Line section protection device that protects a subset of the circuit
Load Tap Changing Voltage Regulator:	Series voltage regulating device that dynamically manages voltage within the circuit
Fixed Tap Voltage Regulator:	Series voltage regulating device that statically manages voltage within the circuit
Step Down/Up Transformer:	Series voltage conversion device that connects two subsets of a circuit of different voltage classes
Fuses:	Line section protection device that protects a subset of the circuit

Selection of Nodes

Within each line section, PG&E selected specific nodes to analyze a range of hosting capacity. The selected nodes were based on the impedance[11] factor, which characterizes the electrical distance to the substation. Impedance primarily determines voltage and amperage conditions at specific points on the grid. These nodes are considered the quartiles of the system Thévenin impedances within each line section. To provide a minimum and maximum (best and worst case) range of results, the first line section node (lowest impedance) and last line section node (highest impedance) must be evaluated. Table 2-3 describes the impedance value of each node:

[11] Impedance is the measure of the opposition that a circuit or distribution feeder presents to an electrical current when voltage is applied.

TABLE 2-3
DESCRIPTION OF SELECTED NODES IN EACH LINE SECTION

Node	Impedance Percentile	Impedance Quartile	Value of Result to Line Section
1	0	0	Minimum system impedance and electrically closest node to substation within the node set
2	25	1	Node with system impedance between point 1 and point 3 within the zone
3	50	2	Median system impedance and electrically “in the middle” of the substation and end of zone within the node set
4	75	3	Node with system impedance between point 3 and point 5 within the zone
5	100	4	Maximum system impedance and electrically furthest node from substation within the node set

Because Integration Capacity values within a given line section can vary depending on the range of impedance, it is important to analyze this variation. PG&E used the quartile selection to understand the range of possible results within a line section. Figure 2-5 illustrates the varying conductor sizes along a circuit. The smaller lines represent small conductors. The smaller the conductor, the larger the levels of impedance. For example, the impedance at the end of a circuit can be on average 8 times higher, with some ratios reaching a high of 100, than the impedance level at the substation where larger conductors are located.[12] Having such a drastic range of impedance levels could result in hosting capacity inaccuracies, unless the range of variation is considered. This is also why line section level detail is important as the average ratio of largest to smallest impedance across the line sections is two (2) rather than eight (8) for circuit level granularity. This will provide a tighter range of results on line section analysis instead of feeder level analysis.

[12] The impedance ratios were determined based on evaluation on the all three phase node impedances analyzed for all PG&E circuit models. These statistics are specific to PG&E and will vary based on specific utilities’ circuit designs and service territories.

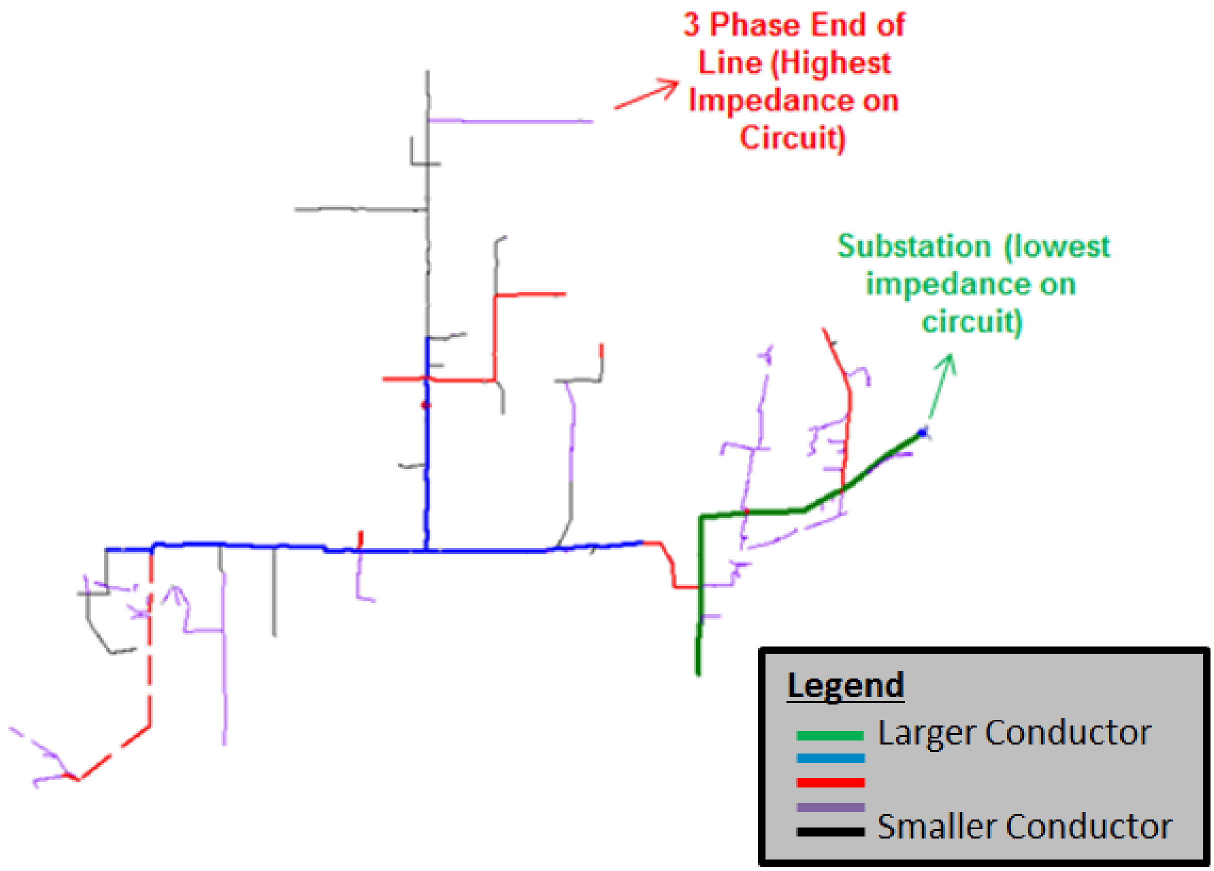


FIGURE 2-5: ILLUSTRATIVE EXAMPLE OF VARYING CONDUCTOR SIZES

2.b.i.2. Model and Extract Power System Data using Load Forecasting and Power Flow Analysis Tools

In step two of PG&E's Integration Capacity Analysis methodology, PG&E models and extracts the power system data needed by using two distribution planning tools. PG&E utilized its advanced planning tools to perform the necessary level of granularity and detail required by the Guidance Ruling. The first tool is a Load Forecasting Analysis Tool, LoadSEER by Integral Analytics, which takes electric power profile (*i.e.*, load and generation profile) data to determine the effects of load and generation on substation assets to determine necessary future investments. The second tool is a Power Flow Analysis Tool, CYMDIST by CMYE International, which calculates the effects of the forecasted power flows through the distribution system from the source to the loads on individual customer service transformers. These tools are currently used in PG&E's normal planning and interconnection study process and are discussed in more detail below.

Load Forecasting Analysis Tool

PG&E's DPP has transitioned from planning based on singular peak values to planning based on representative hourly power profiles. To develop power profiles, PG&E uses its Load Forecasting Analysis Tool that takes representative hourly customer load and generation profiles and aggregates them to determine power profiles at the feeder, substation and system levels. This tool is also used to determine substation level impacts due to forecasted load growth.

To collect customer usage data PG&E uses SmartMeters™, which capture energy usage data on regular intervals 24 hours a day, 7 days a week. SmartMeters™ have been deployed in most of PG&E's service territory. To collect system load data, PG&E uses SCADA metering that monitor certain assets on the power grid and gather load and power quality data. SCADA meters provide real-time operational data so that PG&E can improve power profiling and operate the grid.

In order for the Load Forecasting Analysis Tool to analyze power profiles at the distribution system level, power profiles for all customer class types in PG&E's approximately 245 Distribution Planning Areas (DPA) are created using load research data. These hourly power profiles represent a typical[13] day that each customer type would have during each month of the year. The representative power profiles are comprised of 288 data points that represent each hour for the 24-hour period in a typical day for each month. Figure 2-6 provides a visual example of a representative power profile versus a full detailed yearly profile. The top half of Figure 2-6 shows the representative profile utilized in the Load Forecasting Tool. The bottom half of Figure 2-6 shows the real-time hourly profile for a year represented by 8,760 hours that show the actual demand for each hour of the year. Representative profiling allows PG&E to determine substation power profiles in cases where 8,760 hour power profiles are not available.

13 The shape is representative of a typical shape, but non-typical peak load events are planned for by scaling the shapes based on the historic consumption, future growth, and 1-in-2/1-in-10 weather events.

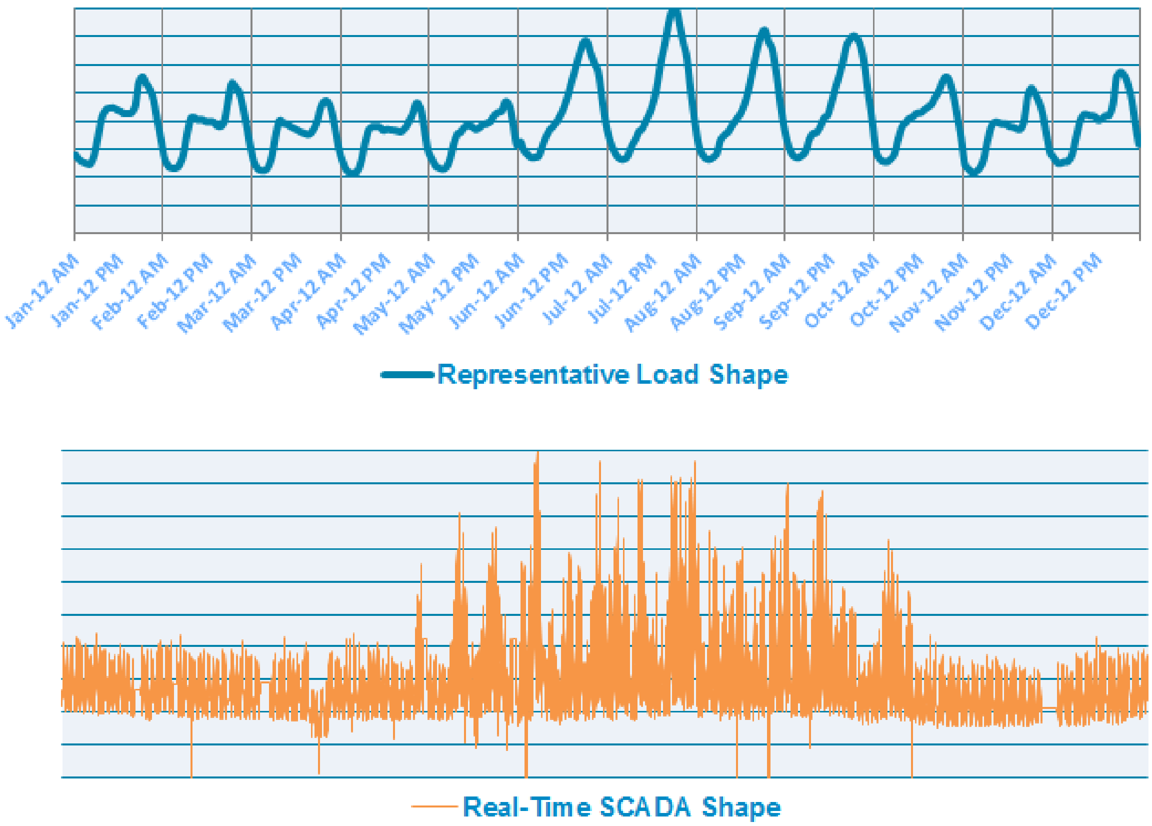


FIGURE 2-6: REPRESENTATIVE LOAD SHAPE COMPARED TO REAL-TIME SCADA

Power Flow Analysis Tool

PG&E models each of its distribution feeders using its Power Flow Analysis Tool. This tool analyzes power flow on distribution feeders by modeling conductors, line devices, loads, and generation to determine impacts on distribution circuit level power quality and reliability. Similar to how SCADA improves power profiling, Geographic Information System (GIS) mapping improves the ability for PG&E to analyze its system assets. GIS mapping traces the distribution system down to the service transformer level. Knowing the composition of a particular series of line conductors as well as their relative location from a power source allows engineers to determine impedance to a specific location on the distribution feeder. These electrical models are updated weekly to reflect changes that occur on PG&E's distribution system. This is distinct from power flow models that validate load flows and planning forecasts, which are updated seasonally.

Evaluating the power system criteria for Integration Capacity requires modeling and extracting data from power flow models. This data extraction is currently accomplished through using internal programming capabilities within the Power Flow Analysis Tool. PG&E has leveraged these programming capabilities to automate the data extraction, but has also utilized it to error check the various distribution feeder configurations results.

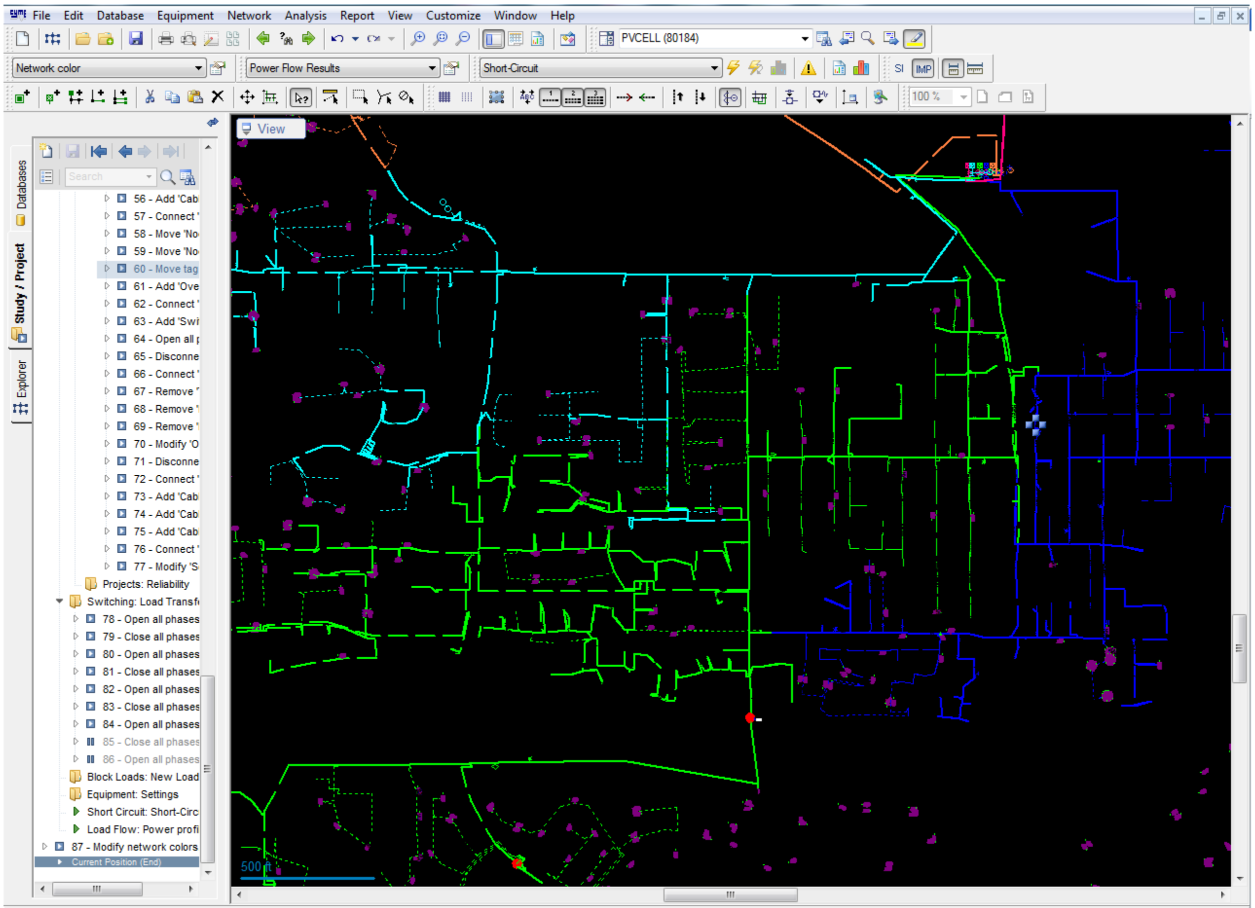


FIGURE 2-7: SCREENSHOT OF DISTRIBUTION CIRCUITS IN PG&E'S POWER FLOW MODELING TOOL

2.b.i.3. Evaluate Power System Criteria to Determine DER Capacity Limits

The third step in PG&E's Integration Capacity Analysis methodology uses the Load Forecasting and Power Analysis tools to evaluate certain power system criteria within the selected nodes and line sections to determine DER capacity limits on each distribution feeder. Integration Capacity Analysis results depend on the most limiting power system criteria. That is, whatever power system criterion has the most limiting capacity result, will establish the overall Integration Capacity result for that line section. Ideally, each criterion should be analyzed independently, to better understand the impact of each power system criteria. Figure 2-8 summarizes the evaluation criteria for Integration Capacity. This section outlines the Power System criteria and sub-criteria to comprehensively evaluate capacity limits, including the criteria analyzed by PG&E for its Initial Integration Capacity Analysis.

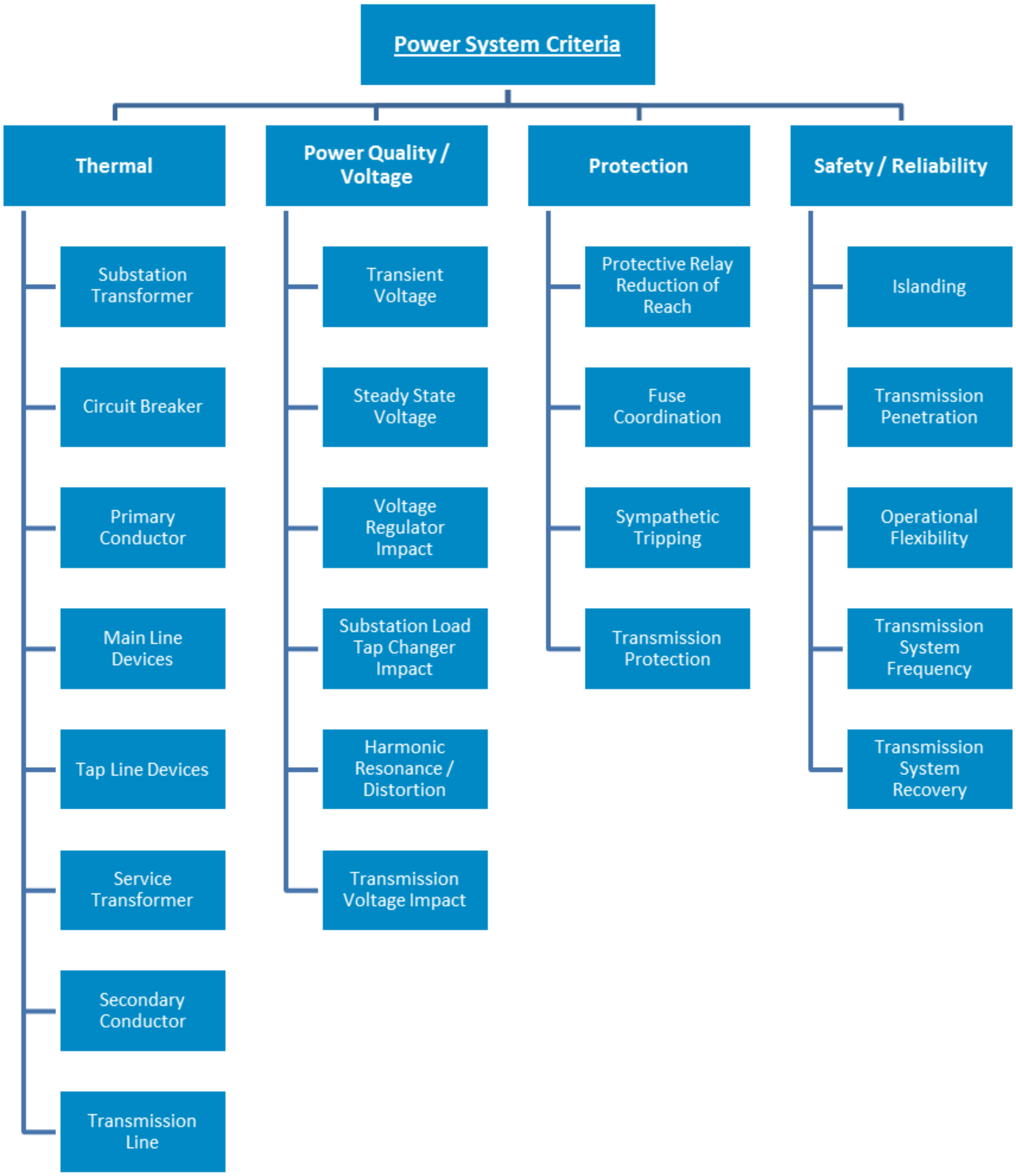


FIGURE 2-8: POWER SYSTEM CRITERIA TO EVALUATE CAPACITY LIMITS

Importance of Power System Criteria and Sub Criteria

Integration Capacity depends on many components that cannot be reduced easily to four calculations. There are additional sub criteria that should also be assessed. Table 2-4 listed below provides detailed criteria evaluated by PG&E, including additional criteria PG&E may consider evaluating in the future.

TABLE 2-4
POWER SYSTEM CRITERIA TO EVALUATE CAPACITY LIMITS

Power System Criteria	Initial Analysis	Potential Future Analysis
Thermal	✓	✓
– Substation Transformer	✓	✓
– Circuit Breaker	✓	✓
– Primary Conductor	✓	✓
– Main Line Devices	✓	✓
– Tap Line Devices	✓	✓
– Service Transformer		✓
– Secondary Conductor		✓
– Transmission Line		✓
Voltage / Power Quality	✓	✓
– Transient Voltage	✓	✓
– Steady State Voltage		✓
– Voltage Regulator Impact		✓
– Substation Load Tap Changer Impact		✓
– Harmonic Resonance / Distortion		✓
– Transmission Voltage Impact		✓
Protection	✓	✓
– Protective Relay Reduction of Reach	✓	✓
– Fuse Coordination		✓
– Sympathetic Tripping		✓
– Transmission Protection		✓
Safety/Reliability	✓	✓
– Islanding	✓	✓
– Transmission Penetration	✓	✓
– Operational Flexibility	✓	✓
– Transmission System Frequency		✓
– Transmission System Recovery		✓

Thermal Criteria

Thermal Criteria determines whether a particular resource causes a change in power flow to exceed any equipment thermal ratings. Exceeding these limits would cause equipment to potentially be damaged or fail.

Assessing thermal equipment loading is essential in distribution planning. When delivered power through a certain asset is determined to exceed its thermal rating, mitigation measures must be performed to alleviate the thermal overload. An hour-by-hour calculation is performed to determine the difference between the loading of the asset and the overload limit. This establishes a set of capacities for each hour. Since the goal is to find the most limiting capacity value, the minimum capacity of the hourly set is taken as the thermal limitation for the Integration Capacity result.

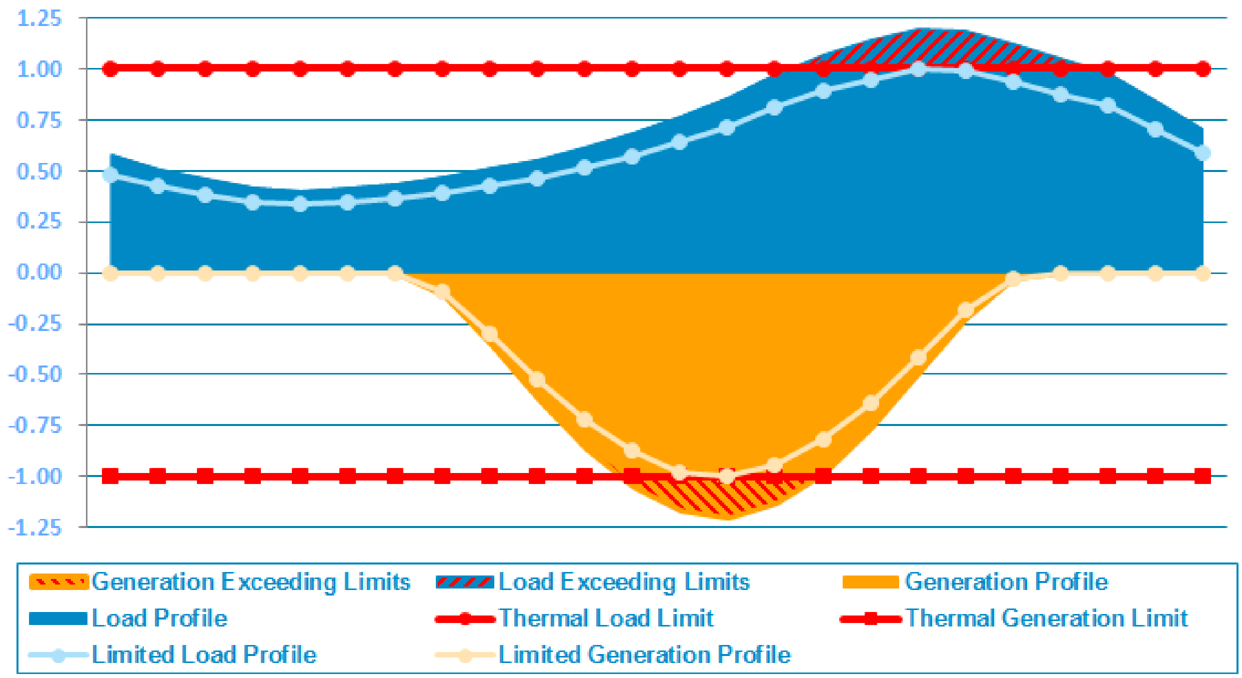


FIGURE 2-9: EXCEEDING THERMAL RATINGS

Protection Criteria

Protection Criteria determine if the resource causes a change in power flow that interferes with the protection schemes on the circuits that protect and isolate during system events. DER planning must account for impacts to protection schemes to keep employees, public and facilities safe from potential electrical disturbances on the distribution system.

DER can lower the contribution of fault current that is measured from the substation. The level of this reduction is dependent on the impedance at the DER location. The calculation will determine a DER capacity that will not allow the contribution to exceed thresholds. Figure 2-10 depicts possible protection impacts that could occur due to interconnecting DER.

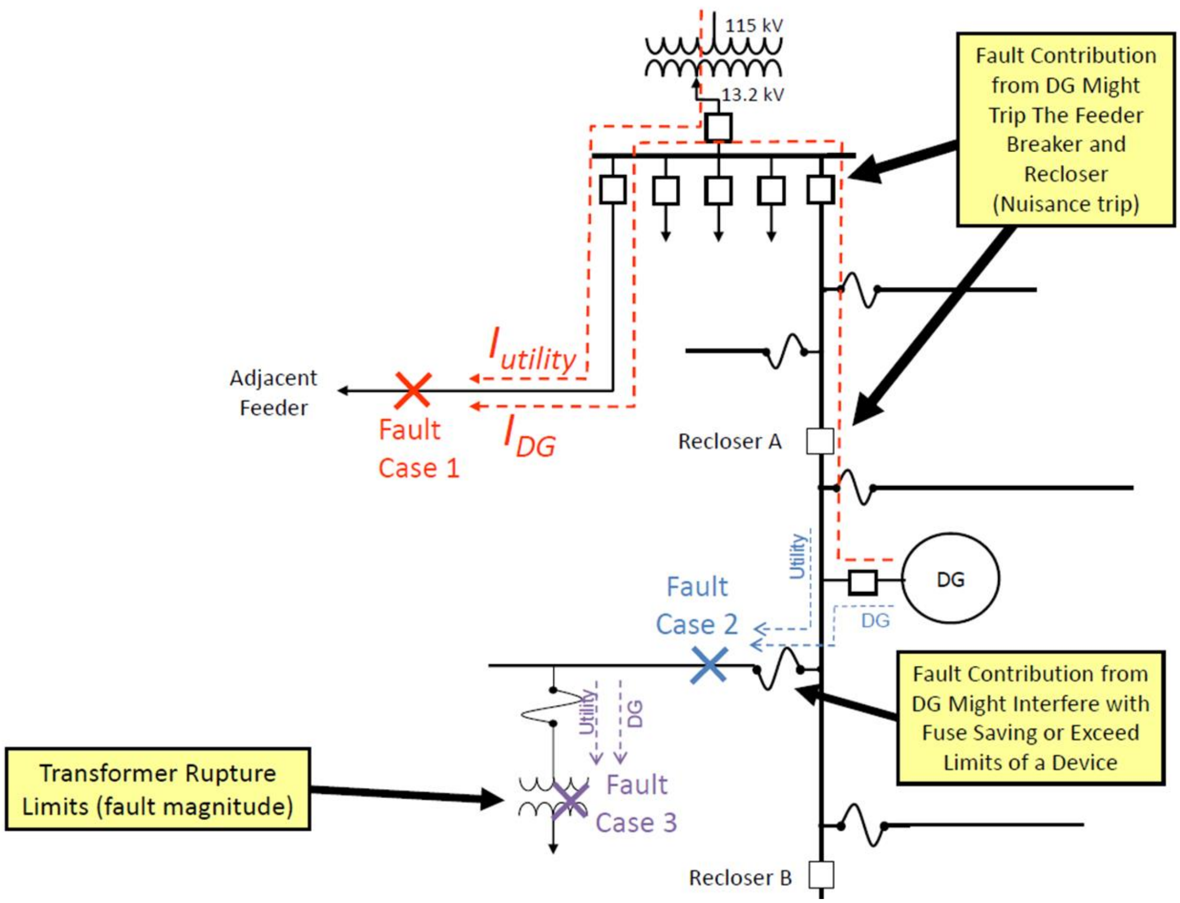


FIGURE 2-10: PROTECTION CONSIDERATIONS

Voltage/Power Quality Criteria

DER planning must include power quality analysis so that new resources are evaluated for sufficient voltage and quality of service. This type of analysis ensures that facilities and customer equipment is not damaged by operating outside of allowable power quality and voltage limits.

PG&E's initial Integration Capacity Analysis cannot directly evaluate all the criteria and sub-criteria of voltage / power quality. Currently, only voltage flicker can be assessed. This calculation will determine the size of a DER that will keep transient voltage flicker below a certain limit. Voltage flicker is dependent on the impedance at the specific location of the DER and is evaluated for intermittent resources that can provide fluctuating demand that exceeds thresholds.

Safety and Reliability Criteria

Safety and Reliability must also be analyzed as part of Integration Capacity. High penetration scenarios of DER have the potential to cause excess back flow that can result in congestion and affect reliability during system events. PG&E currently evaluates Safety and Reliability to ensure that PG&E is reliably serving all customers with quality power, while keeping its customers and the public safe. This criteria is evaluated by ensuring improper islanding conditions are not created and penetration to the transmission system is limited. Because transmission system penetration is limited, PG&E's initial analysis cannot take into account any transmission system impacts or impacts to transmission energy markets.

Operational Flexibility Limits

In addition to the Safety and Reliability criteria analyzed in interconnection studies and Integration Capacity Analysis, the IOUs were encouraged to evaluate limits on operational flexibility. Current Fast Track screens and Interconnection rules do not allow for consideration of abnormal system conditions that could arise during emergency restoration. When certain line sections are electrically isolated from the grid for repair, other line sections are connected to other grid source paths or substations to continue service to customers.

High penetrations of DERs have the potential to back feed into the abnormally connected substation where possible issues are not mitigated. Limiting these possible issues could be achieved by limiting the amount of back feed through the abnormal switching points. This is calculated by determining the minimum load beyond switchable line devices and not allowing the generation to exceed that load. When a line section is switched over, the amount of generation will only serve the local load and theoretically not generate into the abnormally tied circuit. In essence, this will not limit the amount of generation that can be placed on each substation, but disperse the allowable generation across all line sections connected to the substation. This is an important aspect of reliability that needs to be addressed for high penetration scenarios of DER. Figures 2-11 and 2-12 depict the concept of operational flexibility.

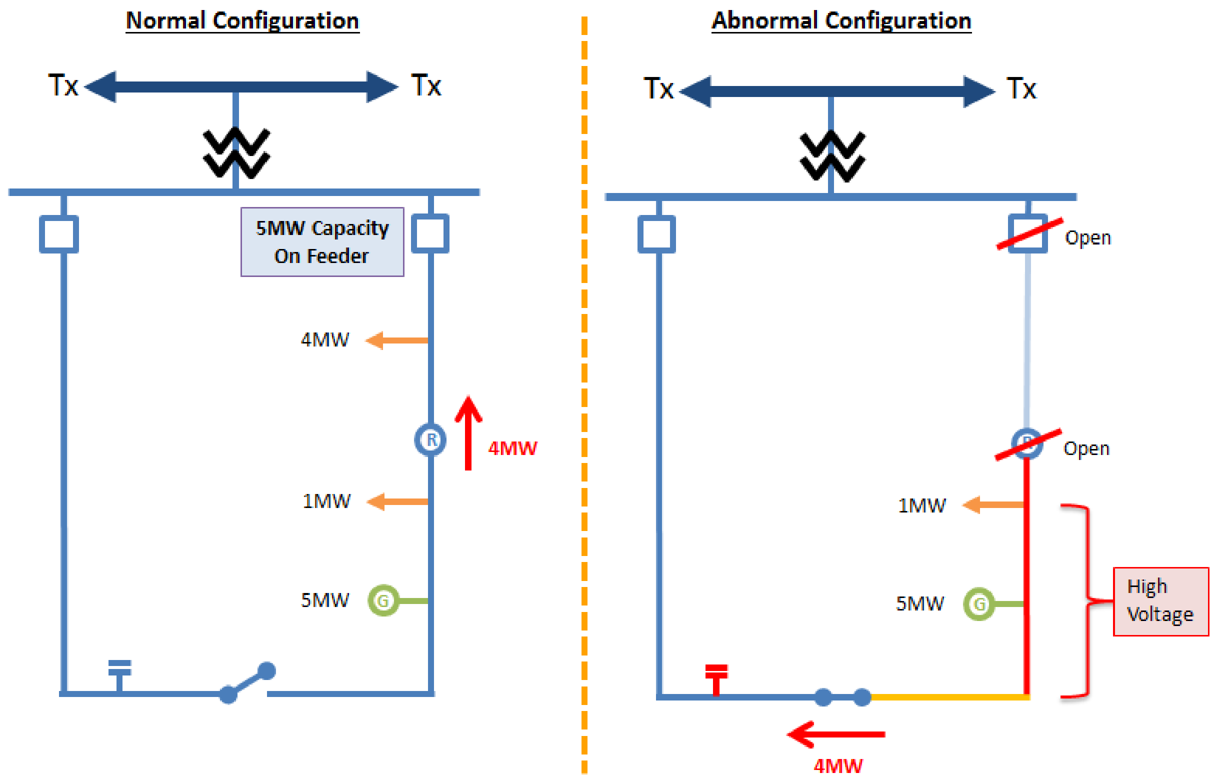


FIGURE 2-11: REVERSE FLOW ISSUES DURING EMERGENCY RESTORATION

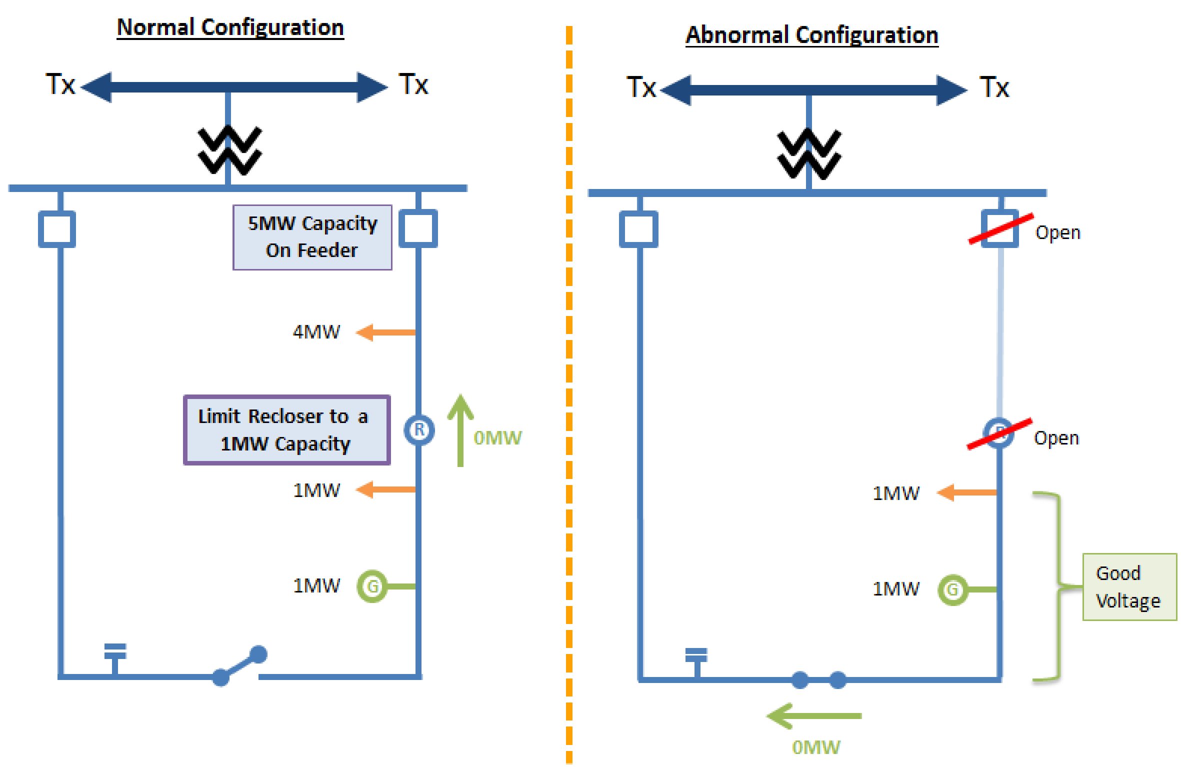


FIGURE 2-12: LIMITING REVERSE FLOW ISSUES DURING EMERGENCY RESTORATION

Results of Power System Criteria Evaluation

PG&E uses a custom database tool to perform the final evaluation of the Power System criteria. The data from the modeling and data extraction is uploaded to PG&E's custom database to establish Integration Capacity Analysis results. When the evaluation is performed, four-key integration capacity values are identified for publication. These values are described in Table 2-5.

TABLE 2-5
KEY INTEGRATION CAPACITY VALUES

Result Name	Description
Line Section Limits	Limits that can be associated to only the nodes and line segments within the selected line section.
– Minimum Impact	Lowest capacity value for the line section that is expected to not cause significant impacts or upgrades.
– Possible Impact	Average capacity value for the line section that may or may not cause significant impacts or upgrades and will be based on where on the line section the DER is interconnecting.
Substation Limits	Limits that can be associated to all line sections that are attached to the associated substation.
– Feeder Limitation	Total feeder capacity value that would cause significant impact by one or multiple DER in aggregation. If interconnecting on multiple line sections on the same feeder, it will be important to not exceed this limit.
– Bank Limitation	Total substation transformer bank capacity value that would cause significant impact by one or multiple DER in aggregation. If interconnecting on multiple line sections on the same substation bank, it will be important to not exceed this limit.

2.b.ii. Integration Capacity Analysis Guidance Ruling Elements

This section discusses how PG&E included the Guidance Ruling's seven elements in its Integration Capacity Analysis methodology.

2.b.ii.1. PG&E Performed an Integration Capacity Analysis at the Line Section and Node Levels

The Guidance Ruling directs the IOUs to perform a distribution system Integration Capacity Analysis down to the line section or node level, using a common methodology across all utilities. The analysis is to quantify the capability of the distribution system to integrate DER within thermal ratings, protection system limits, power quality and safety standards of existing equipment. The results of the analysis are to be published via online maps maintained by each utility and available to the public. Initial Integration Capacity Analyses are to be completed by each utility by July 1, 2015.

PG&E collaborated with SDG&E and SCE to coordinate on a common methodology. At a high level the commonalities are obtained through: (1) utilizing dynamic planning tools for circuit modeling and analysis; (2) analysis of similar power system criteria; and (3) performing analysis and retrieving line section results. The specific implementation of these commonalities are inherently different due to the differing nature of planning toolsets and distribution system configurations. To ensure alignment across the three IOUs, coordination meetings throughout the development of the plans were held.

For its initial Integration Capacity Analysis, PG&E analyzed the hosting capacity for a selected set of DER types on multiple line sections within each of its distribution feeders. Each DER technology has its own result based on the line section analyzed.

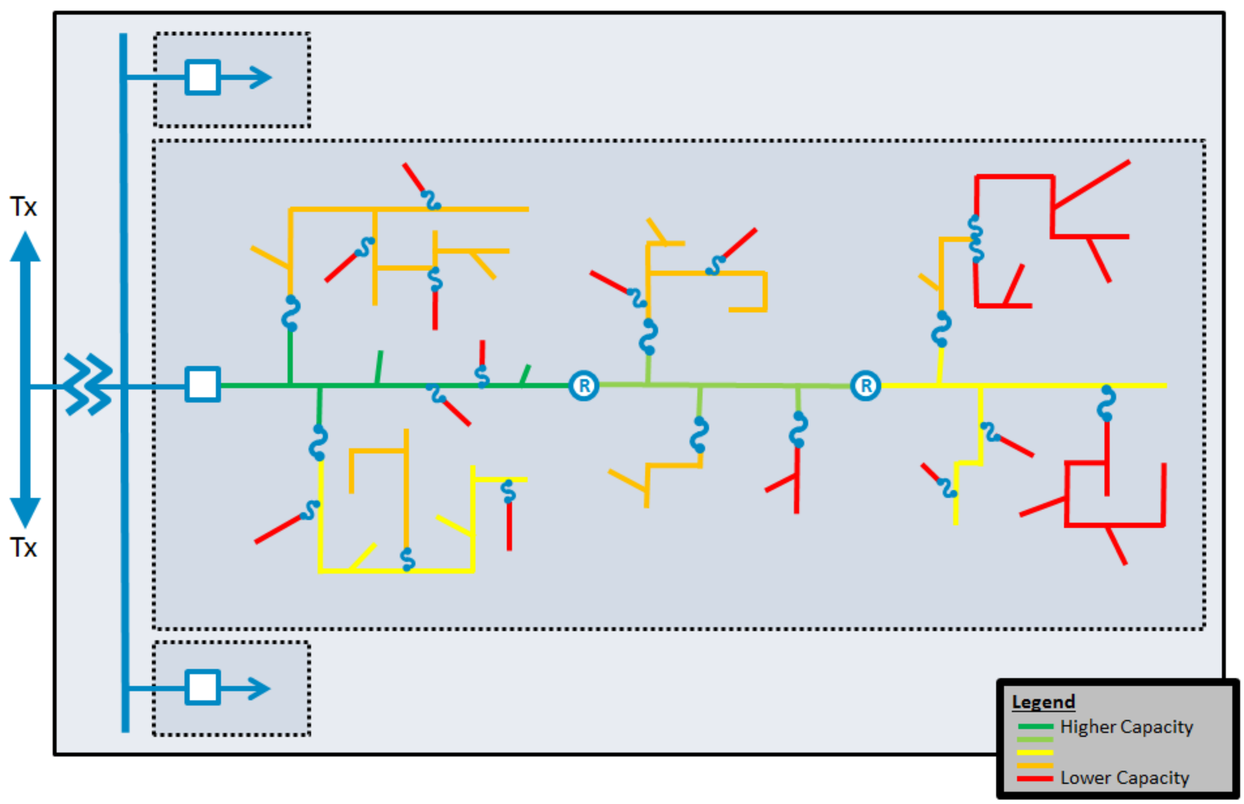


FIGURE 2-13: GRANULARITY OF INTEGRATION CAPACITY ANALYSIS

Figure 2-13 depicts how the analysis is applied at the four major levels of granularity on the distribution system (bank, feeder, line section/node level). The bank level is depicted by a box with the solid border. The feeder level is depicted by a box with a dotted border. Together these boxes represent the Substation Level Limits that cannot be exceeded when interconnecting DERs on multiple line sections. The line section level is depicted by the Red/ Amber/ Green color scale along the feeder. Various line devices are represented by the blue shapes within the feeder. As discussed earlier, PG&E analyzed specific nodes within line sections to establish a range of hosting capacity for each line section. Power System criteria is also evaluated for the line sections and is further applied at the node level (*e.g.*, device load penetration and thermal rating of device). The lower of the two limiting criteria results (nodal limitation or line section limitation) becomes the primary limiting factor. This process continues to be applied for other upstream limiting factors such as feeder and bank limitations.

PG&E Has Published Its Initial Integration Capacity Analysis Results on the Renewable Auction Mechanism Map

In compliance with the Guidance Ruling, PG&E's initial Integration Capacity Analysis results can be found in the Renewable Auction Mechanism (RAM) Map[14] on PG&E's website as of July 1, 2015. The RAM map has a coloring scheme that depicts the capacity level of a line section by a color gradient to better display the varying levels of capacity by location on each feeder. This coloring scheme will help DER developers and customers better understand where on a circuit location of a DER is better suited. Figure 2-14 depicts a RAM map for solar PV DER technology.

[14] PG&E's RAM Map can be found at the following web address: http://www.pge.com/en/b2b/energysupply/wholesaleelectricsuppliersolicitation/PVRFO/pvmap/index.page.

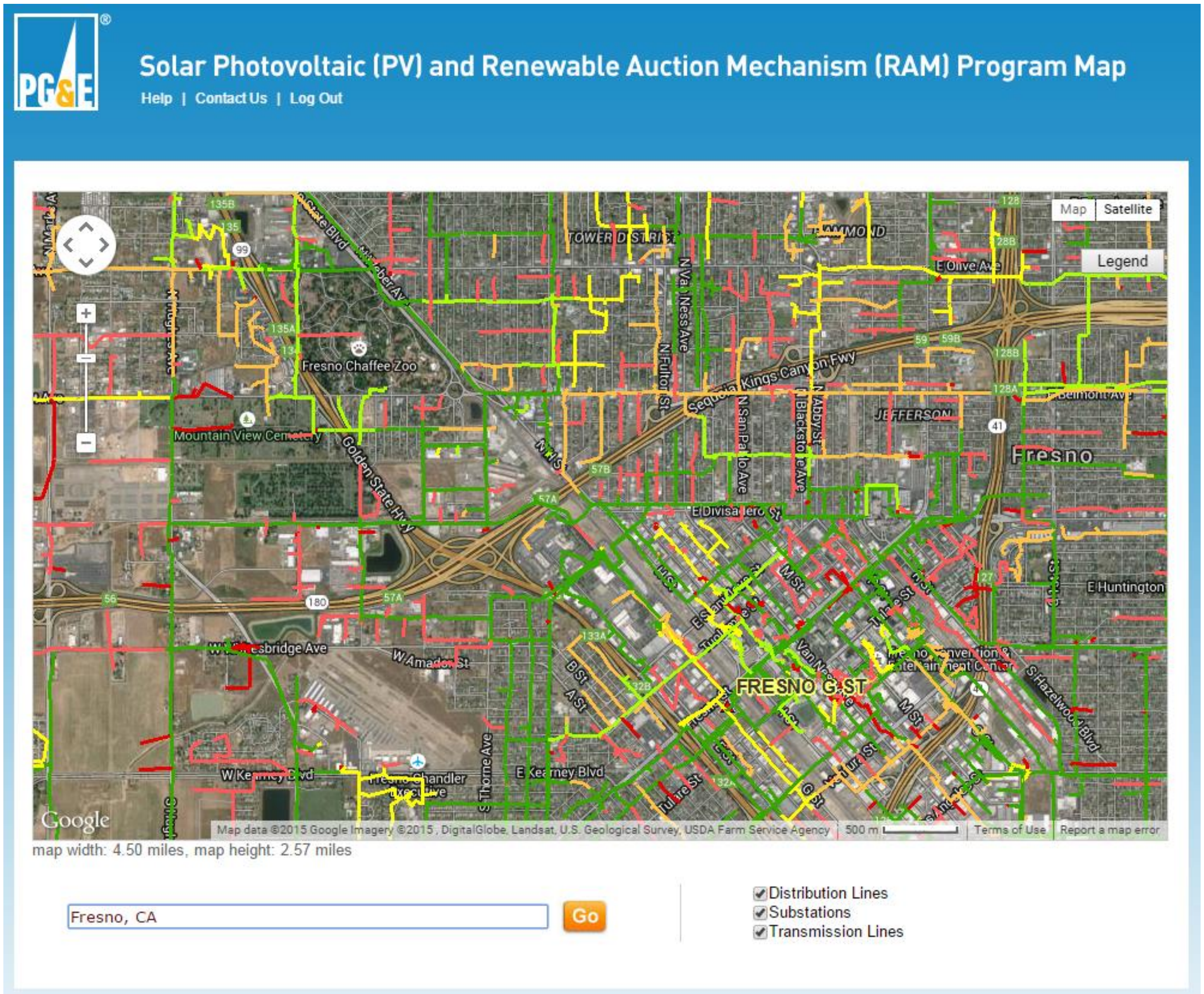
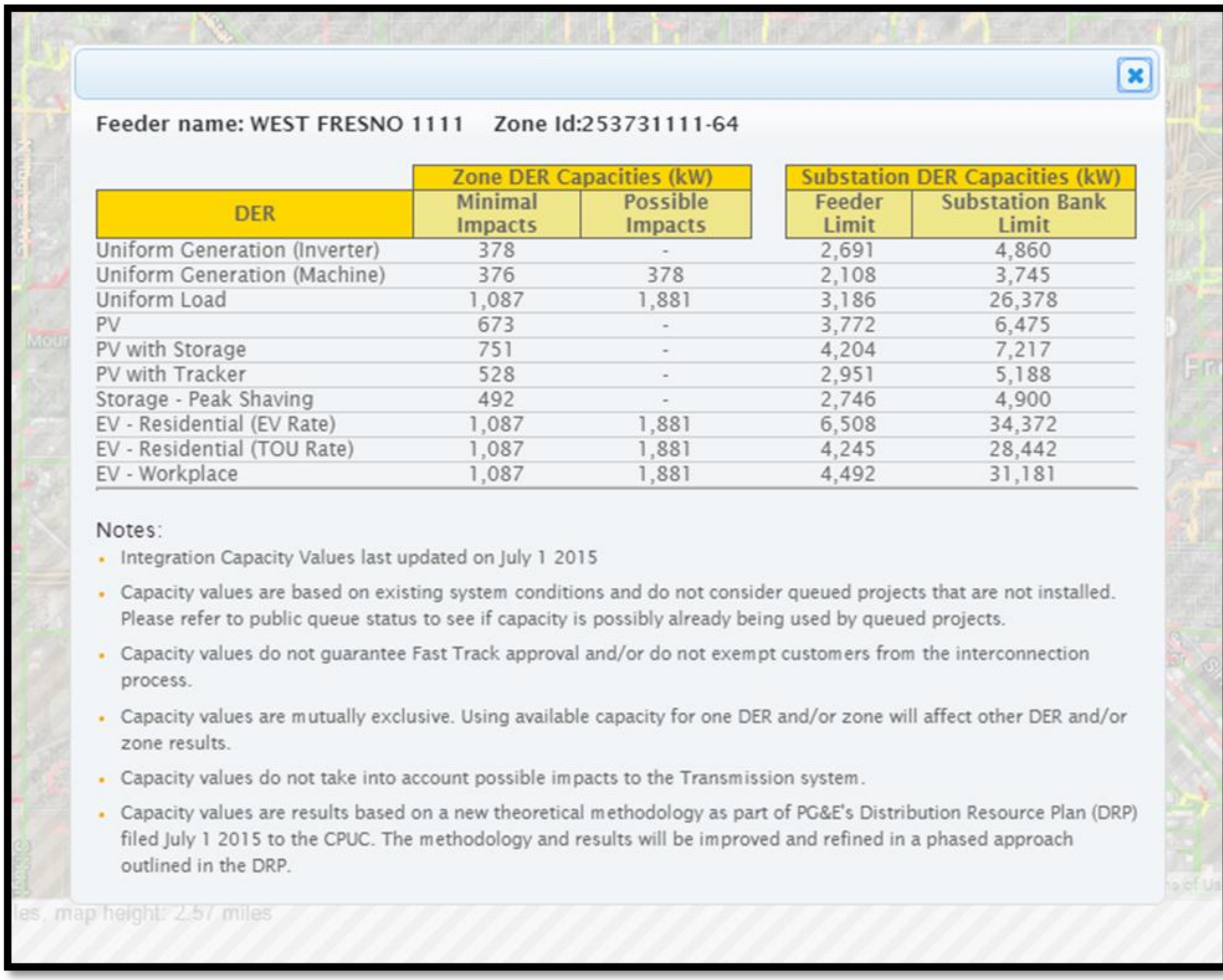


FIGURE 2-14: SCREENSHOT OF RAM MAP WITH INTEGRATION CAPACITY COLORING

Figure 2-15 below shows how PG&E will present its Integration Capacity results on its RAM Map. PG&E provides customers with results for various DER technology types. The results also display limitations of the substation feeders and transformer banks alongside line section results. The additional feeder limit and substation bank limit in the Substation DER Capacities column should better assist wholesale customers that may want to connect using dedicated feeders or developers targeting multiple line sections.


Feeder name: WEST FRESNO 1111 Zone Id:253731111-64

DER	Zone DER Capacities (kW) Minimal Impacts	Zone DER Capacities (kW) Possible Impacts	Substation DER Capacities (kW) Feeder Limit	Substation DER Capacities (kW) Substation Bank Limit
Uniform Generation (Inverter)	378	-	2,691	4,860
Uniform Generation (Machine)	376	378	2,108	3,745
Uniform Load	1,087	1,881	3,186	26,378
PV	673	-	3,772	6,475
PV with Storage	751	-	4,204	7,217
PV with Tracker	528	-	2,951	5,188
Storage - Peak Shaving	492	-	2,746	4,900
EV - Residential (EV Rate)	1,087	1,881	6,508	34,372
EV - Residential (TOU Rate)	1,087	1,881	4,245	28,442
EV - Workplace	1,087	1,881	4,492	31,181

Notes:

- Integration Capacity Values last updated on July 1 2015
- Capacity values are based on existing system conditions and do not consider queued projects that are not installed. Please refer to public queue status to see if capacity is possibly already being used by queued projects.
- Capacity values do not guarantee Fast Track approval and/or do not exempt customers from the interconnection process.
- Capacity values are mutually exclusive. Using available capacity for one DER and/or zone will affect other DER and/or zone results.
- Capacity values do not take into account possible impacts to the Transmission system.
- Capacity values are results based on a new theoretical methodology as part of PG&E's Distribution Resource Plan (DRP) filed July 1 2015 to the CPUC. The methodology and results will be improved and refined in a phased approach outlined in the DRP.

FIGURE 2-15: SCREENSHOT OF RAM MAP WITH INTEGRATION CAPACITY RESULTS

The RAM map was created to help customers and developers identify potential project sites by providing information on locations of distribution and transmission lines, distribution load and interconnection queue. The published results can assist third parties when specific sites are initially determined feasible externally by PG&E. Sites often are proven to not be optimal once an interconnection study is performed and much time and effort has been spent on that project by DER developers. These published results will better inform DER customers and developers in advance of interconnection of potential DER capacity for a particular area on the distribution system.

Limitations of Integration Capacity Results

PG&E's Integration Capacity results do not represent entire distribution system level integration capacity values. The analysis performed only determines results up to the substation level and does not consider the transmission or system level impacts, as well as impacts on transmission energy markets. Therefore, PG&E cautions against aggregating individual results because it could potentially result in an erroneous system capacity total.

Integration Capacity results are a supplement to, not a substitute for, detailed interconnection studies. It remains important for interconnecting DERs to follow the interconnection procedures to make sure the DER will operate effectively and safely when interconnected. As PG&E's Integration Capacity methodology improves, incorporating this methodology into the current interconnection process may be considered. Current CPUC proceedings that address interconnection issues are the appropriate venue to consider the application of this methodology. PG&E's initial Integration Capacity Analysis is an important first step towards determining location specific DER distribution capacity.

Example of Potential Third-Party Application of Integration Capacity Results

A potential third party use case of PG&E's Integration Capacity results could be the further determination of the feasibility of 186 solar PV sites deemed candidates for the Regional Renewable Energy Procurement Project (R-REP) created by Alameda County, Joint Venture Silicon Valley and the Contra Costa Economic Partnership. Figure 2-16 shows that the R-REP solicitation included 19 public agencies for a total of over 180 renewable energy sites totaling 30 megawatt (MW) throughout Alameda, Contra Costa, San Mateo and Santa Clara Counties.[15]

[15] Information received from JointVenture.org at the following web address: http://www.jointventure.org/index.php?option=com_content&view=article&id=646&Itemid=565.

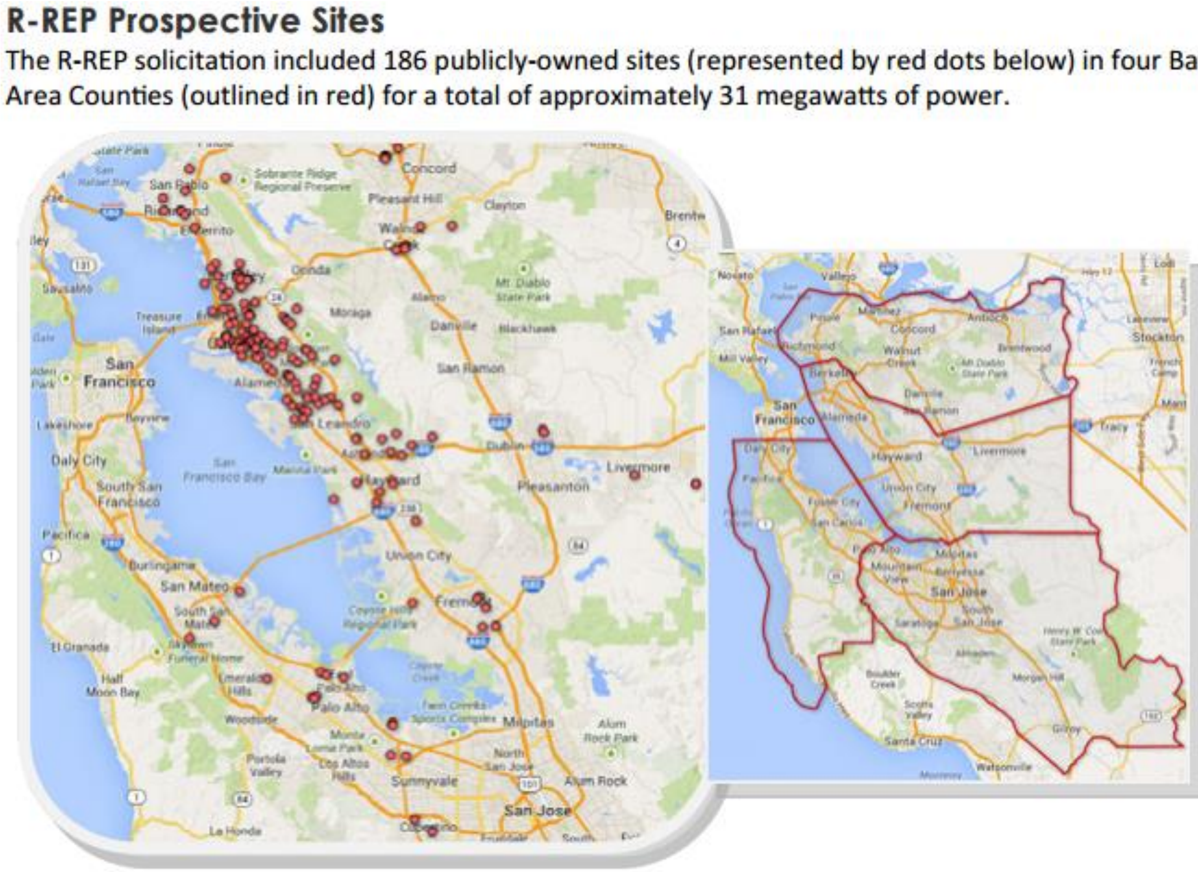


FIGURE 2-16: MAP OF R-REP SOLICITATION SITES[16]

This program can use the published Integration Capacity results to help further determine the feasibility of these sites. This could potentially save time and resources for both third parties and PG&E by early identification of interconnection locations with sufficient capacity and existing infrastructure to accommodate DERs.

2.b.ii.2. Integration Capacity Analysis That Includes Planned Investments Within a Two-Year Period

The IOUs are directed to perform an analysis that assesses current system capability together with any planned investments within a two-year period. The assumptions and methodology used for load and DER forecasts over the two-year period also should be included.

To assess the current system capability together with planned investments within a two-year period, PG&E adjusted the models used in its initial Integration Capacity Analysis by modifying

[16] Image obtained from ACGOV.org at the following web address: http://www.acgov.org/sustain/documents/rrepinfosheet.pdf

the substation ratings to reflect capacity investments made by 2017. Once adjusted, PG&E applied its same Integration Capacity Analysis methodology used for its current system assessment of Integration Capacity.

Each DER profile was used and compared to the current-state Integration Capacity results. Each line section and substation result was compared to the two-year period results to determine the percent change. Table 2-6 lists the percentage change in Integration Capacity between the current state and future two-year state. These changes only reflect substation capacity investments. Thermal Ratings for all the transformers banks and circuit breakers reflect expected 2017 ratings. As the DRP methodologies are further integrated in PG&E's DPP, then additional factors may be considered to help establish more precise impacts to Integration Capacity values in future planning periods.

TABLE 2-6
PERCENT CHANGE IN INTEGRATION CAPACITY BY DER IN 2017

DER	Change in Minimum Impact (%)	Change in Possible Impact (%)	Change in Feeder Limitation (%)	Change in Bank Limitation (%)
Uniform Generation (Inverter)	–	–	–	–
Uniform Generation (Machine)	–	–	–	–
Uniform Load	0.5	1.0	2.4	4.4
PV	–	–	–	–
PV With Storage	–	–	–	–
PV With Tracker	–	–	–	–
Storage - Peak Shaving	0.4	0.5	0.9	1.3
EV - Residential (EV Rate)	0.3	0.6	1.6	2.8
EV - Residential (Time-of-Use (TOU) Rate)	0.3	0.6	2.0	3.6
EV – Workplace	0.4	0.8	1.8	3.5

This assessment demonstrates that the capacity (thermal) upgrades that are performed at the substation mainly affect the load components of the DER. Generating DER has more limiting thresholds in the other categories and not much limitation in thermal capacity. Many other factors will have to be taken into account for the future investment assessment.

2.b.ii.3. Integration Capacity Analysis Using Dynamic Modeling Methods

The Guidance Ruling directs each utility perform an analysis using dynamic modeling methods, which are uniform across all utilities, and circuit performance data. The analysis should avoid the use of heuristic approaches where possible.

As introduced in step two of PG&E's Integration Capacity methodology overview, PG&E uses two dynamic modeling methods to analyze Integration Capacity.[17] This section discusses the importance of these planning tools in PG&E's DPP and provides greater detail on how the dynamic modeling tools are used to assess Integration Capacity for DER technologies.

Importance of Dynamic Planning Tools in Distribution Planning Process

The modeling and data extraction used datasets developed and engineered as part of the PG&E's DPP. Integration Capacity evaluation has strong ties and dependencies to PG&E's existing DPP and will require ongoing coordination. The Load Forecasting Analysis tool and Power Flow Analysis tool are central to establishing quality hosting capacity results at the needed locational level. Informational and operational technologies to further engineering efforts are also needed. Load profiling heavily relies on operational data that records real-time information providing accurate system conditions. Circuit modeling depends on information technologies to help build and maintain quality records of existing assets and their operating parameters. The advanced engineering software is also important to make sure dynamic engineering analysis can be performed on these datasets. Information and operational technologies are critical for establishing quality level results for this level of analyses.

Current Application of PG&E's Dynamic Modeling Methods Using Planning Tools

Under the first dynamic modeling method, PG&E used its Load Forecasting Analysis Tool to analyze feeder load profiles and DER profiles on an hourly basis. Such an hour-by-hour analysis of DER load and feeder profiles provides a more realistic assessment that each DER type may

[17] In the utility industry, the term *dynamic* typically refers to transient stability and system event analysis typically performed on the transmission system. Although there is some level of transient analysis performed in the integration capacity analysis, no *dynamic* system stability analysis is performed as it is typical known as. The *dynamic* analysis performed in the Integration Capacity Analysis refers to the steady state hour by hour load assessment and nodal level power flow calculations being performed.

have on load during different times of the day. Issues that could occur due to the mismatch of DER output/consumption with the feeder's existing load profile must be mitigated. The hour-by-hour modeling will determine whether the DER operation is coincident or non-coincident with load and help to establish capacity values that do not allow criteria thresholds to be surpassed. Hourly DER profile shapes allow PG&E to assess the difference in capacity levels by specific DER technologies.

The second dynamic modeling method occurs at the nodal level, in which PG&E performs engineering calculations on the geospatial circuit models that result from its Power Flow Analysis tool. These circuit models represent all the distribution lines and equipment from the substation to individual service transformers. Analyzing circuit models allows for greater insight into specific locational information, including Thévenin system impedance, upstream asset thermal ratings, and locational fault duties. This more detailed locational insight helps PG&E obtain even more specific thermal, voltage, protection, safety, and reliability impacts.

Figure 2-17 further explains representative profile shapes. These power profiles are built directly from locational customer class shapes and consumption data. Adding a DER profile to representative profile gives PG&E planners more visibility of a DER impact on demand profiles. This figure depicts how the different customer class shapes are added together to form the single feeder shape that is used in Integration Capacity Analysis. Each aggregate shape is then scaled based on the consumption, growth, and weather event potential to determine forecast peak demands. These feeder profiles are developed and used in the DPP for use in load forecasting and investment needs.

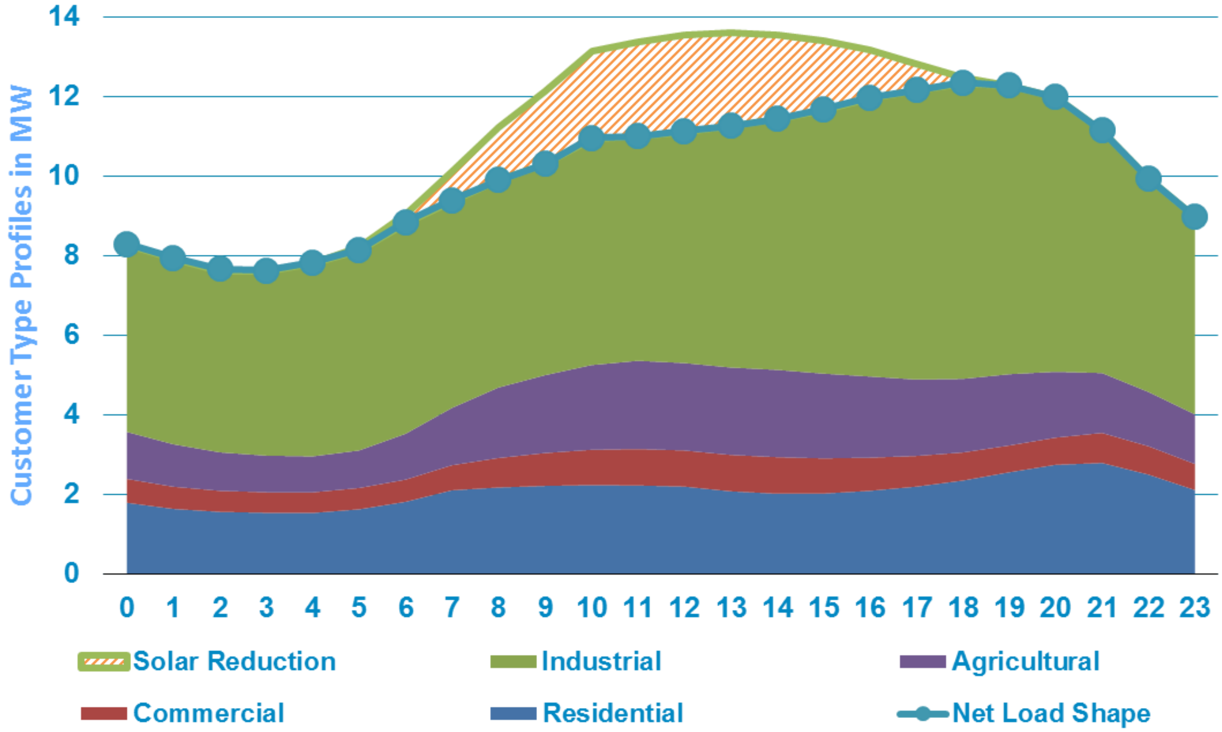


FIGURE 2-17: COMPOSITE FEEDER PROFILE SHAPE

PG&E used similar representative profile shapes to determine the impact of specific DER technologies to specific load shapes. Some samples of the shapes depicted below show one day of these DER profiles.

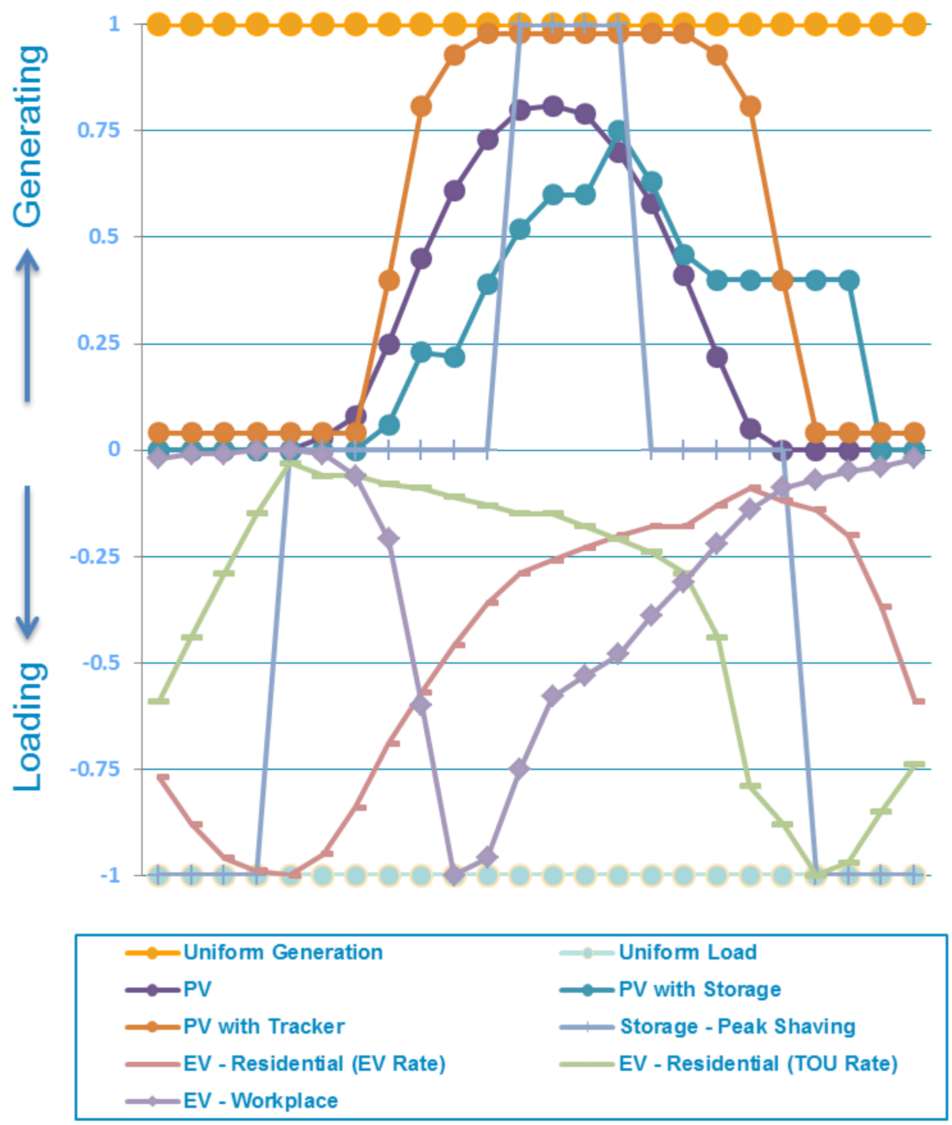
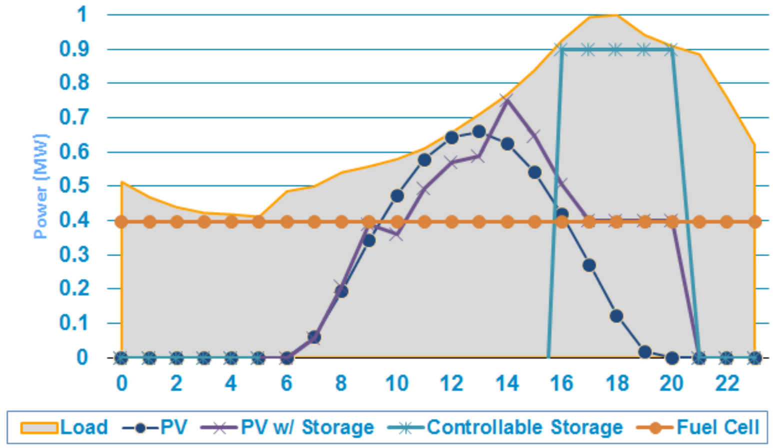


FIGURE 2-18: SAMPLE DAY OF DER SHAPES USED IN INTEGRATION CAPACITY ANALYSIS

PG&E uses specific hour-by-hour DER profiles to analyze Integration Capacity. The level of impact to the system is different for DERs with different output profiles. Figure 2-19 below depicts how different DER could have different integration capacity limitations by comparing the DER output and how it coincides with a load profile. This figure shows that, depending on the DER, there are different hours when the limit is occurring and that it produces different capacity limitations.



DER	Limiting Hour	Max Capacity
PV	12 PM	0.66 MW
PV w/ Storage	2 PM	0.75 MW
Controllable Storage	4 PM	0.90 MW
Fuel Cell	5 AM	0.40 MW

FIGURE 2-19: DER LIMITS MAY DEPEND ON PROFILE SHAPES

This concept is important to show why specific DER shapes must be accounted for in the analysis. It also showcases how one capacity value may not be able to represent the capacity value for each specific DER type.[18]

2.b.ii.4. Assessment of Current State of DER Deployment and DER Projections

The Guidance Ruling directs the Utilities to assess the state of DER deployment and DER deployment projections. For each of the identified DERs, each utility should provide current levels of deployment territory wide, plus an assessment of geographic dispersion with circuits that exhibit high levels of penetration identified.

PG&E's Integration Capacity results includes PG&E's current levels of DER deployment. PG&E assessed the geographic dispersion of DERs, including circuits that currently have high levels of DER penetration and provides additional insights on where additional Integration Capacity related upgrades may be required to accommodate projected DER growth on PG&E's distribution system. Furthermore, this sensitivity assessment also may support the distribution planning process to determine when these distribution infrastructure investments may be required in the future should this DER growth materialize.

This section provides metrics on the state of current DER deployment in the PG&E service territory. The three main metrics analyzed were: (1) installed capacity by county;

[18] Figure 2-19 depicts a Controllable Storage shape. This was not a specific shape that was used in the initial assessment and just used for this figure.

(2) penetration of installed capacity to peak load by county; and (3) highly penetrated substations.

PG&E intends to leverage its Integration Capacity Analysis to further analyze DER penetration. Because peak load does not necessarily best determine when DER capacity issues will arise, a potentially more valuable metric to identify DER issues would be the use of an Integration Capacity Factor (ICF) formula.

ICF can analyze penetration at varying levels of granularity. The ICF could take PG&E's Integration Capacity Analysis methodology and compare the results against current DER deployment numbers. This comparison could more accurately reflect DER penetration since Integration Capacity is designed more to identify when capacity issues will arise. The first step looked at baselining integration capacities by performing an Integration Capacity Analysis without DERs online. The second step is identifying current DER deployment numbers. PG&E considers all interconnected DERs that are downstream of the asset of granularity as part of the existing deployed DER.

The following formula could be used to determine the remaining amount of baseline Integration Capacity:

$$Integration\ Capacity\ Factor\ (\%) = \frac{(IC_{BASELINE} - DER_{DEPLOYED})}{IC_{BASELINE}} \times 100$$

The ICF should never exceed 100 percent. As the ICF gets closer to zero, issues or significant impacts are more likely to occur. When an ICF becomes negative, this means that the DER may be causing issues or is likely to have required mitigations due to interconnection. Substations and feeders that have low and/or negative ICF values would be monitored to determine if any corrective actions need to be implemented. PG&E has identified substations in its territory that have negative ICF values.

Evaluating DER Penetration using the Integration Capacity Analysis methodology or ICF calculation may help ensure DER penetration metrics accurately reflect when hosting issues could occur. PG&E's ICF takes another step towards better understanding where DER issues could occur.

Table 2-9 below identifies highly penetrated substations by comparing Integration Capacity limits determined at the substation level against current DER deployment on each substation. The table lists all substations that have negative ICF values. These negative ICF values indicate that these locations are projected to possibly have capacity issues since DER exceeds the Integration Capacity values.

Table 2-7 and Figure 2-20 depict the state of deployment for all DG by county in the PG&E service territory. Table 2-8 and Figure 2-21 depict the peak load penetration for each county as well. Since the peak load for each county varies in magnitude, the penetration levels do not directly correlate to the deployment capacity values.

TABLE 2-7
DER DEPLOYMENT CAPACITIES BY COUNTY

County	Distributed Generation (MW)	Combustion Technology (MW)	Fuel Cell (MW)	Retail Storage (MW)	Retail PV (MW)
Fresno	316.1	24.6	2.6	0	146.9
Santa Clara	171.1	16.2	21.2	0.4	154.6
Contra Costa	153.5	7.8	5.2	2.1	129.6
Alameda	140.9	8.5	4.8	0.6	96.7
Kern	124.4	17	1.9	0.3	88.4
San Joaquin	63.4	5.3	0.6	0.1	57.2
Sonoma	57.5	0.7	2.5	0.9	72.1
Solano	56.5	6.2	1.7	0	37.9
Placer	55.5	0.1	0.7	0	45.4
San Mateo	52.2	4.6	3	0.1	44.7
San Francisco	50.9	10.5	2	0.5	23.1
Yolo	50.7	1.1	2.2	0	37.2
Monterey	48.2	2.8	2	2.5	29.1
Butte	45.3	0.5	1	0	41.4
Kings	42.0	6.3	0	0	14.4
El Dorado	41.4	8.8	0	0	22.8
Napa	38.7	2.6	2	0.4	31.1
San Luis Obispo	37.6	2.6	0	0.1	31.8
Santa Cruz	36.8	4.8	0.1	0	23.4
Merced	29.0	3.2	0	0.3	24.4
Shasta	26.5	0	0.5	0	12.8
Marin	25.7	4.1	0.2	0	25.4
Colusa	19.1	8.4	0	0	12.9

TABLE 2-7
DER CAPACITIES BY COUNTY (CONT.)

County	Distributed Generation (MW)	Combustion Technology (MW)	Fuel Cell (MW)	Retail Storage (MW)	Retail PV (MW)
Madera	18.6	0.3	0.3	0	20.4
Santa Barbara	17.3	2.5	0	0	11.1
Sutter	16.7	0.4	0.3	0	13.9
Yuba	15.5	0	0	0.1	10.1
Stanislaus	13.8	0	0	0	11.1
Tehama	12.6	0.1	0	0	9.3
Nevada	11.9	0	0	0	8.7
Glenn	8.9	0.5	0	0	7.5
Lake	8.0	0	0	0	8.9
Tulare	6.9	1.3	0.6	0	5.5
Mendocino	6.1	0	0	0	9.1
San Benito	5.9	0	0	0	6
Calaveras	4.4	0	0	0	4.2
Amador	3.8	0	0	0	3.5
Tuolumne	3.6	0	0	0	3.5
Humboldt	3.2	0.8	0	0	3.1
Sacramento	2.5	0	0	0	2.2
Mariposa	1.8	0	0	0	1.7
Plumas	1.4	0	0	0	0.4
Sierra	0.6	0	0	0	0
Trinity	0.4	0	0	0	0
Alpine	0.0	0	0	0	0
Lassen	0.0	0	0	0	0

TABLE 2-8
PEAK LOAD PENETRATION BY COUNTY

County	Peak Load (MW)	Distributed Generation (MW)	Peak Load Penetration (%)
Trinity	1	0.4	26.7
Sierra	3	0.6	23.8
Colusa	102	19.1	18.7
Shasta	156	26.5	17.0
Kings	258	42.0	16.2
El Dorado	274	41.4	15.1
Santa Cruz	248	36.8	14.8
Fresno	2,190	316.1	14.4
Napa	280	38.7	13.8
Placer	471	55.5	11.8
Yolo	435	50.7	11.7
Yuba	136	15.5	11.4
Tehama	114	12.6	11.0
San Luis Obispo	359	37.6	10.5
Glenn	87	8.9	10.2
Sonoma	571	57.5	10.1
Butte	456	45.3	9.9
Marin	261	25.7	9.8
Monterey	513	48.2	9.4
Solano	616	56.5	9.2
Nevada	141	11.9	8.4
Sacramento	30	2.5	8.4

TABLE 2-8
PEAK LOAD PENETRATION BY COUNTY (CONT.)

County	Peak Load (MW)	Distributed Generation (MW)	Peak Load Penetration (%)
Stanislaus	168	13.8	8.2
Alameda	1,730	140.9	8.1
Sutter	205	16.7	8.1
Tulare	86	6.9	8.1
Contra Costa	1,909	153.5	8.0
Lake	106	8.0	7.5
Mariposa	25	1.8	7.3
Santa Clara	2,363	171.1	7.2
Kern	1,749	124.4	7.1
San Benito	83	5.9	7.1
Calaveras	64	4.4	6.9
Santa Barbara	259	17.3	6.7
Plumas	21	1.4	6.6
Mendocino	94	6.1	6.5
Merced	490	29.0	5.9
San Joaquin	1,117	63.4	5.7
San Mateo	919	52.2	5.7
San Francisco	984	50.9	5.2
Madera	400	18.6	4.7
Amador	84	3.8	4.5
Tuolumne	111	3.6	3.2
Humboldt	145	3.2	2.2
Alpine	0	0.0	0.0
Lassen	0	0.0	0.0

TABLE 2-9
SUBSTATIONS WITH LOWEST ICF (HIGHLY PENETRATED)

County	Substation	ICF (%)	Base IC (MW)	All DG (MW)
Fresno	STROUD	-340	4.7	20.9
Plumas	BUCKS CREEK	-238	0.3	1.0
Butte	KANAKA	-214	0.5	1.4
Fresno	CANTUA	-214	6.7	21.0
Fresno	HURON	-195	7.2	21.3
Fresno	GATES	-186	11.6	33.1
Fresno	SCHINDLER	-149	12.1	30.0
Shasta	WHITMORE	-112	0.5	1.1
Fresno	GIFFEN	-105	4.9	10.0
Colusa	CORTINA	-104	2.3	4.7
San Joaquin	VALLEY HOME	-98	1.8	3.5
Monterey	CAMPHORA	-85	1.6	3.0
Monterey	JOLON	-82	1.3	2.3
Kings	AVENAL	-69	3.3	5.6
Kings	GUERNSEY	-66	12.9	21.3
Shasta	PIT NO 1	-62	1.0	1.7
Yolo	KNIGHTS LANDING	-57	1.3	2.1
Yuba	WHEATLAND	-38	4.7	6.4
Fresno	KEARNEY	-37	8.4	11.5
Trinity	WILDWOOD	-37	0.3	0.4
San Francisco	SF J	-32	12.9	17.1
Monterey	CASTROVILLE	-23	10.5	12.9
El Dorado	PLACERVILLE	-23	11.1	13.7
Shasta	PIT NO 5	-21	0.5	0.6
Shasta	MC ARTHUR	-17	1.7	2.0
Shasta	JESSUP	-11	7.5	8.4
Colusa	RICE	-2	2.5	2.6

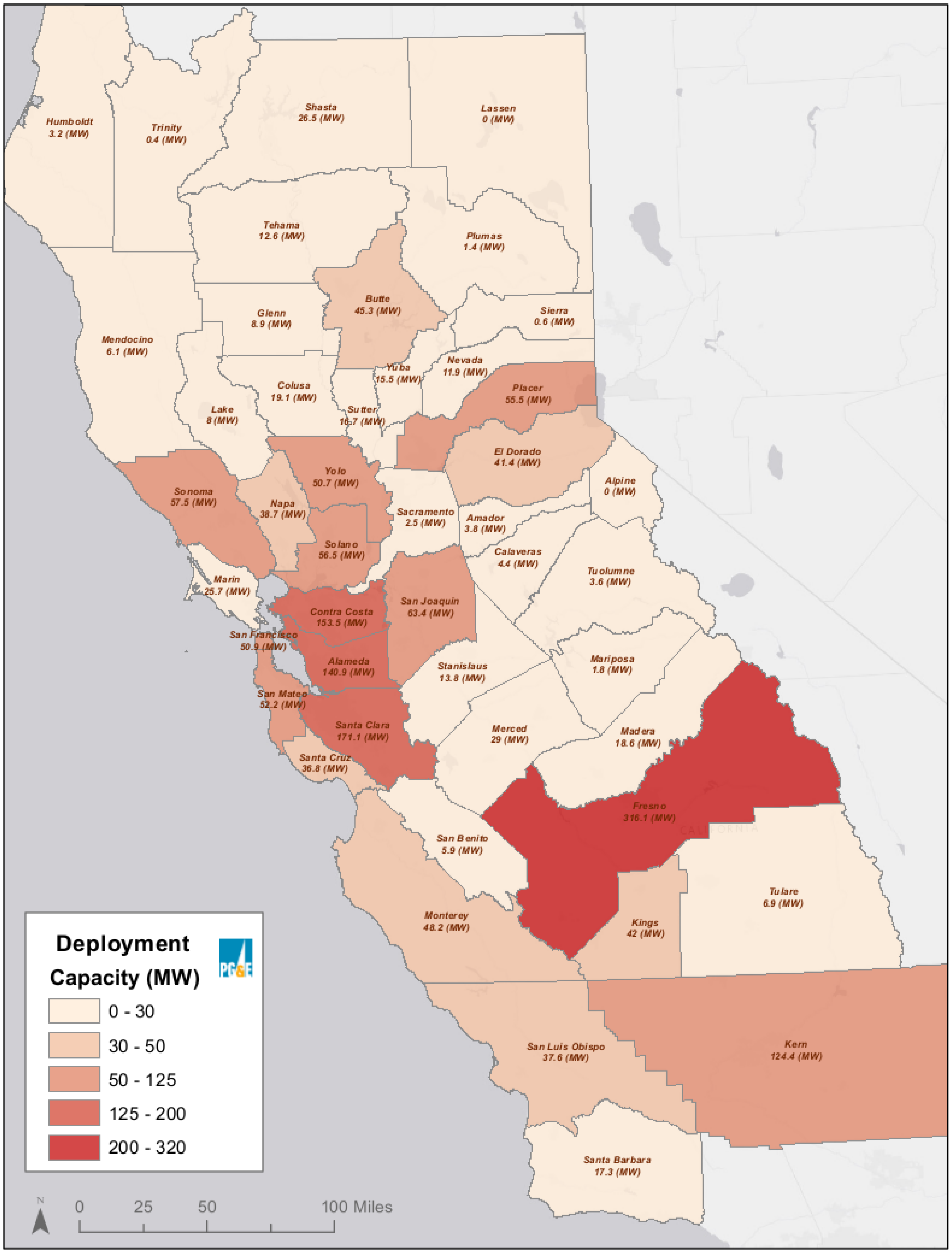


FIGURE 2-20: COUNTY MAP OF CURRENT DEPLOYMENT OF INSTALLED DG CAPACITY

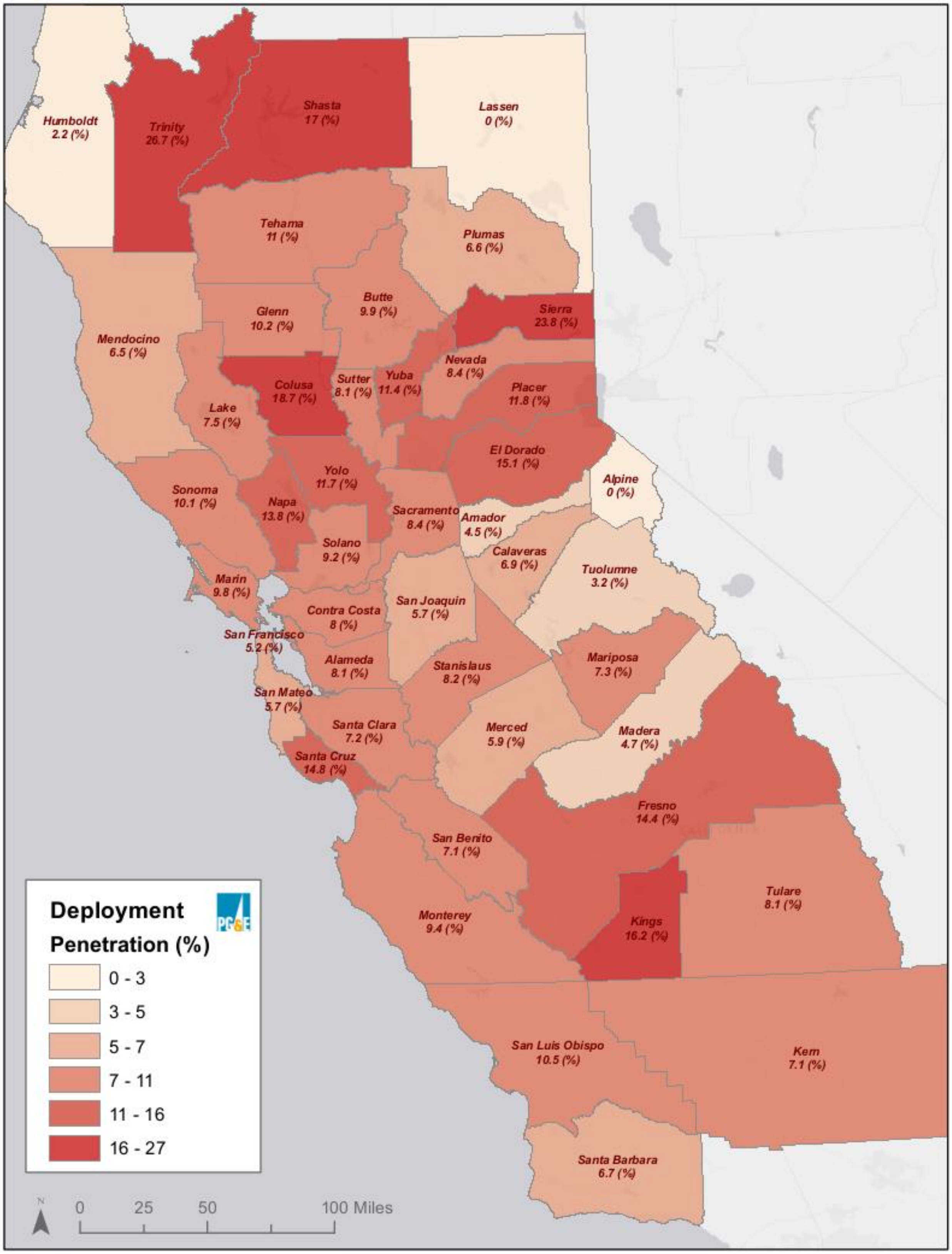


FIGURE 2-21: COUNTY MAP OF CURRENT PEAK LOAD PENETRATION OF INSTALLED DG CAPACITY

2.b.ii.5. PG&E Did Not Conduct an Integration Capacity Analysis on Representative Feeders

The Guidance Ruling allows for a utility to conduct an Integration Capacity Analysis on a select set of representative feeders if the utility is unable to conduct a dynamic analysis for all feeders down to the line section or node.

PG&E was able to conduct dynamic analyses for all relevant distribution feeders down to the line section level. As such, PG&E did not utilize a representative feeder approach for its initial phase of Integration Capacity Analysis. As stated earlier, for its initial Integration Capacity Analysis, PG&E analyzed more than 500,000 nodes and 102,000 line sections across 3,000+ feeders to provide the locational capacity for multiple DERs.

2.b.ii.6. Process for Updating Integration Capacity Analysis

The Guidance Ruling requests a process for regularly updating the Integration Capacity Analysis to reflect current conditions. It identifies the process in place for updating the RAM map monthly as a good starting point.

PG&E proposes to update its Integration Capacity analysis on a quarterly basis in order to allow for proper quality assurance during its initial implementation. The toolsets and processes for evaluating Integration Capacity are new and need further refinement to ensure accurate updates.

As the process and tools develop, PG&E can revisit the frequency of Integration Capacity updates. Regularly updating Integration Capacity results is important and requires a streamlined approach, which is one reason why PG&E developed tools to automatically calculate Integration Capacity results across its entire system. Regularly updating the RAM map while utilizing the automated approach to Integration Capacity would follow this general process depicted in Figure 2-22:

FIGURE 2-22: GENERAL PROCESS TO UPDATE RAM MAP

This process would utilize the datasets in the normal DPP, dynamic planning tools, and the custom developed PG&E tool for analyzing Integration Capacity to more regularly calculate results.

2.b.ii.7. Recommendations for Utilizing Integration Capacity Analysis to Support Interconnection Rules

The Guidance Ruling seeks recommendations for utilizing Integration Capacity Analysis to support planning and streamlining of Rule 21 for DG and Rule 15 and Rule 16 assessments of EV load grid impacts, with a particular focus on developing new or improved 'Fast Track' standards.

To support the Interconnection Rules, PG&E recommends incorporating components of its Integration Capacity methodology into the Rule 15/16/21 processes to supplement existing screens to produce more detailed results. For example, the 15 percent rule used in Screen M of Rule 21 takes the aspect of "penetration" and requires the screener to evaluate non-coincident peak load values to estimate impact. PG&E's Integration Capacity methodology would more accurately evaluate coincident peak load values in two ways. First, it performs an hour-by-hour analysis to better assess the impact of a particular DER to system conditions. Second, it dynamically analyzes specific issues such as thermal and islanding, rather than just the general penetration value.

No other specific recommendations are being suggested at this time, but it will be important to coordinate with other open proceedings that cross over with this topic. There is potential for these proceedings to explore utilizing PG&E's Integration Capacity methodology as it provides a streamlined method of analysis that can differentiate impacts based on whether a DER is generating or consuming power at the respective hourly levels per DER technology.

2.c. Optimal Location Benefit Analysis

INTRODUCTION

The impacts of a DER on the distribution, transmission, and generation elements of the electric grid may vary. The impacts may depend on the particular attributes of the DER, the location at which the DER is interconnected to the electric grid, and the configuration of the electric network. The impacts may be positive or negative; that is, DERs may reduce or increase overall costs of providing electricity via the electric grid. Because DER impacts vary by location, it is important to identify locations where DERs seem to best reduce the overall costs of providing electricity via the electric grid. Such locations could be defined as potential and preliminary "optimal" locations, recognizing that additional analysis would be required to determine feasibility.

The Guidance Ruling directs PG&E and the other utilities to develop a unified locational net benefits methodology. The Guidance Ruling directs the utilities to start with the Commission-approved Cost-Effectiveness Calculator from the firm E3 and to include other components not included in the E3 calculator (hereafter referred to as the Guidance Ruling's value components). This section describes how PG&E plans to meet these guidelines.

Consistent with the Guidance Ruling, PG&E's DRP includes a process for collaboration with Commission Staff, SCE, SDG&E and other stakeholders to reach a common approach for identifying the optimal locations of DERs. The methodology uses incremental costs and benefits of DERs (Locational Impact Analysis). PG&E's proposed impact methodology described in this section has been developed in coordination with SCE and SDG&E.

This section is organized as follows:

- **I. Locational Impact Components:** Describes the value components in the E3 calculator as well as the Guidance Ruling's value components, and brings together both sets of components into PG&E's Locational Impact Analysis.
- II. **Locational Impact Methodology:** Describes PG&E's proposed methods for calculating the incremental cost and benefit impacts of a DER or portfolio of DERs, for the purpose of preliminarily identifying optimal locations for DERs.

2.c.i. Locational Impact Components

This section describes the process PG&E used to develop the set of value components that are considered in PG&E's Locational Impact Analysis, consistent with the Guidance Ruling's directives.

E3 Calculator Value Components

While the Guidance Ruling does not say which Commission-approved E3 calculator should be used as the basis for the utilities' net locational benefits analysis, PG&E, along with the other CA IOUs, proposes to use E3's Distributed Energy Resources Avoided Cost Calculator (DERAC). Table 2-10 lists the avoided cost components in E3's DERAC tool.

TABLE 2-10
AVOIDED COST COMPONENTS IN E3'S DERAC TOOL

Component	Basis of Annual Forecast	Basis of Hourly Shape
Generation Energy	Forward market prices and the $/kWh fixed and variable operating costs of a CCGT.	Historical hourly day-ahead market price shapes from MRTU OASIS
Losses	System loss factors	
Generation Capacity	Residual capacity value a new simple-cycle combustion turbine	Top 250 CAISO hourly system loads.
Ancillary Services	Percentage of Generation Energy value	Directly linked with energy shape
T&D Capacity	Marginal transmission and distribution costs from utility ratemaking filings.	Hourly temperature data
Environment	Synapse Mid-Level carbon forecast developed for use in electricity sector IRPs	Directly linked with energy shape with bounds on the maximum and minimum hourly value
Avoided RPS	Cost of a marginal renewable resource less the energy market and capacity value associated with that resource	Flat across all hours

Each component in the DERAC tool is a system-level benefit (in the context of the DERAC tool, "avoided cost" means a benefit associated with DER) associated with deployment of DERs. PG&E proposes to calculate location-specific values for each component in E3's DERAC tool, instead of the system-level values currently calculated by the DERAC tool.

2.c.ii. Guidance Ruling's Value Components

Table 2-11 lists the value components itemized in the Guidance Ruling. These value components are additional to the DERAC avoided cost components listed in Table 2-10, with the following two exceptions: (1) Transmission and Distribution (T&D) value components (Items 1 through 4 in Table 2-11) would replace the generic "T&D Capacity" avoided cost component in the DERAC tool; and (2) "Avoided Renewables Integration" value component (Item 6 in Table 2-11) would replace the renewables integration cost embedded in the avoided RPS component of the DERAC tool.

TABLE 2-11
GUIDANCE RULING'S VALUE COMPONENTS FOR LOCATIONAL IMPACT ANALYSIS

#	Component
1	Avoided Sub-Transmission, Substation and Feeder Capital and Operating Expenditures
2	Avoided Distribution Voltage and Power Quality Capital and Operating Expenditures
3	Avoided Distribution Reliability and Resiliency Capital and Operating Expenditures
4	Avoided Transmission Capital and Operating Expenditures
5	Avoided Flexible Resource Adequacy (RA) Procurement
6	Avoided Renewables Integration Costs
7	Any societal avoided costs which can be clearly linked to the deployment of DERs
8	Any avoided public safety costs which can be clearly linked to the deployment of DERs

Incorporating All Value Components in PG&E's Locational Impact Analysis

Table 2-12 consolidates all the value components that PG&E proposes to use in its Locational Impact Analysis. In this Locational Impact Analysis, for each individual value component, a DER at a given location (or a portfolio of DERs at one or more locations) may reduce (*i.e.*, avoid) or increase overall costs of providing electricity via the electric grid. Similarly, when considering all value components together, a particular DER at a given location (or portfolio of DERs at one or more locations) may reduce or increase overall costs of providing electricity via the electric grid.

TABLE 2-12
CONSOLIDATED COMPONENTS FOR PG&E'S LOCATIONAL IMPACT ANALYSIS

#	Component	PG&E Definition
1	Sub-Transmission, Substation and Feeder Capital and Operating Expenditures (Distribution Capacity)	Avoided or increased costs incurred to increase capacity on sub-transmission, substation and/or distribution feeders to ensure system can accommodate forecast load growth
2	Distribution Voltage and Power Quality Capital and Operating Expenditures	Avoided or increased costs incurred to ensure power delivered is within required operating specifications (*i.e.*, voltage, fluctuations, etc.)
3	Distribution Reliability and Resiliency Capital and Operating Expenditures	Avoided or increased costs incurred to proactively prevent, mitigate and respond to routine outages (reliability) and major outages (resiliency)
4	Transmission Capital and Operating Expenditures	Avoided or increased costs incurred to increase capacity on transmission line and/or substations to ensure system can accommodate forecast load growth.
5a	System or Local Area RA	Avoided or increased costs incurred to procure RA capacity to meet system or CAISO-identified Local Capacity Requirement (LCR)
5b	Flexible RA	Avoided or increased costs incurred to procure Flexible RA capacity
6a	Generation Energy and GHG	Avoided or increased costs incurred to procure electrical energy and associated cost of GHG emissions on behalf of utility customers
6b	Energy Losses	Avoided or increased costs to deliver procured electrical energy to utility customers due to losses on the T&D system
6c	Ancillary Services	Avoided or increased costs to procure ancillary services on behalf of utility customers
6d	RPS	Avoided or increased costs incurred to procure RPS eligible energy on behalf of utility customers as required to meet the utility's RPS requirements.
7	Renewables Integration Costs	Avoided or increased generation-related costs not already captured under other components (*e.g.*, Ancillary Services and Flexible RA capacity) associated with integrating variable renewable resources
8	Any societal avoided costs which can be clearly linked to the deployment of DERs	Decreased or increased costs to the public which do not have any nexus to utility costs or rates
9	Any avoided public safety costs which can be clearly linked to the deployment of DERs	Decreased or increased safety-related costs which are not captured in any other component

The process of determining the locational impacts of a DER (or portfolio of DERs) requires three steps: (1) determining the impact of the DER on the electric grid; (2) translating that impact into cost—whether an avoided cost (*i.e.*, a reduction in overall cost of providing electricity via the electric grid) or an increased cost—for each of the components listed above;

and (3) aggregating, into a single present value of locational net benefit impact, the identified costs across all value components, for the life of the DER being evaluated. The resulting present value may be positive or negative. A positive present value indicates that deployment of the DER may result in overall savings in the cost of providing electricity via the electric grid, while a negative present value indicates that deployment of the DER may result in an increase in the overall cost of providing electricity via the electric grid. A negative value indicates that the DER is likely to not be cost-effective. However, a positive present value is not enough information to determine whether the DER is cost-effective, since the present value does not include the costs associated with the DER itself.

2.c.iii. Locational Impact Methodology

This section discusses, for each value component, how PG&E plans to: determine a DER's impact on the electric grid and then translate that impact into cost avoided or increased.

PG&E plans to evaluate each of the nine value components listed in Table 2-12. The value for some components may vary from point to point on a distribution feeder, while for other components the value may not vary within a particular distribution feeder but may vary across feeders, and for other components the value may vary from substation to substation.
This locationally varying granularity is discussed below for each value component.

1. **Sub-Transmission, Substation, and Feeder Capital and Operating Expenditures (Distribution Capacity)**

   Definition: Avoided or increased costs incurred to increase capacity on sub-transmission, substation and/or distribution feeders to ensure system can accommodate forecast load growth.

   To the extent that the placement, control and operation of DERs within a certain location defers or accelerates the timing or need for additional capacity to be installed on the electric distribution system, those deferred or accelerated project costs provide a benefit or a cost to the utilities by reducing or accelerating the time of when additional investments are required for the electric distribution system. Examples include deferred or accelerated substation and transformer upgrades, distribution line reconductoring, and line reconfiguration.

With respect to DER deferral of distribution project costs, a benefit can occur only if all of the following four conditions hold: (a) there is an identified need to make distribution capacity expenditures; (b) DER capacity in the correct amount is certain to be available at the time of the relevant circuit or substation transformer peak (capacity need); (c) the DER is connected at the correct locations; and (d) the DER is controlled or managed to avoid any unavailability that could affect reliability or safety.

Determining DER's Impact

Quantification of the locational impact of deploying DERs would leverage a similar approach currently used as approved in GRCs to determine the need for distribution capacity additions. Using this approach for quantifying the cost of the locational impact of deploying DERs will ensure fair and consistent treatment between non-traditional distribution investments (*i.e.*, DERs) and traditional distribution projects that increase capacity (or under other value categories, projects that maintain and enhance distribution reliability and safety) in response to increased local need or potentially degraded local service condition identified in the distribution planning process.

A DER's distribution capacity impact is solely related to the DER's output at the time when the distribution local peak load occurs. This DER output depends on the DER's particular attributes, including how the DER is controlled. This section provides an example for how one type of DER—a standalone PV system—may be able to influence distribution system peak loads.

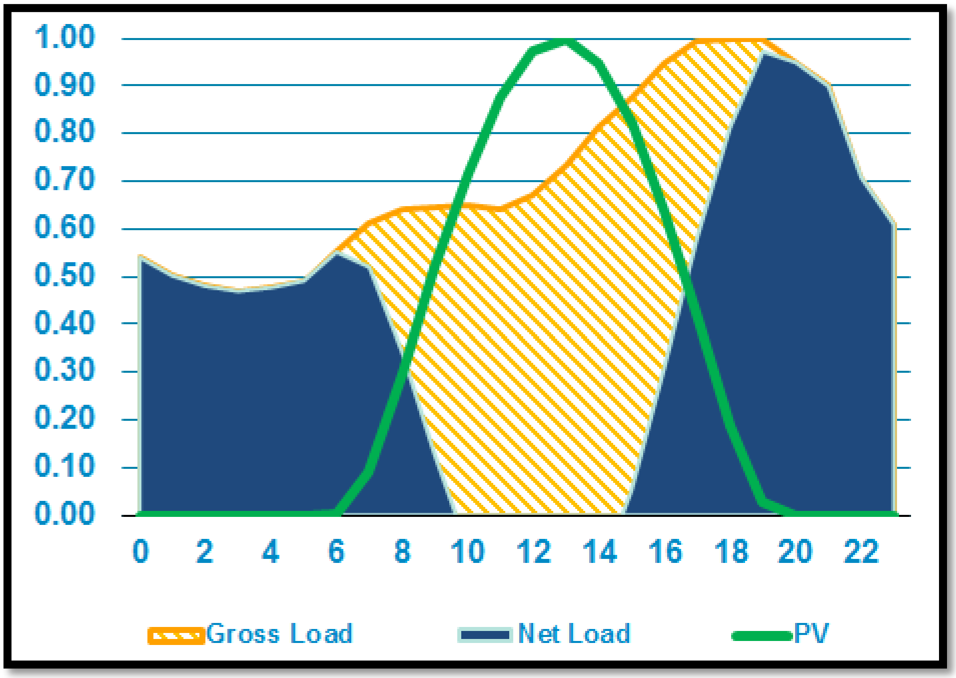


FIGURE 2-22: TYPICAL DG PV GENERATION PROFILE

This figure shows that standalone DER PV provides the most capacity between noon and 1 p.m. Assuming 1,000 kilowatts (kW) of cumulative PV interconnected to a circuit, its output peaks at approximately 1,000 kW of capacity around 1 p.m., however the output during peak load hours, between 4 p.m. and 9 p.m., is approximately 500 kW to 0 kW.

With respect to when the distribution system peaks, nearly 75 percent of PG&E substation transformers peaked after 4 p.m., close to the system peak. The system peak for PG&E's service area has occurred between 4 p.m. and 5 p.m. in the last seven years. As a result, the DER PV in this example would contribute with about 50 percent of its installed capacity toward the distribution capacity benefits.

In a recent data request to the CPUC, PG&E reported the percentage of feeders that peak for each hour of the day. This was determined by using both SCADA data and Representative load profile data to determine when the last hour of the peak occurred, where peak is defined as more than 95 percent or more of maximum demand. Figure 2-23 depicts these metrics and shows that majority of feeder peak times occur in the evening hours.

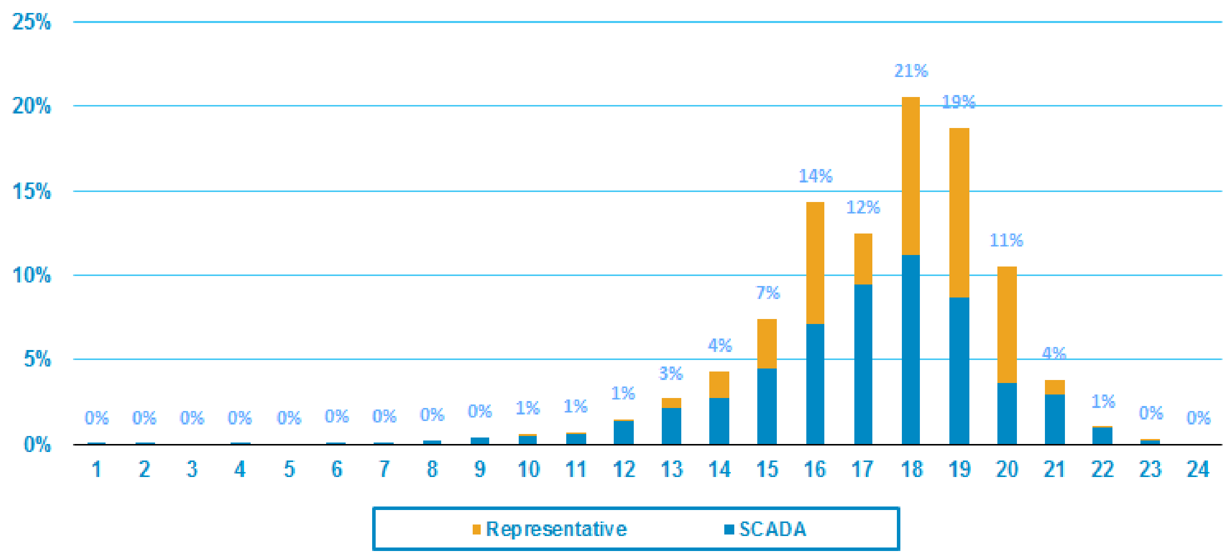


FIGURE 2-23: PG&E FEEDER PEAKS COUNTS BY HOUR ENDING

The next relationship to consider is peak transformer load to available transformer capacity. Eighty-seven (87) percent of PG&E's substation transformers were loaded to less than 90 percent of their capacity and 65 percent are loaded to less than 80 percent of their capacity. The relevance of this is that PG&E generally does not need to make capacity expenditures for transformers that are loaded below their capacity. To illustrate, between 2008 and 2012, PG&E installed 10-25 new substation transformers per year to address capacity needs (some were new units; some replaced existing units with ones having a higher rating). In comparison to the 1,200 substation transformers currently in service, PG&E is only replacing approximately 1.5 percent of all its distribution substation transformers annually. The reasons the percentage of new capacity-related transformers is so much less than the 13 percent of transformers that are loaded to more than 90 percent of their capacity are: (a) many forecasted overloads can be mitigated through switching; (b) one capacity project has the potential to address several highly loaded facilities; and (c) many of the transformers loaded over 90 percent of their capacity are not forecasted to exceed their rating, so no project is necessary.

Translating DER Impact Into Avoided or Increased Cost

The locational impact of deferring or accelerating project costs would be the difference between the deferral benefits (or accelerated costs) and the capacity-related costs for interconnecting DERs, less additional benefits of deferring or accelerating the project.

The formula to calculate the deferral benefits is shown below where $TD[Proj][y]$ is the value of deferring capacity in year *y* of *t* years. Initially, the minimum deferral period is three years to ensure the deferral benefits provide maximum return on investment, as well as a sufficient gain in capacity that provides additional margin for when new or upgraded distribution facilities are deployed. As additional experience is gained, this requirement will be reevaluated in the future

$$TD[Proj][y] = \frac{TDCapital[y][inv] * Inflation[inv] * RRScaler[y][inv] * \left(1 - \left(\frac{1 + i[inv]}{1 + r}\right)^{\Delta t}\right)}{(1 + r)^{(y - StartYr)}}$$

TDCapital = Capital cost of the investment in year *y*. Note that the capital cost should be entered in the year that the expenditure stream is committed, which may be before the in-service year. The costs are lumped together to the commitment date, rather than the construction dates. However, if the project is structured such that there are major work stages that could be deferred separately, then each of the stages of work could be entered as a separate lump sum corresponding to each independent commitment date. Similarly, if there are multiple projects that have different commitment dates within the analysis horizon, each of those projects could be entered as independent lump sum values.

inv = the investment

i[inv] = inflation rate for capital equipment inv, default to general inflation rate

Inflation[inv = (1+i[inv])^(*y*-BaseYear[inv]). Convert investment to nominal dollars in the in-service year.

StartYr = First year of the economic analysis

BaseYear[inv] = Year basis for cost estimate for investment inv.

r = Discount rate

RRScaler[i] = Revenue requirement scaling factor to convert direct capital costs to revenue requirement levels.

Granularity of Locational Variation

PG&E expects this value component to vary from feeder to feeder.

2. Voltage and Power Quality Capital and Operating Expenditures

Definition: Avoided or increased costs incurred to ensure power delivered is within required operating specifications (*i.e.*, voltage, fluctuations, etc.).

To the extent that the placement of DERs within a certain location defers or accelerates the timing or need for additional voltage and power quality upgrades that are to be installed on the electric T&D systems, those deferred or accelerated upgrade costs are a benefit or a cost to the utilities. Examples of deferrable work include installing additional voltage regulation devices, revising existing voltage regulation device settings, and replacing voltage regulation equipment.

Determining DER'S Impact

Determining a DER's or portfolio of DERs' impact on Distribution Voltage and Power Quality value is similar to how a DER or portfolio of DERs' impact is determined for Distribution Capacity.

A DER's distribution voltage and power quality impact is solely related to the DER's or portfolio of DERs' output at the time when the distribution voltage and power quality issue may occur, which is most commonly during local peak load hours, but may also occur outside of peak hours subject to area load composition.

Translating DER Impact Into Avoided or Increased Cost

The locational net benefit or net cost of deferring or accelerating project costs will be the difference between the deferral benefits (or accelerated costs) and the voltage/power quality costs for interconnecting DERs. In the case of deferring project costs, the formulas for determining deferral benefits and net deferral benefits will be the same set of formulas use for the "*Electric Sub-Transmission, Substation, and Feeder Capital and Operating Expenditures (Distribution Capacity)*" benefits.

Granularity of Locational Variation

PG&E expects this value component to vary from feeder to feeder.

3. Electric Distribution Reliability/Resiliency Capital and Operating Expenditures

Definition: Costs incurred to proactively prevent, mitigate, and respond to routine outages (reliability) and major outages (resiliency).

DERs may defer or accelerate the timing or need for additional reliability and resiliency upgrades at different locations, reducing or accelerating the time of when additional investments are required for the electric distribution system. The locational net benefit is the difference between the deferral benefit and any reliability/resiliency costs for interconnecting DERs. Examples include new or upgraded distribution line feeders.

Determining DER's Impact

Determining a DER's or portfolio of DERs' impact on distribution reliability and resiliency value is similar to how a DER or portfolio of DERs' impact is determined for Distribution Capacity.

A DER's reliability and resiliency impact is solely related to the DER's or portfolio of DERs' output at the time when the distribution reliability and resiliency issues may occur, which is most commonly during local peak load hours, but may also occur outside of peak hours subject to area load composition.

Translating DER Impact Into Avoided or Increased Cost

The formulas for determining deferral benefits and net deferral benefits will be the same set of formulas use for the "*Electric Sub-Transmission, Substation, and Feeder Capital and Operating Expenditures (Distribution Capacity)*" benefits.

Granularity of Locational Variation

PG&E expects this value component to vary from feeder to feeder.

4. Deferred Electric Transmission Capacity Capital and Operating Expenditures

Definition: Avoided or increased costs incurred to increase capacity on transmission line and/or substations to ensure system can accommodate forecast load growth.

To the extent that placement of DERs at certain locations defers or accelerates the timing or need for additional capacity to be installed on the electric transmission system, those deferred or accelerated capacity costs are a benefit or a cost to the utilities. The locational net benefit of deferring project costs will be the difference between the deferral benefit and the transmission capacity costs for interconnecting DERs.

Determining DER's Impact

As with distribution capacity deferral, transmission capacity deferral requires a DER to provide output coincident with the local peak load. This output must be sufficient to reduce the forecasted local peak load such that a capacity upgrade can be avoided.

Translating DER Impact Into Avoided or Increased Cost

The formulas and criteria for determining deferral benefits and net deferral benefits will be the same set of formulas use for the "*Electric Sub-Transmission, Substation, and Feeder Capital and Operating Expenditures (Distribution Capacity)*" benefits. Examples of this type of work include construction of new substations and/or transmission lines, substation upgrades, transformer upgrades and/or transmission line reconductoring and reconfigurations.

Granularity of Locational Variation

PG&E expects this value component to vary from substation to substation.

5a. System or Local RA Costs

Definition: Avoided or increased costs incurred to procure RA capacity to meet system or CAISO-identified LCR.

The Commission's RA Program establishes forward procurement requirements for Load Serving Entities (LSE) to demonstrate that they have acquired the necessary capacity to satisfy their respective system or local RA requirements.

There are three types of RA procurement requirements: (1) System; (2) Local; and (3) Flexible. System and Flexible RA capacity requirements are designed to ensure that LSEs have sufficient resources available to the CAISO for reliable operation of California's bulk electric power system. Local RA capacity is designed to ensure that LSEs have sufficient resources in specific transmission-constrained areas to maintain reliable operation in the event of an unplanned outage affecting those areas. Local RA resources are simply system RA resources that are located in specific, transmission-constrained areas (*i.e.*, LCR areas).

In simple terms, the system RA requirement or procurement obligation for an LSE is that LSE's forecasted coincident peak load plus 15 percent. The CAISO establishes local RA requirements for each LCR area as part of the annual TPP and these are adopted in the CPUC's annual RA decision. These LCR areas and local RA requirements are established in order to meet North American Electric Reliability Corporation (NERC) reliability standards.

The net system/local RA benefit will be quantified as the avoided system/local RA purchases net of any increase in system/local RA purchases required as a result of a DER project. One example of such an increase would be an increase in system RA procurement required as a result of a DER increasing the PG&E's forecasted peak load in any month.

Determining DER's Impact

In order for any DER to have a net impact on the IOU's RA procurement, it is critical to establish that the DER in question is not already embedded in the current studies that are used to determine the RA requirements. Separately counting the net impact of a DER that is already embedded in the study would double count that resource's impact. In most cases, the studies conducted to determine RA requirements use load forecasts that are based on the most recent CEC Integrated Energy Policy Report (IEPR) load forecast, which includes impacts of most forecasted DER additions, such as PV and non-PV self-generation, DR, EE and EVs.

After it is established that a DER is not already embedded in the most recent CEC IEPR load forecast or other current studies that are used to determine the RA requirements, PG&E would determine the quantity (*i.e.*, MW) of avoided or increased system or local capacity associated with that DER using an Equivalent Load Carrying Capability (ELCC) methodology. PG&E plans to use a marginal ELCC RA value for DERs to recognize their incremental contribution to system reliability. PG&E plans to use an hourly, CAISO-wide Loss of Load Probability model to determine a DER's ELCC. PG&E anticipates that the DER would be represented in the model using an hourly profile of load increase or load decrease/generation levels specific to that DER or ensemble of DERs. If a project-specific profile is not available, a standard profile would be used. If a DER is dispatchable, the model may include logic to mimic the dispatch process for that resource.

The result of this methodology is the net increase or decrease in system RA (or local RA if in an LCR area) required to maintain the applicable reliability standard.

PG&E recognizes that there is a complex suite of approaches to quantifying the various DERs' impact on RA,[19] and that many of these approaches are continually

[19] For example, in order for a DG resource to qualify as a RA resource, it must be deemed "deliverable" by the CAISO. The CAISO's annual DG Deliverability Assessment determines where and how much excess deliverability is available for DG resources to take advantage of without incurring additional upgrades.

evolving.[20] PG&E believes that an ELCC-type analysis is the most consistent and comprehensive approach to determining any resource's contribution to reliability across all hours in the year. Use of ELCC is also consistent with the direction indicated by recent Commission activity.[21]

Translating DER Impact Into Avoided or Increased Cost

Once the net increase or decrease in MW of System RA (or local RA if in an LCR area) associated with a DER is determined, translating that quantity impact into a net avoided cost requires a price forecast of System RA (or Local RA).

To forecast the price of System RA, PG&E anticipates estimating the net cost of marginal capacity on the system. This net cost of marginal capacity is an estimate, for the resource identified as being on the margin in providing RA to the system, of that marginal resource's going-forward costs minus that marginal resource's forecasted revenues associated with the energy and ancillary service markets.

The price of System RA is affected by increasing amounts of variable renewable generation on the system. The amount of variable renewable generation that is producing energy has increased dramatically since 2012, and is anticipated to increase further in future years. Consequently, the system needs more operationally flexible capacity to manage increased ramps, renewable generation forecast uncertainty and intra-hour variability for CAISO to balance loads and resources and maintain reliability. The result is that the system has less need for, and derives lower benefits from, incremental capacity that is not flexible.

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[20] For example, in D.14-12-024, the Commission approved a process for the Commission to enhance the role of DR in meeting California's electric resource planning needs, the objective of R.13-09-011. As part of that process, D.14-12-024 established several working groups, including the Load Modifying DR Valuation Working Group.

[21] Senate Bill (SB) 2 (1X) ordered to the CPUC to "use those effective load carrying capacity [or ELCC] values in establishing the contribution of wind and solar energy resources toward meeting […] resource adequacy requirements," and the Commission expressed its intent to use ELCC in D.14-06-050.

Where a DER is located in a LCR area, PG&E would forecast an RA price for that area. This price forecast is anticipated to reflect the anticipated year of need for new RA in that area.

Procurement activity in an LCR area can be needed due to an increase in the local RA requirements in that area or due to resource retirement or contract expirations in that LCR area. In LCR areas where the market can sustain local RA prices that are above system RA prices, DERs may realize a net locational RA benefit that is above the net system RA benefit.

Forecasting the price of local RA in an LCR area is a highly commercially sensitive process given the potential market power of generators in that LCR area. Therefore PG&E cannot make public its local RA price forecasts, for that information would be used by market participants to the disadvantage of PG&E's procurement activities and costs for PG&E's bundled customers might be increased; however, the public result of CAISO's annual LCR studies typically evaluate whether new local capacity is needed in the five-year timeframe. In addition, CPUC's annual RA report may include a price analysis for certain LCR areas, while other areas may be reported in aggregate.[22]

PG&E also notes that DERs may need to meet certain additional operating requirements to avoid local RA. For example, DR located in an LCR area must be dispatchable based on local needs to qualify for local RA, meaning the resources within that area must be able to be dispatched independently of resources outside of the area so that they can respond to a local reliability event. Local reliability events may not coincide with system-wide events that typically trigger DR.

Granularity of Locational Variation

PG&E expects this value component to be the same for locations in its system that are not in LCR areas. For LCR areas, PG&E expects this value component to vary from LCR area to LCR area.

[22] See for example, Table 12 in the 2012 RA Report located here: http://www.cpuc.ca.gov/NR/rdonlyres/94E0D083-C122-4C43-A2D2-B122D7D48DDD/0/2012RAReportFinal.pdf.

5b. Flexible RA

Definition: Avoided or increased costs incurred to procure flexible RA capacity to meet PG&E's Flexible RA requirements.

In simple terms, the current flexible RA requirement for LSEs is the sum of 3.5 percent of the LSE's forecasted coincident peak load[23] plus the forecasted largest three-hour ramp in net load[24] plus an error term.[25]

Flexible RA is a new procurement requirement—2015 was the first RA year that LSEs were required to meet a flexible RA requirement. The current flexible RA framework based on the 3-hour net load ramp is an interim approach and is anticipated to change for the 2017 RA compliance year.[26]

Determining DER's Impact

After it is established that a DER is not already embedded in the most recent CEC IEPR load forecast or other current studies that are used to determine the RA requirements, PG&E would determine the quantity (*i.e.*, MW) of avoided or increased flexible capacity associated with that DER using an hourly model. This model would mimic the model that CAISO uses to determine the flexible RA requirement.

PG&E would run the model with and without the DER to determine the MW change in PG&E's flexible RA requirement. The DER would be represented in the model using an hourly profile of load increase or load decrease/generation levels specific to that DER or ensemble of DERs. If a project-specific profile is not available, a standard profile would be used. If a DER is dispatchable, the model may include logic to mimic the dispatch process for that resource.

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[23] Or the most severe single contingency if larger.

[24] Load minus wind and solar generation.

[25] Currently set at zero.

[26] See D.14.06.050 located here: http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M097/K619/97619935.PDF.

Currently, a DER's flexible RA impact is based on its expected generation profile at the time of the greatest 3-hour net load ramp. For example, because its output is decreasing during the evening ramp, standalone PV increases the CAISO's 3-hour ramp-based flexible RA requirement, and therefore is likely to increase the utility's flexible RA costs. This analysis would change as the flexible RA program evolves over the coming years.

Translating DER Impact Into Avoided or Increased Cost

Once the net increase or decrease in MW of Flexible RA associated with a DER is determined, translating that quantity impact into a net avoided cost requires a price forecast of Flexible RA.

PG&E would estimate this cost using a methodology similar to that for System RA, with appropriate inputs specific to flexible conventional generation resources.

Granularity of Locational Variation

PG&E expects this value component to vary from LSE service area to LSE service area.

6a. Generation Energy and GHG

Definition: Avoided or increased costs incurred to procure electrical energy and associated cost of GHG emissions on behalf of utility customers.

Determining DER's Impact

Depending upon the specific characteristics of a particular DER, the DER can be a generator or a load, and sometimes both. PG&E would use an hourly profile of load increase or load decrease/generation levels specific to that DER or ensemble of DERs. If a project-specific profile is not available, a standard profile would be used.

Translating DER Impact Into Avoided, Net Avoided or Increased Costs

Once the hourly net increase or decrease in energy procurement due to a DER is determined, an energy price forecast is needed to translate that impact into a cost. Since California's Cap and Trade system has gone into effect, energy prices have included the cost of GHG emissions, and PG&E's energy price forecast would also include that cost.

PG&E proposes to use a model based on the energy price forecasting model developed for its 2015 Rate Design Window Application (A.14-11-014). This model uses public data from the CAISO and a forecast of system net load using public data to determine future energy prices. With the increase in renewable generation, and particular solar DER and wholesale generation, DERs may increase the potential for over-generation conditions and low and negative energy benefits particularly during low net load hours in the middle of the day.[27]

PG&E would also develop location-specific energy price adders to capture locational variation in energy price due to transmission congestion. These adders would be determined based on an analysis of historical Locational Marginal Prices (LMP) throughout PG&E's service territory. This congestion analysis would account for impacts from anticipated transmission projects initiated through the TPP and would also be informed by publicly available CAISO modeling data, such as the 2014 LTPP PLEXOS production simulation results. PG&E notes that it is possible to use historical LMPs directly; however PG&E believes this is not appropriate, since LMPs do not provide a consistent or significant price signal from year to year[28] and, under current market rules, PG&E does not pay the LMP at a specific location when meeting load at that location.

Granularity of Locational Variation

PG&E expects this value component to vary from CAISO PNode to PNode.

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[27] Net load is the residual load left after subtracting wind and solar generation.

[28] In a recent analysis of several years' worth of LMPs, the CAISO found that: (1) LMPs do not vary significantly across the system; (2) most variation is caused by the congestion component; (3) there is little consistency in LMPs from year to year. Much of the variation in LMPs is a result of temporary changes on the transmission system, such as line outages causing local congestion, which results in short-term variability in some LMPs, but no clear long-term, location-specific price signal. CAISO Load Granularity Refinements Pricing Study Results and Implementation Costs and Benefits Discussion, 2015. Located here: http://www.caiso.com/Documents/PricingStudyResults-ImplementationCosts-BenefitsDiscussionPaper_LoadGranularityRefinements.pdf.

6b. Energy Losses

Definition: Avoided or increased costs to deliver procured electrical energy to utility customers due to losses on the T&D system.

DERs can increase or decrease energy losses. When a DER is consuming energy, the incremental increase in losses associated with delivering that energy must be accounted for. When a DER is reducing load, the incremental decrease in losses associated with not delivering energy to meet that load must be accounted for. When a DER generates energy, losses may be reduced if the energy is consumed close to that DER; if the DER's energy is consumed by loads in other parts of the system losses may actually be increased.

Determining DER's Impact

PG&E proposes to use engineering principles to develop a function that would estimate combined T&D losses at the line section level based on several easily estimated quantities, such as distance from substation and interconnection voltage level.

In hours when a DER such as energy storage consumes energy, losses will increase energy and GHG costs. In hours when a DER such as energy efficiency reduces load, losses will decrease energy and GHG costs.

For hours when a DER (*e.g.*, DG) generates energy, PG&E would use an hourly model to determine the hours that the DER is resulting in backflow onto the transmission system. At these times, the DER-generated energy is not consumed locally and losses are not avoided. The combined T&D loss factor will be used to decrease energy and GHG costs in hours when that a generating DER is not resulting in backflow onto the transmission system.

Translating DER Impact Into Avoided or Increased Cost

Once the hourly application of the combined T&D loss factor is determined, it would be applied to the hourly DER net avoided or increased energy and GHG cost described previously.

Granularity of Locational Variation

PG&E expects this value component to vary from line section to line section within a feeder.

6c. Ancillary Services

Definition: Avoided or increased costs to procure ancillary services on behalf of utility customers.

Determining DER's Impact

A DER's impact on Ancillary Services procurement would be estimated as a function of its energy and GHG net avoided cost.

Translating DER Impact Into Avoided or Increased Cost

PG&E would use a standard rule of thumb that ancillary service costs can be captured by increasing energy price forecast by 1 percent. This rule of thumb is used in other avoided cost methodologies, such as E3's DERAC.

Granularity of Locational Variation

Same as energy and GHG value component.

6d. RPS

Definition: Avoided or increased costs incurred to procure RPS eligible energy on behalf of utility customers as required to meet the utility's RPS requirements.

Determining DER's Impact

DERs can avoid or increase RPS procurement costs. For example, DERs could reduce RPS procurement costs by reducing the utility's sales of electricity (currently, the utility's RPS procurement requirement is 33 percent of electricity sales). For DERs which reduce the utility's electricity sales, an hourly profile of the generation would be used to estimate the reduction in sales and corresponding decrease in RPS procurement due to the DERs. If a project-specific profile is not available, a standard profile would be used.

DERs could also increase the utility's RPS procurement costs if the DER results in an increase in sales or if a generating DER increases the utility's over-generation and creates additional RPS curtailment. In the latter case, DERs would increase the utility's RPS procurement costs if the additional curtailed RPS needs to be replaced to satisfy the utility's RPS requirements.

Translating DER Impact Into Avoided or Increased Cost

Once the RPS procurement impact is determined, an RPS price premium is needed to translate that impact into an avoided or increased RPS cost. The RPS price premium is the difference between the RPS price and the capacity and energy value of the RPS resource. PG&E would use a proprietary RPS price forecast.

Consistent with E3's DERAC tool, PG&E would apply the RPS premium to the quantity of avoided or increased RPS procurement to yield a DER's locational RPS impact.

Granularity of Locational Variation

PG&E expects this value component to vary from LSE to LSE.

7. Renewable Integration Costs

Definition: Avoided or increased generation-related costs not already captured under other components associated with integrating variable renewable resources.

The net renewable integration benefit or cost of DERs would be estimated based on the renewable integration cost adder guidelines for wind and solar resources adopted by the CPUC, in a recent RPS proceeding decision.[29] In general, this decision identifies renewable integration costs as system-wide generation-related costs incurred to provide the flexibility needed to integrate variable renewables, namely wind and solar. Any estimate of net benefit or cost associated with increased or decreased renewable integration costs would be consistent with the interim methodology adopted in this decision, as long as the interim adders are in effect.

Determining DER's Impact

For DERs which avoid RPS procurement—some of which comes from wind and solar resources—the cost of integrating that avoided RPS wind and solar is also avoided. PG&E would estimate the portion of a DER's avoided RPS that comes from wind and solar using its most recent public RPS procurement records.

For DERs which are themselves standalone wind or solar resources (*i.e.*, not shaped or firmed by storage), a renewable integration cost would be applied per megawatt-hour (MWh) of production from that DER resource to account for the utility's integration cost increase.

Translating DER Impact Into Avoided or Increased Cost

For DERs which avoid RPS procurement, the MWh of avoided wind would be multiplied by a wind integration cost, and the MWh of solar would be multiplied by a solar integration cost. Consistent with D.14-11-042, these integration costs would include a variable and a fixed component.

The interim methodology currently sets the variable component at $3/MWh for solar and $4/MWh for wind. This component includes integration variable costs such as increased fuel and variable operation and maintenance costs, and increased ancillary service costs needed to balance renewables in real time. The ancillary service cost

[29] See pages 53 to 63 of D.14-11-042 here:
http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M143/K313/143313500.PDF.

here is associated with the uncertainty and variability of wind and solar resources. This is distinct from the ancillary service cost described in Component 6c, which is driven by the uncertainty and variability in load and renewable resources already included in the utility's portfolio. The interim methodology also includes a fixed cost component which captures fixed costs associated with additional flexible RA capacity requirements that result from wind or solar resources.

For DERs, which are themselves standalone wind or solar resources (*i.e.*, not shaped or firmed by storage), a renewable integration cost would be applied per MWh of production from that resource. The integration cost would only include fixed and variable components consistent with D.14-11-042.

Granularity of Locational Variation

PG&E expects this value component to vary from LSE to LSE.

8. Societal Avoided Costs Linked to Deployment of DERs

Definition: Avoided or incremental costs to society which do not have any nexus to utility costs or rates.

The Commission's ratemaking and procurement rules and decisions have already internalized various categories of "societal" costs and benefits attributable to DERs, including avoided GHG emissions costs; the energy procurement loading order for "preferred resources" such as renewable resources, DR and EE. Accordingly, a good part of societal avoided costs linked to DERs are already included in the Locational Impact Analysis and Methodology for the various component values described above. To avoid double counting, such avoided costs should not be included in the value component. PG&E proposes to consider qualitatively *Societal Avoided Costs Linked to Deployment of DERs* and of other alternatives, including distribution capacity additions, that are not already included in other components previously described.

9. Public Safety Avoided Costs Linked to Deployment of DERs

Definition: Decreased or increased safety-related costs which are not captured in any other component.

For this phase of the DRP, any avoided public safety costs due to the deployment of DERs are considered quantitatively in the Locational Impact Analysis and Methodology for evaluating reliability and safety related distribution capacity additions. This is because these avoided public safety costs are effectively equivalent to the costs to obtain a higher level of electric system reliability and resiliency to ensure electric service continues to be provided to PG&Es' customers safely, reliably and affordably. PG&E proposes to consider qualitatively *Public Safety Avoided Costs Linked to Deployment of DERs* and of other alternatives, including distribution capacity additions, that are not already included in other components previously described.

2.c.iv. Integration Into Long-Term Planning (TPP, LTPP, IEPR)

All long-term electric system planning processes in California currently include various DER growth assumptions as part of scenarios used for planning. In recent years, the CPUC and CAISO have striven to use common assumptions in the LTPP and TPP, and typically those common assumptions originate from the CEC IEPR forecast. In the past the IEPR process adopts multiple levels of forecasts—typically high, mid and low—for load, additional energy efficiency, behind-the-meter PV and CHP. The most recent IEPR forecast also embeds EV and other electrification load as wells as non-event based DR in its load forecasts.

In its recent "Ruling on Assumptions and Scenarios"[30] for the 2014 LTPP and the 2015-2016 TPP the Commission directs CAISO, in its 2015-2016 TPP to use scenarios which represent various combinations of IEPR forecasts of load, efficiency and behind-the-meter PV and CHP. In specific instances where IEPR does not provide sufficient information, the ruling refers to other sources: for a high behind-the-meter PV scenario, the ruling refers to an E3 forecast developed under the direction of the CPUC; for a forecast of event-based DR to model as a supply resource, the ruling refers to the most recent annual Load Impact Reports. Finally the ruling also gives specific direction on energy storage assumptions to use in the CAISO's model.

[30] http://www.cpuc.ca.gov/NR/rdonlyres/DA742AFC-ECF2-47DD-9734-BB859DD694F7/0/ACR_Attachment_2015.pdf.

Although consistency in assumptions across the IEPR, LTPP and TPP has largely been achieved, the DRP may be an avenue for the utilities to develop alternative growth scenarios to inform the IEPR, and other planning forums with the utility's view of future DER adoption. In particular, PG&E has provided in its 2014 Bundled Procurement Plan (BPP) a public forecast of behind-the-meter PV adoption in its territory that more closely follows current trends and is roughly double that of the IEPR forecast.

1. Integration of DER impacts Into IEPR

The IEPR is a biennial (odd year) CEC effort which produces, among other things, long-term peak and energy demand forecasts for California. As described above, the IEPR is typically the source for all or most of the forecasts used for generation planning in the LTPP and transmission planning in the TPP.

As the IEPR forecast forms the basis for RA requirements, it is critical to establish that the impacts of a DER or portfolio of DERs are not embedded in the IEPR forecast before assigning them additional RA avoided cost.

2. Integration of DER Impacts Into LTPP

The LTPP proceeding is an even-year biennial proceeding to determine whether any new resources are needed to maintain system-level reliability over a long timeframe. (The LTPP also is the venue where the CPUC approves each IOU's BPP as required by AB 57.) Typically, the LTPP looks at a snapshot of system reliability for a 10-year horizon. The LTPP typically only considers the need for incremental resources at a system-wide level, however location-specific analysis may be considered if necessary (*e.g.*, in the 2012 LTPP after San Onofre Nuclear Generating Station (SONGS) closure).

The impact of DERs on long-term system reliability is already included in the LTPP by reference to the IEPR forecast which includes the impact of those DERs. If the Commission determines a need for incremental resources exists, the Commission can direct IOUs to procure additional resources to meet that need, with all benefiting customers paying for the costs of the needed resources. The Commission may authorize IOUs to conduct all-source Request for Offers (RFO) to meet an identified need. When meeting an identified need with DERs, care must be taken to ensure that the DER resources are incremental to DERs that are already included in the LTPP input assumptions, otherwise double counting would occur and the sought-after reliability would not be attained.

In general, the LTPP includes existing and forecasted future DERs as follows:

- EE is incorporated through the adoption of the IEPR forecast; for example, the 2014 LTPP Trajectory scenario includes the forecasted mid-case “additionally achievable energy efficiency.”
- DR is modeled at levels determined using the most recent Load Impact reports provided by the Demand Response Measurement and Evaluation Committee under guidance of the CPUC.
- Energy storage has been incorporated into the 2014 LTPP in correspondence with the CPUC’s energy storage procurement targets.
- Existing and future Behind-the-meter DG is incorporated at the level assumed in the IEPR forecast; however it is modeled as a supply resource rather than embedded in the load to capture the operational flexibility challenges associated with integrating variable generation connected behind the meter. The LTPP includes scenarios with high DG penetration above the IEPR mid case forecast.
- Existing and future Wholesale DG is included in the RPS resource portfolios that are modeled in the LTPP.

Care will need to be taken to ensure that any new DERs integrated onto the distribution system would be modeled in the LTPP accordingly, even where this requires departure for the standard planning assumptions or scenarios.

3. Integration of DER Impacts Into TPP

The CAISO’s TPP is an annual process wherein CAISO conducts transmission planning analysis to determine what transmission expansion projects, if any, are needed to maintain reliability or meet policy goals (*e.g.*, RPS). As part of the TPP, the CAISO also performs analyses to determine the LCRs needed to ensure reliability is met on a CAISO system level, as well as a local area level.

CPUC sets standard planning assumptions for the various scenarios that are studied in the LTPP and TPP, and these are typically based directly on forecasts provided in the IEPR. The impact of DERs on long-term system reliability is already included in the TPP in many cases, and care must be taken to avoid double counting resources that may be assumed to provide local RA or to reduce the local RA requirement.

2.c.v. Process for Maintaining Ongoing Updates to the DER Integration Capacity Analysis and the Optimal Location Analysis

PG&E anticipates that significant experience will be gained in calculating and applying Locational Impact Analysis in its demonstration and deployment projects as described in Chapter 3. At the conclusion of those projects, that experience gained will inform future refinements to the Locational Impact Methodologies and applications.

In the near-term, PG&E expects to make minor refinements as interim approaches under the flexible capacity and integration cost value components are solidified.

2.c.vi. Conclusion

PG&E's DRP Locational Impact Methodology can be integrated in long-term planning initiatives like the CAISO's TPP, CPUC's LTPP, and the CEC's IEPR as needed to influence the outcome of the planning process, such as improving the forecast of DER growth in the IEPR, or in the TPP as an alternative to address transmission deficiencies or local reliability needs, which in turn may also influence the outcome of the LTPP.

2.d. DER Growth Scenarios

The Guidance Ruling requires the IOUs to develop three 10-year scenarios for projected growth of DERs through 2025, including estimates of DER geographic dispersion at the distribution feeder level and their impacts on distribution planning. This section summarizes the methodological approach taken by PG&E to develop DER growth scenarios and presents high level summaries of projected results by DER technology category. Further details on development of the DER growth scenarios are provided in Appendix C. Section 2.d.i provides an overview of the DER technologies as well as current adoption/deployment in PG&E's territory. PG&E's approach to developing the growth scenarios is summarized in Section 2.d.ii and Section 2.d.iii provides aggregated growth scenario results. The impacts of DER growth on PG&E's distribution planning is covered in Chapter 8.

The Guidance Ruling notes that California's energy policy has supported the widespread adoption and deployment of DERs across the IOU service areas. These resources, including EE, DR, DG technologies, EVs and energy storage, are critical components of a cleaner, more sustainable energy future for California. PG&E and the other utilities are enabling deployment of these resources through the management of ratepayer-funded DER incentives and other programs/tariffs, and through customer education and assistance. In recent years, PG&E's distribution planning process also has facilitated the safe and timely interconnection of DERs, such as rooftop solar PV systems, to the grid.

PG&E is also enabling DER technology deployment by incorporating DERs into its distribution grid planning to facilitate higher penetrations of DERs while modernizing and maintaining a grid that is safe, reliable, and affordable. Because decisions about grid investments need to be made years in advance, and there is significant uncertainty in the quantities and locations of future deployment of DERs, PG&E is leveraging growth scenarios to project the quantities and locations of future DER deployment and to plan for DER system and local-level impacts.. Decisions about when and where DERs will be deployed are generally made by our customers, so PG&E's understanding of customer DER adoption patterns is critical to estimating where DER is likely to be deployed and its impact on the distribution system. PG&E's DER growth scenarios under the Guidance Ruling are not forecasts that PG&E can use for specific locational distribution capacity planning, but can be useful in helping PG&E distribution planners anticipate the quantities and locations of potential future DER deployment.

While accounting for the uncertainties in the DER growth scenarios, the scenarios are used in conjunction with PG&E's Integration Capacity Analysis to determine areas that are most likely to benefit from DER-enabling investments, areas where system upgrades are not required to accommodate additional DERs, and areas where system upgrades may be necessary to integrate additional DERs. The DER growth scenarios improve PG&E's ability to direct future distribution asset investments to the most appropriate areas to improve customer reliability, power quality, and cost of service.

PG&E utilized the best tools and information available at this time to provide DER growth scenarios for the purposes of this DRP, using multivariate regression analysis to estimate DER growth trends and future scenarios. PG&E will continue to refine its DER growth planning tools and data sources, and will update its DER growth scenarios to reflect dynamic market conditions as the DER markets evolves. While the trajectory growth scenario (Scenario 1) presented herein represents PG&E's best estimates of future DER adoption and deployment, it is important that planners and regulators consider the significant uncertainty in technology diffusion forecasting when evaluating the net benefits and distribution asset investments associated with DER deployment. These uncertainties are outlined in Section 2.d.ii.and further described in Appendix C for each technology category. Due to the dynamic and evolving nature of the DER market and policy landscape, the process of projecting DER growth should be an iterative process in which previous assumptions are revisited and updated regularly with current market information.

2.d.i. Technology Categories Included in DER Growth Scenarios

The DRP takes into account that the term "Distributed Energy Resources," as defined in Public Utilities Code Section 769, covers broad and different technology categories.[31] DERs are generally understood to be energy management or generation technologies that are sited at or near where energy is consumed, either on the customer side of the meter or the utility side of

[31] For the purposes of the DRPs, Public Utilities Code Section 769 defines distributed resources as "distributed renewable generation resources, energy efficiency, energy storage, electric vehicles, and demand response technologies."

the meter but interconnected to the distribution grid. For the purposes of this DRP, PG&E limited its analysis to DG less than or equal to 20 MW in size. This section provides background on the DER technologies included in the DRP.

Consistent with the Guidance Ruling, PG&E considered both customer side of the meter and utility side of the meter DERs. The following technology categories of DERs were included in PG&E's analysis:

- Energy Efficiency
- Demand Response
- Retail DG (Customer side of the meter)
  - Solar PV
  - Combustion and Heat to Power Technologies
  - Fuel Cells
- Retail Storage
- PEVs
- Combined Heat and Power Associated with the CHP Feed in Tariff Program (< 20 MW)
- Wholesale Solar and Biomass (utility side of the meter < 20 MW)
- Wholesale Storage (utility side of the meter < 20 MW)

Adoption of distributed wind in PG&E's service area has been limited (~12 MW to end of year (EOY) 2014). PG&E did not have an adequate sample size to project the geospatial adoption of this technology, so retail wind was not included in its analysis. The potential impact of Vehicle to Grid Integration (VGI) technology on EV load and capacity is not included in the DER growth scenarios at this time due to uncertainty about the timeline for development of the technology necessary to facilitate VGI as well as a lack of data about what VGI load profiles will look like. PG&E is currently working with BMW on a pilot that tests the value of smart charging with over one hundred residential customers. This pilot also evaluates the benefit of stationary storage from used EV batteries and information from this pilot and other VGI research efforts may be incorporated into future distribution planning.

The Guidance Ruling states that while the emphasis should be on distributed resources fueled by renewable resources, natural gas-fueled distributed resources that have a GHG emissions benefit should also be considered. For the purposes of load projections for planning, including the IEPR and LTPP proceedings, PG&E includes DG technologies that run on both renewable and non-renewable fuels (primarily natural gas), independent of GHG impacts. For this reason, and because non-renewable DG resources impact distribution planning, they were included in PG&E's DER growth scenarios for the DRP.

Each category of DER, and specific technology within each category, will have different impacts on the distribution grid due to differences in how a given technology impacts load, due to varying generation profiles (for DG resources), and variable operating profiles for EE measures, energy storage, DR, and EVs. For example, a solar PV installation may reduce customers' electricity demand during the day, while an EE measure that impacts lighting may primarily reduce electricity demand in the evening. When incorporating DERs into distribution planning, it is critical to consider the time of day (or hours of the year) in which the DER will impact the grid, as well as the reliability or consistency of that impact.

Here, PG&E provides an overview of the DER technology categories included in the DRP growth scenarios:

2.d.i.1. Energy Efficiency

EE has been a key component of California's energy planning since the first ratepayer-funded programs and codes and standards were implemented in the mid-1970s. Ratepayer-funded programs promote the use of more efficient technologies and practices, from emerging technologies to mass market products and approaches to advocacy for greater levels of efficiency in state and federal codes and standards (Title 20 appliance standards, Title 24 building standards, and federal appliance standards). Codes and standards codify savings in state and federal product or building requirements by mandating efficiency in new construction, building retrofits, and energy-consuming products.

EE has a significant and lasting impact on the grid. EE program goals have been in the range of 1 percent to 1.5 percent of annual sales for many years, which cumulatively amount to significant impacts. Over the period 2008-2014, EE measures have reduced PG&E's system peak by an estimated 1,300 MW.[32] The savings is long-lived, with appliances, insulation, and light-emitting diode light bulbs being three examples of products that last 10+ years. Program impacts work in conjunction with codes and standards, which have become increasingly stringent in recent years. This means that for many energy efficiency interventions, participants are not able to purchase a less efficient product in the future, thereby contributing to persistence of energy savings over time. In addition to reducing overall levels of energy consumption, EE programs may shift temporal patterns of energy consumption. Such impacts may be particularly significant on load at the local level, and may impact distribution planning in the future.

2.d.i.2. Demand Response

DR is designed to enable customers to contribute to energy load reduction during times of peak demand. Most DR programs offer financial incentives to program participants who temporarily reduce their electricity use when demand could outpace supply.

Occasional storms and heat waves, as well as periodic power plant repairs and maintenance, have the potential to affect California's supply and demand for electricity. When demand is high and supply is short, power interruptions may occur. Building power plants with low utilization to satisfy infrequent periods of high demand is one option to address this issue, but the cost and environmental impact of this approach is high. DR programs are designed to be both fiscally and environmentally responsible ways to respond to occasional and temporary peak demand periods. In fact, California's Energy Action Plan, adopted by the CPUC and the CEC, puts DR along with EE at the top of the loading order before building more power plants.

PG&E offers a wide range of DR programs, from cycling residential air conditioning units, to fully automated "load shedding" strategies controlled by computers, to emergency programs where large industrial customers voluntarily reduce their electricity demand in less than an hour. Overall, PG&E's DR programs and non-residential incremental TOU rates avoided the purchase of over 600 MW of power generation capacity in 2014, thereby reducing pollution and saving our customers money.

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[32] Based on historical evaluated impacts from 2008-2012; reported impacts for 2013-2014; measured on a net basis to align with IEPR accounting practices.

2.d.i.3. Retail Distributed Generation

Retail DG[33] technologies that produce power at the site of customer load have been a part of the electric system from the start of the power industry. With the development of long distance transmission networks and distribution grids as well as large centralized power stations, most customers in California and the U.S. have come to rely on grid-supplied electricity. However, for a number of reasons, a significant portion of the CA IOU's customers have installed DG to offset all, or in most cases a portion, of their electricity needs. In California, ratepayer-funded incentive programs such as the Emerging Renewables Program, the SGIP, and the California Solar Initiative, have helped spur adoption of DG technologies. Special rate structures such as NEM—which allows DG customers to use credits from on-site generation to offset their electricity bills—have also been important policy tools to enable more DG adoption. Recent growth in the DG market has also been driven by declining DG technology costs and new financing structures that reduce upfront costs for customers, thereby lowering financial barriers to deployment.

Since 2001, PG&E customers have installed approximately 1,700 MW of retail DG in our service area through EOY 2014. Most (~1,360 MW) of the installed retail DG capacity in PG&E's service area consists of solar PV. Combustion and heat to power technologies also comprise a significant portion of DG in the service area, with about 250 MW of generation installed since 2001. This does not include CHP generation associated with California's implementation of the Public Utilities Regulatory Policy Act (PURPA) of 1978. Most of this pre-2001 CHP capacity is larger scale and does not meet the criteria for DG generally used (*i.e.*, DG is less than 20 MW). Fuel cell installations have increased in recent years and now account for about 60 MW of capacity in PG&E's service area. Due to siting and other constraints, the amount of distributed wind installed in PG&E's territory has been relatively small at about 12 MW total. Of the DG technologies in PG&E's service territory, solar rooftop PV has experienced the fastest and most sustained growth trajectory with about a 30 percent year-over-year (YOY) growth in cumulative installed capacity since 2009, and driven by very high growth (40-50 percent per year) in the residential PV market segment.

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33 Customer-side of the meter (*i.e.*, behind-the meter), designed primarily to offset on-site load, less than 20 MW.

2.d.i.4. Electric Vehicles

A plug-in EV is a vehicle that can be plugged into an electrical outlet or charging device to recharge its battery. There are two types: battery EVs, which run only on electricity, and hybrid EVs, which run mainly or solely on electricity until the battery is depleted and then are powered by an Internal Combustion Engine (ICE). Currently, there are about 60,000 EVs in PG&E's service area.

Electrifying transportation has been identified as an essential strategy for California to meet its GHG emissions reduction goals. In March 2012, Governor Brown recognized the crucial role that EVs will play by setting a statewide goal to have 1.5 million Zero Emission Vehicles (ZEV) on the road by 2025.[34] Governor Brown reinforced support for EVs in his 2015 State of the State address which called for a 50 percent reduction of petroleum use in cars and trucks by 2030.[35] Increasing EV adoption will add load to the electric system and could have significant impacts on system capacity.

The maximum charging level of an EV is determined both by the car (the voltage level it can accept) and the by the charger (the voltage level at which it can charge). There are three common charging levels:

- Level 1 (120-Volt (V)) – this is equivalent to plugging an EV into a grounded wall outlet and yields approximately 5 miles per hour of charging
- Level 2 (240 V) – up to four times faster than Level 1, Level 2 charging requires 240 V Electric Vehicle Supply Equipment (EVSE, commonly referred to as a charging station) and yields approximately 13-25 miles per hour of charging (depending on the charge level the vehicle can accept)
- Direct Current (DC) Fast Charging (500 V) – DC fast charging stations operate fast enough to charge a battery to 80 percent capacity in 30 minutes or less, not all EVs are equipped with a plug compatible with DC fast charging

The charging level of Level 2 and DC Fast Charging can result in significant load on the distribution system. Customers are therefore required to contact PG&E when installing these

[34] Executive Order B-16-2012, issued on March 23, 2012, http://gov.ca.gov/news.php?id=17463.

[35] Edmund G. Brown, Jr., Inaugural address remarks as prepared January 5, 2015. http://gov.ca.gov/news.php?id=18828.

chargers so that the utility can determine whether electrical service or system upgrades are needed.

PG&E offers two EV rate plans for residential customers, EV-A and EV-B, both of which are non-tiered, TOU plans. The EV-A rate applies to the whole house load including the EV charging. Alternatively, customers can have a second meter installed and use the EV-B on that meter to separate their EV electricity costs from their home electricity costs. Both rates seek to encourage usage in off-peak hours (from 11:00 p.m. to 7:00 p.m.), more details about these rates and their impacts the “Joint IOU Electric Vehicle Load Research Report”.[36] PG&E will build on this time-variant pricing with future smart charging programs that enable PG&E to use EV load for system wide benefit.

2.d.i.5. Retail Storage

Retail energy storage covers a suite of technologies that can store energy. Energy storage is a key element of the Grid of Things™, and can be used to provide a variety of services such as shifting energy among time periods, shaving peak loads, smoothing intermittent renewable generation, keeping voltage at a constant level, maintaining and enhancing reliability, as well as other services. This scenario covers retail energy storage, meaning storage devices that have been installed on the customer side of the meter (also referred to as “behind-the-meter”).

Per AB 2514, California utilities have been directed to procure 1.3 gigawatts of energy storage by 2020, 580 MW of which is to be procured by PG&E. Of that 580 MW, 85 MW of energy storage is targeted to be installed on retail customer sites. This is a dramatic increase from the approximately 10 MW of retail storage installed in PG&E’s service area as of the end of 2014. PG&E supports distributed energy storage primarily through the SGIP, which provides an up-front incentive to energy storage developers, covering up to 60 percent of project costs. Developers have been installing distributed energy storage devices in PG&E territory with the support of SGIP since 2010.

[36] The Joint IOU Electric Vehicle Load Research Report can be accessed at: http://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M143/K954/143954294.PDF.

2.d.i.6. Wholesale Distributed Generation

Wholesale DG refers to electric generation resources, less than or equal to 20 MW, that are interconnected to PG&E's distribution system on the utility side of the electric meter (also referred to as in-front of the meter). These resources export power onto the electric grid and typically sell power directly to PG&E, or in wholesale markets through PG&E's distribution network. Wholesale DG resources that hold a power purchase agreement (PPA) with PG&E are included in PG&E's bundled electric portfolio.

PG&E procures wholesale DG through a number of established procurement programs, which include the PV Program, the RAM, the Electric-Renewable Market Adjusting Tariff (ReMAT), as well as the Green Tariff Shared Renewables (GTSR) Program and the Electric Bioenergy Market Adjusting Tariff (BioMAT) which are currently undergoing implementation. Under these established procurement programs, PV, small hydroelectric and bioenergy projects represent the predominant technologies interconnected at the distribution-level.[37]

At the end of 2014, PG&E's bundled electric portfolio included approximately 232 MW of distribution-connected solar PV, 29 MW of distribution-connected bioenergy, and 41 MW of distribution-connected small hydroelectric resources.[38]

2.d.i.7. CHP From CHP Feed-In Tariff (FiT) Programs

CHP describes the simultaneous production of electricity and thermal energy from the same fuel source. Historically, CHP has been perceived as an efficient technology and is promoted as a preferred electrical generation resource by California energy policies.[39] Currently there are about 4,800 MW of CHP resources located in PG&E's service territory, mainly spurred by

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[37] Customer-side distributed wind energy is very limited at the present time on PG&E's system. To the extent that this technology category grows in the future, it would be included in PG&E's DER distribution planning process.

[38] These figures include capacity additions through 2014 associated with all active contracts as of May 14, 2015.

[39] The 2003 Energy Action Plan, adopted by California's energy agencies, established a "loading order" of preferred energy resources, placing EE as the state's top priority procurement resource, followed by renewable energy and DG. DG may include CHP. For more information see: CEC, 2005, *Implementing California's Loading Order for Electricity Resources*

California's implementation of PURPA.[40] This number is based on the physical location of the CHP system and some of this capacity is sold to other parties outside of PG&E's service territory or is used to serve on-site load. PG&E has PPAs with about 2,000 MW of CHP resources. This includes about 80 MW of CHP PPAs with nameplate capacity less than 20 MW.[41] For the purposes of the DER growth scenarios, PG&E included growth from CHP systems less than 20 MW.

PG&E procurement of new CHP resources that meet the definition of wholesale DERs is primarily done through the CHP FiT Program per AB 1613. PG&E has three *pro forma* AB 1613 PPAs available for new exporting CHP.[42] As of April 2015, PG&E has executed one PPA under the AB 1613 program. To date, most of the CHP deployments in the state have been natural-gas fueled. About 85 percent of the installed CHP facilities in the state are natural gas-fired topping-cycle units, also known as conventional CHP.[43] A small number of CHP units are renewable fuel-fired (*e.g.*, wood or biomass fueled) or are bottoming-cycle (Waste Heat to Power, or WHP) units.[44] PG&E considers the long-term carbon neutral forms of CHP such as WHP or bottoming-cycle CHP and biomass/biogas CHP resources to be better suited than conventional CHP for meeting the State's long-term GHG emission reduction targets.

2.d.i.8. Wholesale Distribution-Connected Energy Storage

Distribution-connected wholesale energy storage refers to energy storage resources that are interconnected to PG&E's distribution grid on the utility-side of the electric meter (*i.e.*, in-front

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40 CHP Installation Database: http://www.eea-inc.com/chpdata/. Supported by U.S. Department of Energy, Oak Ridge National Lab and maintained by ICF International.

41 Sources: January 2015 PG&E Cogeneration and Small Power Production Semi-Annual Report http://www.pge.com/includes/docs/pdfs/b2b/qualifyingfacilities/cogeneration/jan2015cogen.pdf.

42 PG&E AB 1613 *pro forma* PPAs: one for projects less than 20 MW, one for projects less than 5 MW, and one for projects less than 500 kW. http://www.pge.com/en/b2b/energysupply/qualifyingfacilities/AB1613/index.page.

43 *Topping-cycle CHP* generates electric power first and uses excess heat for a productive purpose. The vast majority of the total installed capacity in the state is natural gas-fired topping cycle units. *See*: California Energy Commission, 2012, *Combined Heat and Power: 2011-2030 Market Assessment Report,* pp. 35-36.

44 *Bottoming-Cycle CHP* generates process heat first, typically for an industrial application, and subsequently captures excess heat to generate power. This configuration is also known as W*aste Heat to Power*, as waste heat from industrial process is used as input to generate power.

of the meter). PG&E procurement of these resources will be done in accordance with the CPUC Decision Adopting Energy Storage Procurement Framework and Design Program (D.13-10-040) issued in the Energy Storage Rulemaking 10-12-007. Energy storage technologies are broadly defined as those commercially available technologies that use mechanical, chemical, or thermal processes to store energy generated at a given time for later use.[45] At the end of 2014, PG&E had 6 MW of distribution-connected wholesale storage; consisting of two utility-owned sodium sulfur batteries.

PG&E's implementation of its Energy Storage Program commenced in the 2014-2015 procurement cycle and is designed to support three overarching objectives: (1) optimization of the grid, including peak reduction, contribution to reliability needs, or deferral of T&D upgrade investments; (2) integration of renewable energy; and (3) reduction of GHG emissions to 80 percent below 1990 levels by 2050, per California statewide goals.[46]

2.d.ii. Approach to Developing DER Growth Scenarios

In this section, PG&E provides a summary level description of its approach to developing DER growth scenarios. Further details on the methods used for DER technology are provided in Appendix C.

A sizable body of literature has been developed to describe patterns in consumer adoption of DER technologies. Consumer behavior with regard to energy efficiency technologies is the most extensively studied, but research on DG adoption (particularly retail solar), EVs, and other technologies have also been conducted in recent years. [47]

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[45] Consistent with California Public Utilities Code 2835 found online at: http://www.leginfo.ca.gov/cgi-bin/displaycode?section=puc&group=02001-03000&file=2835-2839.

[46] Consistent with PG&E's 2014 Energy Storage Procurement Application found online at: http://www.cpuc.ca.gov/NR/rdonlyres/9D8AC3CE-AA20-4827-A192-89ADEE7673AE/0/PGE_StorageTestimony.pdf.

[47] See for example:

Cai D W H et al. 2013 Impact of residential PV adoption on retail electricity rates Energy Policy doi:10.1016/j.enpol.2013.07.009i

Davidson et al. 2014 Modeling photovoltaic diffusion: an analysis of geospatial datasets. Environ. Res. Lett. 9 (2014) 074009

Plug-in Electric Vehicle Multi-State Market and Charging Survey. EPRI, Palo Alto, CA: 2014. 3002002931.

The Guidance Ruling directs the IOUs to estimate the deployment of DERs at a feeder-level over a 10-year horizon. Although it is commonplace for utilities to estimate future DER capacity at a system level, estimating the future geospatial (*i.e.*, feeder-level) dispersion of DER deployment is a new endeavor and represents an industry-leading practice. Through the Guidance Ruling, the IOUs are among the first utilities required to establish projections of DER dispersion at this level of granularity. As a result, there were few existing resources, tools and established practices to draw upon. PG&E developed its DER growth modeling methodologies, and will continue to refine methods as warranted to reflect improved methodological approaches, new data sources, market trends, emerging customer preferences and other factors that influence DER adoption and deployment.

In developing its geospatial DER growth scenarios, PG&E leveraged customer characteristics and energy usage information as well as internal and external research on customer DER adoption behavior to estimate how much DER technology is likely to be installed over the prescribed 10-year period and where that deployment is likely to occur. The growth estimates provide an indication of the potential magnitude and location of future DER impacts to the distribution grid.

The Guidance Ruling also directs the IOUs to incorporate "additional information from Load Serving Entities, third-party DER owners, and DER vendors" for Scenario 2. The Utilities asked for input from DER vendors and other stakeholders on our DER growth scenarios through an email to the DRP service list on April 3, 2015. The IOUs did not receive any responses that addressed this request, but look forward to developing greater coordination of data and information sharing with DER providers and other stakeholders. PG&E's proposal for data sharing and management are further described in Chapter 4.

2.d.ii.1. DER Growth Scenarios

In compliance with the Guidance Ruling, PG&E developed 10-year growth scenarios for each of the technologies for the three scenarios outlined in the Guidance Ruling:

Center for Sustainable Energy, Feb. 2014, *California Plug-in Electric Vehicle Owner Survey* https://energycenter.org/sites/default/files/docs/nav/transportation/cvrp/survey-results/California_PEV_Owner_Survey_3.pdf.

- Scenario 1 – Trajectory (or Expected) DER growth
- Scenario 2 – High DER growth
- Scenario 3 – Very High DER growth

In the Guidance Ruling, for Scenarios 1 and 2, the IOUs were instructed to adapt the DER growth scenarios that are provided by the CEC as part of the California Energy Demand (CED) report that is developed to facilitate the IEPR proceeding.[48] As part of the IEPR process, scenarios of DER growth are produced by the CEC every two years, with an update in intervening years.

In general, PG&E supports consistency between the DRP growth scenarios and the most recent DER IEPR forecasts and updates. Where appropriate, PG&E's DER growth scenarios are consistent with the CEC's IEPR forecasts. However, for certain technologies (*i.e.*, retail and wholesale storage, and wholesale PV and CHP), forecasts are not developed as part of the CEC's CED forecast for IEPR. Because, however, these technologies are interconnected on the utility distribution systems, they are included in the DRP.

Another exception to using the unmodified 2014 IEPR forecast is in the Retail DG technology area. PG&E is concerned that the CEC's most recent 2014 projection[49] for DG growth, particularly for solar PV, significantly under-forecasts adoption and does not reflect current adoption levels, technology trends, market conditions and policy support. For the trajectory scenario presented in the DRP for retail DG, PG&E used the scenario that it submitted to the CEC on April 20, 2015 as part of the 2015 IEPR proceeding (Form 3.3).

Growth Scenario 1 for EVs used in this DRP also deviate from the CEC's 2014 IEPR update. Instead, PG&E based the DRP growth scenarios for EVs on its Submittal to CEC for the IEPR on April 2015, Form 1.1(a).

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48 Per SB 1389 (Bowen and Sher, Chapter 568, Statutes of 2002) *See*: http://www.energy.ca.gov/energypolicy/.

49 California Energy Commission, February 2015. California Energy Demand Updated Forecast, 2015-2025. Demand Forecast Forms, Mid-Case Final Baseline Demand Forecast, file: "PG&E Mid" Forms 1.2 and 1.4, Modified December 22, 2014.

Lastly, for EE, a number of scenarios are produced in the Additional Achievable Energy Efficiency (AAEE) component of the IEPR that are intended to be used in various combinations depending on the need. The scenarios used for the DRP align with the direction agreed to by the CPUC, CEC, and CAISO in a January 2014 letter to Senator Alex Padilla of the Senate Committee on Energy, Utilities and Communications.[50] The letter committed the three agencies to using the mid-AAEE forecast for system-wide procurement and transmission planning and the low-mid case for local studies. PG&E aligned with this decision by using the AAEE low-mid for the trajectory scenario, AAEE mid for the high scenario, and the AAEE high-mid for the very high scenario.

Rather than prescriptively following the IEPR forecasts, PG&E developed its DER growth scenarios by adapting the IEPR estimates, consistent with the Guidance Ruling, to reflect the following:

- Scenario 1, an adaptation of the CEC's CED/IEPR DER forecasts, represents PG&E's best estimate of expected or 'trajectory' DER adoption
- Scenario 2 reflects 'high' levels of DER deployment that are possible with increased policy interventions and technology/market innovations
- Scenario 3 reflects 'very high' levels of growth in DER deployment and is likely to materialize only with significant policy interventions such as those outlined in the Guidance Ruling

It is important to note that there may be interdependencies between growth of DER technologies. For example, increased EV adoption may drive increased retail solar adoption. PG&E's residential retail storage forecast is tied to its retail PV forecast, but generally speaking, these interdependencies were not explicitly modeled in the DER growth scenarios. As further information is developed on the relationship between adoption of multiple DER technologies, these interdependencies may be considered in future growth projections.

[50] January 31, 2014 letter from Robert Weisenmiller, Michael Peevey, and Steve Berberich to Senators Padilla and Fuller, retrieved June 11, 2015 from http://www.cpuc.ca.gov/NR/rdonlyres/2D097AAD-5078-47E9-A635-1995668F34B7/0/Padilla_Fullerletter_13114.pdf.

TABLE 2-13
SUMMARY OF DER GROWTH SCENARIOS BY TECHNOLOGY

DER Technology Category	Scenario 1 “Trajectory Growth”	Scenario 2 “High Growth”	Scenario 3 “Very High Growth”
Energy Efficiency	Consistent with IEPR AAEE study Low-Mid	Consistent with AAEE Mid	Consistent with AAEE high-mid
Demand Response	PGE& April 2014 Load Impact Compliance Filing	5 percent of PG&E system peak. Parallels Energy Action Plan II and CPUC Decision 03-06-032	7.5 percent of PG&E system peak. 50 percent above the goal of the Energy Action Plan II
Retail Distributed Generation	PG&E Submittal to CEC for IEPR April 2015, Form 3.3	Scenario 1 plus: • Greater PV cost-effectiveness • Consolidation of solar provider activity to CA market after Investment Tax Credit reduction • Moderate residential Zero Net Energy (ZNE) driven adoption • Barriers to non-residential market growth overcome	Scenario 2 plus: • Increased pressure to partially meet the Governor’s 2030 renewable energy policy goals through retail renewable DG • High residential ZNE driven adoption
CHP associated with FiT Programs (< 20 MW)	CHP FiT Program per AB 1613 procurement targets met	Same as trajectory	Technical potential for WHP (bottom-cycling) CHP per ICF study realized
Electric Vehicles	PG&E Submittal to CEC for IEPR April 2015, Form 1.1(a)	IEPR high case, consistent with Cal ETC “Aggressive Adoption” scenario	Consistent with Governor Brown’s 2030 energy goal “Reduction of petroleum used by cars and trucks by half”
Retail Storage	SGIP drives demand to 2019, slowdown after	• SGIP drives demand to 2019-NEM policy incentivizes storage paired with PV in the residential sector	• SGIP drives demand to 2025 • NEM and RPS policy incentivizes storage paired with PV
Wholesale Solar	Assumes full subscription under established procurement programs – ReMAT, RAM, PV Program and Green Option	120 percent of Scenario 1	150 percent of Scenario 1
Wholesale Biomass and Small Hydroelectric	Assumes full subscription under established procurement programs - ReMAT and BioMAT	Same as Scenario 1	Same as Scenario 1

DER Technology Category	Scenario 1 “Trajectory Growth”	Scenario 2 “High Growth”	Scenario 3 “Very High Growth”
Wholesale Storage	54 percent of PG&E’s energy storage procurement targets as established by CPUC Decision 13-10-040; Remaining capacity under the distribution-connected procurement target is assumed to be added to PG&E’s transmission-connected energy storage target.	76 percent of PG&E’s energy storage procurement targets as established by CPUC Decision 13-10-040; Remaining capacity under the distribution-connected procurement target is assumed to be added to PG&E’s transmission-connected energy storage target.	100 percent of PG&E’s energy storage procurement targets as established by CPUC Decision 13-10-040.

2.d.ii.2. Geographic Granularity of Growth Scenarios

The Guidance Ruling directs the IOUs to provide distribution feeder level projections for each DER technology. A distribution feeder is a low–mid voltage line used to distribute electric power from a substation to consumers or to smaller substations.

In PG&E's service area, feeders have on average about 1,700 customers but can range anywhere from a single customer to over 10,000 customers on a feeder. Feeder-level projections were performed for retail solar PV, retail non-PV technologies, and for DR technologies. For other DER technology categories, projections were performed at a higher level of geographic granularity due to limitations in data availability, limited historical adoption to use for building predictive models, and general uncertainty in the models. Table 2-14 summarizes the geographic unit that was used for projecting the DER growth planning scenarios for a given DER technology.

For those DER technology types where growth was estimated at a level of geographic granularity larger than a feeder, the technology deployment was distributed to the feeder level using a simple allocation method that distributed adoption according to distribution feeder peak demand and integration capacity availability.

TABLE 2-14
GEOGRAPHIC GRANULARITY OF DER SCENARIOS BY TECHNOLOGY TYPE

DER Technology Type	Geographic Unit for Growth Scenarios	
EE	Busbar	
DR	Feeder	
EVs	County	
Retail Storage	County	
Retail DG	Retail Solar PV (except for ZNE)	Feeder
	PV associated with ZNE Requirements	County
	Combustion and Heat to Power Technologies	Feeder
	Fuel Cells	Feeder
Wholesale DG	Solar PV	County
	CHP	County
	Storage	County

2.d.ii.3. Modeling Scenario Impacts by Time of Day and Month

Daily and annual consumption patterns vary across customers and geography, and DER technologies have different impacts on load. Consequently, distribution planners must consider how a given DER technology will impact load on a distribution asset such as a substation and feeder.

To help estimate the impact of each DER technology on distribution feeders, load impact curves were developed for each technology type as described in Section 2.b, Integration Capacity Analysis, of PG&E's DRP. For retail DG assets, typical generation profiles were developed for solar PV, combustion and heat to power technologies, and fuel cells. For retail storage, residential and non-residential charging and discharging profiles were estimated based on behavior anticipated for peak shaving and TOU rate optimization. Charging patterns for workplace and residential charging were developed for EVs. For EE and DR, information regarding availability and performance during system peak was incorporated.

Appendix C provides more details on how the load profiles were developed for each DER technology category.

Appendix C provides more details on how the load profiles were developed for each DER technology category.

2.d.ii.4. Limitations and Caveats of DER Growth Scenarios

The scenarios presented in this chapter represent estimates of potential future DER growth. It is critical, however, that planners and other consumers of this information keep in mind the limitations and uncertainties around these scenarios. In Appendix C, we outline specific uncertainties associated with each DER technology's growth scenarios. General limitations include the following:

- **Uncertainty in Modeling Consumer Behavior** – A number of the scenarios depend on modeling consumer behavior (*i.e.*, will a consumer invest in an EE upgrade or a PV system). While a relatively robust body of research literature exists on modeling consumer behavior around technology adoption, the diffusion patterns of any particular technology may deviate considerably from general patterns. Furthermore, later DER adopters may exhibit markedly different consumer behavior than early adopters, so models based on historical adoption behavior may not accurately predict future technology diffusion patterns. Consumer behavior is also dependent on public policies that directly affect cost to consumers, such as tax credits and other subsidies.

- **Uncertainty in Future Policy Developments** – Many of the technologies modeled here depend on policy supports that have not yet been established, or around which there is considerable uncertainty. These policies are likely to affect both system level adoption and geospatial distribution of the DERs over the scenario period (*i.e.*, Zero Net Energy (ZNE) policy, NEM successor tariff, the SGIP, mandated DG procurement programs, and other factors).

- **Limited Sample Sizes** – For some technology categories, such as fuel cells, combustion technologies, retail and wholesale storage, and wholesale DER, the limited number of adopters/deployment constrains PG&E's ability to elicit general trends that can be applied across our service area.

- **Difficult to Predict Patterns of Retail DER Growth on a Given Distribution Asset –** Particularly for larger scale retail DER adoption in the non-residential sector, there can be little relationship between historical adoption on the asset and future adoption. This is because larger-scale DER is installed in "chunks" rather than in more predictable incremental additions that might be seen on a distribution asset that serves primarily residential load. This is illustrated by Figures 2-24 and 2-25 which are scatterplots of 2013 and 2014 interconnected PV capacity by substation. Each point in these figures represents annual PV additions connected to a given substation and shows the much stronger correlation between a previous year's PV additions (2013) and the current year's additions (2014) for PV installed by residential compared to non-residential customers.

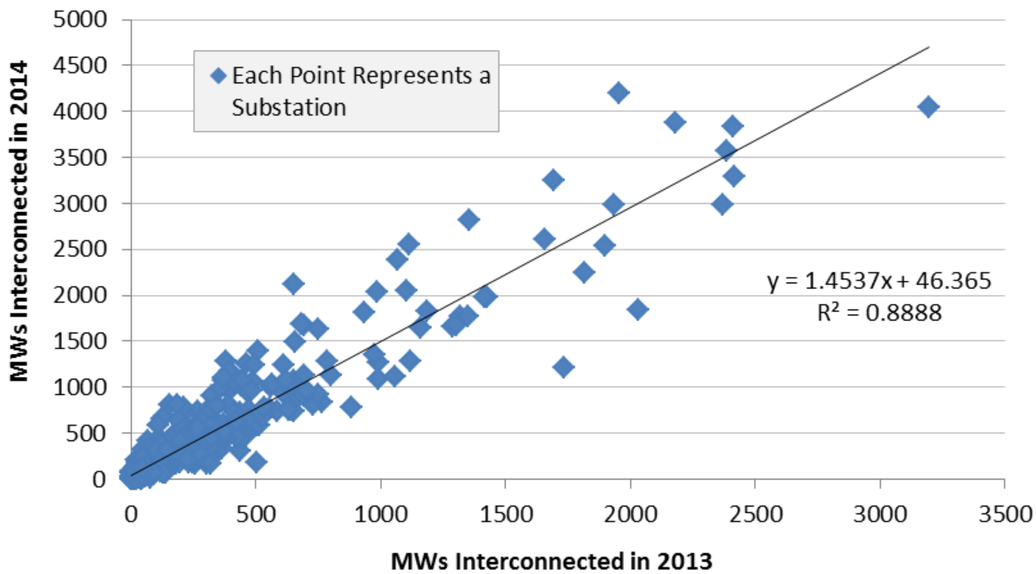

FIGURE 2-24: PV INTERCONNECTED BY RESIDENTIAL CUSTOMERS TO A GIVEN SUBSTATION, SCATTERPLOT OF 2013 VS. 2014 ANNUAL ADDITIONS

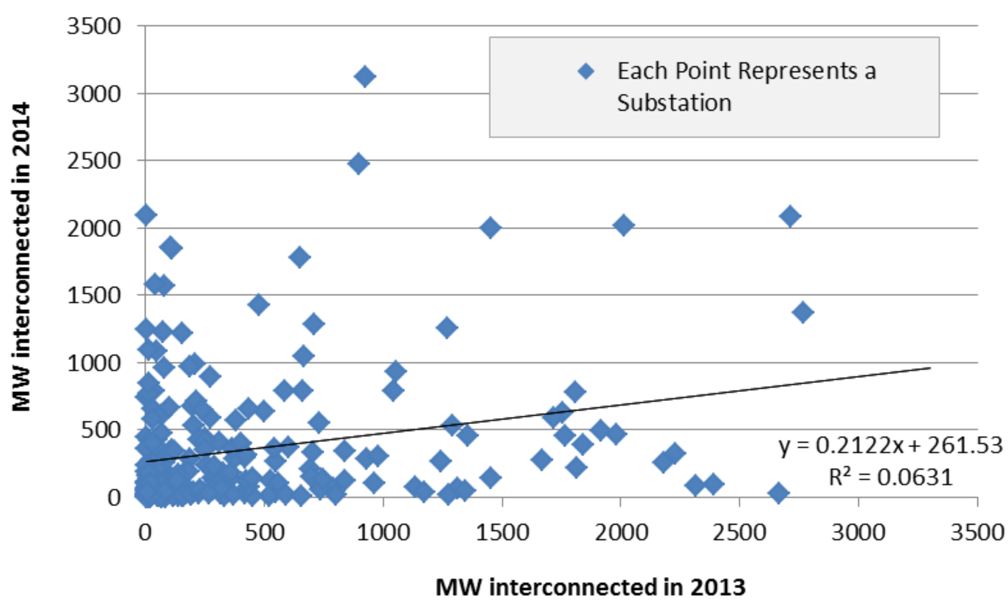

FIGURE 2-25: PV INTERCONNECTED BY NON-RESIDENTIAL CUSTOMERS TO A GIVEN SUBSTATION, SCATTERPLOT OF 2013 VS. 2014 ANNUAL ADDITIONS

2.d.ii.5. Approach to Developing Growth Scenarios by Technology

Energy Efficiency

The approach for generating EE growth scenarios uses existing and in-process work. The first step involves estimating the amount of remaining, achievable EE potential at a system level. To do this, the CPUC conducts a potential and goals study every 2-3 years that leverages numerous supporting studies (Database of Energy Efficiency Resources (DEER)) and IOU workpaper savings parameters, saturation surveys, cost studies, macroeconomic inputs, and a variety of other Evaluation, Measurement and Verification (EM&V) research). This study produced a model and report that projects EE potential for a 10-year period.

The resulting potential model is then used by the CEC to produce scenarios for the IEPR's AAEE study. Scenario selection is done through a collaborative process with stakeholders, including the IOUs.

The scenarios used for the DRP align with the direction agreed to by the CPUC, CEC, and CAISO in a January 2014 letter to Senator Alex Padilla of the Senate Committee on Energy, Utilities and Communications.[51] The letter committed the three agencies to using the mid-AAEE forecast for systemwide procurement and transmission planning and the low-mid case for local studies. PG&E aligned with this decision by using the AAEE low-mid for its expected case, AAEE mid for our high case, and the AAEE high-mid for our highest case.

For T&D planning, greater levels of geographic granularity are required. As a result, PG&E has leveraged previous work from the CEC and IOUs to map busbar loads by sector, initiated by an annual data request from the CEC through the CPUC as part of the LTPP process. As part of this effort, the CEC then allocates the AAEE scenarios to the busbar-level using the sector busbar loads that were provided in the data request. The allocation is performed such that customer class impacts are appropriate to the

[51] January 31, 2014 letter from Robert Weisenmiller, Michael Peevey, and Steve Berberich to Senators Padilla and Fuller, retrieved June 11, 2015 from http://www.cpuc.ca.gov/NR/rdonlyres/2D097AAD-5078-47E9-A635-1995668F34B7/0/Padilla_Fullerletter_13114.pdf.

customer class load on each busbar, with checks to ensure aggregated busbar impacts equal system-level impacts. For the DRP, PG&E also worked with the CEC to disaggregate the impacts by sector (residential, commercial, industrial, agricultural) and by EE type (programs or codes and standards). Future work will allocate this bus-level data to the feeder level.

Demand Response

To forecast impacts of DR programs and technologies, feeder-level modeling output for each of PG&E's dispatchable DR programs and non-residential incremental TOU was performed. This modeling is consistent with guidance in CPUC D.08-04-050 which provided detailed and rigorous DR evaluation protocols and established an annual compliance filing requirement.[52] During the five years since D.08-04-050 was issued, PG&E has developed a deep knowledge of the performance of individual DR customers and its DR programs as a whole. Scenario 1 presented here is consistent with PG&E's April 2014 DR Load Impact compliance filing.

The source data for the model was developed pursuant to the Load Impact Protocols specified by D.08-04-050 Attachment A.[53] In accordance with the Load Impact Protocols, the load impact data was developed using rigorous econometric models and experimental design techniques. Official compliance filing reports that document how the load impacts were developed for each program are publicly available and provide highly detailed descriptions of how the source data was developed for each program as well as performance characteristics.[54]

The potential load reductions in the trajectory Scenario 1 align with the load impact filings of April 1, 2014. The high growth Scenario 2 assumes an aggressive but achievable increase in demand response impacts that offset, by 2019, 5 percent of PG&E expected peak demand, which parallels the Energy Action Plan, Energy Action

[52] http://docs.cpuc.ca.gov/PublishedDocs/WORD_PDF/FINAL_DECISION/81972.PDF.

[53] http://docs.cpuc.ca.gov/PublishedDocs/WORD_PDF/FINAL_DECISION/81979.PDF.

[54] https://pgera.azurewebsites.net/Regulation/ValidateDocAccess?docID=300477.

Plan II and CPUC D.03-06-032. The very high growth Scenario 3 assumes that DR can offset—by 2024—7.5 percent of PG&E highest system peak demand, a 50 percent increase over the 5 percent target in the Energy Action Plan II.

Retail Distributed Generation

For Scenario 1, the "trajectory" case, PG&E used the DG scenario it submitted to the CEC on April 20, 2015 as part of the 2015 IEPR proceeding. PG&E is concerned that the CEC's 2014 IEPR update significantly under predicts likely retail solar PV adoption. PG&E thus used the growth scenario developed by PG&E as part of the 2015 IEPR proceeding (Forms 3.3 and 6)[55] for the trajectory DG growth scenario 1 presented in this DRP. For Scenarios 2 and 3, the high and very high growth scenarios, PG&E evaluated policy changes and market developments that could lead to higher PV growth and projected additional adoption that could be driven by these conditions.

PV accounts for about 90 percent of projected retail DG capacity in the trajectory scenario by 2025. For this reason, PG&E focused on potential growth scenarios for PV, and chose not to vary the non-PV technologies within the retail DG growth scenarios. Retail PV capacity growth also includes PV adoption due to compliance with Zero Net Energy requirements (ZNE-PV). The methodology for estimating ZNE-PV is further described in Section 4 of Appendix C.

PG&E's approach to forecasting DG technology adoption geospatially consisted of allocating our trajectory, high, and very high system level DG scenarios to a given feeder based on the probability of DG technology adoption on that feeder, as estimated through multivariate regression modeling. While it is challenging to predict precisely which customers will adopt a given technology, historical information on technology adoption patterns and information on customer characteristics can provide an indication of what areas are more likely than other areas to see DG growth given our current understanding of market conditions.

[55] PG&E Form 6 Submittal, April 20, 2015. http://docketpublic.energy.ca.gov/PublicDocuments/15-IEPR-03/TN204261-10_20150420T154647_Pacific_Gas_and_Electric_Company's_Form_6__Incremental_DemandSi.pdf.

Electric Vehicles

Plug-in EV[56] forecasting is challenging given the rapid changes that are occurring in the EV policy arena and marketplace. In order to respond to the Guidance Ruling, PG&E leveraged: (1) aggregated registration and rebate data available through the end of 2014; (2) policy goals declared through January 2015 as well as modeling of compliance for existing policy; and (3) EV adoption scenarios developed by ICF International Inc. in the California Electric Transportation Coalition (CalETC) Transportation Electrification Assessment.[57]

To develop the EV inputs to PG&E's DRP, three scenarios of EV adoption were developed consistent with the DRP guidance. Scenario 1 is similar to the CEC's 2014 IEPR mid case EV forecast and represents PG&E's expected "trajectory" planning scenario.[58] This scenario assumes continuation of adoption growth rates from recent years in the near term and projects adoption in later years based on CalETC Transportation Electrification Assessment EV growth scenarios. PG&E chose the midpoint between "ZEV Compliance" and "Aggressive Adoption" scenarios to sync with recent adoption growth rates. Scenario 1 is generally consistent with Governor Brown's goals set forth in the ZEV Action Plan which are driving current policy and regulatory decisions.

Scenario 2 is based on the CalETC Transportation Electrification Assessment EV "Aggressive Adoption" projection and aligns with the CEC's IEPR high EV adoption case.

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[56] Includes both Plug-in Hybrid Electric Vehicles and Battery Electric Vehicles.

[57] CalETC, "California Transportation Electrification Assessment, Phase 1 Final Report," September 2014, pg. 8. http://www.caletc.com/wp-content/uploads/2014/09/CalETC_TEA_Phase_1-FINAL_Updated_092014.pdf .

[58] PG&E's forecast of EV load assumes approval and implementation of PG&E's Electric Vehicle Infrastructure and Education Program, currently pending before the CPUC. If PG&E's Program is not approved, the forecast EV load is likely to be significantly less than provided in this forecast.

Scenario 3 is based on Governor Brown's goal to "reduce today's petroleum use by cars and trucks by up to 50% [by 2030]"[59] PG&E modeled EV adoption assuming petroleum reduction beyond existing regulations (which will currently create ~20 percent reduction by 2030) is achieved through EVs displacing IC engines.

Scenario 3 should be interpreted as a stress-test scenario because the goal has yet to be codified by legislation or regulations and because other measures could be used to help achieve petroleum reductions (*e.g.*, reduce vehicle miles traveled with increases in public and shared transportation, increase IC engine vehicle efficiency, and reduce carbon intensity of fuel by strengthening Low Carbon Fuel Standard (LCFS)).

PG&E is actively working toward a future where VGI enables EVs to contribute electricity back to the grid at times when that energy is needed and valuable. PG&E's BMW pilot referenced above also evaluates the benefit of stationary storage from used EV batteries. The potential impact of VGI on EV load and capacity is not included in the forecast at this time due to uncertainty about the development timeline of the necessary technology as well as lack of data about VGI operating profiles.

Retail Storage

The retail energy storage technology category covers all energy storage devices that are or will be installed on the customer side of the meter.

To forecast retail energy storage adoption for 2015, PG&E estimated additions based on queued projects in the SGIP, assuming an attrition rate that is consistent with historical dropout rates. In addition, four queued Permanent Load Shift (PLS) energy storage projects were included in the 2015 scenario. Post 2016, PG&E projected separate adoption rates for the residential and non-residential sectors.

The historical growth rates found in the SGIP database are not likely to be representative of future growth, because there were a number of regulatory factors, such as the timing of the Net Energy Metered-paired storage decision (D.14-05-033)

[59] Edmund G. Brown Jr., Inaugural Address, Remarks as Prepared, January 5, 2015, http://gov.ca.gov/news.php?id=18828.

that caused developers to delay progress of their SGIP applications and affected historical growth patterns.

Instead, energy storage growth rates were selected by benchmarking against industry reports, while keeping overall growth within the confines of the statewide energy storage targets (the lower bound) and the latest Greentech Media Research [60] growth scenarios for energy storage, scaled to PG&E's territory (the upper bound). The growth rates also assume that residential energy storage will take on a more aggressive growth trajectory, primarily driven by PV pairing, whereas non-residential retail energy storage adoption will grow more slowly and be focused within particular customer segments.

In Scenario 1, we project that residential energy storage growth rates will decline by 50 percent after 2020, and that non-residential energy storage growth rates will decline by 5 percent after 2020, due to the cessation of the SGIP incentive. For Scenario 2, we assume that only residential storage adoption will decline by this amount, assuming that SGIP will not be needed to make retail storage economically viable by 2020.

Finally, in all cases, retail energy storage is taken offline after ten years of operation (*e.g.*, the incremental installations in 2020 subtract the energy storage installed in 2010). The expected life of an energy storage device is 10 years. In reality, there is a range of potential life spans of energy storage devices based on technology, but PG&E finds ten years to be a reasonable estimate, aligning with an EPRI industry report and current market offerings.[61] The true effects of this assumption in the scenario do not become apparent until 2020.

To drive the system level scenario to a county level, PG&E assigned adoption to a given County by population for residential storage adoption and by North American Industry

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[60] Greentech Media Research, *U.S. Energy Storage Monitor 2014 Year in Review*, December 2014.

[61] A) B. Kaun, *Cost-Effectiveness of Energy Storage in California,* EPRI, June 2013; B) SolarCity's initial service contract for battery backup offerings is for nine years. SolarCity Corporation (2015) Battery Backup. Retrieved 6/22/2015 at http://www.solarcity.com/residential/backup-power-supply.

Classification System (NAICS) code for non-residential adoption, with higher adoption projected for sectors such as hotels, supermarkets and hospitals that generally have lower load factors. Storage will generally be more economically attractive for non-residential customers with low load factors as it enables them to manage demand charges.

Wholesale DG (Solar PV, Small Hydroelectric, Bioenergy)

Consistent with PG&E's interpretation of the Guidance Ruling, PG&E developed projections for the DRP of wholesale renewable generation (wholesale DG) capacity additions—less than or equal to 20 MW—that will interconnect to PG&E's distribution grid.[62] The CEC does not forecast wholesale DG as part of IEPR planning process as wholesale resources are not considered demand-side resources. Therefore, alignment with the IEPR does not apply to the wholesale DG growth scenarios.

Technology types included in this scenario include solar PV, small hydroelectric, and bioenergy resources, given that this mix of technologies represent the predominant wholesale renewable generation technologies interconnected to PG&E's distribution grid.[63]

To develop the projections for Scenario 1 (trajectory growth) we projected wholesale DG deployment consistent with meeting capacity goals established in existing CPUC wholesale DG procurement programs, namely the ReMat Program, the RAM, the Solar PV Program, the Green Tariff Shared Renewables Program (Green Option) and the BioMAT.

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[62] For the purpose of these scenarios, wholesale DG is defined as electric generation resources less than or equal to 20 MW, interconnected to PG&E's distribution grid, on the utility-side of the meter.

[63] Wind and geothermal resources, while eligible under the RAM program, are not included in the wholesale renewable DG growth scenarios given the limited number of projects in PG&E's bundled electric portfolio which have been procured under the RAM program and are interconnected at the distribution-level. While wind and geothermal resources are not included in these growth scenarios, PG&E recognizes the possibility that both wholesale wind and geothermal projects may interconnect to PG&E's distribution grid in the future.

Under the high growth Scenario 2 and the very high growth Scenario 3, PG&E projected incremental growth of distribution-connected solar PV using generic scaling factors of 120 and 150 percent of the levels in Scenario 1 respectively.[64] Incremental capacity additions attributed to the generic solar PV scale factors are allocated evenly over years 2022 through 2025.

Wholesale distributed renewable generation capacity additions were allocated geospatially to a county-level under various siting assumptions attributed to each individual wholesale DG procurement program. A summary of county-level siting assumptions applied in this scenario is outlined Appendix C.

CHP From FiT Programs

For the DER growth scenarios, PG&E assumed continued availability of existing CHP wholesale DG procurement programs through 2025. PG&E procurement of new CHP resources that meet the definition of wholesale DERs is primarily done through the CHP FiT Program AB 1613. PG&E currently has three *pro forma* AB 1613 PPAs available for new exporting CHP.[65] As of April 2015, PG&E has executed one PPA under the AB 1613 program. PG&E's DER Growth Scenario 1 includes additional capacity additions that are projected to come online under the CHP FiT program.[66] Capacity additions were then geographically distributed to the county-level using publicly-available data for similar size projects under previous CHP procurement programs in the state of California.

For Scenario 3 (high DER growth), PG&E included additional capacity installations of carbon neutral forms of CHP technologies, aligned with the State's objectives of achieving long-term GHG reduction targets. The Guidance Ruling also directs the IOUs

[64] Scale factors were applied exclusively to the solar PV component of this forecast given the cost competitiveness demonstrated by distribution-connected solar PV projects over other distribution-connected technologies included within the scope of this forecast.

[65] PG&E AB 1613 *pro forma* PPAs: one for projects less than 20 MW, one for projects less than 5 MW, and one for projects less than 500 kW. http://www.pge.com/en/b2b/energysupply/qualifyingfacilities/AB1613/index.page.

[66] Consistent with PG&E 2014 BPP CHP assumptions.

to prioritize carbon neutral forms of CHP. In 2014, PG&E retained ICF International Inc. to study technical and expected market potential of these cleaner forms of CHP by 2030. For Scenario 3, PG&E utilized ICF International Inc.'s 2025 expected capacity (MW) market potential estimate for bottom-cycling and biomass/biogas CHP. The study also provides the expected county-level distribution of these projects.[67]

Wholesale Storage

The basis of the projection for wholesale energy storage under all three DER growth scenarios is achieving compliance with CPUC requirements as established by CPUC D.13-10-040, pursuant to the Energy Storage Order Instituting Rulemaking (R.10-12-007). We assume that any variation in distribution-connected wholesale energy storage procurement across the three DER growth scenarios would result in an equivalent and opposite variation of transmission-connected energy storage procurement, such that the sum total of distribution-and transmission-connected energy storage procurement remains constant across all three scenarios.

PG&E's scenario of distribution-connected wholesale energy storage is allocated geospatially at the county-level under three separate types of energy storage projects: (1) PG&E-specified projects; (2) Co-location with power generation; and (3) Stand-alone energy storage projects. Each project type is assigned a weighting factor based on PG&E assumptions made independent of project offer data received under the PG&E's 2014 Energy Storage RFOs. Further details on the wholesale storage scenario are presented in Appendix C.

2.d.iii. DER Growth Scenarios – Results

In this section, PG&E presents its planning scenarios for DER technology adoption/deployment under the three scenarios outlined in the DRP guidance: "trajectory" growth (Scenario 1), "high" growth (Scenario 2), and "very high" growth (Scenario 3).

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[67] The ICF International Inc. study identifies the site specific technical potential and aggregates these results to provide a consolidated California market outlook. However, the study does not consider site specific energy feasibility. Therefore, these results should be treated as an aggregated general market trend.

As described earlier in this chapter, DER growth Scenario 1 reflects an adaptation of the CEC's CED forecasts developed for the IEPR, and represents PG&E's best estimate of expected or 'trajectory' DER adoption. Scenario 2 reflects aggressive levels of DER deployment that are possible with increased policy interventions and technology / market innovations. Scenario 3 reflects a 'stress case' scenario, and is likely to materialize only with significant policy interventions such as those outlined in the Guidance Ruling accompanied by substantial technology / market innovations.

This section provides a summary-level description of the DER growth planning scenarios results. Further description of results by DER technology can be found in Appendix C.

2.d.iii.1. DER Growth Scenarios Impact at System Level Peak Demand

Figure 2-26 shows the estimated impact at retail system peak load by DER technology projected through 2025 for the trajectory growth scenario (Scenario 1). Here, PG&E peak demand is defined as occurring between 4-5 p.m. (Hour Ending 17) in August.[68] While examining DER impacts at the time of retail system peak provides a useful system-level perspective, the DRP is primarily focused on local distribution impacts of DER. Therefore, it is important to consider that the local impacts of a given DER technology on a particular distribution asset (substation, feeder, etc.) will depend on the load profiles of customers connected to that asset, as well as the operating profiles of the interconnected DER.

For the purposes of illustrating the magnitude and relative impacts of the DER technology categories, Figure 2-26 shows historical cumulative impacts over the period 2008-2014, and then cumulative impacts by year with the projected capacity added to the 2008-2014 historical data. EE standards, technologies, and programs have had a significant ongoing impact on reducing demand growth in California and PG&E's territory for decades; however, the EE numbers presented here reflect only recent impacts, since 2008. Most solar has been installed post 2007, though PG&E had about 270 MW of solar installed at the end of 2007. Most storage

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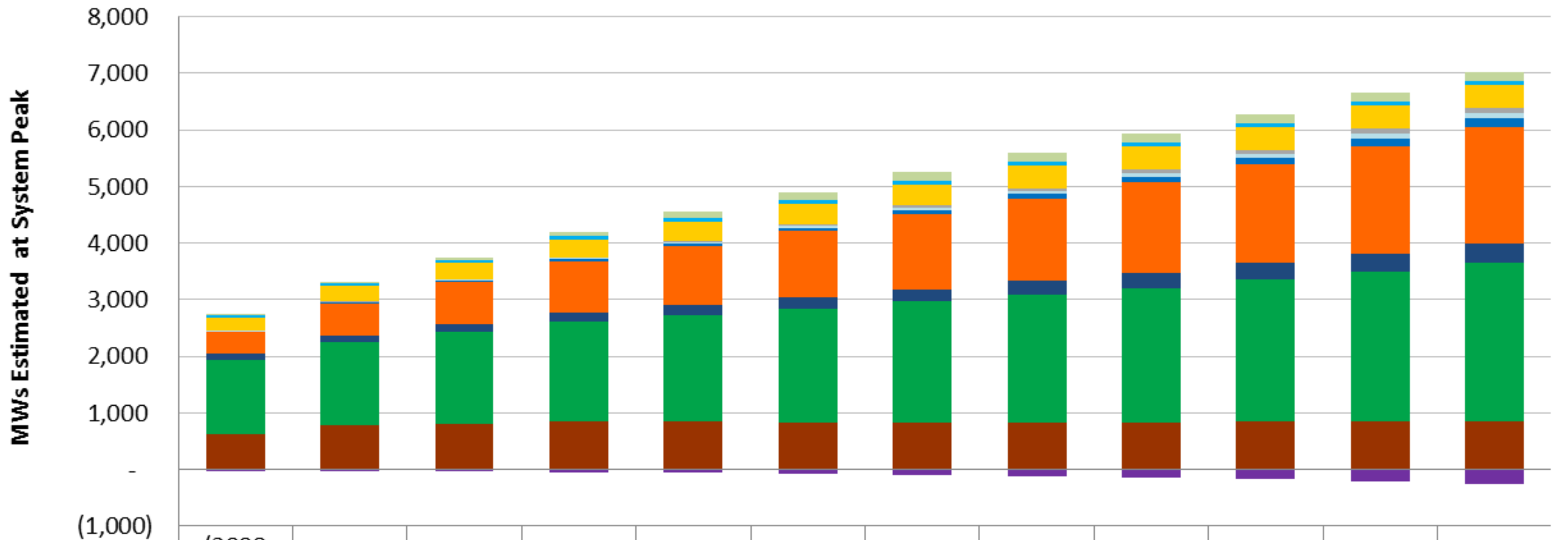
[68] PG&E's system peak demand has generally occurred during the months of June and Aug between hours-ending 4 p.m. to 6 p.m. See FERC Form 1 filings for PG&E, page 401(b). In 2014, PG&E's peak demand in June, July, and August was approximately 17,600 MW. https://pgeregulation.blob.core.windows.net/pge-com-regulation-docs/FERCForm1.pdf.

EE efficiency impacts are based on the DEER definition of average impacts at the three consecutive hottest days of the year.

and DR capacity additions and EV adoption have also occurred after 2007. To estimate the impact on system peak for each DER technology, the nameplate capacity for each DER was adjusted to account for the estimated capacity contribution that is coincident with the system peak, as described in the footnotes of Figure 2-26.

EE is the DER technology category that has had the greatest estimated impact on system peak over the period 2008-2014, with about 1,300 MW of estimated reduction in PG&E's system peak demand. DR has had the next largest estimated impact on system peak over this period, with an estimated reduction of over 600 MW. Retail solar has had an estimated impact of approximately 370 MW at system peak as of 2014, reflecting capacity installed from 2008-2014.

Looking forward, the scenarios indicate that EE resources and retail solar PV are estimated to continue to have the largest impact on system peak, with a cumulative impact of about 2,800 MW by 2025 for EE and about 2,000 MW for retail solar PV. Accounting for wholesale solar PV would add another 400 MW of system PV impact. DR is estimated to produce approximately 800 MW of savings at peak. Wholesale distribution-connected PV and storage technologies may comprise a growing portion of the DER portfolio within PG&E's service area. The additional load at system peak from EVs is estimated at about 240 MW by 2025, because under current charging patterns, most vehicles charge at night. Given very low penetration of EVs for commercial fleet operations, little information is available on charging profiles under this EV use case, which may increase charging needs during the day.



	(2008 -2014)	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Wholesale Bioenergy	29	29	39	73	104	126	147	162	162	162	162	162
Wholesale Small Hydro	41	43	48	55	63	63	63	63	63	63	63	63
Distributed Wholesale Solar PV	232	275	284	315	346	363	380	406	406	406	406	406
Distributed Wholesale Energy Storage	6	6	6	6	20	20	40	40	61	61	97	97
Electric Vehicles	(16)	(25)	(36)	(48)	(63)	(78)	(95)	(117)	(142)	(173)	(208)	(248)
CHP from Feed in Tariffs	9.6	16	23	30	36	43	50	56	63	70	76	83
Retail Storage	7.4	23	28	34	41	52	68	79	95	113	137	156
Retail PV	396	556	756	916	1,046	1,180	1,317	1,458	1,604	1,752	1,901	2,052
Retail Non-PV DG	92	112	132	153	175	197	220	244	269	295	321	347
Energy Efficiency	1,318	1,467	1,616	1,770	1,883	2,013	2,134	2,251	2,373	2,513	2,653	2,809
Demand Response	627	788	808	845	840	832	834	838	838	842	841	841

FIGURE 2-26: SCENARIO 1 – "TRAJECTORY" DERS AGGREGATE ESTIMATED GENERATION/ SAVINGS OR LOAD (NEGATIVE) AT SYSTEM PEAK DEMAND (4-5 P.M. AUG) - CUMULATIVE POST 2008

Notes:

1. Estimated capacity/load at PG&E system peak load occurring HE 17 in August. EE efficiency impacts are based on the DEER definition of average impacts at the three consecutive hottest days of the year.
2. *DR* -As of 2014, PG&E has 595 MW of DR capacity that is projected to continue to be available through 2025.
3. *Retail PV and PV from ZNE* – Assumes 33 percent capacity factor at system peak[69] for non-ZNE PV and 40 percent for PV associated with ZNE assuming more westward facing PV systems.
4. *EE – Reflects uncommitted cumulative savings from 2008-2014.*
5. *Retail Non PV DG* – Assumes 60 percent capacity factor at system peak[70]
6. *Retail Storage* – Assumes 80 percent capacity factor at system peak.
7. *Wholesale Energy Storage* – Assumes 90 percent capacity factor at system peak.
8. *Wholesale Non PV* – Assumes 80 percent capacity factor at system peak.
9. *Wholesale Solar PV* – Assumes 60 percent capacity factor at system peak.
10. *EVs* –Peak contribution developed using average car charging profile based on actual EV charging data.[71] EVs are shown as negative because they are modeled solely as load and thus have the opposite impact as generation and load reducing DERs. EV load contribution at peak is based on current charging patterns which could shift in the future with shifts in technology, customer patterns of EV usage, and customer participation in EV rates or other programs to shift EV charging behavior. Additionally, future development of Vehicle to grid EV integration technologies could enable some EVs to act as a source of electricity rather than a load at system peak.

[69] 2010 CSI Impact Evaluation Report. See Figure 6-3, page 6-13, http://www.cpuc.ca.gov/NR/rdonlyres/E2E189A8-5494-45A1-ACF2-5F48D36A9CA7/0/CSI_2010_Impact_Eval_RevisedFinal.pdf.

[70] 2013 SGIP Impact Evaluation Report Figure 6-7.

[71] CalETC, “California Transportation Electrification Assessment, Phase 1 Final Report,” October 2014, pg. 31, http://www.caletc.com/wp-content/uploads/2014/10/CalETC_TEA_Phase_2_Final_10-23-14.pdf.

The scenarios indicate that under the trajectory DER growth scenario, the aggregate impact of all DERs at system peak would be over 6,000 MW (Figure 2-27). With high DER growth (Scenario 2), the impact is estimated at about 10,000 MW, and under a very high growth scenario (Scenario 3), the impact is nearly 14,000 MW.

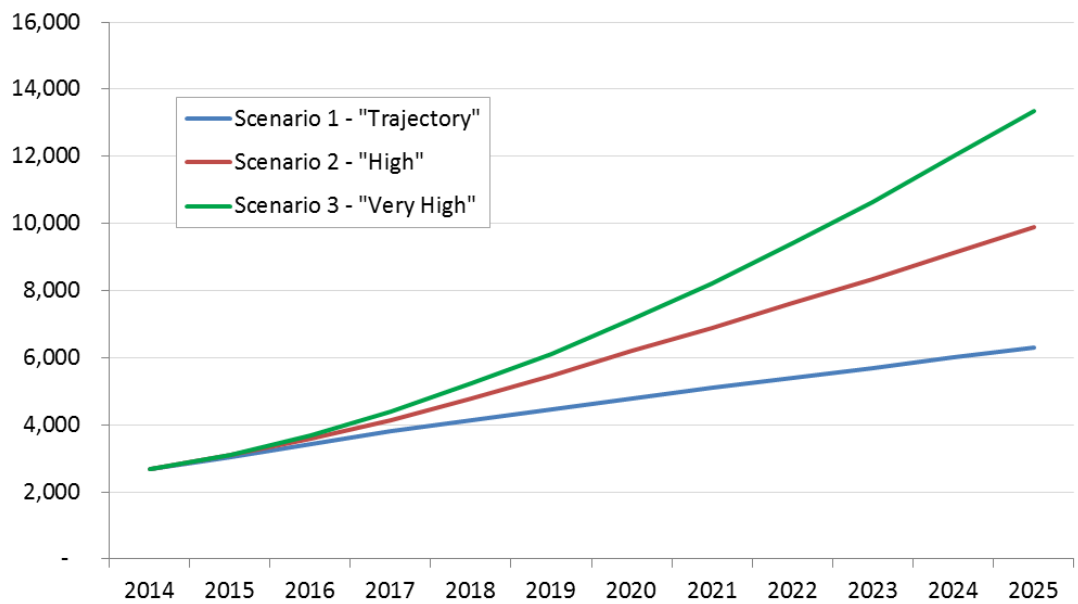


FIGURE 2-27: DERS AGGREGATE ESTIMATED IMPACT AT SYSTEM PEAK (HE 17 AUG) – CUMULATIVE POST 2007

From the perspective of system load management, DERs in aggregate could yield over 6,000 MW reduction in load at the time of the current system peak. However, it is important to note that as more renewable resources, particularly solar energy, come on line to meet RPS and other policy objectives, the net system peak will migrate from its current summer 4-5 p.m. hour (HE 17) to later evening hours. As such, the impact of distributed solar on system peak demand would be reduced dramatically. The impact of other DERs would also be dependent upon their availability at the later evening peak. DER impact on the future system peak could be influenced by policies requiring greater dispatchability of grid-connected DERs or by incenting DERs that are coincident with the future system peak.

2.d.iii.2. DER Growth Scenarios Impact on Local Peak Demand

The impact of each technology on system peak is illustrative of the relative impact by DER technology at a system-level. However, the primary focus of the DRP is the impact of DERs on local, distribution assets. This impact is highly dependent on the operating profile of a particular DER technology, as well as the gross electricity consumption patterns affecting a given distribution asset. Significant variation exists across distribution assets in terms of when peak demand on that asset occurs, depending on the type of load served.

To demonstrate this point, Figures 2-28 and 2-29 show the load impact patterns on a typical August day of retail PV on two illustrative feeders—one that serves a typical residential load and one that serves a typical commercial load. As is shown in these figures, retail PV has a generation profile that is more coincident with the load profile on a typical commercial feeder (Figure 2-29) as compared to a typical residential feeder (Figure 2-28). Therefore, the same PV generator would have greater potential to reduce peak demand on the feeder that serves commercial load. This illustrates the importance of differentiating the distribution system impact of different DERs at the appropriate level of granularity. It is critical that distribution scenario planning tools account for feeder-specific loads and the operating profile of DER interconnected to individual distribution assets to more accurately assess potential impacts from DER growth.[72]

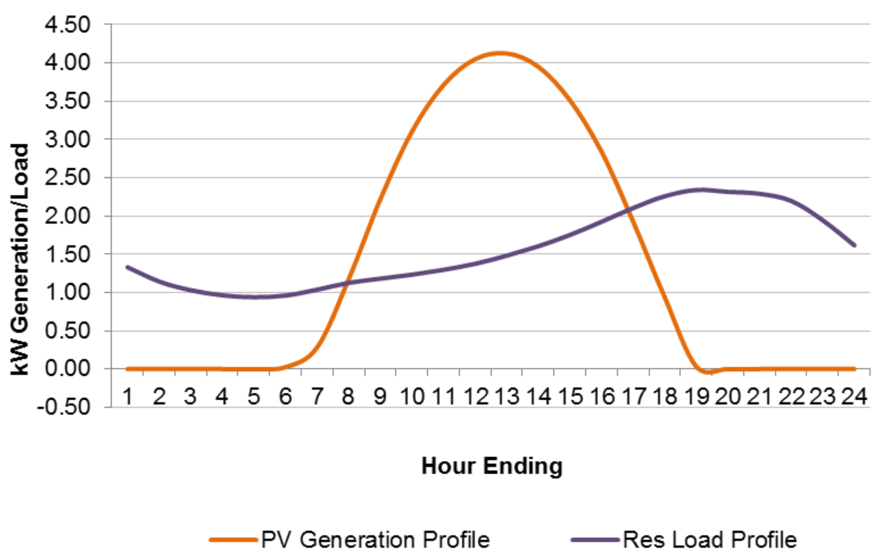


FIGURE 2-28: TYPICAL RESIDENTIAL LOAD PROFILE AND SOLAR GENERATION PROFILE ON AN AUGUST DAY

[72] See Section 2.b for more information on how DER load impact profiles are being used in PG&E's distribution planning tools.

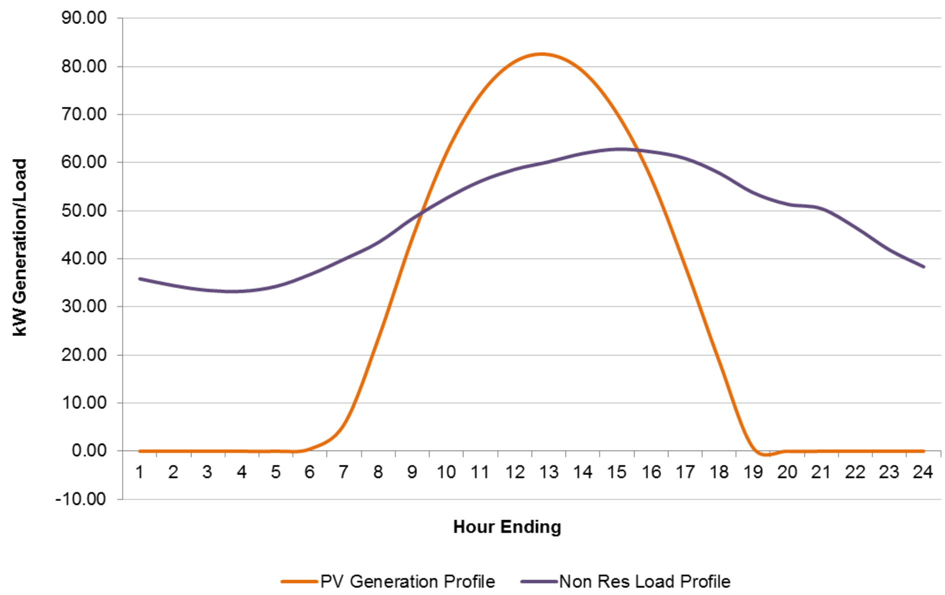


FIGURE 2-29: TYPICAL COMMERCIAL BUILDING LOAD PROFILE AND SOLAR GENERATION PROFILE ON AN AUGUST DAY

The importance of considering the particular load patterns and DER load impact profiles associated with a given distribution asset are further illustrated by Figures 2-30 and 2-31. Figure 2-30 shows the projected installed retail PV capacity over the period 2015-2025. The impact that PV growth will have on a distribution asset depends on the particular load profile of customers served by that asset. Figure 2-31 shows an average generation profile for a typical PG&E retail solar system, and shows the variability in solar PV production by season and hour of the day.[73] If the customers are generally consuming the energy generated by the PV facility onsite during the day, the distribution impact may be limited, and may result in some local capacity reduction. On the other hand, if the customers are generally exporting the energy produced by PV, the distribution system may require upgrades to enable more two-way flow.

[73] This PV generation profile represents modeled generation using PV Watts, a tool of the National Renewable Energy Laboratory based on typical system configuration of PG&E systems as determined by California Solar Initiative data on the tilt and azimuth of systems in PG&E's service area.

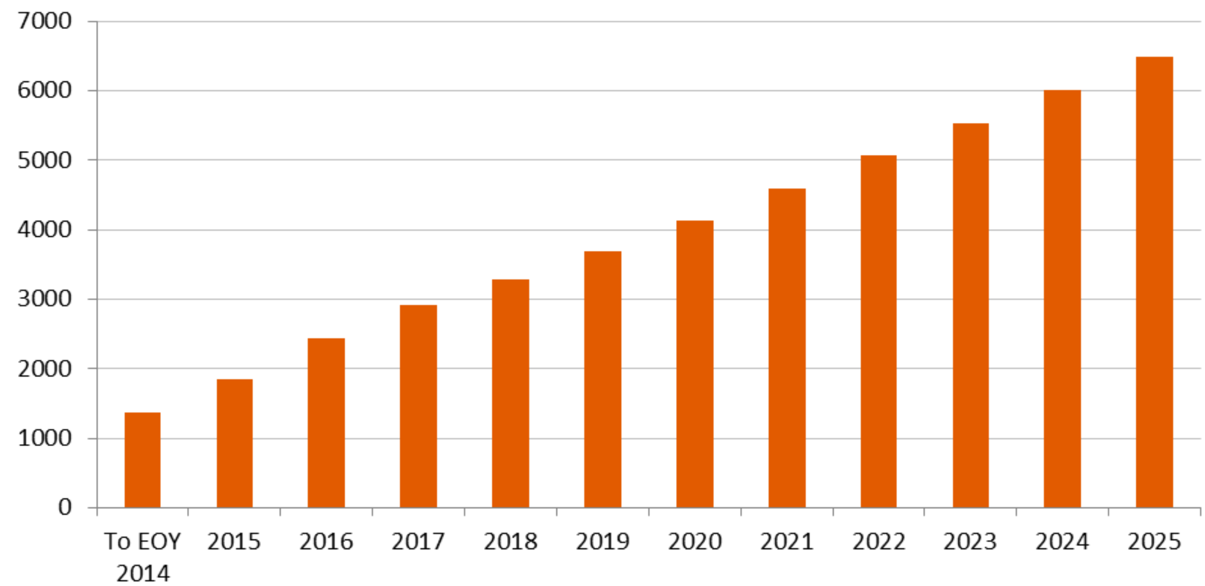


FIGURE 2-30: CUMULATIVE PROJECTED RETAIL PV CAPACITY INSTALLED, SCENARIO 1

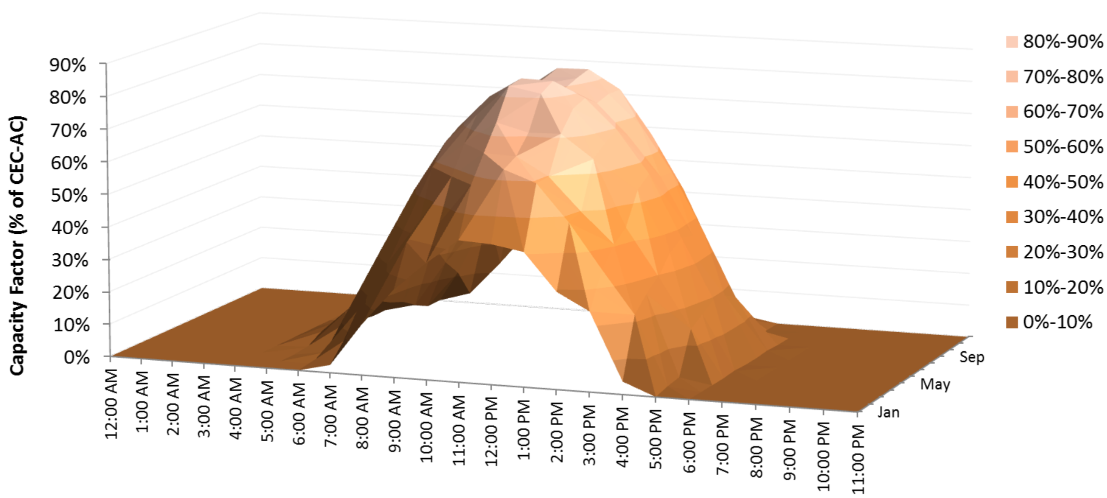


FIGURE 2-31: AVERAGE GENERATION PROFILE OF A TYPICAL PG&E RETAIL PV SYSTEM

Also indicative of the importance of evaluating DER impacts on distribution planning assets by specific DER technology is the diurnal variability in charging patterns for EVs. While the estimated load at system peak associated with EVs is about 250 MW in 2025, the greatest EV charging load occurs between 8 p.m. and 9 p.m. (Figure 2-32). Assuming charging behavior remains consistent with this timing, then with the projected EV adoption under Scenario 1, EVs are expected to contribute 528 MW of load at 8 p.m. in 2025.

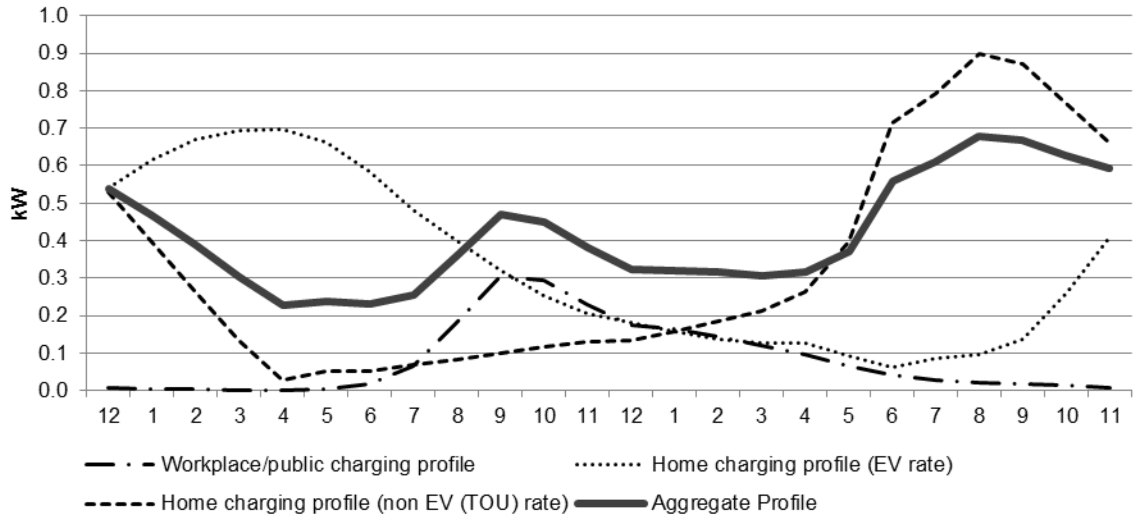
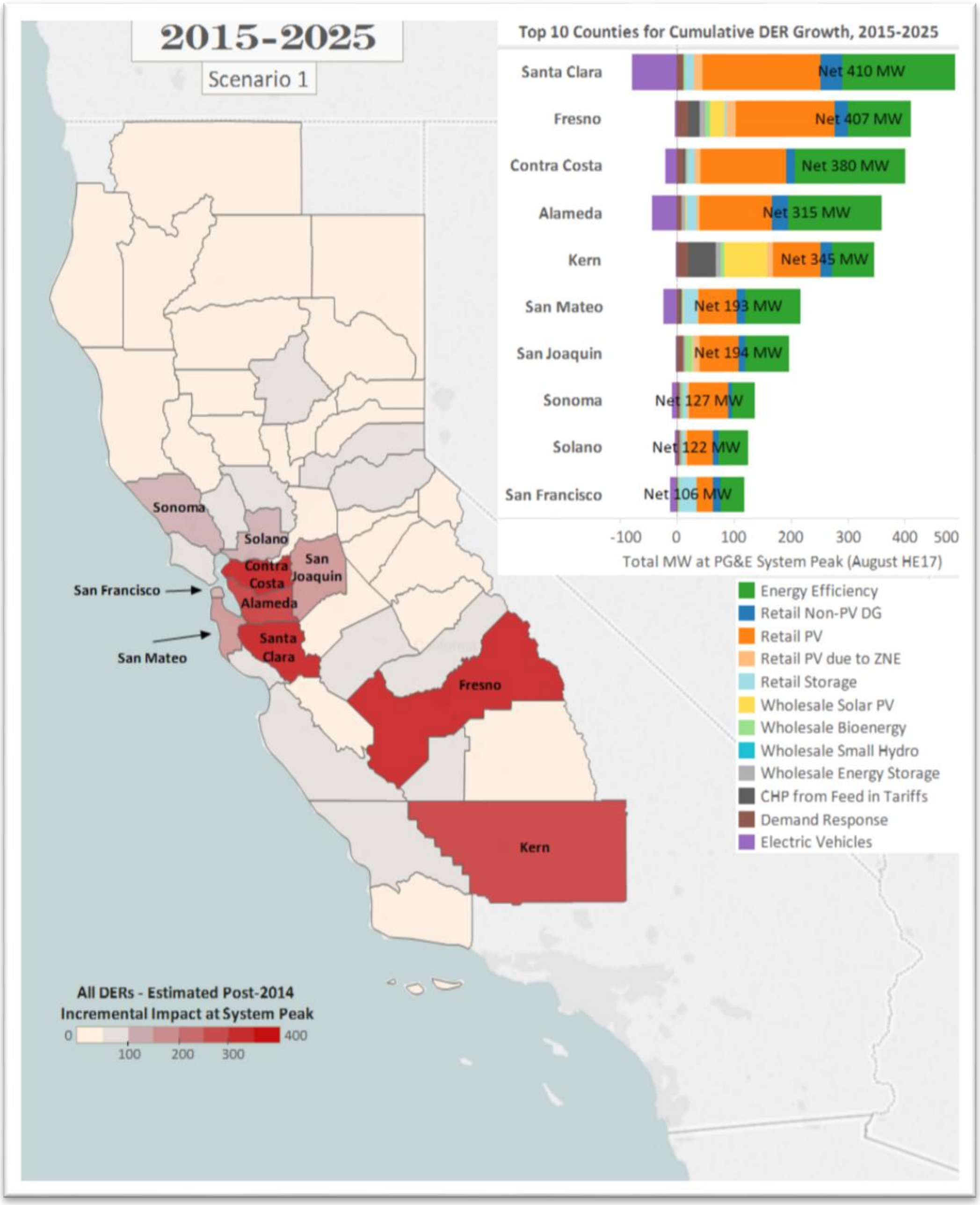


FIGURE 2-32 AVERAGE CHARGING LOAD PROFILE PER EV[74]

2.d.iii.3. Areas of High DER Adoption/Deployment

Figure 2-33 shows the impact at system peak from projected DER deployment for the trajectory planning Scenario 1 developed by PG&E. As would be expected, DER adoption is concentrated in PG&E's population centers, the San Francisco Bay Area and the Central Valley Counties of Fresno and Kern. The high DER impacts for the East and South San Francisco Bay Area Counties and in Fresno, San Joaquin, and Kern Counties reflect increased retail PV adoption in those areas as well as efficiency improvements associated with air conditioning load. In Figure 2-34, we can see that these counties have recently experienced higher YOY growth in retail PV adoption than other counties that have significant retail PV penetration. Relatively high levels of estimated DER impacts in Kern County are associated with retail PV and energy efficiency but also wholesale distribution connected PV which is expected to be deployed primarily in Kern County.

[74] EV charging profiles are based on published reports on charging behavior. See Appendix C for additional information.



Notes:

Reflects incremental capacity additions from 2015-2025; does not include pre-2015 installed capacity

Please see Footnotes to Figure 2-26 for capacity factor at peak assumed for each DER technology category

FIGURE 2-33: SCENARIO 1 "TRAJECTORY" PROJECTED IMPACT AT SYSTEM PEAK FROM DER GROWTH (2015-2025)

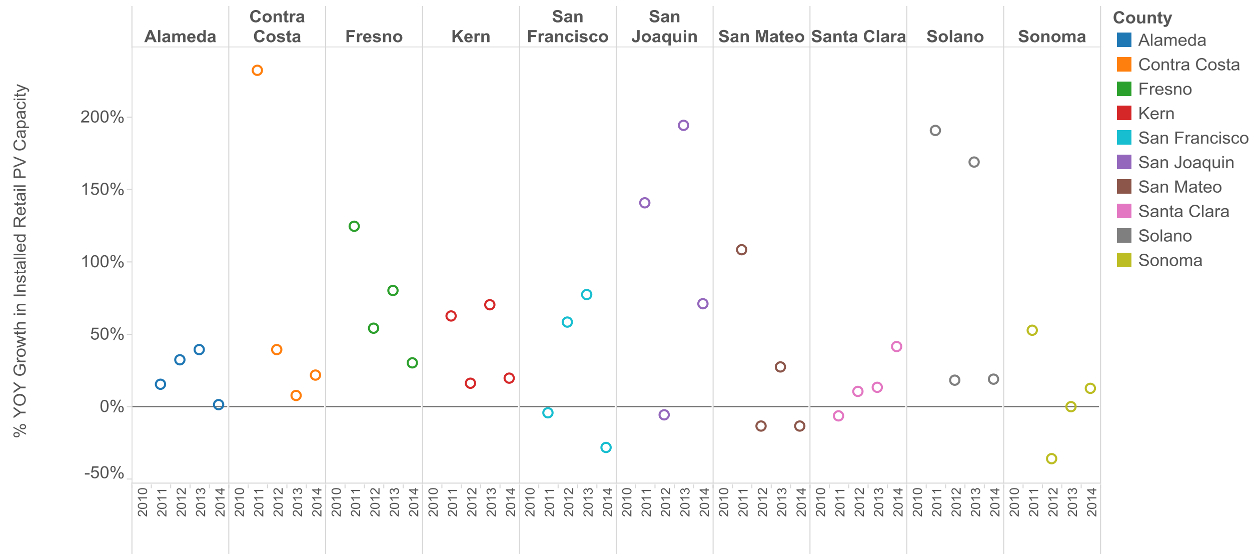


FIGURE 2-34: PERCENT YEAR-OVER-YEAR GROWTH 2010-2014 IN TOP TEN COUNTIES FOR PV ADOPTION

At levels of more geographic granularity, DER adoption is also highly clustered. For example, retail solar PV has been adopted primarily by higher income single family homeowners, who are generally concentrated in particular neighborhoods served by a feeder or substation. Electric vehicle adoption has been most prevalent among customers with similar demographics, single family home dwellers with higher incomes, and are also clustered in certain areas. This may shift over time, if EV charging becomes more available it could open up the opportunity for EV ownership by customers outside the current observed demographic. However, this shift would only supplement, not replace, the current adoptions patterns upon which the EV planning scenarios are based. Retail non-residential storage adoption tracks population as well as commercial activity for certain target customer segments, such as hotels, hospitals and supermarkets. Retail residential storage adoption tracks population as well as PV adoption, since these technologies are often paired.

The clustered pattern of retail PV adoption is illustrated in Figures 2-35 and 2-36. These figures show interconnected PV capacity by feeder for the years 2008, 2014, and estimated for 2020 and 2025.

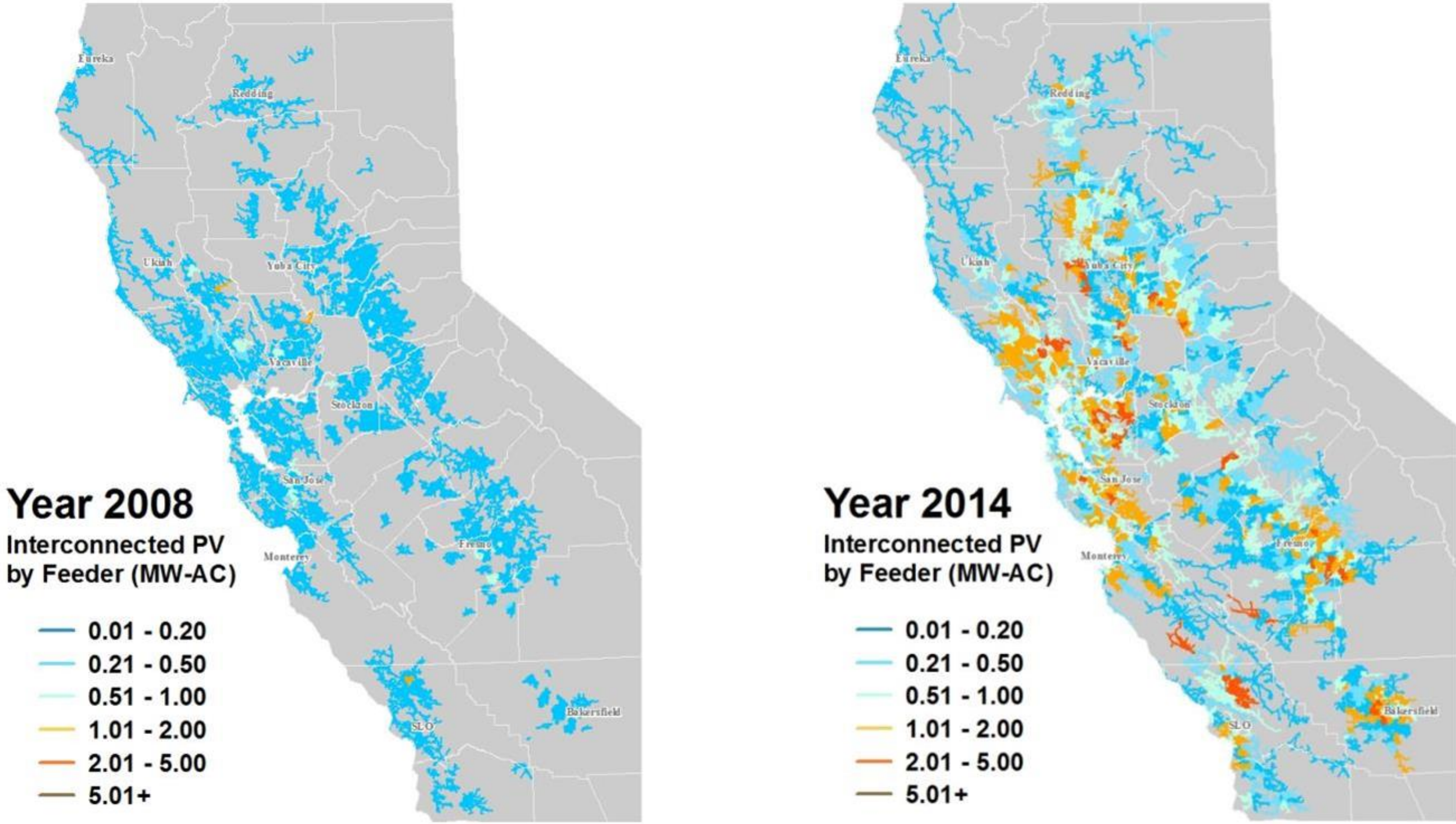


FIGURE 2-35: PG&E SERVICE AREA - INSTALLED PV CAPACITY (MW CEC-AC) IN 2008 AND 2014

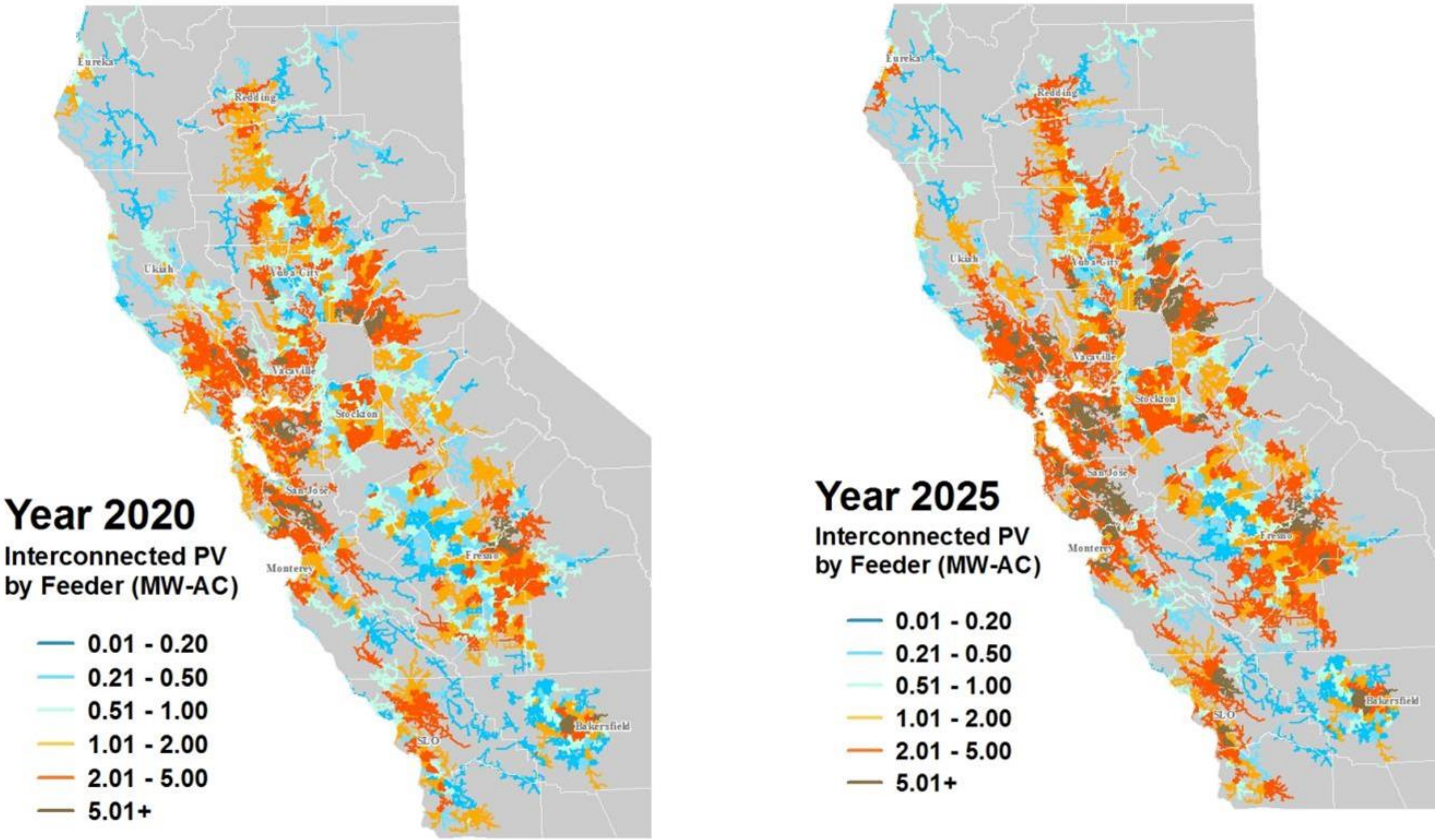


FIGURE 2-36: PG&E SERVICE AREA – ESTIMATED INSTALLED PV CAPACITY (MW CEC-AC) IN 2020 AND 2025

2.d.iv. Implications of DER Technology Services, Dispatchability, and Controls for Distribution Planning

While the DER growth scenarios illustrate the relative order of magnitude and likely location for each DER type, the distribution system impact is highly dependent on the services, dispatchability, and controls associated with each DER. The impacts that the DER growth scenarios presented in this section may have on distribution planning depend on the distribution services the DERs are able to provide, how quickly/regularly a service can be dispatched, and what controls are in place to ensure that the DER technology will have the expected impact as required to manage distribution assets safely, reliably, and affordably on a continuous, uninterrupted basis.

The communication and control systems in place for DER resources are a key consideration for distribution planning. Operation of DER resources is generally controlled by the customer, and distribution planners must plan for uncertainty in how DER will impact distribution assets. A variety of load management technologies, including storage, load shifting, and load curtailment technologies can help optimize the impact of DERs on distribution assets, but this optimization depends on reliable and coordinated communication and control systems.

2.d.v. Conclusion

In response to the Guidance Ruling, the IOUs have established industry-leading processes and methodologies to estimate deployment of DERs at a distribution feeder-level of granularity. PG&E's DER growth scenarios illustrate geographical trends in DER deployment that can be useful for PG&E's on-going DER integration capacity analysis, and may help PG&E identify potential locations for soliciting DER alternatives to traditional distribution capacity investments. The growth scenarios also can inform investment planning decisions where system upgrades may be necessary to accommodate higher penetrations of DERs (*e.g.*, identify areas that are likely to require investments to enable two way energy flow). At the same time, because the market penetration and deployment of DERs is not controlled or initiated by utilities, the use of DER growth trends to make electric distribution capacity decisions is limited and involves considerable uncertainty.

At the aggregate level, load-reducing DERs may exhibit strong growth through 2025, mostly attributable to EE and PV. EVs are expected to add to load, but to a lesser degree over the primarily in later evening hours. Adoption of DER technologies is also expected to be highly clustered, driven largely by customer demographics (for residential customers), sector and tariff (for non-residential customers) and energy usage profiles.

The local, distribution-level impacts of DER is highly variable across technology type, geographic factors (*e.g.*, solar insolation and weather patterns), and feeder load profiles. DER impacts on the distribution system are also a function of DER dispatchability and the availability of reliable and coordinate DER communications and control systems.

Chapter 3 – Demonstration and Deployment

3. Demonstration and Deployment

As required by the Guidance Ruling, the purpose of this chapter is to describe the pilot projects that PG&E proposes to conduct to demonstrate its enhanced distribution planning methodologies before applying those methodologies on a system wide basis. The Guidance Ruling has identified a set of five recommended pilot concepts for which the Utilities are directed to develop project specifications to demonstrate the proposed distribution planning methodologies, the capabilities of DERs to meet grid planning and operational requirements, and the integration of locational net benefits analysis into distribution planning and operations.

The following sections of this chapter describe the project specifications for the following five (5) proposed pilot demonstration projects:

1. **Section 3.a. –** Demonstrate Dynamic Integrated Capacity Analysis
2. **Section 3.b. –** Demonstrate the Optimal Location Benefit Analysis Methodology
3. **Section 3.c. –** Demonstrate DER Locational Benefits
4. **Section 3.d. –** Demonstrate Distribution Operations at High Penetrations of DERs
5. **Section 3.e. –** Demonstrate DER Dispatch to Meet Reliability Needs

Authorization and Cost Recovery for Demonstration Projects

If the CPUC approves and mandates PG&E's proposed demonstration projects as part of PG&E's DRP, the CPUC should authorize PG&E to file an advice filing that includes PG&E's requested revenue requirement for recovery of the reasonable cost of each project. The advice filing will include a schedule, scope, and cost estimate for each project comparable to the level of detail PG&E includes in its triennial EPIC plans, along with a summary of PG&E's collaboration with other stakeholders on the design of each project. Upon approval of the advice filing, PG&E would be authorized to implement the demonstration projects and recover the costs associated with the projects.

3.a. Demonstrate Dynamic Integration Capacity Analysis

3.a.i. Objective

This project aims to demonstrate the Utilities' Commission-approved Integration Capacity Analysis methodology for all line sections or nodes within a DPA. This demonstration will utilize fully dynamic modeling techniques for all line sections or nodes within the selected DPA. This demonstration shall consider two scenarios for the Integration Capacity Analysis:

1. The DER capacity does not cause power to flow beyond the substation busbar.
2. The DERs technical maximum capacity is considered irrespective of power flow toward the transmission system.

This project shall be scoped to commence no later than six months after Commission approval of PG&E's DRP.

3.a.ii. Proposed Area of Demonstration

PG&E has identified the Central Fresno DPA for demonstrating the integrated capacity analysis methodology.

Central Fresno Distribution Planning Area

The Central Fresno DPA is located in Fresno County and services the central portion of the city of Fresno. The DPA is bounded by Herndon Avenue to the north, CA-99 to the west, CA-180 to the south, and Clovis Avenue to the east. Approximately 92,500 customers with a 2014 peak demand of 428 MW are served by four substations: Ashlan Avenue, Barton, Bullard, and Manchester. These substations are comprised of 11 substation transformer banks in total individually ranging in size from 30 megavolt amperes (MVA) to 60 MVA. The total substation loading capacity of this DPA is 491 MW. By 2020 the DPA has a forecasted load of 490 MW (62 MW increase in five years). Also by 2020 the DPA has a retail DER expected scenario of 76.9 MW. The county of Fresno has an expected wholesale DER scenario of 58.2 MW[75] by 2020.

3.a.iii. Pilot Specifications

PG&E plans to utilize the same study specifications, datasets and tools for determining Integration Capacity as discussed in Chapter 2. The datasets include hourly load profiles and power flow circuit models. Areas of improvement have been identified in both the datasets and tools to be able to more effectively and accurately determine results.

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[75] The wholesale forecast is 58 percent PV which is likely to show up in the rural areas outside of Fresno City.

PG&E is partnering with external vendors to create a year-long process of improving and enhancing the planning tools PG&E uses in distribution planning. This process involves nine major tasks that are listed as follows:

1. Load Shape Enhancement – Will develop more accurate and detailed load shapes for feeders to analyze.
2. SCADA Data Analysis – Incorporates SCADA data to validate and improve load shapes used for analysis.
3. DER Forecast Integration – Integrates methodology and results of DER scenario into planning forecast to use in locational benefit scenario analysis.
4. DER Scenario Enhancement – Develop scenario analysis to evaluate DER scenario impact to system.
5. DER Penetration Assessment – Incorporate integration capacity and penetration assessment within PG&E's load forecasting tool.
6. DRP Methodology Integration – Dynamically coordinate with development of DRP for proactive integration of methodologies.
7. Power Flow Batch Automation – Develop automation scripting to be able to analyze models in batch mode.
8. Locational Benefits – Implement locational benefit analysis into load forecasting tool.
9. Final DRP Methodology Integration (upon plan approval) – Finalize integration of DRP methodologies based on plan approval and any changes required.
10. Perform Central Fresno Analysis (upon plan approval) – Perform final integration capacity analysis on the whole DPA using completed tool.

3.a.iv. Programs, Initiative, and Funding Utilized

As part of this pilot, PG&E plans to utilize enhancements as part of EPIC-2 Project 23 (EPIC 23), *Integrate Distributed Energy Resources into Utility Planning Tools,* to further increase the accuracy and granularity of the Integration Capacity Analysis. Specifically, EPIC Project 23 will enhance and integrate existing Load Analysis and Power Flow tools to help evaluate various DER solutions, for integration into utility investment planning. This would be a significant and novel expansion beyond what has been deployed by known utilities. This project facilitates the integration of a broader range of customer-side technologies and DER approaches into grid planning and operations in a least cost framework by piloting integration and usage of

SmartMeter™ data, node based modeling, customer segmentation analysis, and customer specific DER forecasting.

3.a.v. Proposed Schedule

Development of a detailed schedule is contingent upon CPUC approval. Assuming there are no additional modifications to the specifications of this demonstration as well as there are no modifications to the Integration Capacity Analysis methodology required by the CPUC, PG&E plans to complete this Integration Capacity Analysis within six months after CPUC approval of this DRP.

3.b. Demonstrate the Optimal Location Benefit Analysis Methodology

3.b.i. Objective

This project aims to demonstrate PG&E's Commission-approved optimal location benefit analysis methodology for one DPA, in which that DPA has one near term (0-3 years) and one longer term (3 years or greater) distribution infrastructure project that can be deferred due to integration of DERs.

This demonstration project shall be scoped to commence no later than 1 year after Commission approval of PG&E's DRP.

3.b.ii. Proposed Area of Demonstration

To further demonstrate alignment of the proposed distribution planning frameworks, PG&E is proposing to demonstrate its Optimal Location (Net) Benefit Methodology on the Central Fresno DPA, which is also being utilized for the demonstration on Dynamic Integration Capacity Analysis (3.a). A description of the Central Fresno DPA is included in Section 3.a.ii. Specifically, for the Central Fresno DPA, PG&E is considering one near term (0-3 years) project involving deferral of increasing distribution transformer capacity. In the long term (greater than 3 years), PG&E is also evaluating if this distribution transformer capacity can be deferred beyond three years.

3.b.iii. Pilot Specifications

The specifications for this pilot include the following steps:

1. Perform distribution planning capacity and reliability assessment to determine location and timing of impacted facilities in Central Fresno DPA.
2. Determine project scope, cost estimate and implementation schedule for upgrading impacted facilities
3. Perform Integration Capacity Analysis for Central Fresno DPA.
4. Evaluate DERs as an alternative to mitigate identified capacity/reliability issue.
    i. Determine feasible short term projects that can deliver requirements for projects within a 3-year time frame.

ii. Determine feasible long-term projects that can deliver requirements for projects that are greater than three years out.

5. Determine service requirements for DERs to address identified capacity/reliability issue.
6. Determine location(s) where DER(s) are required in Central Fresno DPA, along with suggested DER portfolio mix (considering DER loading profile).
7. Compute locational value for specific points within Central Fresno DPA based on avoided utility costs and amount of DER required per location.
8. Compute ratio of avoided cost and required DER capacity (results provided in $/kW, cost per DER capacity)

3.b.iv. Programs, Initiative, and Funding Utilized

This demonstration will both leverage and inform the work envisioned under EPIC Project 23 to enhance planning tools for dynamic DER analysis. EPIC Project 23 is focused on integrating enhanced techniques of DER analysis into PG&E's Load Forecasting and Power Flow Analysis planning tools, which are used to perform technical studies regarding distribution system reliability.

3.b.v. Proposed Schedule

Development of a detailed schedule is contingent upon CPUC approval. Assuming there are no additional modifications to the specifications of this demonstration as well as there are no modifications to the optimal location net benefits methodology required by the CPUC, PG&E plans to complete this analysis within 12 months after Commission approval of this DRP.

3.c. Demonstrate DER Locational Benefits

3.c.i. Objective

This project aims to demonstrate the ability of DERs to achieve locational benefits. Specifically, this pilot project should involve up to three DER avoided cost categories or services for which only "normative value data" presently exist (*e.g.*, avoided resource adequacy capacity, distribution capacity deferral, voltage/reactive power management, etc.) can validate the ability of DER to achieve net benefits consistent with the optimal location benefit analysis.

The pilot specification should include a detailed implementation schedule. Such a DER demonstration project will either displace or operate in concert with existing infrastructure to provide the defined functions. This demonstration shall also explicitly seek to demonstrate the operations of multiple DER types in concert, and shall explain how minimum-cost DER portfolios were constructed using locational factors such as load characteristics, customer mix, building characteristics and the like.

This demonstration project shall be scoped to commence no later than one year after Commission approval of the DRP.

Use cases shall employ services obtained from customer and/or third-party DERs. Each Utility shall specify products and services employed to obtain the avoided costs or net benefits, and shall specify related transaction methods (*e.g.*, contract, tariff, marginal price) by which customer and/or third-party DERs will provide services under the demonstrations.

3.c.ii. Proposed Area of Demonstration

To further align the proposed distribution planning frameworks (Integration Capacity and Optimal Location Net Benefit Methodology), PG&E is proposing to demonstrate DER Locational Benefits on the Central Fresno DPA, which is also being utilized for the demonstration on Dynamic Integration Capacity Analysis (3.a) and Optimal Location Net Benefit Methodology (3.b). A description of the Central Fresno DPA is included in Section 3.a.ii.

3.c.iii. Pilot Specifications

The following outlines the anticipated approach to designing, demonstrating, and deploying a DER portfolio to meet locational benefits.

1. Customer and Stakeholder Engagement
2. Technical Approach
    A. Define Load Scenarios
    B. Define and Analyze DER Portfolios
    C. Select DER Portfolio
    D. Energy Management System
    E. Demonstration Implementation
    F. Performance Monitoring and Analysis

3.c.iii.1. Customer and Stakeholder Engagement

PG&E will seek to formalize a working relationship with customers and third-parties in the context of this project. This will include PG&E holding one or more collaborative customer meetings in order to, for example:

- Gain a clear understanding of the ways in which a DER portfolio could provide locational benefit
- Examine current and expected loads, including potential load growth
- Discuss operational priorities in the context of the load analysis.
- Discuss EE and DR potential.
- Discuss energy storage and DG potential, including preliminary assessment of possible sites.
- Review process considerations (*e.g.*, permitting and regulatory) required for implementing DERs around the city, including identifying appropriate stakeholders to include in the process.
- Discuss the business relationship preferences with respect to DG assets.

PG&E will seek to provide EE, DR, and energy storage. DG could be provided by third parties and operationally integrated.

Building upon the outcomes of PG&E and stakeholder meetings, and informed by load analyses and preliminary DER opportunity assessments, PG&E will issue one or more Request for

Proposal (RFP) to invite contractors to support the work of PG&E in designing, building, operating, and maintaining the system.

3.c.iii.2. Define Pilot Functions

The Locational Net Benefits Pilot is discussed in the following will include the following:

- Location – To effectively coordinate, leverage and align the work performed in other proposed pilots, PG&E has identified the Central Fresno DPA for demonstrating the DER Locational Net Benefits.
- Avoided Utility Cost/Net Benefits targeted
- DER Services Required – Distribution Capacity, Distribution Voltage, Decreased Renewable Integration Costs
- Transaction Method for DER Services – PG&E will be developing an innovative commercial solicitation and accompanying contractual and ownership structure to support deployment of distribution connected DERs in the Central Fresno DPA. This service based contract will be targeted for specific locations within the Central Fresno DPA where it has been identified by the utility that placing DERs within those particular locations will provide value.

3.c.iii.3. Define and Analyze DER Portfolios

- Define a range of DER portfolio objectives to guide DER portfolio design.
- Design multiple DER portfolio mixes (likely to include, for example, EE, DR, storage, solar, wind, and potentially others including EVs and Vehicle-to-Grid applications) to meet the requirements of load service scenarios and DER portfolio objectives.
- Perform analysis of planned system performance of each DER portfolio mix in order to inform DER portfolio selection.

3.c.iii.4. Select DER Portfolio

In close collaboration with stakeholders, review DER portfolio analysis and select optimal DER portfolio for implementation. Key decision factors are likely to include and are not limited to customer reliability, cost effectiveness, alignment with related stakeholder goals.

3.c.iii.5. Energy Management System

PG&E intends to leverage PG&E's second triennial EPIC (EPIC 2) Project 2 to support the demonstration of operations of multiple DERs using dedicated control system to meet reliability needs. Project 2 specifically aims to demonstrate a Distributed Energy Resource Management

System (DERMS) pilot system to coordinate the control of various types of DERs, which could include DG, EVs, energy storage, DR, and microgrids.

3.c.iii.6. Demonstration Implementation

Following selection of the specific DER portfolio, overall engineering and system design will commence. The following tasks are anticipated in order to design, build, and implement the demonstration project:

- Procure DERs – PG&E will issue one or more RFPs inviting contractor(s) to bid for designing and building various DER components at selected sites, as specified by the DER portfolio analysis.
- Design and Install Network Upgrade – PG&E will perform any necessary additions and modifications to the existing distribution network in order to interconnect, monitor, and control DERs and the distribution system.
- Install and Test DERs – PG&E will work with contractors to install and test various DERs to ensure each individual component performs as desired.
- Install and Test the New Control System – PG&E will leverage EPIC 2 Project 2 to the extent possible in order to install and test the DERMS system to ensure the designed mechanism and algorithms are functional.
- Conduct Pre-Operational Testing – PG&E and its contractor(s) will run an integrated pre-operational testing to ensure the systems work properly.
- Conduct Performance Demonstrations – Scenarios may be developed to demonstrate the capabilities of controlling and dispatching DER

3.c.iii.7. Performance Monitoring and Analysis

During the demonstration project, performance monitoring and analysis tasks are anticipated to include:

- Defining the data collection requirements for the demonstration project. The data requirements would include the types of system variables to be collected, the resolution and duration of data required, and the timing of data collection.
- Collecting the data as required.
- Developing an analysis plan to utilize collected data for performance verification. Appropriate technologies will be selected for analysis and verification.
- Perform data analyses as defined in the analysis plan. If applicable, sensitivity analysis will be performed to demonstrate the contributions of various system components to

the reliability of the overall system so that DER dispatch mechanisms can be further improved.

3.c.iv. Proposed Schedule

Development of a detailed schedule is contingent upon CPUC approval. Assuming there are no additional modifications to the specifications of this demonstration PG&E plans to complete detailed scoping of this demonstration within 12 months after Commission approval of this DRP. Planned in-service date for this demonstration is subject to the results of detailed scoping findings and will be updated accordingly.

3.d. Demonstrate Distribution Operations at High Penetration of DER

3.d.i. Objective

The project will develop a specification for a DPA level demonstration of high DER penetrations that integrate into PG&E's distribution system operations, planning and investment for implementation. This analysis of potential benefits and locational values associated with high-DER penetration will be conducted at the Substation level, which for the specified area involves six circuits. This demonstration seeks to demonstrate the operations of multiple DERs in concert, and will explain how DER portfolios were constructed.

High penetration of DERs can lead to many possible grid issues if not addressed. These issues could be unknown thermal overloading, nuisance tripping, fault mis-coordination, steady state voltage violations, transient voltage disturbances, outage recovery limitations, and many more. Although many of these issues are addressed in the interconnection phase, there are some limitations that may not arise until operation. Also, some mitigation caused in the interconnection phase might have potential to be forgone if proper control and coordination with DERs is in place. It is the purpose of this demonstration to determine the proper measures that are needed to operate DERs during high penetration scenarios to mitigate the issues previously mentioned in a way that provides benefit to the customer in less mitigations and benefit to the grid by dynamic operations.

3.d.ii. Proposed Area of Demonstration

PG&E has identified the Gates DPA for demonstrating operation of multiple DERs at high penetration. This DPA is also being utilized for the Dynamic Integration Capacity Analysis and Optimal Location (Net) Benefit Methodology demonstrations (3.a and 3.b). A description of the Gates DPA is included under Section 3.a.ii.

Within the Gates DPA resides Huron Substation, which experiences electric loading patterns that closely resemble the "Duck Curve" where higher generation output occurs during the "daytime" hours of 11 a.m. to 3 p.m. while demand is low and higher demand during "evening hours" when distributed PV generation is low or offline. It also has an unpredictable agricultural hourly profile mixed with very high solar penetration. Currently, there is 20 MW of solar generation on the Huron Substation that is thermally rated for 18.8 MW. The amount of base minimum load allows the small amount of excess generation. The high penetration of PV has shifted the daytime peak to an evening peak. Even with all this solar generation there is still an 18 MW peak demand of load during the evening hours. As seen in Figures 3-1 and 3-2 below there is a load peak that occurs in the summer and a reverse generation peak that occurs in the winter.

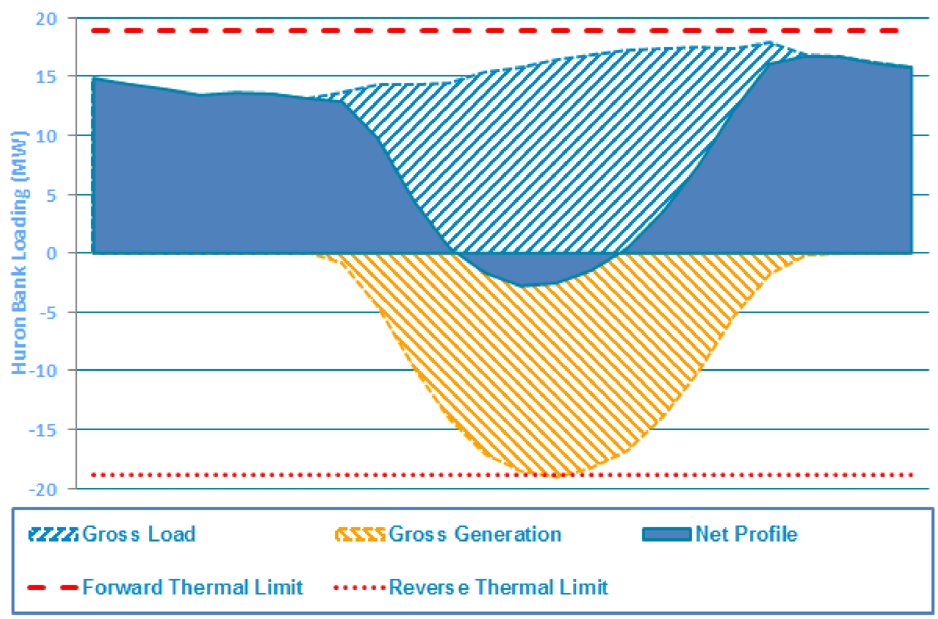

FIGURE 3-1: HURON SUBSTATION FORWARD POWER PEAK DURING SUMMER DAY

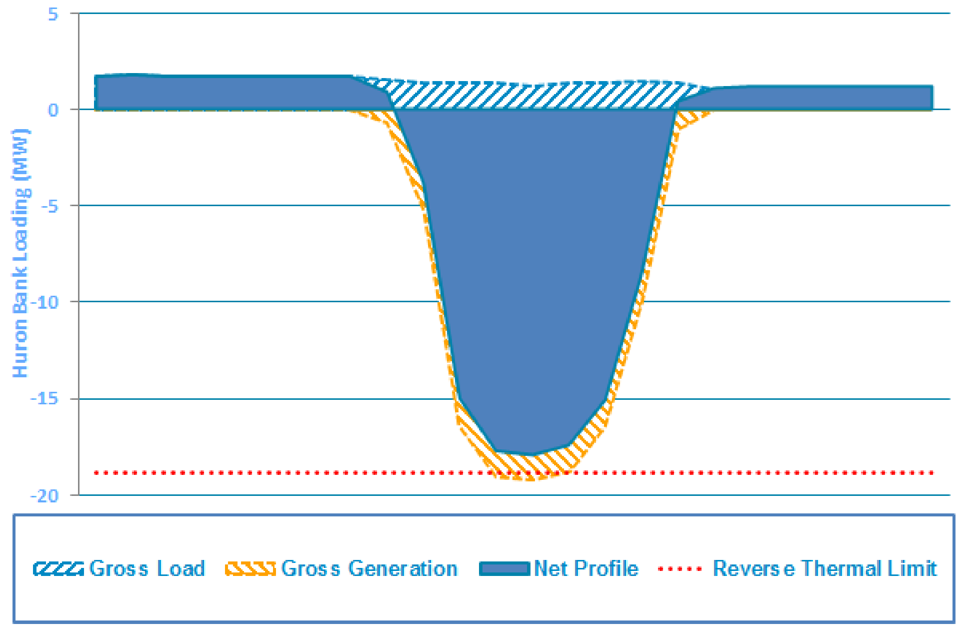

FIGURE 3-2: HURON SUBSTATION REVERSE POWER PEAK DURING WINTER DAY

This substation has a very high ratio of peak load to minimum load. It also has limited times throughout the year when these overload conditions occur. These conditions allow it to be a prime candidate for dynamic operations to mitigate issues and allow for further adoption of more solar and other DERs despite current limiting conditions.

3.d.iii. Pilot Specifications

The following outlines the specifications for this pilot project:

- Project Location – Huron Substation 12 kilovolts (kV) bus.
- Locational Net Value Components Targeted – This project will demonstrate the ability of a utility operated energy storage system to address distribution capacity and over-generation issues. Secondary energy storage functionalities, such as smoothing DG output to improve voltage and power quality will also be demonstrated to evaluate the practical ability of a single storage resource to provide "stacked" distribution benefits.
- DER Type – Energy storage, DR, DG

3.d.iii.1. Customer and Stakeholder Engagement

PG&E will seek to formalize a working relationship with customers and third-parties in the context of this project. This will include PG&E holding one or more collaborative customer meetings in order to, for example:

- Gain a clear understanding of the ways in which highly penetrated systems can be controlled
- Examine current and expected loads, including potential load growth
- Discuss operational priorities in the context of the load analysis.
- Discuss DR potential.
- Discuss energy storage and DG potential, including preliminary assessment of possible sites.
- Review process considerations (*e.g.*, permitting and regulatory) required for implementing DERs around the area, including identifying appropriate stakeholders to include in the process.
- Discuss the business relationship preferences with respect to DG assets.

PG&E will seek to provide DR and energy storage. DG could be provided by third parties and operationally integrated.

Building upon the outcomes of PG&E and stakeholder meetings, and informed by load analyses and preliminary DER opportunity assessments, PG&E will issue one or more RFPs to invite contractors to support the work of designing, building, operating, and maintaining the system.

Key elements of the technical approach to be proposed will likely include but are not limited to the following:

3.d.iii.2. Define Pilot Functions

The operations at high penetration pilot will include the following:

- <u>Operational Control</u> – Increasing the visibility and control of the DER will insure the system operators can provide safe and reliable power to the customers while still utilizing and enabling DERs.
- <u>Customer Benefits</u> – This demonstration will allow for more DERs to be placed in a localized area and minimize the amount of negative impact it will provide while

maximizing the benefit. Customers will have more choice and greater ability to place DERs on the system.

- Location – To effectively coordinate, leverage and align the work performed in other proposed pilots, PG&E has identified the Gates DPA for demonstrating this pilot.
- DER Services Required – Visibility and Control

3.d.iii.3. Define and Analyze DER Portfolios

- Define a range of DER portfolio objectives to guide DER portfolio design.
- Design multiple DER portfolio mixes (likely to include, for example, EE, DR, storage, solar, wind, and potentially others including EVs and Vehicle-to-Grid applications) to meet the requirements of load service scenarios and DER portfolio objectives.
- Perform analysis of planned system performance of each DER portfolio mix in order to inform DER portfolio selection.

3.d.iii.4. Select DER Portfolio

In close collaboration with stakeholders, review DER portfolio analysis and select optimal DER portfolio for implementation. Key decision factors are likely to include and are not limited to customer reliability, cost effectiveness, alignment with related stakeholder goals.

3.d.iii.5. Energy Management System

PG&E intends to leverage PG&E's second triennial EPIC (EPIC 2) Project 2 to support the demonstration of operations of multiple DERs using dedicated control system to meet reliability needs. Project 2 specifically aims to demonstrate a DERMS pilot system to coordinate the control of various types of DERs, which could include DG, EVs, energy storage, DR, and microgrids.

3.d.iii.6. Demonstration Implementation

Following selection of the specific DER portfolio, overall engineering and system design will commence. The following tasks are anticipated in order to design, build, and implement the demonstration project:

- Procure DERs – PG&E will issue one or more RFPs inviting contractor(s) to bid for PG&E's work designing and building various DER components at selected sites, as specified by the DER portfolio analysis.

- Design and Install Network Upgrade – PG&E will perform any necessary additions and modifications to the existing distribution network in order to interconnect, monitor, and control DERs and the distribution system.

- Install and Test DERs – PG&E will work with contractors to install and test various DERs to ensure each individual component performs as desired.

- Install and Test the New Control System – PG&E will leverage EPIC 2 Project 2 to the extent possible in order to install and test the DERMS system to ensure the designed mechanism and algorithms are functional.

- Conduct Pre-Operational Testing – PG&E and its contractor(s) will run an integrated pre-operational testing to ensure the systems work properly.

- Conduct Performance Demonstrations – Scenarios may be developed to demonstrate the capabilities of controlling and dispatching DER

3.d.iii.7. Performance Monitoring and Analysis

During the demonstration project, performance monitoring and analysis tasks are anticipated to include:

- Defining the data collection requirements for the demonstration project. The data requirements would include the types of system variables to be collected, the resolution and duration of data required, and the timing of data collection.

- Collecting the data as required.

- Developing an analysis plan to utilize collected data for performance verification. Appropriate technologies will be selected for analysis and verification.

- Perform data analyses as defined in the analysis plan. If applicable, sensitivity analysis will be performed to demonstrate the contributions of various system components to the reliability of the overall system so that DER dispatch mechanisms can be further improved.

3.d.iv. Proposed Schedule

Development of a detailed schedule is contingent upon CPUC approval. Assuming there are no additional modifications to the specifications of this demonstration PG&E plans to complete detailed scoping of this demonstration within 12 months after Commission approval of this DRP. Planned in-service date for this demonstration is subject to the results of detailed scoping findings and will be updated accordingly.

3.e. Demonstrate DER Dispatch to Meet Reliability Needs

3.e.i. Objective

This project aims to demonstrate the capability of managing and operating multiple DERs using a dedicated control system within a microgrid system, with PG&E operating the microgrid, potentially with both third-party- and utility-owned DERs supporting the customer loads.

3.e.ii. Proposed Area of Demonstration

PG&E has identified Angel Island electric system for demonstrating DER dispatch to meet reliability needs demonstration project. This project presents an alternative to cable replacement that will demonstrate and deploy on-island DERs to meet reliability needs, and which shares broad goal alignment with respect to Angel Island management and operations. It is intended to operate an optimal DER portfolio that will run 24 × 7 and 365 days to maximize the benefits of the DER and reduce the dependency on the cable.

Angel Island

The proposed host site for this demonstration project is Angel Island, which is a state park managed under the California Department of Parks and Recreation (CDPR). Angel Island supports approximately 20 full time residents, and offers historic preservation and interpretation, boating, hiking, camping, and other activities. A recent load analysis indicates a peak demand on Angel Island of approximately 100 kW. Electrical loads include lighting, baseboard electric heat, minor concession operations, waste lift pumps, work vehicle charging, and boat dock hook-ups. PG&E has historically supplied electricity to Angel Island with two submarine cables from Tiburon Substation at a voltage of 12 kV.

The submarine section is approximately 1-mile long and crosses the Raccoon Strait in the San Francisco Bay. One of the cables is no longer in service and the other electric cable's status is deteriorating in need of replacement.

CDPR is interested in promoting on-island renewable generation at Angel Island to align with the Governor's clean energy and climate goals. Park management has also expressed interest in the "interpretation" (visitor experience) opportunities presented by an on-island microgrid system. Somewhat recently, the park management would like to consider using EVs for tourist shuttles and for work vehicles in order to mitigate the risk of transporting diesel fuel across the bay and to further reduce GHG emissions.

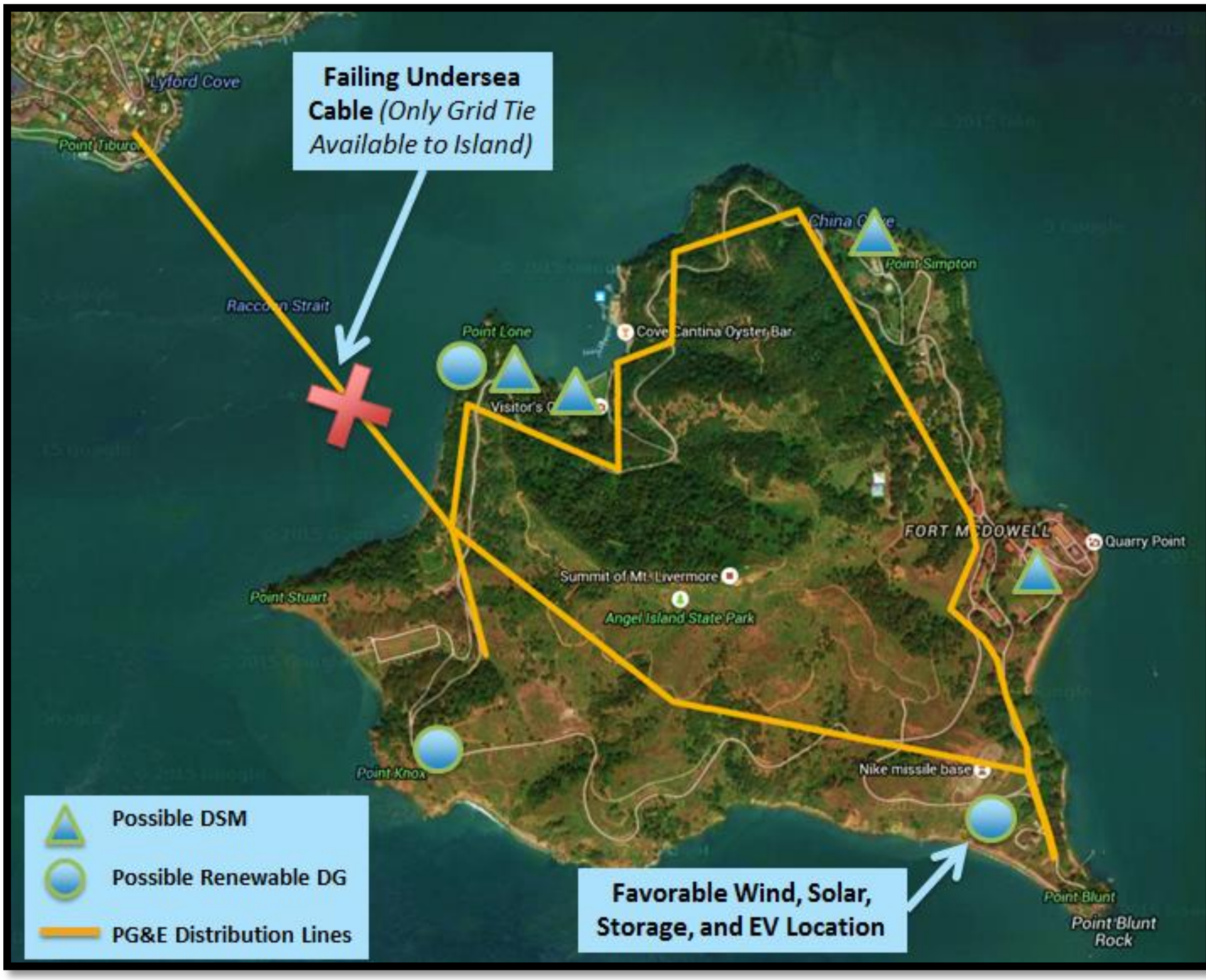

FIGURE 3-3: OVERHEAD VIEW OF ANGLE ISLAND AND POSSIBLE DER LOCATIONS

3.e.iii. Pilot Specifications

The following outlines the anticipated approach to designing, demonstrating, and deploying a microgrid on Angel Island to meet customer reliability needs.

1. Customer and Stakeholder Engagement
2. Technical Approach
   A. Define Load Scenarios
   B. Define and Analyze DER Portfolios

C. Select DER Portfolio

D. Energy Management System

E. Demonstration Implementation

F. Performance Monitoring and Analysis

3.e.iii.1. Customer and Stakeholder Engagement

PG&E has engaged with CDPR and conducted a site visit in order to explore DER potential and gauge interest in pursuing a microgrid solution that is based on the installation of on-island generation and storage in-lieu of cable replacement. With initial interest established, PG&E will seek to formalize a working relationship in the context of this project. This will include PG&E and CDPR holding one or more collaborative customer meetings in order to, for example:

- Gain a clear understanding of the ways in which a microgrid system could contribute CDPR's vision for Angel Island.
- Examine current and expected loads, including potential load growth from EV charging.
- Discuss operational priorities in the context of the load analysis.
- Discuss EE and DR potential.
- Discuss energy storage and DG potential, including preliminary assessment of possible sites.
- Review process considerations (e.g., permitting and regulatory) required for implementing DERs on the Island, including identifying appropriate CDPR stakeholders to include in the process.
- Discuss the CDPR's business relationship preferences with respect to DG assets.

PG&E initiated a Large Integrated Audit, which commenced in the first half of 2015, in order to inform the discussion points listed above.

As indicated above, PG&E will operate an on-Island microgrid utilizing a dedicated control system. PG&E will seek to provide EE, DR, and energy storage. DG could be provided by third parties or PG&E, and operationally integrated with the dedicated control system.

Building upon the outcomes of CDPR and PG&E customer meetings, and informed by load analyses and preliminary DER opportunity assessments, PG&E will issue one or more RFPs to invite contractors to support the work of designing, building, operating, and maintaining the system.

Key elements of the technical approach to be proposed will likely include but are not limited to the following:

3.e.iii.2. Define Load Scenarios

- Develop load scenarios reflecting potential changes in customer demand, for example:
  - Slow/natural load growth of existing customers;
  - Slow/natural load growth of existing customers with new EV parking lot charging demand (work vehicle charging); and
  - Slow/natural load growth of existing customers with new EV parking lot and tourist center demand (work vehicle and tourist shuttle charging).

3.e.iii.3. Define and Analyze DER Portfolios

- Define a range of DER portfolio objectives to guide DER portfolio design.
- Design multiple DER portfolio mixes (likely to include, for example, EE, DR, storage, solar, wind, and potentially others including EVs and Vehicle-to-Grid applications) to meet the requirements of load service scenarios and DER portfolio objectives.
- Perform analysis of planned system performance of each DER portfolio mix in order to inform DER portfolio selection.

3.e.iii.4. Select DER Portfolio

In close collaboration with CDPR, review DER portfolio analysis and select optimal DER portfolio for implementation. Key decision factors are likely to include and are not limited to customer reliability, cost effectiveness, alignment with related CDPR goals including historical preservation, visitor experience, and sustainability, as well as demonstration value.

3.e.iii.5. Energy Management System

PG&E intends to leverage PG&E's second triennial EPIC (EPIC 2) Project 2 to support the demonstration of operations of multiple DERs using dedicated control system to meet reliability needs. Project 2 specifically aims to demonstrate a DERMS pilot system to coordinate the control of various types of DERs, which could include DG, EVs, energy storage, DR and microgrid.

3.e.iii.6. Demonstration Implementation

Following selection of the specific DER portfolio, overall engineering and system design will commence. The following tasks are anticipated in order to design and build the Angel Island microgrid system and to implement the demonstration project:

- Procure DERs – PG&E will issue one or more RFPs inviting contractor(s) to bid for designing and building various DER components at selected sites, as specified by the DER portfolio analysis.
- Design and Install Network Upgrade – PG&E will perform any necessary additions and modifications to the existing distribution network in order to interconnect, monitor, and control DERs and the distribution system.
- Install and Test DERs – PG&E will work with contractors to install and test various DERs to ensure each individual component performs as desired.
- Install and Test the New Control System – PG&E will leverage EPIC 2 Project 2 to the extent possible in order to install and test the DERMS system to ensure the designed mechanism and algorithms are functional.
- Conduct Pre-Operational Testing – PG&E and its contractor(s) will run an integrated pre-operational testing to ensure the microgrid system works properly.
- Conduct Performance Demonstrations – Scenarios may be developed to demonstrate the capabilities of controlling and dispatching DERs for reliability needs. For example:
  - Parallel operation: demonstrate DER dispatch for serving the Island customer load with broader PG&E distribution system as backup when the DERs cannot supply 100 percent of Island demand.
  - "Islanding" operation: demonstrate DER dispatch for serving the island customer load without broader PG&E system backup when the DERs can supply 100 percent of Island demand.
  - Demonstrate DER dispatch for restoring power to certain island customers when there are faults causing power outages.

3.e.iii.7. Performance Monitoring and Analysis

During the demonstration project, performance monitoring and analysis tasks are anticipated to include:

- Defining the data collection requirements for the demonstration project. The data requirements would include the types of system variables to be collected, the resolution and duration of data required, and the timing of data collection.

- Collecting the data as required.
- Developing an analysis plan to utilize collected data for performance verification. Appropriate technologies will be selected for analysis and verification.
- Perform data analyses as defined in the analysis plan. If applicable, sensitivity analysis will be performed to demonstrate the contributions of various system components to the reliability of the overall microgrid system so that DER dispatch mechanism can be further improved.

3.e.iv. Programs, Initiatives, and Funding Utilized

If the CPUC approves and mandates PG&E's proposed demonstration projects as part of PG&E's DRPs, the Commission should authorize PG&E to file an advice filing that includes PG&E's requested revenue requirement for recovery of the reasonable cost of each project. The advice filing will include a schedule, scope and cost estimate for each project comparable to the level of detail PG&E includes in its triennial EPIC plans, along with a summary of PG&E's collaboration with other stakeholders on the design of each project. Upon approval of the advice filing, PG&E would be authorized to implement the demonstration projects and recover the costs associated with the projects.

3.e.v. Proposed Schedule

Development of a detailed schedule is contingent upon CPUC approval. Assuming there are no additional modifications to the specifications of this demonstration PG&E plans to complete detailed scoping of this demonstration within 12 months after Commission approval of this DRP. Planned in-service date for this demonstration is subject to the results of detailed scoping findings and will be updated accordingly.

Chapter 4 – Data Access

4. Data Access

Pursuant to the Guidance Ruling, the purpose of this chapter is to provide PG&E's proposed policy and procedures for mutual sharing of data among utilities, customers and DER developers to support integration of DERs onto the distribution grid.

Section 4.a. provides **PG&E's proposed data sharing policy**.

S**ection 4.b.** provides **PG&E's proposed procedures for data sharing**, consistent with existing privacy, security and confidentiality requirements.

Section 4.c. provides specific recommendations for **how data on grid conditions should be shared** in order to ensure the safe and reliable integration of DERs onto the grid. As the Guidance Ruling recognizes, successful integration of increased amounts of DERs onto PG&E's electric distribution grid requires that various amounts and types of data be exchanged between PG&E and DER customers and developers. The types of data that need to be shared will depend on the use of the shared data, such as data on the integration capacity, locational benefits, production data from DERs, and geo-spatial DER growth trends described in Chapter 2, above. The Guidance Ruling identifies the following types of data that PG&E and the other utilities should evaluate for purposes of enhancing data access and transparency in distribution resources planning:

Utility Planning Data

- Existing distribution characteristics at substation and feeder-level—coincident and non-coincident peaks / capacity levels / outage data / projected investment needs
- EV and charging station populations
- Existing DG population characteristics
- Backup generator population
- Generation production characteristics, associated with intermittent resources
- Existing CHP installations

Market Data

- Demographics: household income levels, CARE customers

- Customer DG adoption scenarios
- Other customer DER adoption scenarios
- Distribution Planning load forecasts, based on forecasting scenarios proposed elsewhere in the plan

In the sections below, PG&E describes: (a) its proposed policy to enhance data sharing among utilities, DER customers and developers under its DRP, including maximizing the amount of data available from the utility, customers and DER developers under PG&E's Integration Capacity, location net benefits and geospatial DER growth scenarios without violating customer privacy or utility or third party physical or cyber security; (b) its proposed procedures for data sharing among utility planners and DER developers, using enhanced and continuously updated RAM maps and other existing data sharing tools in order to reduce implementation costs; and (c) new initiatives to demonstrate near-real time sharing of DER production data, grid conditions and Advanced Metering Infrastructure (AMI) data for purposes of operating and managing DER projects that provide alternatives to distribution capacity projects.

4.a. Proposed Policy on Data Sharing

PG&E intends to enhance and improve the access of third-parties and the public to PG&E's distribution feeder-specific distribution planning data, such as the data generated by the Integration Capacity and Locational Net Benefit analyses and tools described in Chapter 2, above (including geo-spatial trends in DER growth that affect the Integration Capacity Analysis). As suggested by the Guidance Ruling, PG&E will appropriately anonymize or aggregate customer-specific, security-sensitive and proprietary data to maximize the access of customers, DER developers and other stakeholders to the data, consistent with protection of customer privacy, proprietary and market sensitive data, and physical security and cyber-security.
In addition, PG&E's enhanced distribution planning data access initiatives will comply with CPUC and other regulatory agency rules and regulations, including the CPUC's customer data privacy and energy data access rules and FERC critical infrastructure rules.

PG&E's data access policy will go beyond the distribution planning and interconnection data already provided to customers and their third-party DER developers under existing CPUC rules and tariffs, such as the RAM Maps, under Electric Rule 21, and in GRCs.

PG&E's Integration Capacity Analysis and Locational Net Benefits methodology will update PG&E's RAM Maps to allow customers and DER developers to access expanded feeder-specific data on a streamlined basis, tailored to the specific needs of customers and DER developers to optimize the location of their projects and services from a cost and reliability perspective. The enhanced data may include the relevant feeder or substation load shape. PG&E's Integration Capacity Analysis will provide more detailed up-front, location-specific data on locations where DERs may be deployed where there is additional capacity. This additional transparency and data access will be in addition to existing interconnection screening tools and processes. PG&E's DRP also proposes to include publicly-available processes and methodologies that provide more granularity and insights into distribution planning data.

Subject to authority to recover the reasonable costs of implementation, PG&E will provide web-based platforms, tools and portals for convenient and continuous access to expanded and updated distribution planning data, standards, and project-specific applications resulting from the enhanced distribution planning tools and methods proposed in this DRP. These web-based tools and portals will be modeled on similar web-based tools made available to customers, developers and the public in PG&E's interconnection, Customer Data Access, and Energy Data Access proceedings.

The scope of distribution planning data that PG&E will make available will include the data generated by the enhanced planning tools and methodologies discussed in Chapter 2. Additional categories of data from customers, DER developers or other sources may be added if useful for the distribution planning and DER integration processes.

4.b. Procedures for Data Sharing

PG&E's data access procedures will be modeled on the customer privacy and other information security standards and expedited data release procedures approved by the Commission in D.11-07-056 (customer energy usage data privacy), D.13-09-025 (Customer Data Access), and D.14-05-016 (Energy Data Center). These procedures will be designed to provide more granularity and insights into PG&E's distribution planning, including assisting in determining whether DERs may provide cost effective alternatives to or better optimize PG&E's future traditional capital expansion upgrades (wires, transformers, capacitors). The data access procedures also will inform customers and DER developers regarding areas where there is available distribution capacity for location of DERs, and also provide improved integration of resources between distribution and transmission.

If PG&E's DRP and cost recovery for these data initiatives are approved, PG&E will implement procedures for collection of data from DERs and customers, and customer and developer access to distribution planning data and tools, using these models already approved by the Commission and in place for access to anonymized and aggregated customer-specific and security-sensitive data. This includes making available generic types of data and tools through web portals without the need for individual customer, utility or DER developer requests, as well as deadline-specific processes for more customized requests for data from customers, utilities or developers working on specific distribution resource projects. Customer-specific data is already available today through PG&E's Share My Data Energy Services Provider Interface on-line customer data access process. To the extent that the requested data is security-sensitive, private or otherwise confidential, PG&E will make available individual non-disclosure agreements similar to the model agreement approved by the Commission in the Energy Data Center proceeding (D.14-05-016) or else inform the requestor by appropriate deadlines why the data cannot be provided. For data that is particularly sensitive, due to physical security or cyber-security concerns, such as NERC Critical Infrastructure data, PG&E will continue to protect that data from disclosure, but subject to a transparent and agreed-upon process for third parties and PG&E to resolve any disagreements over the classification of such data and information through an expedited CPUC review process.

4.c. Grid Conditions Data and SmartMeters™

PG&E recognizes that data access can become prohibitively expensive and time-consuming unless the data formats and elements are standardized and generically available, particularly for highly granular data, such as grid conditions data and data generated by individual PG&E SmartMeters™. For this reason, PG&E will leverage the DRP pilot and demonstration projects proposed in Chapter 3 as well as development of the operating procedures to test and evaluate streamlined and generic formats for sharing grid conditions, relevant DER production data, and SmartMeter™-related data for purposes of considering DER projects that may defer distribution capacity investments. If the DRP demonstration projects validate additional categories of grid conditions and SmartMeter™ anonymized and DER production data that may support expanded integration of DERs, PG&E will seek funding to scale up the new or enhanced systems, such as SCADA or sensor systems, to support the additional data sharing.

Chapter 5 – Tariffs and Contracts

5. Tariffs and Contracts

Pursuant to the Guidance Ruling, the purpose of this chapter is to summarize all standard tariffs, contracts and other mechanisms that govern and/or incent DERs, and to identify any new or modified tariffs that should apply to the demonstration and deployment projects identified in Chapter 3. Section 5.a. describes relevant existing tariffs that apply to DERs. Section 5.b. describes how locational values could be integrated into existing DER tariffs. Sections 5.c. and 5.d. provide preliminary recommendations on new or modified tariffs that could apply to the DER demonstration projects and future DERs. The Guidance Ruling noted that the DRPs are not the forum for discussing new or modified tariffs and contracts for certain DER technologies, because tariffs for specific DER technologies are assigned to the appropriate DER-specific rulemaking. Instead, the Guidance Ruling requires PG&E and the other utilities to provide: (a) an outline of all relevant existing tariffs that govern/incent DERs;
(b) recommendations for how locational values could be integrated into the above existing tariffs for DERs; (c) recommendations for new services, tariff structures or incentives for DER that could be implemented as part of the demonstration programs; and (d) recommendations for further refinements to interconnection policies that account for locational values.

5.a. Relevant Existing Tariffs That Apply to DERs

PG&E has various existing tariffs and rate schedules that govern and / or incent the deployment of DERs. Appendix D summarizes relevant existing tariffs and rate schedules that govern/incent DERs that require interconnection. The most common tariffs and rates that govern DERs are the NEM tariff and the residential and non-residential rates applicable to customers who consider or deploy behind-the-meter DERs. The most commonly utilized tariff that governs the interconnection of the largest volume of generating DERs to PG&E's grid is PG&E's Rule 21 tariff. Each of these is summarized below.

Net Energy Metering Tariff

The NEM tariff is an electricity tariff that applies to the deployment of renewable DERs, notably solar PV, wind and bioenergy generation. Under the NEM tariff, customers receive a bill credit for energy that they generate and export to the grid. This NEM schedule is applicable to a customer who uses a Renewable Electrical Generation Facility as defined below with a capacity of not more than 1,000 kW that is located on the customer's owned, leased, or rented premises, is interconnected and operates in parallel with PG&E's T&D systems, including wind energy co-metering customers as defined in California Public Utilities Code Section 2827.8, and is intended primarily to offset part or all of the customer's own electrical requirements (hereinafter eligible customer-generator or customer). The NEM tariff provides customers with bill credits at the full retail rate for solar PV, wind and bioenergy generation, even though the actual market value of the exported energy is significantly less than the retail credit provided to the customer. Consequently, the costs of the bill credit that exceed the market value of the energy are paid for, *i.e.*, subsidized, by other utility customers. A CPUC analysis estimates that the NEM tariff currently costs other utility customers $79 million to $252 million per year, with the costs increasing to $370 million to $1 billion per year by 2020 at the current 5 percent NEM program transition level. AB 327 directed the CPUC to develop a successor tariff to the current NEM tariff, in order to balance the need to avoid shifting excessive costs to non-NEM customers while at the same time maintaining the sustainability of DERs subject to the NEM tariff.

In R.14-07-002, the CPUC is currently considering NEM tariff changes and is required to adopt changes to the NEM tariff by December 31, 2015. Changes to the NEM tariff that make the pricing of DERs more transparent, equitable and cost-based are needed in order to ensure that DERs subject to the NEM tariff are deployed cost-effectively and in optimal locations without shifting significant costs to other utility customers. These changes to the NEM tariff are essential to achieve the cost-effective deployment of DERs as required by AB 327.

Residential and Non-Residential Electric Rate Design Reform

Similar to the NEM tariff, customers who consider deploying DERs also consider the cost effectiveness of their current electric rates as an alternative to the costs of leasing or purchasing a DER, such as rooftop solar PV. The higher the monthly electric bill of a residential or non-residential customer, the less cost-effective the utility's electric service is compared to the cost of installing and operating a DER. Likewise, if a customer pays a monthly service fee or demand charge to compensate the utility for the fixed costs the utility incurs to interconnect the customer's DER with the utility grid or to stand ready with generating capacity to serve the customer if its DER is not generating electricity (such as rooftop solar PV on a cloudy day), then the cost of the service fee or demand charge must be considered by the customer in deciding whether and where to install its DER.

In R.12-06-013 and other electricity rate design proceedings, the CPUC is currently considering changes in residential and non-residential electricity tariffs that would reform electric rates to ensure that the rates are closer to the costs incurred by utilities to serve customers. These changes are essential to the optimal deployment of DERs under PG&E's DRP. Utility rates that are above cost-of-service or which do not include fixed or demand charges to recover the fixed costs of interconnecting and standing by to serve DERs send inaccurate price signals to DER customers, inequitably shifting costs to other customers. In order for the DRPs to achieve AB 327's goal of cost-effective deployment of DERs, rate design reforms that eliminate cost shifts and return utility rates closer to cost of service are essential.

Rule 21

This Rule describes the interconnection, operating and metering requirements for those Generating Facilities to be connected to the Distribution Provider's Distribution and Transmission Systems over which the CPUC has jurisdiction. It also applies to generating facilities paired with energy storage.

All Generating Facilities seeking Interconnection with Distribution Provider's Transmission System are required apply to the CAISO for Interconnection and be subject to the CAISO Tariff except for: (1) NEM Generating Facilities; and (2) Generating Facilities that do not export to the grid or sell any exports sent to the grid (Non-Export Generating Facilities).

Net Energy Metering

NEM Generating Facilities and Non-Export Generating Facilities subject to Commission jurisdiction must interconnect under Rule 21 regardless of whether they interconnect to Distribution Provider's Distribution or Transmission System. Subject to the requirements of this Rule, the Distribution Provider must allow the Interconnection of Generating Facilities with its Distribution or Transmission System. Generating Facility interconnections to the Distribution Provider's Distribution System that are subject to FERC jurisdiction must apply under

Distribution Provider's Wholesale Distribution Tariff (WDT) whether they interconnect to Distribution Provider's Distribution or Transmission System.

Customer Programs

Non-generation DERs (EE and DR), which do not require interconnection agreements with the distribution system, are implemented through utility-run programs that are approved by the CPUC.

Energy Efficiency Programs

PG&E is a program administrator for a full suite of EE programs, which are funded through modest charges embedded in PG&E's rates – specifically gas Public Purpose Program surcharges, as authorized by Public Utilities Code Sections 890-900, and electric procurement rates, as authorized by the CPUC. EE has long been California's top priority resource to meet new electricity needs. This preference was formalized in the State's first Action Plan, adopted in 2003, subsequently updated in 2005 and 2008. The Action Plan established a loading order of energy resources to meet the State's growing electricity needs first with EE and DR, then with renewable energy and DG, and finally with clean fossil fuel sources and infrastructure improvements.

The loading order concept is consistent with Public Utilities Code Section 454.5(b)(9)(C), which requires IOUs to first meet their "unmet resource needs through all available energy efficiency and demand reduction resources that are cost effective, reliable, and feasible."

To promote the resource procurement policies articulated in the Energy Action Plan and by CPUC, ratepayer-funded cost-effective EE programs are designed to serve as alternatives to more costly supply-side resource options.

The CPUC establishes electricity and natural gas savings goals for the IOUs, pursuant to Public Utilities Code Sections 454.55 and 454.56. PG&E develops its EE program portfolio to meet or exceed these savings goals.

For the 2013-2015 program cycle, PG&E's EE portfolio includes a robust suite of rebates, incentives, services and tools for targeting every customer segment with a comprehensive set of technologies through multiple delivery channels in order to help customers reduce energy usage and save money. These channels include utility staff, government partnerships, trade professionals, retailers, distributors, manufacturers, and other third party providers.

Demand Response Programs

In addition to the rate schedules for DR programs listed below, PG&E also implemented the Aggregator Managed Portfolio (AMP) program, which consist of bilateral contracts with third-party DR providers. Also, PG&E's commercial critical peak pricing program, Peak Day Pricing, is embedded within the rate schedules of the commercial electric customers eligible for the program.

TABLE 5-1
DEMAND RESPONSE PROGRAMS

Rate Schedule	Description	Eligible Customers
E-BIP	Base Interruptible Program	Non-residential customers
E-CBP	Capacity Bidding Program	Non-residential customers
E-CSAC	Commercial SmartAC™	Non-residential customers
E-DBP	Demand Bidding Program	Non-residential customers
E-OBMC	Optional Binding Mandatory Curtailment	Non-residential customers
E-RSAC	Residential SmartAC	Residential customers
E-RSMART	SmartRate™	Residential customers
E-SLRP	Scheduled Load Reduction Program	Non-residential customers

Cost recovery for DR programs is primarily done through distribution rates, the only exception being that AMP incentives are recovered through generation rates.

Energy Storage

Since energy storage can be used in a variety of ways, it is interconnected and procured under a variety of programs and rules. Certain types of standalone behind-the-meter energy storage fall under the utility's SGIP. Behind-the-meter thermal energy storage falls under the utility's PLS Program. Wholesale standalone energy storage connected to the distribution system interconnects under the FERC WDT.

5.b. How Locational Values Could Be Integrated Into Existing Tariffs and Incentive Programs for DERs

The Guidance Ruling solicits recommendations on how locational values could be integrated into current and future potential DER related tariffs and programs.

If and when PG&E's DRP is approved and in addition to the use of locational values for assessing the ability of DERs to defer distribution or transmission capacity additions as discussed in Chapter 2, PG&E intends to use its EE and DR programs to support distribution reliability and renewables integration. This includes the upcoming program cycle and, to the extent possible, any other Integrated Demand Side Management program offerings. Implementation of these components will take place as part of the relevant Commission EE, DR and Integrated Demand Side Resources proceedings underway at that time.

5.c. Recommendation for New Services, Tariff Structures or Incentives for DERs

Except for the changes to residential, non-residential and NEM rates discussed above and in the CPUC's electricity rate design and NEM proceedings, PG&E does not intend, in the near term, to make significant changes to its DER-related tariffs. The changes to DER-related electricity pricing policies are a high priority and essential for successful implementation of PG&E's DRP on a cost-effective and equitable basis. For EE and DR incentive programs, as discussed above, PG&E is already in the process of developing locational targeted components and associated avoided costs. Further, as part of the Demonstration and Deployment proposals in this DRP, PG&E will be developing innovative commercial solicitations and contractual structures to support deployment of distribution connected DERs. These service based contracts will be targeted for specific locations on the distribution grid (wholesale and behind-the-meter interconnections) where it has been identified by the utility that placing DERs in a particular location will provide value.

5.d. Recommendation for Further Refinements to Interconnection Policies That Account for Locational Values

PG&E's DRP incorporates its existing streamlined interconnection policies and standards as approved in applicable Commission proceedings, such as Electric Rule 21, and no changes or refinements are required to interconnection polices to account for the locational values in this DRP.

Chapter 6 – Safety Considerations

6. Safety Considerations

As required by the Guidance Ruling, the purpose of this chapter is to summarize the reliability and safety standards that DERs must meet, changes to those standards that may be required under increased deployment of DERs, identification of how DERs may support higher levels of system reliability and safety. In addition, this chapter describes PG&E's process for coordinating DER safety and reliability standards with local permitting authorities.

Section 6.a. describes the PG&E's current safety and reliability standards applicable to DERs. Section 6.b. describes potential modifications to those standards to support increased DER deployment. Section 6.c. discusses higher levels of system and safety reliability that may be provided by DERs and grid modernization. Sections 6.d. and 6.e. identify major safety considerations that need to be taken into account by DER customers and developers, and potential technical measures to mitigate those risks. Section 6.f. discusses PG&E's education and outreach activities to coordinate its safety and reliability standards for DERs with local permitting authorities.

Although the Utilities must comply with applicable safety and reliability standards in the Public Utilities Code and General Orders, it may be necessary to propose new standards or modify existing standards in order to accommodate high levels of DER. For the purposes of this initial DRP, the Commission has directed the Utilities to include the following:

a. Catalog of potential reliability and safety standards that DERs must meet and a process for facilitating compliance with these standards. Are there different requirements or standards that should be considered for different types of DERs?

b. Description of how DERs and grid modernization could support higher levels of system reliability and safety (*e.g.*, improved SAIDI/System Average Interruption Frequency Index, resiliency, improved cyber security)

c. Description of major safety considerations involving DER equipment on the distribution grid that could be mitigated or obviated by technical changes

d. Description of education and outreach activities by which the Utility plans to inform engage local permitting authorities on current best practice safety procedures for DER installation, so that local permitting of DER equipment is not outdated, onerous or overly prohibitive or limiting of otherwise safely and soundly designed projects.

As the volume of DER interconnections increase, PG&E will continue to re-evaluate its existing safety and reliability standards and, in some cases, may propose new standards to ensure that public and system safety, as well as reliability are maintained. In addition, PG&E will continue to update and expand as necessary the physical and cyber security standards that apply to all third parties who access or interconnect with PG&E's grid, including DER customers and suppliers.

6.a. Current Reliability and Safety Requirements

PG&E's current interconnection requirements encompass reliability and safety requirements for the interconnection of DERs. Specifically, PG&E's Distribution Interconnection Handbook contains the interconnection requirements on how to safely and reliably interconnect distributed generating facilities onto PG&E's electrical system.

All DERs that have the ability to generator / discharge energy must follow the same requirements, *i.e.*, fault duty contribution, isolation requirement from the grid, harmonic distortion, and voltage regulation. Safety and reliability issues are still a concern even when DER does not export onto the distribution grid. The presence of a generating source influences the flow of power and fault currents the same as exporting DER. The Fast Track study screens are designed to determine when generators are well below thresholds to have significant impacts. However, this does not mean that they do not have any impact. When penetration is at certain thresholds, detailed studies must be performed to determine the aggregate impacts regardless of exporting status. The level of detailed review of these requirements is based on the DERs' expected system impact and mitigation. For DG and storage DER, any safety or reliability concerns are identified and mitigated on a project by project basis through the specific Rule 21 and Wholesale Distribution Tariff study screens. An interconnection applicant's permission to operate their generator is contingent on the installation of mitigations identified in the study phase.

6.b. Potential Modifications to Reliability and Safety Standards

Potential modifications to existing reliability and safety standards that PG&E may consider in the future relate to how the increased volume of DERs and their output variability could impact the operating life of utility distribution equipment (*e.g.*, transformer, regulators, and load tap changers). Increased variability could create additional wear and tear on the equipment through increased operations of switching or "tap changes" due to the variability in output. Additional research would have to be conducted in this area before any modifications are considered.

Other potential modifications that should be considered relate to how the interconnection processes for the various forms of DER technologies (Renewable DG, storage, EE, DR, and EV) can be coordinated for interconnection points that involve multiple variations of DER to ensure safety and reliability levels are upheld.

Physical security standards, including those that protect the safety of the grid from both natural events, such as wildfires, and terrorist events, will continue to be enhanced and applied to all activities that affect the grid, including interconnection and access to the grid by DER customers and suppliers.

In addition, cybersecurity standards related to the real-time data exchange between the Utilities and DER operators for the monitoring and control of DERs would need to be enhanced, or are currently being developed and covered in other proceedings and working groups (*e.g.*, Smart Inverter Working Group).

6.c. Higher Levels of System Reliability and Safety From DERs and Grid Modernization

DERs may improve system reliability under a properly set up utility-side microgrid during substation and transmission outages. Feeder microgrids may not improve reliability for feeder outages since all generation on the affected section need to be cleared during an in-section fault.[76] This is to ensure generators do not feed into faulted lines which would degrade public safety and damage equipment.

For potential microgrid operation of the feeder or the entire substation area, protection and control schemes need to be set up on the respective systems for microgrid operation. Breakers and relays need to be installed as necessary. Existing grid-interactive inverters need to be

[76] Facility micro-grids may improve facility reliability but do not count towards utility system reliability metrics because it is a behind the meter occurrence.

retrofitted to enable microgrid operation as needed. Storage or back-up generation needs to be provided to supplement intermittent DER. In the event that there is not enough DER in the designated area to operate in microgrid mode, all of the loads need to be identified that can be shed to enable microgrid operation.

Sufficient DER capacity, including storage, is needed to serve peak local load, 24 × 7 if possible. Due to the low PV capacity factor and storage conversion losses, this may require doubling the size of the available DER capacity to enable full microgrid operation.

Limited local DER operation is needed during hours when DER is generating by setting up standards to isolate the DER from the system. This may enable cell phone charging and refrigerator operation during parts of the day to reduce hardship during multiple day major outages. Current national standards, as well as the Rule 21 Tariff, require the grid interactive units to be shut down during grid outages for safety reasons. But if the DER can be isolated from the grid via a pre-approved control scheme, the DER may be able to serve limited local load without compromising safety.

It is important to note that for DER facilities that are designed for resiliency, the required operating conditions to operate an island do not align with current allowable operating parameters for grid-interactive mode. An analogous situation would be for a "Hurricane Sandy condition." All electric power equipment and supporting structures should be designed to withstand the mechanical stress due to the hurricane and to locate all electrical equipment above flood levels, or a minimum of 10' above ground level. For a "Fukushima scenario", all electrical equipment and structures need to be designed to withstand the expected earthquake and tsunami forces and locate all electrical equipment above the 30' tsunami level. For DER islanding scenarios where the system is expected to operate isolated from the electric grid, the generators need to be designed to operate in an islanded mode. This requires the DER to be able to regulate voltage and frequency, and accommodate the largest motor start without going unstable. Most of these operating parameters are not aligned with the grid-interactive parameters. Also, most of the existing certified grid-interactive inverters are not designed for this mode of operation and may need to be retrofitted or replaced for microgrid operation.

6.d. Major Safety Considerations for DER Owners and Operators and First Responders

As the use of DERs proliferates, First Responders (*e.g.*, fire service, police, emergency medical technicians, etc.) may have a number of areas of concern with hazard mitigation and emergency response. This includes DERs that may introduce new and unexpected hazards to First Responders.

A major safety concern to the public, employee and equipment is the possibility that after a distribution feeder fault, all of the generation connected to that feeder does not isolate from PG&E grid. Thus, the line is not dead.

Some distribution feeders that have large amounts of generation connected to them have a voltage transducer—which can only be added if the feeder has SCADA. A line potential light indicator is added and the Distribution Operator SCADA screen, so the SCADA screen has a bottom that indicates if the line is still hot after the breaker has been lockout. The hot line potential indicator is not required on adjacent feeders used to pick up the load of the faulty feeder. Thus, if a fault occurs on the adjacent feeder that is picking the portion of the line serving the generation, there is no indication that the feeder is electrically de-energized (*e.g.*, disconnected feeder, dead) or electrical energized (*e.g.*, live wire or hot).

As DER technology is enhanced, it will reduce installation complexities and make system installation a simpler task readily available to potential customers. This raises issues regarding DER installations by unregulated consumers (*i.e.*, purchase of self-install kits from a local hardware store). Additional monitoring by safety professionals ultimately may be required to assure safe and proper installations for occupants and First Responders. Unregulated private occupant installations (Unauthorized DER installations) raise questions that are not necessarily within the present regulatory infrastructure (*e.g.*, via building and/or electrical permits). Further attention to this issue will likely be required as these self-installed systems become more common. Specifically, some considerations that first responders and owners / operators of DER should consider are:

DER Owners and Operators

- Certification of DER installer
- On-going maintenance of DER equipment
- Management of any hazardous/flammable materials and equipment
- DER system contact for emergencies

First Responders

- First Responder Training on DER equipment (*e.g.*, types of DER technologies, operating characteristics, how to power down DER equipment, etc.)
- The need to create consistent labeling and signage for First Responders
- Consider DER Equipment always energized.

6.e. Major Safety Considerations Involving DER Equipment on the Distribution Grid That Could Be Mitigated by Technical Changes

A major safety consideration is to ensure all DER – DGs separate from the grid during local feeder faults. However, they do not need to trip for remote out of section faults. For distribution feeders without DER – DG interconnected, following a local feeder fault condition, utilities would trip the feeder breaker during a fault to de-energize the feeder to ensure safety. However, in the future with high penetration levels of DER – DGs capable of back-feeding to the grid, opening the feeder breaker alone is no longer adequate. The utilities would need to have a reliable way to disconnect all of the DER-DGs during a fault. At low penetration levels, utilities are relying on anti-islanding schemes and natural load-gen imbalance to separate DER – DGs from the grid.

However, for high DER-DG penetrations levels along with smart inverters enabled with active voltage and frequency support capabilities render these old methods potentially unnecessary. The utilities would need to have a secure way to ensure all of the DERs (particularly inverter-based DERs) trip off line during a fault. Sandia Labs is proposing a Programmable Logic Controller method to perform this function. The permissive signal is normally present on the feeder but it will go away whenever the feeder breaker or recloser is opened. When the DER senses the absence of the signal, it will trip. Another approach is to broadcast a radio signal to trip the DER – DGs whenever the breaker opens. Also, these signals can be used to open the Point of Common Coupling breaker and still allow the DER to supply the local load, if it is designed to do so.

6.f. Education and Outreach Activities to Inform and Engage Local Permitting Authorities on Current Best Practice Safety Procedures for DER Installation

Since the majority of DER systems are behind the meter interconnections, all permitting responsibilities associated with DERs are the responsibility of the site owner where the DERs are located. However, the utilities do have opportunities to engage the local authorities within their service territory in educating them about the new technologies of DERs and related customer programs involving interconnection of DERs that are available for consumers in their respective communities. This type of education would provide the Local Authorities an opportunity to learn more about a specific DER technology, as well as educate them on what type of impacts locating this type of technology has on their respective communities.

Another opportunity for Utilities and Local Authorities is better coordination of the local permitting process with the Utilities DER interconnection application process to further streamline the consumer’s DER interconnection experience through the use of online portals.

Chapter 7 – Barriers to Deployment

7. Barriers to Deployment

Public Utilities Code Section 769 and the Guidance Ruling require each IOU to identify barriers to the deployment of distributed resources, including, but not limited to, safety standards related to technology or operation of the distribution circuit in a manner that ensures reliable service. The purpose of this chapter is to identify and describe three categories of barriers that are related to PG&E's electric utility services and distribution grid:

a. Barriers to integration / interconnection of DERs onto the distribution grid;

b. Barriers that limit the ability of a DER to provide benefits; and

c. Barriers related to distribution system operational and infrastructure capabilities.

Currently, there are a number of issues that can slow or otherwise develop into barriers to the integration of reliable, cost effective DERs onto the distribution grid. Addressing these barriers will not be an easy task, and in some cases may present significant challenges and costs, which may take several years to fully achieve. The IOUs, the Commission, and DER market participants will need to continue thoughtful collaboration and coordination in developing tailored recommendations and actions to realize continued successful integration of DERs. Each of these barriers is further evaluated below using the following categories of barriers consistent with the Guidance Ruling:[77]

- **Statutory and Regulatory** – Statutory prohibitions (*e.g.*, inability of a large campus with a single master meter to deploy more than 1 MW of NEM); regulatory rules or processes that increase the cost of DER deployment, reduce the cost-effectiveness of DERs, inequitably allocate the costs of DERs, or limit DER functionalities.
- **Grid Insight** – Lack of visibility into distribution system conditions, Bulk Electric System conditions, or actual performance of DERs that limit DER deployment or operations.
- **Standards and Safety** – Inadequate or undefined standards; safety standards related to technology or operation of the distribution circuit
- **Benefits Monetization** – Lack of a mechanism to monetize DER benefits or equitably recover DER costs

[77] For convenience of review, PG&E has combined some of the Guidance Ruling's categories of barriers that are substantially similar.

- **Communications** – Lack of a communications link between DERs and utility grid operators, which limits deployment or benefits-monetization of DER.

7.a. Barriers to Integration/Interconnection of DERs Onto the Distribution Grid

PG&E defines barriers to integration of DERs as issues that limit the IOUs' ability to cost effectively integrate DERs into the planning and operation of the distribution grid. Barriers to interconnection are defined as issues that are related to the operational requirements and other processes for interconnecting DERs that do not relate to whether the DERs provide direct distribution-related benefits. PG&E considers these barriers related to the sub-categories of **Standards** and **Safety**. The following sections describe the status of these different integration and interconnection barriers at PG&E.

7.a.i. Barriers to Integration Onto the Distribution Grid

PG&E has identified the following integration barriers for evaluation in its DRP:

- Reliance on DERs to address distribution capacity and reliability needs
- Predicting future DER adoption in order to reduce impacts of DERs on grid reliability and safety
- Detailed modeling of multiple DER technologies and behind-the-meter resources in order to ensure that customers realize the value of their investment in DERs
- Large scale integration of DERs that impact transmission planning and operation

7.a.i.1. Reliance on DERs to Address Distribution System Capacity and Reliability Needs

A barrier to cost effective deployment of DERs includes whether DERs can be incorporated into distribution planning in order to meet PG&E's distribution capacity and reliability needs. Historically, PG&E has incorporated existing DERs into the base assumptions and forecasts in its respective distribution planning models. Specifically, distributed solar PV and EE have been the largest contributors to reduced distribution load in PG&E's ongoing distribution planning and routinely factored into PG&E's distribution planning analyses and forecasts.

In order to realize the benefits that DERs may provide, as well as to ensure that the most cost effective options for distribution capacity and reliability are being considered, PG&E's DRP will develop distribution planning standards that consider DERs as potential alternatives to traditional distribution capacity and reliability investments. To effectively include DERs as potential alternatives, PG&E's distribution engineering standards will be updated to cost effectively consider both existing and forecast DERs as potential tools to mitigate projected distribution deficiencies.

In addition, PG&E's engineering standards will include specific and transparent DER performance criteria to ensure that distribution grid safety and reliability are maintained by cost effective DERs. These DER performance criteria may vary from location to location on the distribution grid depending on the specific local distribution grid needs and attributes (*e.g.*, loading profile). DER is currently not held to any constraints of staying online and compensated purely on energy production. This might be sufficient for the energy generation component of locational benefit, but if a DER is to provide locational benefit on the other components then they must meet the requirements of each component. For example, if a solar technology is trying to provide capacity benefits there could be issues if the capacity needs occur during hours when solar production is non-existent. Figure 7-1 helps provide a visual of how a DER might have to utilize extra components to assure it can meet benefit needs. This figure shows how solar itself cannot meet the capacity needs in this location. It requires additional operating constraints and/or DER pairing components to meet the need. It will be the intent of the performance criteria to outline these needs and requirements.

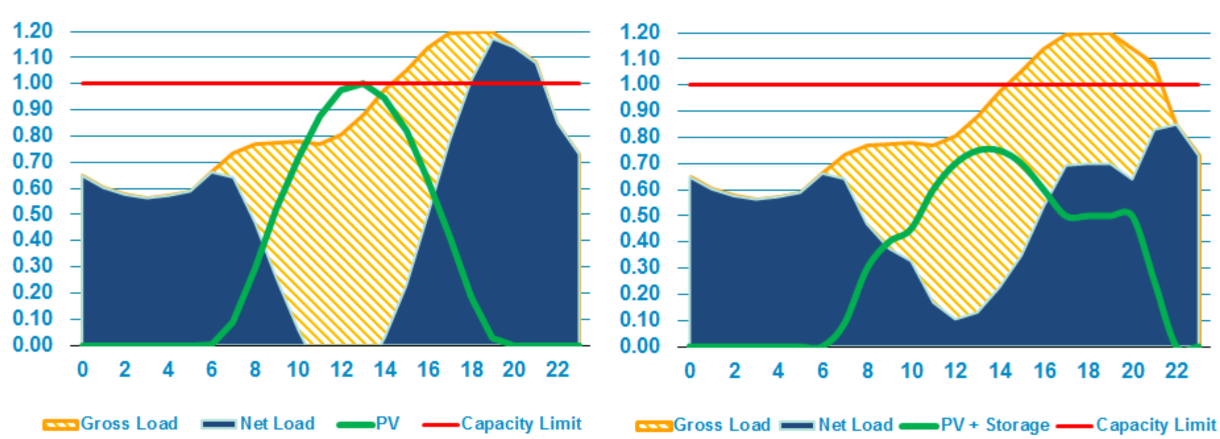

FIGURE 7-1: DER MEETING PERFORMANCE REQUIREMENTS AND CRITERIA

These performance criteria also will include up-front guidance to DER developers and customers about the availability and reliability of the DER or DER portfolio to be able to perform the specific criteria needed to maintain the safety and reliability of the grid. PG&E also may provide backstop criteria for redundancy in the event cost effective DERs or a DER portfolio are not able to meet the required grid performance criteria.

To address this barrier (**Standards** and **Safety** related), PG&E has updated its distribution planning standard to evaluate DERs as alternatives to traditional distribution investments for addressing distribution capacity issues.

7.a.i.2. Predicting Future DER Adoption

Some **Grid Insight-**related limitations and uncertainties affect PG&E's ability to forecast local DER adoption, which limits the ability of DER developers and customers to provide cost effective integration and benefits of DERs, including providing the right service, at the right location and at the right time.

First, the accuracy of forecasts of future DER technology adoption will depend on modeling both the complexity of consumer behavior and DER technology economics from the DER customer's or developer's perspective. Although there is some market information around DER adoption, there are limitations to using projected adoption patterns to forecast future DER capacity at the level of granularity needed for distribution planning. For example, adoption trends, both local and system-wide, are dynamic (*i.e.*, future adopters may be different from existing adopters) which limits the accuracy of using historical adoption trends to forecast future DER growth.

Second, regulatory policy inequities and uncertainty regarding pricing of DERs in the marketplace (*e.g.*, NEM successor tariff and SGIP) drives additional uncertainty in forecasting future DER adoption (**Benefits Monetization**). Also, because a number of DERs are emerging technologies that are not yet of commercial scale or mass marketed, other factors such as subsidies for pilot projects or research and development may drive future adoption in PG&E's service area. Not all customers are homogenous and could have very different interests and perspectives relating to energy. The same will be true for new DER technologies. A one size fits all approach for pricing may not be able to effectively meet the specific needs and desires of all customers.

Lastly, limited market penetration is a barrier to accurately predicting the future growth of DERs. For example, the current level of energy storage installations is fewer than 500 projects, while the NEM rooftop solar program is well over 170,000 installations within PG&E's service territory. Predicting consumer behavior is not an exact science because of the multiple economic and non-economic factors in consumer decision making.

7.a.i.3. Detailed Modeling of Multiple DER Technologies Behind the Meter

In addition to the challenges of predicting future DER adoption, another **Grid Insight** barrier that PG&E's DRP identifies is the modeling of DERs' actual operations and performance for the use of distribution planning. With the potential adoption of multiple DER technologies situated behind a customer's meter, such as storage, DR, and EVs, PG&E and DER customers and aggregators need to collaborate on standardized metrics for reporting and monitoring of the actual daily and / or hourly performance of individual and aggregated DERs and their impact on distribution grid operations. To begin to address this barrier so that customers and aggregators may realize the full benefits of their DERs, PG&E's DRP will develop modeling and reporting standards for monitoring DER adoption and operating performance over time for accurate and transparent assessment of distribution grid impacts.

7.a.i.4. Integration of DERs Into Transmission Planning and Operation

As more DERs interconnect and integrate onto the distribution grid, impacts on the overall reliability and operability of the transmission grid, including transmission market operations, may become an additional **Grid Insight** barrier that will need to be addressed by DER customers and developers, the CAISO and PG&E. Currently, the CAISO has visibility (*e.g.*, ability to monitor generator output and status) into wholesale generation participating in the wholesale energy markets within California. However, the CAISO does not have visibility into behind-the-meter DERs (*e.g.*, load masking). As a result of this, the CAISO may experience challenges in ensuring the state's demand and supply (generation resources and imports) are in balance to ensure overall transmission grid stability in California and throughout the Western bulk power system. In addition, with the continued growth of DERs, the transmission grid could expect to experience higher sustained voltage levels that would require additional mitigation to avoid creating reliability and operability issues on the transmission grid.

To address this barrier consistent with the Guidance Ruling's requirement for coordination with the CAISO, PG&E's DRP recommends that a coordinated transmission planning study be performed by the CAISO, in collaboration with the CPUC, the investor-owned and publicly-owned utilities, interested representatives of other Western utilities, and other stakeholders, assessing the overall California transmission grid's reliability and operability under various DER growth scenarios that are included in PG&E's and the other utilities' DRPs. This study should then be used to inform how the DRPs in this proceeding should be coordinated with bulk power system planning and reliability, as well as develop overall policy recommendations on how DERs should be integrated onto the California and Western transmission grid.

Another **Grid Insight** issue related to DER integration onto both the T&D grid is the uncertainty regarding short term locational forecasts of actual DER power delivery (*e.g.*, unpredictability of solar DG power deliveries is an issue for both distribution and transmission operators).[78] Much effort can be done to forecast and estimate the amount of DG that is exported at a given moment, but the lack of visibility regarding the exact amount of PV energy reduces the value of PV energy deliveries because of the need to mitigate grid impacts for resources they have no control over. PG&E's DRP recommends further collaboration among the CAISO, utilities and DER stakeholders to provide objective operating data reporting and monitoring to mitigate this barrier.

7.b. Barriers to Interconnection of DERs Onto the Distribution Grid

As mentioned in the previous section, PG&E has defined "barriers to interconnection" as issues that are related to the processes for interconnecting DERs to the distribution grid without regard to whether the DERs provide distribution-related benefits or not. PG&E has identified the following interconnection barriers for discussion:

- Interconnection Process
- Integration Capacity
- Permitting

[78] PBS Newshour. 2015. http://www.pbs.org/newshour/bb/gridlocked-power-grid-hawaiis-solar-energy-industry-crossroads/.

7.b.i. Interconnection Process

Prior to this DRP, PG&E has experienced rapid growth of DERs in its service area, requiring early on that it manage and update the interconnection process as a major pathway to enabling customer choice to interconnect DERs. Typical interconnection times in the United States are about 50 business days, according to recent analysis of 87 utilities.[79] At PG&E, consistent investments and interconnection process improvements have reduced interconnection times (**Regulatory and Standards** categories). Figure 7-2, Standard NEM Cycle Times, below illustrates PG&E's continued efforts to maintain a low interconnection timeframe for Standard NEM (30 kW or smaller wind and PV generation) projects, its most voluminous program. For example, in 2014, Standard NEM projects experienced a median interconnection timeframe averaging only four (4) business days after completing their interconnection application and barring any system and safety upgrades. By developing an automated application process (the NEM Web Portal), which was formally launched in early 2015, PG&E has removed a key barrier to DER adoption, growth and deployment.

[79] Ardani, K. et al. (2015). "A state-level comparison of processes and timelines for distributed photovoltaic interconnection and the United States." National Renewable Energy Laboratory. NREL/TP-7A40-63556. http://www.nrel.gov/docs/fy15osti/63556.pdf.

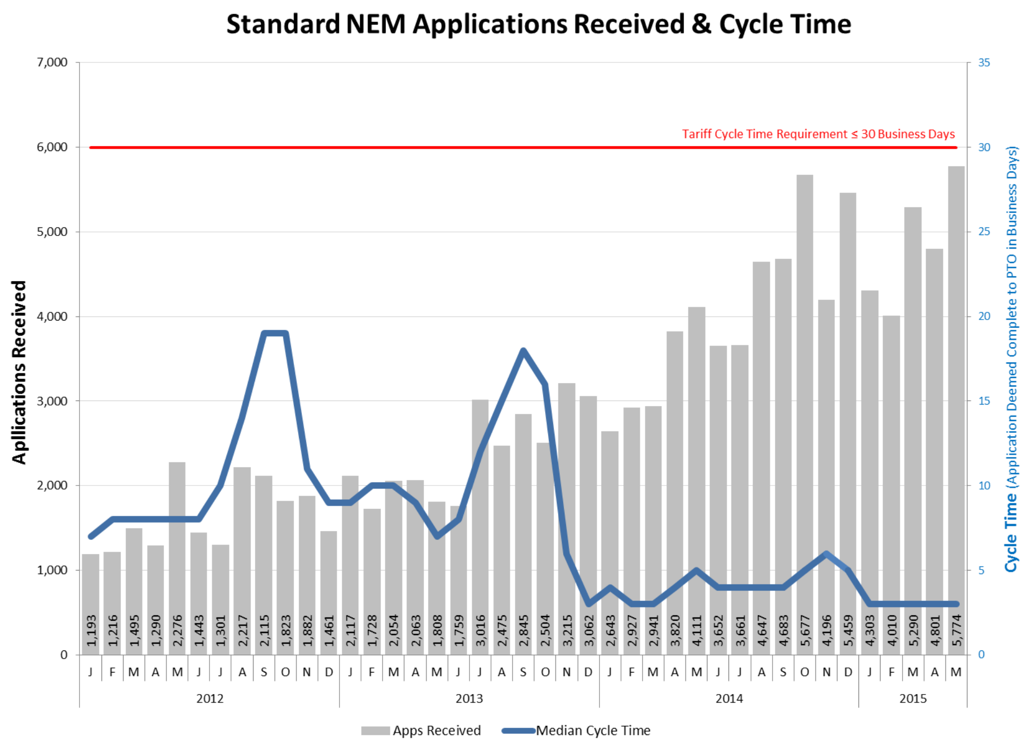

FIGURE 7-2: STANDARD NEM CYCLE TIMES

Although PG&E has overcome most barriers associated with interconnection delays, these improvements were not easy and took several years of consistent investments in process improvements, IT upgrades, staff training, and learning to achieve PG&E's industry-leading interconnection time.

New tools now also offer more automated processes in evaluating Rule 21 and wholesale generator DG applicants within PG&E's service territory. Continued investments, process advancements, and experience will further enable PG&E to improve and efficiently support safe and reliable interconnections of DER technologies by third-parties. During the past few years, the striking levels of cost reductions in solar energy technologies have led to higher-than-anticipated adoptions of DG solar in PG&E's service area and elsewhere in California, which have resulted in significant interconnection challenges in some markets.[80] Interconnection process improvements must combine both the forecasted local and dispersed levels of increasing DER adoption, which is challenging to anticipate for reasons discussed earlier, with

80 Some delays in Hawaii exceeded two years.

development of new and improved tools and resources needed to respond to customers' expectations that DERs will be interconnected "faster, cheaper, better."

FIGURE 7-3: BASIC INTERCONNECTION PROCESS

Core near-term challenges regarding interconnections involve the uncertainties of new DER attributes and rates of adoption, anticipating when the size and location of DERs may trigger the need for interconnection studies, and coordinating consistent and transparent standards among stakeholders, regulators and the utilities. For example, regulators typically need time to assess and respond to new technology innovations, and the timing of regulatory standards heavily influence overall utility response times. PG&E's DRP assumes that well-coordinated, multi-stakeholder engagements will continue to serve an important role to advance interconnection processes. A current example is the current regulatory and stakeholder proceedings to establish interconnection standards and tariffs for energy storage. Clear regulatory direction on how to evaluate the complexities of interconnecting energy storage onto the distribution and transmission grid is needed before interconnection timeframes can be standardized. PG&E is working on solutions to this barrier in the Energy Storage Proceeding (R.10-12-007).

7.b.ii. Integration Capacity

Integration Capacity is a **Grid Insight** issue for DER customers and developers who must balance local site availability and customer preferences with local line capacity to accommodate an interconnection project without triggering expensive upgrades that make the project uneconomic or infeasible.

As discussed in Chapter 2, prior to this DRP PG&E has put information on local distribution capacity in customers' hands through the publicly available RAM map, as well as providing Pre-Application reports, allowing a customer to see general system information affecting their preferred interconnection location. PG&E provides customers with Pre-Application data quickly and efficiently, including more information than required by the tariff.

The Pre-application is a convenient tool for customers to obtain details about a specific DER interconnection location. However, despite all the information the Pre-application provides, it is not designed to determine a capacity value that avoid significant distribution grid impact. For this reason and as described in Chapter 2, PG&E's DRP proposes to enhance the tools available to customers by including integration capacity results paired with the Pre-application information in order to assist DER customers and developers to make more informed siting decisions based on additional transparent data.

By putting its Integration Capacity Analysis in the hands of DER customers and developers, PG&E's DRP will reduce the amount of guesswork in identifying suitable locations for DERs, and in turn reduce the amount of studies required to determine project impacts to the grid. As mentioned in Section 2.b.iv., if customers have a higher confidence that their project is feasible (i.e., likelihood of mitigating upgrades) at the outset of the interconnection process, it will result in more efficient utilization of everyone's resources.

The tools PG&E uses for the Integration Capacity Analysis can determine the effects and impacts of the components of Integration Capacity at a local feeder level, but those components are currently not yet at a level of detail sufficient to determine exact interconnection issues that instead can be found using detailed studies. The integration capacity results will help DER customers and developers know where to connect their DERs relative to other locations and feeders. It also will provide capacity values that can guide the customer to a general range of sizes that are likely to not cause significant impact to the grid.

An important aspect to consider is operational flexibility which is related to the load masking issue. Figure 7-4 depicts the load masking issue which exacerbates the operational flexibility issue.

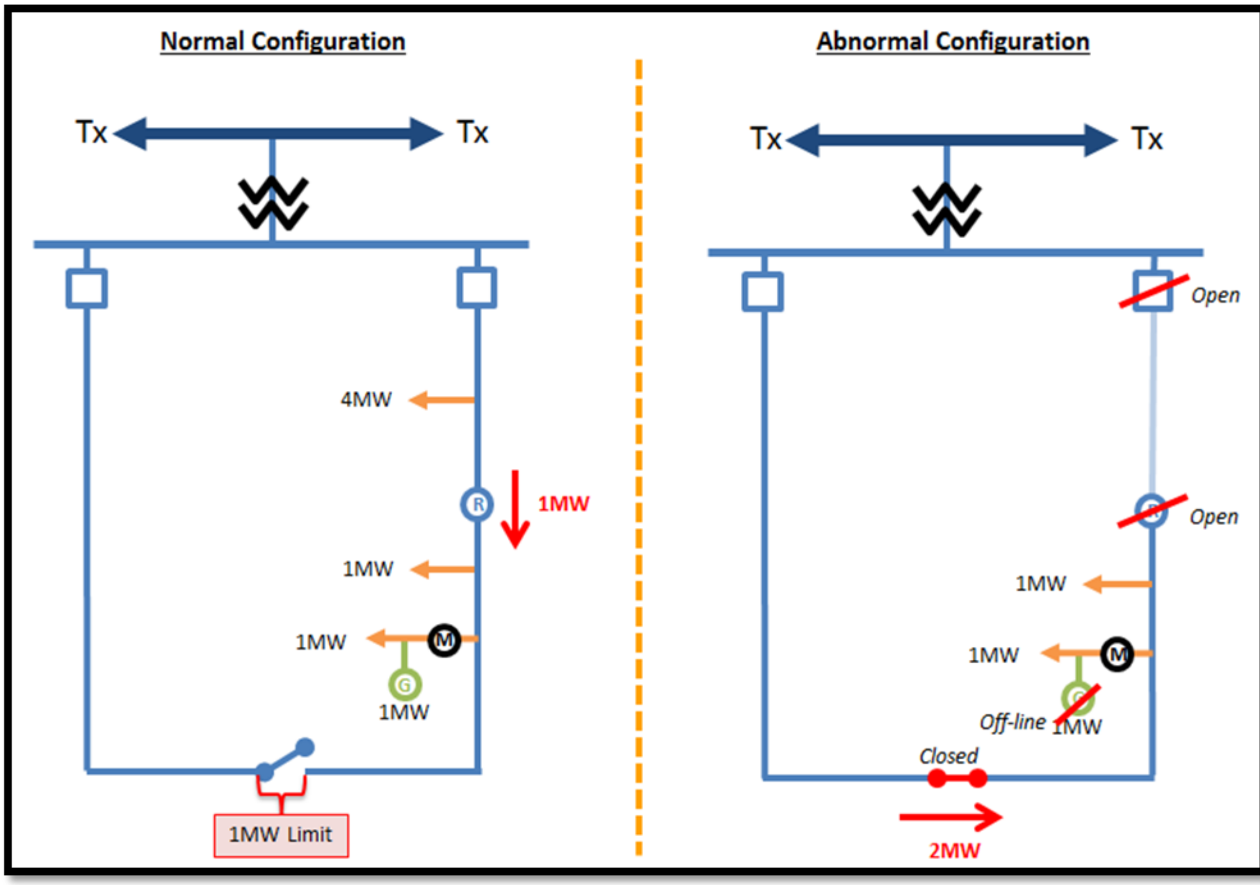

FIGURE 7-4: LOAD MASKING SCENARIO

All these improvements will allow for more transparency and customer involvement in the interconnection study process and thus make it more efficient for all participants. For interconnection customers requiring a detailed and reliable interconnection study prior to moving ahead with the execution of their projects, the option is to undergo a six to nine month Detailed Study Process.

7.b.iii. Permitting

A **Statutory and Regulatory** barrier in the interconnection process is obtaining local governmental permit approvals in a timely manner. Obtaining local approval from the local jurisdictional authority is a critical step for customers to ensure that the interconnection work on the customer side of the meter is installed and performed in a safe and reliable manner. This work would include all wiring on the customer's side of the meter as well as installation of the DER equipment on the customer's premises (*e.g.*, PV panel mounting on property). According to feedback PG&E has received from the PV installer community, the cycle time to obtain local permits for a roof top solar installation has become one of the longer lead time items and barriers to timely DER deployment.

PG&E's DRP does not address policies for streamlining the permit process, because those processes are within the control of local jurisdictions. However, the permitting process requires coordination between the DER installer and the local jurisdictional agencies to review and inspect the behind the meter interconnections to ensure that those interconnections comply with current interconnection and electrical codes. The delays in obtaining local permit approvals are a barrier that PG&E's DRP acknowledges and recommends that the Commission and stakeholders address directly with local permit agencies.

7.c. Barriers That Limit the Ability of DERs to Provide Benefits

In order to develop opportunities for DERs to realize net benefits, it is important to identify any barriers that limit the ability of DERs to provide either resource or grid benefits (**Regulatory , Standards, and Benefits Monetization** categories). The following is a listing of some barriers identified and within the scope of PG&E's DRP that limit the ability of DERs to provide resource or grid benefits:

- DER Equipment Operational Limits
- Tariffs and Rates
- Resource Availability and Intermittency
- Measurement of EE Benefits

7.c.i. DER Equipment Operational Limits

Operational constraints on DER equipment can serve as a significant barrier (**Standards** barrier) to DER deployment. Transitioning from analog to digital systems, developing and installing real-time controls and telemetry closer to customers, and supporting a multitude of variable generation resources operating under dynamic conditions through the installation of additional sensing and control technologies are all critically important to meet DER operational limits.

Current Institute of Electrical and Electronics Engineers (IEEE) and other operational guidelines specify applicable standards for DER equipment and prohibit DER from actively controlling voltage to simplify interconnection and minimize the need to coordinate with existing voltage regulation equipment at low penetration levels. The Smart Inverter working group, held jointly by the CEC and CPUC, revised the previous low penetration Rule 21 requirements to new smart inverter requirements that are compatible with high DER penetration. The national standard, IEEE-1547 is also under revision to allow high DG penetrations without adverse system impacts. These efforts naturally will work their way into DERs' ability to influence power quality and reliability, but another aspect of this is utility procedures and methods applied to islanding and distribution operational issues.

PG&E is working with the Smart Inverter working group to develop two main components for all future interconnected inverters to use: (1) Ride through features; and (2) Voltage control. The ride through features will allow inverters to operate longer and not shut off during major system events. Voltage control will allow inverters to dynamically inject/absorb reactive power into the grid to actively control voltage within prescribed limits. This mode will be more complicated and require close coordination between the various DERs with automatic voltage control capability and the existing voltage regulation devices. However, the higher penetration levels of DERs may be able to materially affect voltage to a degree not possible at lower penetration levels. Previously, this functionality was not possible or is very limited due to the overly restrictive requirements of national electrical operating standard, IEEE-1547. In an effort to start updating this standard, an amendment, IEEE-1547a, was instituted in 2014 to allow active voltage regulation only if coordinated with the local utility. When a DER has the ability and permission under applicable operating standards and in coordination with the local utility to actively change distribution voltage, then it may have the ability to directly affect distribution voltage and power quality up to the capability of the DERs, as well as mitigate voltage issues that may arise due to the interconnection/operation of the DER.

Currently, PG&E is still at relatively low system penetration levels and the existing DER facilities are designed to rely on the grid for voltage and frequency regulation as well as back-up power support. Inverters are also designed to trip off line, via certified anti-islanding scheme, during system events to prevent DER from back-feeding and energizing downed conductors. These anti-islanding schemes bypassed the need for typical protection and interconnection requirements required by non-inverter based generators. This mode of operation works well at low penetration levels and simplifies the interconnection process but significantly degrades the reliability of the system at high penetration levels. It also may be a barrier to capturing the full benefit of DERS, such as microgrids, at high DER penetration levels. The current grid-interactive inverters are designed to require anti-islanding by default. This prohibits its ability to operate as a standalone island as it may need to be coupled with a strong source, such as a synchronous generator, to sustain a stable island and not activate the anti-islanding triggers. Smart Inverters and DER portfolios are starting to be designed in ways that allow local facilities to isolate from the grid automatically for intentional islanding to serve the local load during outages. Conceptually these functions could be scaled up to operate on distribution gird levels to be used to improve resiliency during major disasters. But most of the DERs were designed for grid-interactive mode and not designed for intentional islanding at this time. Communication based anti-islanding signals have potential to provide a solution to high penetration islanding concerns. These signals ensure that, in the event of a feeder trip, the DERs can be isolated from the grid quickly and/or initiate the formation of a microgrid on command based on utility signals. This way, the feeder safety is preserved and the microgrids can be formed quickly.[81]

7.c.ii. Limitations of Tariffs and Rates

PG&E's system average rates reflect average system costs, and the Public Utilities Code bars rates that unreasonably differ between the location of the customer, or that are not reasonable (**Regulatory** and **Benefits Monetization** barriers). As discussed in Chapter 5 – Tariffs and Contracts, electricity pricing policies that are not based on cost-of-service or which otherwise inequitably shift costs from DER customers to other customers, such as under current NEM tariffs, need to be changed in order to ensure that DERs deployed on PG&E's distribution grid are cost-effective, as intended by Public Utilities Code Section 769. The lack of cost-based and equitable rates for DER energy is a significant barrier to achievement of cost-effective, economically efficient deployment of DERs under PG&E's DRP.

Although the value components of DERs that may defer distribution or transmission capacity additions may be location-specific as discussed in Chapter 2, the rates for the resource components of the DER would need to be specific to the distribution planning area or even to

[81] At the June 1-3, 2015, IEEE-1547 working group meeting, anti-islanding was identified as an issue that needed to be addressed in the current standard revision process. Currently this working group is looking at the potential of using communication based anti-islanding schemes.

the circuit to be effective. This could require significant versions of rates by area which may be infeasible.

7.c.iii. Resource Availability and Intermittency

A barrier to deployment of DER is that most DERs are controlled by customers or third-party non-utilities and thus there is no assurance that the DER will be available when required to provide safety and reliability benefits to the grid (**Benefits Monetization** barrier). For DERs to provide an optimized, compensable benefit, they need to be controlled and managed to ensure that they are not compensated if they are not available when needed. This applies particularly to the intermittency of certain renewable technologies, such as solar PV. The availability and intermittency must be properly evaluated in order to establish accurate pricing of the net localized benefits of DER resource availability and adequacy. Combined technologies that mitigate the risk of non-performance can assist in providing a more reliable resource, but there still must be a structure in place to penalize/incent DERs to make sure they are available when such benefits can be realized.

A related barrier is the difficulty in accurately analyzing the level of adequacy and reliability required from a DER. As part of this DRP, PG&E is proposing methods and demonstration projects that will test the ability to analyze DER distribution benefits based on their expected local availability and reliability. These methods and demonstrations may result in more effective DER capability numbers that can be used rather than speculative, unverified best or worst case capabilities.

7.c.iv. Measurement of Energy Efficiency Benefits

Current rules for nearly all ratepayer-funded energy efficiency projects require that energy savings benefits be measured from a building or appliance code baseline (*e.g.*, 2013 Title 24) or, for industrial energy efficiency projects, from an industry standard practice (ISP) baseline. This is not a true reflection of a project's real energy savings because they do not include the savings from bringing equipment or facilities up to the code or ISP level (**Regulatory** and **Benefits Monetization** barriers). In many cases, these to-code savings can be the majority of project energy savings because as building codes and appliance standards increase efficiency levels over time, existing buildings and equipment are not required to upgrade. The difference between measured energy savings (*i.e.*, only above code energy savings) and real energy savings can be especially large when energy efficiency projects target equipment or buildings that have not been brought up to code in a long time or when control systems are installed that are part of 2013 Title 24. In the latter case, no energy savings from control systems are considered above code, no matter how large. This creates a barrier and a risk. The barrier is that because incentives are set relative to the beyond code savings, EE program administrators are unable to offer attractive incentives for buildings or facilities with a significant to code savings to upgrade, even though the incentives are cost effective. The risk is that when EE projects are completed, the impact to the grid will be substantially greater than what is claimed by the EE program (load masking).

7.d. Barriers Related to Distribution System Operational Related Infrastructure Capability to Enable DER Related to Investment in Advance Technology (Advanced Protection, Control and Sensing)

Over the last several years, PG&E has successfully invested and deployed Smart Grid solutions that innovatively manage and improve electric service delivery and reliability with cutting edge technology. Going forward, in order to deploy increasing amounts of DERs, PG&E's future DRPs will consider and potentially propose additional investments in the area of advanced protection and control systems, telecommunications, Information Technology (IT) and real-time grid sensing to enhance the distribution system as DER adoption permeates PG&E's system. PG&E and DER customers and developers will face barriers (**Communications** and **Grid Insight** barriers) in distribution system operational capability if these advanced technologies are not in place to be able to effectively and reliably operate the distribution system. These investments will be ongoing and integrated with existing modernization investments. These investments and associated requirements for advanced protection and control systems, telecommunications, IT and real-time grid sensing are described below:

Operational Communications

Operational communications requirements are evolving based on a more highly distributed power system. The increasing need is for highly available, low latency[82] fiber networks to link substation and control center operations, as well as robust, secure wireless field area networks to support distribution automation, mobile field force automation, and DER integration leveraging PG&E's existing multi-tier smart metering communication system.

State Measurement

State measurement with forward-looking state measurement and operational decision support tools can help grid operators manage dynamic operating conditions. As distribution sensing technology enables synchronized measurements to be collected, state measurement can enable greater operational reliability for a distribution system with significant amounts of integrated DER already being experienced on several distribution feeders and more broadly envisioned in California. The state measurement, using perhaps distribution phasor measurement units (PMU), will feed PG&E's existing grid situational awareness capabilities. This is not unlike what PMUs have done for transmission system engineering and operations.

Distributed Energy Resource Management System

In the near term, however, to support the benefits and operational demonstrations there is a need for a DERMS that augments our existing distribution management system to provide the distributed controls necessary for the integrated operation and optimal dispatch of a portfolio of DER provided distribution services.

DERMS software solutions are commercially available and can provide distributed control and optimal dispatch to support PG&E's near term demonstration projects as well as future growth of flexible DER on its system. A DERMS platform can enable PG&E to integrate a wide variety of flexible DER (*e.g.*, energy storage, DR, smart inverters, DG, EV chargers) into real-time operations to assess their effectiveness and to determine costs and benefits of these resources in support of the Pub. Util. Code Section769 requirements.

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[82] Latency refers to the time from the source sending a voice/video/data packet to the destination receiving it.

To accomplish a seamless integration of these resources, a DERMS platform should provide the following key capabilities.

Multi-Layer Optimization

The ability to optimize DER performance at multiple layers in the system hierarchy (*i.e.*, customer, circuit, feeder, substation) in order to provide optimal power system performance based on local or regional requirements. This includes local optimization as well as distribution area, regional and system wide power system optimization applications delivered through DER portfolio optimization. The ability to optimize for multiple grid services with the same infrastructure enables a lower cost of ownership.

Constraint-Based Forecasting and Control

The ability to operate DER assets within the operating constraints set by the aggregator and / or customer assets or site performance characteristics. This provides advanced algorithmic processing and dynamic and continuous asset control without disrupting customer operational constraints and conditions. DERMS systems can compute optimal set-points for up to 1 million DER every two seconds based on energy, power, reactive power, voltage and phase-angle control parameters.

As such, a wide range of DER provided distribution grid services with different performance requirements and unique time dimensions can be managed with a DERMS platform, including:

- Distribution capacity deferral services
- Voltage and reactive power services
- Power quality services
- Reliability services

Distributed Architecture

An architecture that is designed to match the highly distributed nature of DERs. This architecture provides a comprehensive and robust cyber-security model that is designed into the core of the platform. Such a lightweight distributed computing framework provides both low-latency and highly resilient services due to the distributed nature of the computations.

This also allows a network management approach to system monitoring and deployment leading to an easily scalable deployment model. This type of platform is inherently a least regrets type of investment that is capable of supporting the optimizing the value of DERs in the future.

7.d.i. Conclusion

Expanding DER markets face issues that could potentially slow the transition to higher levels of DER deployment onto electric distribution grids. However, opportunities are available to plan for and mitigate these barriers. Interconnection and integration considerations, the tracking and monetization of net benefits through equitable and cost-based electricity pricing, and distribution system operational and infrastructure considerations are all potential barriers to assess. PG&E will play an essential role to address these barriers, and will continue to do so as advancements and policy designs lead to more DER deployment onto PG&E's distribution grid. By participating in multi-stakeholder processes and adapting to DER developments using the best-available analytical planning tools, PG&E's DRP will achieve its vision for effective distribution resource planning and the Grid of Things™.

Chapter 8 – DRP Coordination With General Rate Cases

8. DRP Coordination With General Rate Cases

In compliance with Public Utilities Code Section 769(b)(4) and (d) and the Guidance Ruling, the purpose of this chapter is to describe how PG&E's DRP will be coordinated with PG&E's GRC filings which provide that PG&E's investments and expenditures for electric distribution capacity and other capital projects are identified and reviewed every three years in PG&E's Phase 1 GRC.[83]

PG&E's GRCs will include an evaluation of its proposed distribution capital investments and forecast expenditures for distribution planning, consistent with the available distribution tools, methodologies and criteria in this DRP. As required by Public Utilities Code Sections 353.5 and 769, PG&E's GRCs will consider non-utility DERs that may provide alternatives to investments in PG&E's distribution system, as well as identify additional spending for distribution capacity additions that are needed to integrate cost-effective DERs onto PG&E's grid.

Under this coordinated approach, there is no need for separate Commission proceedings to update the utilities' approved DRPs, because each utility's DRP investments and expenditures will be evaluated in each utility's GRC consistent with the overall criteria established by the Commission in approving the initial DRPs. This coordinated approach also ensures that the approved DRPs are "hard-wired" to each utility's distribution planning processes and budgets which are reviewed and approved in their triennial GRCs. Finally, this coordinated approach saves the time and resources of the Commission and stakeholders, because there is no duplication of effort between the DRP proceedings and the utilities' GRCs, where distribution capacity plans are reviewed and approved.

In addition, for the demonstration projects proposed in Chapter 3, PG&E recommends that the Commission authorize funding through an advice filing using procedures similar to approval of projects under PG&E's triennial EPIC plan.

[83] In exceptional cases where PG&E needs more rapid approval of DER-related distribution capacity investments, it can file a separate application from its GRC.

8.a. DRP Related Investments to Be Included in PG&E's 2017 GRC

The Guidance Ruling directs PG&E to describe any specific actions or investments that may be included in its next GRCs as a result of the DRP process. With the development of the new analytical distribution planning frameworks related to Integration Capacity and DER growth scenarios, PG&E has identified the following actions and investments that will be included in PG&E's 2017 GRC filing are: (a) DER Integration Capacity; (b) Volt/VAr Optimization; and (c) other DRP-related investments and expenditures that will be identified in PG&E's 2017 GRC filing.

Chapter 9 – DRP Coordination With Utility and CEC Load Forecasting

9. DRP Coordination With Utility and CEC Load Forecasting

Pursuant to the Guidance Ruling, the purpose of this chapter is to describe how the results of the DRP will influence PG&E's own internal load forecasting, the CEC IEPR load forecast, and by extension, the Commission's LTPP and the CAISO's TPP. The Guidance Ruling further notes that the DRP process will result in greater granularity and accuracy in utility forecasting of DERs impact on load. Therefore, the more granular load forecasting will likely impact PG&E's input to the CEC's IEPR forecast.

At this juncture, the most effective way to ensure coordination between the DRP results and PG&E's internal forecasting, CEC IEPR load forecast, and by extension the CPUC's LTPP process and the CAISO's TPP is to identify how DER input assumptions for each DER type are developed or adopted in each process, which ultimately inform the DER Growth Scenarios in the DRP. That way, each utility can ensure that the DER assumptions for the DRP's DER Growth Scenarios are not only coordinated and consistent with PG&E's internal load forecast, the CEC's IEPR process, CPUC's LTPP proceeding and the CAISO's TPP, but also ensuring that each DER is being properly tracked and accounted for.

As noted in the growth scenarios section, PG&E's growth scenarios are currently not "forecasts" but can be help PG&E distribution planners anticipate potential future DER deployment locations using DER market penetration trends. PG&E will continue to improve the growth scenario modeling to improve the granularity of load forecasting and ultimately provide input to the CEC's IEPR forecast.

This section describes how the inputs used to develop the DRP results will be coordinated with PG&E's internal forecast process, the CEC IEPR load forecast, the CPUC LTPP process and the CAISO's TPP process.

9.a. PG&E Current Forecasting Methodology

PG&E uses econometric models to forecast electric customer demand, with individual regression equations specific to each major customer class-residential, commercial, industrial and agricultural. The models predict sales or sales per customer using various PG&E service area economic measures, price variables, and weather variables. Although the model-based forecast remains at the core of PG&E's sales and peak demand forecast process, the regression forecast alone cannot incorporate all of the impacts of new technologies and policy impacts. In general, adjustments are designed to incorporate the latest EE, DG, EV, Direct Access and Community Choice Aggregation expectations and account for T&D losses and unaccounted for Energy.

9.b. DRP Coordination With PG&E's Internal Load Forecast and CEC's California Energy Demand Forecast to Facilitate the CEC's IEPR

Every year, PG&E develops load forecasts for each of its distribution planning area and for its total service area based on linear regression modeling and post-regression adjustments for policy drivers such as EE, EVs, and DG, including PV, CHP, fuel cells, and all other types of DG.

Every two years, the CEC is required to submit an overview of the major energy issues and trends to the Governor in its IEPR submission. The report makes energy policy recommendations and provides demand and supply forecast to the state. PG&E provides demand forecasts as input to the CED forecast to facilitate the CEC's IEPR.

On April 20, 2015, PG&E provided its latest data and forecast assumptions as input to the CEC's 2015 IEPR forecast (Form 3.3). To ensure that the DRP is coordinated with PG&E's inputs and assumptions to the 2015 IEPR, the DRP used consistent assumptions for EE, EV, and DG. However, forecasts for technologies such as retail and wholesale storage and wholesale PV, were not developed as part of the CEC's CED forecast for IEPR, as these are considered supply-side resources.

Once the CEC's energy and demand forecasts are finalized, PG&E uses as appropriate CEC's energy and demand forecasts for the PG&E area in the LTPP along with its own internal load forecast consistent with PG&E's prior practices.

9.c. DRP Coordination With the LTPP Proceeding

The LTPP proceeding is a biennial proceeding to determine whether any new resources are needed to maintain system-level reliability over a long timeframe (typically LTPP looks at a 10-year out snapshot of system reliability). The LTPP typically only considers the need for new resources at a system-wide level, however location-specific analysis may be considered if the need arises (*e.g.*, in the 2012 LTPP after SONGS closure).

The LTPP is also the venue where CPUC approves the IOU's BPP. The impact of DERs on long-term system reliability is already included in the LTPP in many cases, by reference to the IEPR forecast which includes the impact of those DERs. When meeting an identified need with DERs, care must be taken to ensure that those resources are additional to DERs that are already included in the LTPP analysis to avoid double counting.

In general, the LTPP follows California's Loading order, including existing and forecasted future DERs:

- EE is incorporated through the adoption of the IEPR forecast; for example, the 2014 LTPP Trajectory scenario includes the forecasted mid-case "additionally achievable energy efficiency."
- DR is modeled at levels determined using the most recent Load Impact reports provided by the Demand Response Measurement and Evaluation Committee under guidance of the CPUC.
- Energy storage has been incorporated into the 2014 LTPP in correspondence with the CPUC's energy storage procurement targets.
- Existing and future Behind-the-meter DG is incorporated at the level assumed in the IEPR forecast; however it is modeled as a supply resource rather than embedded in the load to capture its intra-hour variability and forecast uncertainty. The LTPP includes scenarios with high DG penetration above the IEPR mid case forecast.
- Existing and future Wholesale DG is included in the RPS resource portfolios that are modeled in the LTPP.

Care will need to be taken to ensure that any new DERs procured by the IOUs would be modeled in the LTPP accordingly, even where this requires departure for the standard planning assumptions or forecasts. Where procurement of new resources is approved in the LTPP, this is a clear opportunity for DERs to meet system-level need; however such resources would need to compete with other resources that could meet the identified need.

9.d. DRP Coordination With the CAISO's TPP

The CAISO's TPP is an annual process wherein CAISO conducts transmission planning analysis to determine what transmission expansion projects, if any, are needed to maintain reliability or meet policy goals (*e.g.*, RPS). As part of the TPP, the CAISO also performs analyses to determine the LCRs needed to ensure reliability is met on a CAISO system level, as well as a local area level.

The CPUC sets standard planning assumptions for the various scenarios that are studied in the LTPP and TPP, and these are typically based directly on forecasts provided in the IEPR. The impact of DERs on long-term system reliability is already included in the TPP in many cases, and care must be taken to avoid double counting resources that may be assumed to provide local RA or to reduce the local RA requirement.

9.e. Future DRP Process Will Seek to Improve Granularity of DER Growth Scenarios

The DRP process will further improve the granularity of projected DER Growth, including expected geographic dispersion at the distribution feeder level.

PG&E's Growth Scenarios present a range of outcomes subject to the limitations and uncertainties of the assumptions made to produce these scenarios. For example, there is uncertainty in modeling consumer behavior to determine if a consumer will invest in an EE upgrade, PV system or both. Other limitations include uncertainty in future policy developments, which may impact the adoption over the forecast period. Given the limited adoption of other technology areas such as fuel cells, as well as retail and wholesale storage, and wholesale DG, trends may not be readily established. As part of its Growth Scenarios, PG&E provides geographic granularity for some DER types, but many remain on the county or substation bus-bar level. PG&E intends to continue to refine its growth assumptions for use in internal and external planning processes.

Chapter 10 – Phasing of Next Steps

10. Phasing of Next Steps

As requested by the Guidance Ruling, the purpose of this chapter is to provide PG&E's proposal for rolling updates to PG&E's DRP, and a phased approach to DRP filings.

10.a. Rolling Updates to PG&E's DRP

Currently, PG&E implements its internal DPP on an annual basis that is geared towards identifying projected capacity deficiencies on the distribution grid as well as in developing future plans that address these issues via expanding, replacing or reconfiguring portions of the electric distribution system. The output of the DPP forms the foundation of the electric Distribution Capacity Program, which includes identified distribution capacity projects that are included in each subsequent GRC every three years.

Although PG&E's GRC is filed on a triennial schedule, PG&E will make improvements in its annual DPP to further integrate DERs into the current planning cycle efforts that occur on an annual basis consistent with its approved DRP. These improvements include the incorporation of various DER growth scenarios in the annual DPP to assess the impacts on the distribution system and the proposed future distribution plans. These impacts may require installing additional distribution capacity to meet DER growth as well as deferring the need for future capacity to serve load growth or additional infrastructure for improving reliability performance between GRCs as well as in GRC filings. Furthermore, PG&E considers DER alternatives in its evaluation of alternatives for addressing identified capacity or reliability deficiencies on the distribution grid in its annual DPP.

By including its DRP improvements, PG&E's annual DPP will result in a deeper integration of DERs onto the distribution grid.

On a rolling update basis with its GRC filings, PG&E will use its DRP as implemented in its DPP to continue to include future distribution capacity investments for evaluation in its GRC filings.

This approach is similar to the CPUC's approval of the utilities' Smart Grid Deployment Plans, under which the specific projects identified in the Smart Grid Plans are reviewed and implemented in the utilities' GRCs or separate applications in accordance with the metrics and criteria adopted by the Commission in its approval of the initial Smart Grid Plans. In addition, each utility files an annual report with the CPUC on Smart Grid performance metrics and approved Smart Grid projects, and those reports and metrics help evaluate new Smart Grid investments and projects in the utilities' respective GRCs.

PG&E recommends the same approach for the DRPs, once approved by the CPUC. In addition, if the CPUC deems it necessary, each utility can file an annual report on its DRP implementation and performance metrics in years in which its GRC is not pending.

PG&E recommends this consolidated approach to rolling updates of its DRP, in order to align the DRP with the CPUC's ratemaking policies and proceedings, and to save time and resources.

10.b. Phased Approach to DRP Filings

As part of the CPUC's consideration for this initial DRP filing, and consistent with PG&E's recommendation of a consolidated approach to updating DRPs (above), PG&E recommends the following scope and phased approach for the development of subsequent DRPs with the goal of improving the overall integration of cost effective DERs into the planning and operation of the distribution grid. The scope for this phased approach is further described below:

10.b.i. Phase 1 (Two Years, 2016-2017)

Although much progress has been made with the development and implementation of the distribution resource planning tools and methodologies for this initial DRP, there may be opportunities to improve and refine these tools and methodologies in the future. For the next phases of implementation of its DRP prior to approval of its 2017 GRC, PG&E intends to focus on the following activities:

- Refinement of distribution resource planning models:
  - Incorporation of additional SCADA and AMI information to drive additional granularity into distribution system models (enhance feeder and section load shapes).
  - Improve DER modeling (loading profile shape enhancements, various combinations of DER load shapes).
  - Update DER modeling to incorporate Smart Inverter functionalities.
- Refinement of Integration Capacity methodology and analysis:

    - increase granularity of assessment including emergency/circuit switching conditions, steady state voltage, service transformer loading).
    - Refine integration capacity methodology and analysis to factor in transmission limitations.
    - Assess transmission system impacts of DERs.
    - Industry benchmarking on Integration Capacity methodology.
    - Improve GIS maps to integrate additional Integration Capacity analysis results.
- Assess impacts to transmission system.
- Stakeholder meetings / workshops focused on various DER integration issues:
    - Incorporate third-party information for refinement of DER growth scenarios.
    - Data access and Data Sharing.
    - Develop DER Services performance criteria.
- Development of policy and process for sharing data.
- Develop and deploy additional pilots to test DER integration.
- PG&E to continue to deploy SCADA and other sensor devices onto its distribution grid.

10.b.ii. Phase 2a (Two Years, 2018-2019)

For the two years between PG&E's 2017 and 2020 GRCs, PG&E intends to focus its DPP on the following activities:

- Refine Locational Net Benefits Methodology to increase locational granularity.
    - Calculate locational net values for various pockets requiring distribution upgrades within the service territory.
    - Industry benchmarking on Locational Net Benefits Methodologies.
    - Develop Distributed Energy Resource Zones that could be attributed to locational values.
- Enhance tools and process to compare DERs as an alternative to traditional distribution capacity additions.
- Deploy Pilot projects to test communications infrastructure for forecast/monitoring/control of large quantities of DERs (DERMS/DMS).

- Planning and design of communications infrastructure to support monitoring and control of DERs (DERMS/DMS).
- PG&E to continue to deploy SCADA and other sensor devices onto its distribution grid.
- Scoping and development of web based platform for sharing data (subject to cost recovery).
- Assess results of deployed pilots from initial DRP that tests integration of DERs into planning and operation.

10.b.iii. Phase 2c (Ongoing, 2019 and Beyond)

The years in PG&E's 2020 GRC cycle will largely be focused on enhancement of DER distribution deferral mechanisms, as well as consideration of other proposals for DER services that are ancillary to distribution capacity needs. Specific activities will depend on the outcome and results of the demonstration and deployment projects approved and implemented under PG&E's DRP.

Appendix A

Acronyms and Definitions

AAEE – Additional Achievable Energy Efficiency Study

AB – Assembly Bill

AMI – Advanced Metering Infrastructure

AMP – Aggregator Managed Portfolio

BioMAT – Bioenergy Market Adjusting Tariff

BIP – Base Interruptible Program

BPP – Bundled Procurement Plan

Busbar – A system of electrical conductors in a generating or receiving station on which power is concentrated for distribution.

CAISO – California Independent System Operator

Capacity Factor – The percentage of Distributed Generation output compared with its nameplate rating.

CDPR – California Department of Parks and Recreation

CEC – California Energy Commission

CED – California Energy Demand

CHP – Combined Heat and Power

CPUC – California Public Utilities Commission

CYMDIST – A power flow program used to determine the impacts that added customers and changing grid conditions have on existing customers and distribution assets in terms of power quality and reliability. The capability to analyze and extract data from circuit models in a batch mode, using Python scripting, is a feature in CYMDIST that can be utilized for IC Analysis.

DC – Direct Current

DEER – Database of Energy Efficiency Resources

DERAC – Distributed Energy Resources Avoided Cost Calculator

DERMS – Distributed Energy Resource Management System

Detailed Modeling – In the context of IC, detailed modeling refers to implementing hour-by-hour load/DER profile data and geospatial circuit model data for the purpose of developing IC results of greater accuracy when compared to standard heuristic approaches used in current generation interconnection screenings.

DG – Distributed Generation

Distributed Energy Resources (DERs) – Distributed renewable generation resources, energy efficiency, energy storage, electric vehicles, and demand response technologies.

Distribution Planning Area (DPA) – A DPA is a designation that refers to a geographic grouping of circuits and substations in relatively close proximity compared to the entire service territory. The approximate 3,200 distribution circuits are grouped into 245 DPAs.

DPP – Distribution Planning Process

DR – Demand Response

E3 – Energy + Environmental Economics

EE – Energy Efficiency

ELCC – Equivalent Load Carrying Capability

EOY – End-of-Year

EPIC – Electric Program Investment Charge

EPIC-2 Wave 1 Project 23 (EPIC 23) – Pilot program that will integrate DERs into utility planning tools. Integration and usage of SmartMeter™ data, node based modeling, customer segmentation analysis, and customer specific DER forecasting are planned.

EPRI – Electric Power and Research Institute

ESPI – Energy Services Provider Interface

EV – Electric Vehicle

Evaluation Category – In the context of IC, the evaluation category is a characteristic of the electrical distribution system that has a limit to which the system must not exceed as to require mitigation.

EVSE – Electric Vehicle Supply Equipment

Fast Track – Streamlined evaluation used in Rule 21 and Wholesale Distribution Tariff (WDT) Interconnection studies that currently utilizes heuristic ("rule of thumb") criteria to determine DER impact.

Feeder (a.k.a. Circuit) – A high voltage (typically 4 kV-34 kV) line feeding power from the substation transformer to the customers, which may also include electric service down to the "final line transformers."

FERC – Federal Energy Regulatory Commission

FiT – Feed-In Tariff

FLISR – Fault Location, Isolation and Service Restoration

GHG – Greenhouse Gas

GIS – Geographic Information System

Granularity – In the context of IC, granularity refers to the depth or precision at which IC results can be effectively calculated and reported, i.e., system, substation, feeder breaker, line device, and node where your granularity is the highest.

GRC – General Rate Case

Grid of Things™ – PG&E's vision of a "plug-and-play" distribution grid platform that facilitates emerging energy technologies to be interconnected with each other and integrated into the larger grid. Just like with "internet of things," grid assets can interact with each other to optimize group coordination for the benefit of customers.

GTSR – Green Tariff Shared Renewables

ICE – Internal Combustion Engine

ICF – Integration Capacity Factor

IEEE – Institute of Electrical and Electronics Engineers

IEEE 1547 – A standard for distributed resources interconnections to electric power grids. It was recently amended to allow DERs to actively regulate distribution service voltage issues.

IEPR – Integrated Energy Policy Report

Impedance – This is the unit of measure for how much resistance a conductor will place on energy being delivered through it. Larger impedance means more energy loss and voltage drop.

Integration Capacity (IC) – Quantity/Result provided in units of DER nameplate real power that specifies how much of a specific DER can connect to a specified zone on the distribution system.

IOU – Investor Owned Utility

ISP – Industry Standard Practice

IT – Information Technology

kV – kilovolt

kW – kilowatt

LCR – Local Capacity Requirement

LED – Light-Emitting Diode

LIA – Large Integrated Audit

Line Device – A device that is somewhere along the feeder that performs a function to help operate the system.

Line Section (a.k.a. Zone) – A line section is a collection of line segments that consists of all loads, devices, conductors, etc. downstream of a specific delineating asset (i.e., Substation, Circuit Breaker, Line Recloser, Voltage Regulator, etc.). The zone will establish the granularity of the results.

Line Segment – A line segment is a component of the distribution mapping structure that connects one node to another node. One can think of a line segment as the span of wire that goes from one power line pole to another power line pole. Circuit models may have 10's of lines sections, but each line section could have hundreds of lines segments.

LMP – Locational Marginal Price

LoadSEER – A cloud based load forecasting program that can create representative hourly customer load/generation profiles and can aggregate them to create net demand profiles at the feeder, substation and system levels. These forecasts are typically used to find future substation level impacts.

LSE – Load Serving Entity

LTPP – Long-Term Procurement Plan

MVA – megavolt ampere

MW – megawatt

MWh – megawatt-hour

NEM – Net Energy Metering

NERC – North American Electric Reliability Corporation

Node – A node is a specific point that is in the distribution circuit model that connects two lines (section of conductor) to one another. In terms of the Distribution Resources Plan, a node is being used to refer to the construct described as a point to perform an analysis on. Circuit models may have 10's of lines sections, but each line section could have hundreds of nodes.

North American Industry Classification System (NAICS) – A standard used by Federal statistical agencies in categorizing businesses in order to publish data analytics related to the U.S. business economy. This was implemented in the Retail Storage Forecast in order to drive the non-residential storage data to the county level.

PLS – Permanent Load Shift

PMU – Phasor Measurement Unit

Power Profile – A set of numbers that represent what the loading/generation of a resource/asset over a period of time.

Power Quality – A term that is used to describe the compatibility of delivered grid power with utility owned assets and customer equipment. Categories of power quality include acceptable voltage magnitude limits, acceptable frequency limits, acceptable voltage fluctuation limits, and acceptable frequency fluctuation limits.

PPA – Power Purchase Agreement

Protection System Limits – The maximum power that can be generated by a DER in a protection zone such that there are no impacts that will necessitate changes in protection device hardware changes or protection schemes.

PURPA – Public Utilities Regulatory Policy Act

PV – Photovoltaic

R-REP – Regional Renewable Energy Procurement Project

RA – Resource Adequacy

ReMAT – Renewable Market Adjusting Tariff

Renewable Auction Mechanism (RAM) Map – PG&E's web-based map that is used to help customers identify potential interconnection project locations. Selected electric transmission lines, distribution lines, and substations can be identified in this map as well as well as operating voltages, line capacity and substation names. In the future, IC Analysis data will be implemented as well.

RFO – Request for Offer

RFP – Request for Proposal

RPS – Renewables Portfolio Standard

SAIDI – System Average Interruption Duration Index

SB – Senate Bill

SCADA – Supervisory Control and Data Automation

SCE – Southern California Edison Company

SDG&E – San Diego Gas & Electric Company

Service Transformer – Step down transformer that is located near customers to transform the high voltage power to medium voltage power that is serviced through the secondary conductors that feed the customer residence/facility.

SGIP – Self-Generation Incentive Program

SONGS – San Onofre Nuclear Generating Station

Substation – Location at which one or multiple substation transformers converts power from transmission voltage to the distribution voltage.

Substation Transformer (a.k.a. Bank) – Transformer that feeds one or multiple feeder lines that transport power throughout distribution system.

T&D – Transmission and Distribution

Thermal Rating – The maximum power that can pass through given distribution system equipment before damage is done to the equipment due to excessive heat. This will be one of the categories of power limits in the IC Analysis.

TOU – Time-of-Use

TPP – Transmission Planning Process

V – volt

VGI – Vehicle to Grid Integration

WDT – Wholesale Distribution Tariff

WHP – Waste Heat to Power

YOY – Year-over-Year

Zero Net Energy (ZNE) – Photovoltaic (PV) Forecast – A component of PG&E's retail solar PV forecast, made at the county level, that includes compliance driven solar PV installations due to expected ZNE adoption in residential new construction.

ZEV – Zero Emission Vehicle

Appendix B

PG&E's Distribution Planning Process

1. Appendix B – PG&E's Distribution Planning Process

Overview of PG&E's Electric Distribution System

Pacific Gas and Electric Company's (PG&E) electric distribution system, as with most distribution systems in the United States, is predominantly a radial design (i.e., electric power flows away from the substation to each of the customers along a single path).[1] The distribution system is dynamic as feeders are interconnected in order to allow system reconfiguration to restore service during outages, perform maintenance, connect new customers, redistribute load, etc.

PG&E's distribution system has four primary voltages: 4 kilovolts (kV), 12 kV, 17 kV and 21 kV. Feeder capacities increase as voltage increases. While a single maximum rating is assigned to every feeder, it is important to note that the rating is not uniform along the entire feeder. This is because distribution feeders are "tapered." A 12 kV feeder rated for 12,000 kilowatts (kW) has that level of capacity at the beginning of the feeder, but the value decreases as the distance from the substation increases because feeder conductors become smaller.

Four kV feeders have much less capacity as compared to other feeders because of their lower voltage and because of their age. Four kV feeders are generally older compared to other feeders. When addressing a 4 kV capacity deficiency, PG&E generally does not seek to increase the capacity of 4 kV distribution systems by installing new 4 kV transformers and feeders (PG&E also looks to connect large new loads to higher primary voltages rather than 4 kV as well).

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[1] PG&E does have spot and grid network systems in San Francisco and Oakland. Network systems are characterized by multiple circuits operating in parallel. The Distribution Resources Plan does not consider the relationship between these network systems and Distributed Energy Resources (DER) because: (1) network systems represent a very small portion of PG&E's overall distribution system; (2) the interconnection of DERs to network systems is more limited (as compared to radial systems) due to technical issues relating to how network systems operate; and (3) there is no physical interconnection between network circuits and radial distribution circuits.

Rather, PG&E will seek to convert portions of 4 kV systems to a higher primary voltage.[2] This approach provides an opportunity to upgrade the distribution system and gradually reduce the amount of 4 kV feeders.[3]

In addition to delivering energy to customers, specific distribution configurations provide connectivity services to customers during emergency situations. Connectivity is important because it is necessary to be able to: (a) restore service to customers when outages occur; (b) facilitate clearances (i.e., de-energize equipment) to perform work on the distribution system; and (c) reconfigure feeders for other operating reasons (i.e., reliability, redistributing load, voltage, etc.).

Distribution Capacity Planning

PG&E evaluates and plans for seasonal peak demands (kW) on distribution substations all the way down to individual customer service transformers. Energy consumption (kilowatt-hour) is only used to determine load factors and to help score areas for new load based on consumption growth. Peak demand for any distribution system component is evaluated on the highest peak occurrence in the summer and winter seasons and this peak load is compared to the components' rated capacity for that season within the distribution capacity planning process. The summer peak load is normally used to determine the system growth each year and to identify future component deficiencies because the rated capacity is lowest in the summer. Some areas may experience higher peak loads during the winter. But in general, the equipment has 20-30 percent more capacity during the winter periods due to the ambient air temperature. In winter, capacity deficiencies are infrequent and normally associated to voltage regulation or protection settings. The duration and occurrence of peak events may vary by

[2] In some instances, it is necessary to replace 4 kV equipment due to age, deterioration, etc. In these instances, PG&E may consider alternatives involving conversion to a higher primary voltage.

[3] These 4 kV systems are very limiting on DER capacity. This inhibits the ability for DER to provide system benefit. There may be limited DER benefits on 4 kV systems and improvements to these systems will typically be voltage conversion.

feeder and by season across the system. The elements PG&E considers for its distribution capacity planning process are:

- Substation transformers (compare transformer capacity to forecasted transformer load)
- Substation breakers (compare breaker and other substation equipment ratings to forecasted load)
- Distribution line equipment (switches, protective devices and voltage regulation equipment, etc.—performed via circuit modeling)
- Primary distribution conductors (overhead and underground wires at voltages 4 kV to 21 kV—performed via circuit modeling)

From a distribution capacity planning perspective, the most relevant DER characteristic to consider for capacity planning is its ability to reduce the duration and the amount of peak demand the distribution system must serve (i.e., the load the distribution components "see") at peak. With the exception of energy efficiency, a DER does not reduce the load itself (e.g., a DER does not change the amount of energy consumption or contribution to peak associated with the air-conditioner itself). Rather, a DER reduces the amount of load the distribution system must serve. For example, a feeder serving 5 megawatts (MW) of load with 1 MW of DER will "see" a net 4 MW of load. Should the 1 MW of DER disconnect from the system, the feeder will need to serve 5 MW of load. Some DERs, such as stored energy and electric vehicles, will require the distribution system to serve an increased amount of load during those periods when they are recharging. These DERs may not have negative effects if this recharge period is controlled and only occurs during periods when the peak load is not near the maximum capacity limits.

Each year, PG&E's distribution engineers forecast the magnitude and location of load growth to ensure that adequate distribution capacity is available to meet peak demand. First, PG&E performs a load forecast analysis for each circuit breaker ("feeder"), substation transformer ("bank"), and Distribution Planning Area (DPA). This analysis uses historical annual peak load data, historical temperature data, geospatial economic factors, and allocated system level forecasts. A 10-year load forecast for each feeder, bank, and DPA is performed across the whole system. The results of these forecasts are used to analyze deficiencies on each of those elements for 10 years and identify potential projects that will be needed to correct these deficiencies. In addition to identifying forecasted deficiencies on banks and feeders, the distribution engineers run feeder power flow models applying future growth for a 3-year period to identify localized deficiencies throughout each distribution feeder being served by a feeder.

Whether additional facilities are needed in an area is determined by following the steps listed below. Each year, these steps are completed for both summer and winter peaking seasons, as appropriate. Only DPAs with winter peak loads that exceed the summer peak loads will be analyzed for both winter and summer critical capacity deficiencies. The steps can be summarized by the following flowchart:

FIGURE B-1
PG&E'S GENERAL CAPACITY PLANNING FLOWCHART

DPA Planning

Using the LoadSEER distribution load growth program, PG&E prepares 10-year growth projections for each feeder, bank, and DPA, compares it to normal capability, and develops alternatives to solve deficiencies.

↓

Normal Bank and Feeder Planning

PG&E develops three-year bank and feeder load projections, compares it to normal capability, prepares seasonal feeder planning studies, and develops alternatives to solve deficiencies.

↓

Feeder Planning

PG&E imports three years of growth for each feeder into the feeder modeling program (CYME) and identifies any localized deficiencies. PG&E models the necessary load transfers or new added capacity. PG&E compares bank and feeder load projections to normal capabilities. PG&E uses seasonal feeder planning studies to develop alternatives to solve deficiencies.

↓

Forecast Adjustment

Following the feeder and bank level analysis, PG&E enters future planned transfers and projects into the forecast to determine the long term impacts.

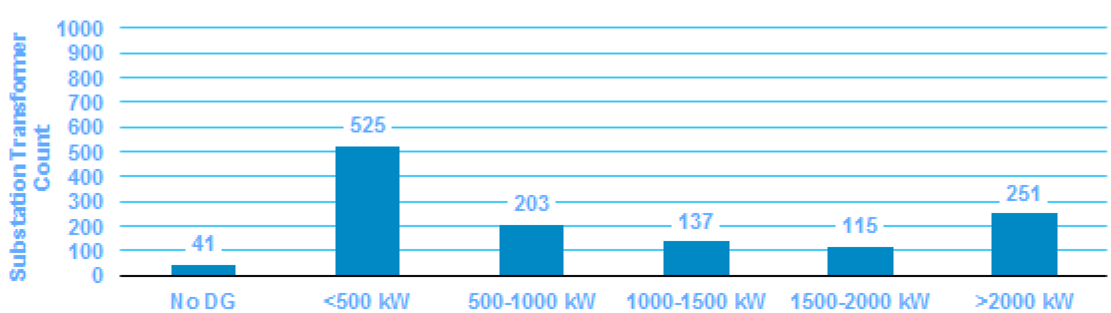
PG&E uses its load forecasting process to project DPA load growth 10 years into the future in order to develop preliminary plans and expenditure estimates for future capacity additions and to identify the need for new substation projects, which can have long lead times. As previously mentioned, 3-year transformer and feeder forecasts are prepared using the DPA load forecast. PG&E updates the load forecast annually to capture distribution system changes due to non-capacity related expenditures (i.e., modifications associated with work to connect new customers, improve reliability and operational flexibility, asset replacement, Rule 20A, etc.) and load growth, which varies over time due to the influence of the economy, etc. Consequently, plans relating to distribution capacity change frequently from year to year.

From a detailed capacity planning perspective, PG&E typically identifies new feeder projects approximately two years in advance and new substation transformer projects approximately two-to-three years in advance. The relevance of this from a DER perspective is that it may be reasonable to use similar time frames when considering how DERs influence capacity expenditures.

DER Impact on Capacity Planning

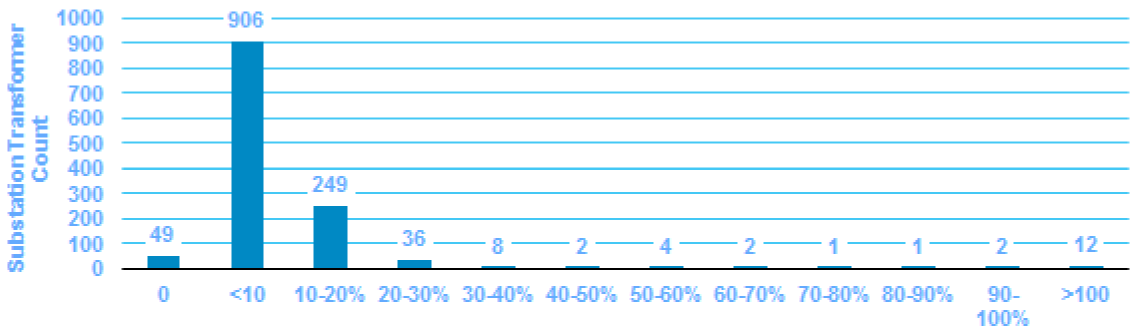
DERs are dispersed throughout PG&E's service territory. The following figures illustrate the distribution of Photovoltaic systems on substation transformers by size and ratio to peak load:

FIGURE B-2
DISTRIBUTION OF TOTAL INTERCONNECTED DG ON SUBSTATION TRANSFORMERS



This figure shows that over one-half of all distribution substation transformers have more than 500 kW of cumulative Distributed Generation (DG) interconnected. Approximately one-fifth of all distribution substation transformers have more than 2,000 kW of cumulative DG.[4] These values of interconnected capacities are typically compared to peak loads in order to project any potential issues. The figure below depicts the amount of substation transformers that are at specific ranges of distributed generation capacity to peak load penetration.

FIGURE B-3
DISTRIBUTION OF DG TO PEAK LOAD PENETRATION ON SUBSTATION TRANSFORMERS



This figure shows that despite the fact that over half of the distribution substation transformers have more than 500 kW, the ratio of nameplate DG capacity compared to peak load for the transformers trends on the lower end. About 75 percent are less than 10 percent penetrated. This shows the importance to determine locational benefit as the DER impact can be different depending on location.

PG&E accounts for the contribution of interconnected DG in its forecasting process. PG&E makes no adjustments to its load forecasting process to remove effects of small DG systems (i.e., less than 100 kW), which represents about 99 percent of all the DG interconnected to the distribution system. In effect, PG&E records the peak load that substation transformers and feeders serve (or “see”). Since substation transformer loads reflect the amount of DERs that are interconnected and operating on the peak day, the recorded peak load includes the influence that DERs have on the load that the distribution system serves (which is not necessarily the full capacity value of the DER). Since the load forecast is based on historical

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[4] For a point of reference, the standard size of distribution substation transformers PG&E installs ranges from 12,000 kW to 45,000 kW.

peaks, and the historical peaks reflect the contribution that a DER makes to the amount of load the system serves, existing DER is incorporated into the load forecast in terms of both quantity and trend.[5]

Capacity expenditures are caused by the relationship of the load forecast relative to available capacity for a specific system component such as a substation transformer, feeder, etc. If there is insufficient capacity (i.e., a deficiency), then a project may be necessary. The ability of DERs to influence the capacity expenditure is the confluence of the correct amount, timing, and location of DERs relative to the deficiency.

Distribution Power Quality Planning

After PG&E performs its capacity planning, the planners take the results, along with planned investments, and input them into the feeder models to perform power flows and determine any power quality issues that arise. Using the power flow software CYMDIST, planners can evaluate voltage issues, thermal overloads, protection needs, etc. all the way down to individual service transformers. When issues are seen, the planners evaluate possible mitigations.

[5] Historical data forms the trend, so if DERs are growing in a particular area, then that growth is captured to at-least some extent in the forecast. Future forecasts will incorporate DER forecasts developed in this plan rather than historical trends.

FIGURE B-4
PG&E'S GENERAL POWER QUALITY PLANNING FLOWCHART

DPA Modeling Assessment

PG&E imports load growth and capacity planning projects into the base case model. Using the CYMDIST distribution power flow program, PG&E prepares three scenario models representing the conditions for each of the following three years for each DPA. PG&E assess abnormal conditions and develops alternatives to solve deficiencies.

Correct Thermal Overloads

PG&E evaluates abnormal conditions and assess any thermal overloads that occur and determine alternatives to correct the overload.

Power Factor Correction

PG&E assesses power factor needs for each feeder to ensure peak condition power factor is between 0.99 lagging and 0.97 leading. PG&E determines feeder locations where new capacitors can be placed to meet power factor and voltage needs.

Voltage Regulation

PG&E evaluates any residual abnormal voltage issues and determine alternatives to correct. Alternatives may include reconductoring, voltage regulators, and/or capacitors.

DER Impact on Power Quality Planning

Historically, PG&E has not considered DERs as a practical means of satisfying distribution service voltage requirements.[6] However, with the recent amendments to Institute of Electrical and Electronics Engineers (IEEE) 1547 (IEEE standard for interconnecting distributed resources with electric power systems) and Rule 21 (that allows for active voltage regulation), distributed generators will be able to actively regulate voltage, in which PG&E may consider DERs as an alternative for satisfying voltage requirements in the future. In addition, PG&E has a number of traditional techniques to regulate primary voltage within operating standards (e.g., substation voltage regulators, line voltage regulators, capacitors, and fixed voltage boosters). However, there have been instances when PG&E has made distribution system modifications to account for high-voltage issues associated with DERs.

One such modification that accounts for the high voltage issues from DER is power factor control on inverters.[7] This is a DER solution currently in practice to combat the high voltage issue produced by excess generation. Power factor control is currently within the operating parameters allowed within the rules stated earlier. The Smart Inverter Working Group is currently working to create standards for more advanced forms of voltage control that will be recommended as changes and/or amendments to the standard interconnection rules.

PG&E's Interconnection Study Process

For its interconnection study process for distributed generation, PG&E is currently capable of performing very detailed and thorough studies with the datasets and tools available. PG&E analyzes each distribution feeder down to the node and service transformer level using a

---

[6] Voltage impacts from the DER are evaluated and taking into account for planning studies. However, they are currently not considered to be able to actively participate in correcting voltage due to IEEE 1547 and Rule 21 limitations.

[7] Power factor control is when the inverter is set to operate at a specific power factor other than unity (typically absorbing reactive power). This will limit the high-voltage impact from DER and has been a viable option in some instances.

distribution power flow program, CYMDIST, when performing detailed interconnection studies. The current process and toolsets for detailed studies can vary in duration as the complexity of a new generator at different locations can provide drastically different impacts across the system. Detailed studies usually only occur when significant upgrades are expected to be needed, which require additional engineering judgment and review. Depending on the size and complexity of a project, a study can take days and even weeks evaluating different scenarios of cost-effective mitigation at one location. Usually, the actual determination of issues does not take long, but the determination of the most cost-effective solution to address the issues may take time.

The main factor in the length of studies is the fact that if capacity, voltage, and reliability problems arise, mitigating solutions must be determined. Determination of these solutions is very manual and can require significant engineering judgment. This is due to the fact that the toolsets are not currently capable of such problem solving and there are utility specific operational and reliability factors that must be considered. This is why some interconnection studies can be time consuming.

This plays an important role in Integration Capacity Analysis, as the essence of Integration Capacity is to identify DER capacities that avoid having any distribution system problems. This concept supports the creation of a streamlined approach that can be quick and automated. PG&E performs the Integration Capacity Analysis to make sure that it finds DER capacities that are expected to not cause significant problems and thus do not require time consuming evaluation of mitigations.

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1. Energy Efficiency

1.a. Introduction

Energy Efficiency (EE) has been a key component of California's energy planning since the first ratepayer-funded programs and codes and standards were implemented in the mid-1970s. Ratepayer-funded programs promote the use of more efficient technologies and practices, from emerging technologies to mass market products and advocacy for greater levels of efficiency in state and federal codes and standards (Title 20 appliance standards, Title 24 building standards, and federal appliance standards). Codes and standards codify savings in state and federal product or building requirements by mandating efficiency in new construction, building retrofits, and energy-consuming products.

EE has a significant and lasting impact on the grid. EE program goals have been in the 1 percent - 1.5 percent of sales range per year for many years, which cumulatively amount to very large impacts. Over the period 2008-2014, EE measures have reduced PG&E's system peak by an estimated 1,300 megawatts (MW).[1] The savings is also long-lived, with appliances, insulation, and Light-Emitting Diode light bulbs being three examples of products that last 10+ years. Program impacts work in conjunction with codes and standards, which have become increasingly stringent in recent years, meaning that for many EE interventions, participants will not be able to purchase a less efficient product once the incented one fails—contributing to persistence over time.

1.b. Methods and Data Sources

1.b.i. Growth Scenarios and Geospatial Modeling

The approach for generating EE growth scenarios leverages existing and in-process work. The following is the series of steps and data sources involved:

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[1] Based on historical evaluated impacts from 2008-2012; reported impacts for 2013-2014; measured on a net basis to align with Integrated Energy Policy Report (IEPR) accounting practices.

- **EE Potential:** The first step involves estimating the amount of remaining, achievable EE potential at a system level. To do this, the California Public Utilities Commission (CPUC or Commission) conducts a potential and goals study every 2-3 years that leverages numerous supporting studies (Database for Energy Efficient Resources and Investor-Owned Utility (IOU) work paper savings parameters, saturation surveys, cost studies, macroeconomic inputs, and a variety of other Evaluation, Measurement and Verification (EM&V) research). This study produces a model and report that projects EE potential for a 10-year period. Data source: *2013 Potential and Goals Study*[2]

- **EE Scenarios:** The resulting potential model is then used by the California Energy Commission (CEC) to produce scenarios for the IEPR's Additional Achievable Energy Efficiency (AAEE) study. The study includes variable input assumptions across 17 areas, including the level of emerging technology, macroeconomic variables, energy savings, costs, cost-effectiveness screens, measure densities, marketing and word of mouth effects, implied discount rates, and future codes and standards.[3] Scenario selection is done through a collaborative process with stakeholders, including the IOUs. See Table 1-1 at the end of Section 1.

  The scenarios used in the EE scenarios align with the direction agreed to by the CPUC, CEC, and California Independent System Operator (CAISO) in a January 2014 letter to Senator Alex Padilla of the Senate Committee on Energy, Utilities and Communications.[4] The letter committed the three agencies to using the mid-AAEE scenarios for systemwide procurement and transmission planning and the low-mid case for local studies. PG&E Distributed Energy Resource (DER) growth scenario are aligned with this decision by using the AAEE low-mid for its expected case, AAEE mid for its high case, and the AAEE high-mid for its highest case. PG&E supports the goal outlined in the letter to converge on the same AAEE scenarios for all studies in the next IEPR cycle. PG&E also believes this approach is prudent given the untested nature of cascading EE potential to such granular levels.

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[2] 2013 California Energy Efficiency Potential and Goals Study Final Report, Navigant Consulting, Inc., for the CPUC, February 14, 2014, retrieved June 12, 2015 from http://www.cpuc.ca.gov/PUC/energy/Energy+Efficiency/Energy+Efficiency+Goals+and+Potential+Studies.htm.

[3] 2013 California Energy Efficiency Potential and Goals Study Final Report, Appendix O, Navigant Consulting, Inc., for the CPUC, February 14, 2014, retrieved June 12, 2015 from http://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M088/K661/88661909.PDF.

[4] January 31, 2014 letter from Robert Weisenmiller, Michael Peevey, and Steve Berberich to Senators Padilla and Fuller, retrieved June 11, 2015 from http://www.cpuc.ca.gov/NR/rdonlyres/2D097AAD-5078-47E9-A635-1995668F34B7/0/Padilla_Fullerletter_13114.pdf.

Data source: 2014 Estimates of Additional Achievable Energy Efficiency.[5]

- **Geospatial Granularity:** For Transmission and Distribution planning, greater levels of granularity are required, thus the CEC has worked with the IOUs to map busbar loads by sector (initiated by an annual data request from the CEC through the CPUC in the Long-Term Procurement Plan (LTPP)). The CEC then allocates the AAEE scenarios to the busbar-level using the sector busbar loads, such that customer class impacts are appropriate to the customer class load on each busbar, with checks to ensure aggregated busbar impacts equal system-level impacts. PG&E then uses these busbar-level impacts to allocate savings to the relevant level (e.g., county). PG&E also worked with the CEC to disaggregate the impacts by sector (residential, commercial, industrial, agricultural) and by type (programs or codes and standards) for the Distribution Resources Plan (DRP) effort. A work in progress is to allocate this bus-level data to the feeder level.[6]

1.b.ii. Load Impact Modeling

Energy efficiency is a diverse resource, with many end uses that have many different load shapes. The CEC is pursuing, through an EPIC project, data that would enable load shape integration at this level of granularity.[7] PG&E is also investigating ways to incorporate existing technology-specific load shapes into the data. An example load shape for residential indoor Compact Fluorescent Lamp (CFL) lighting is included in Figure 1-1 below.

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[5] 2013 California Energy Efficiency Potential and Goals Study Final Report, Appendix O, Navigant Consulting, Inc., for the CPUC, February 14, 2014, retrieved June 12, 2015 from http://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M088/K661/88661909.PDF.

[6] Jaske, Mike, "Allocating Additional Achievable energy Efficiency Program Initiatives to Load Busses for Power Flow Modeling."

[7] "Market Analysis of Trends in California Investor-Owned Utility Electricity Load Shapes," RFP-15-301, issued March 2015.

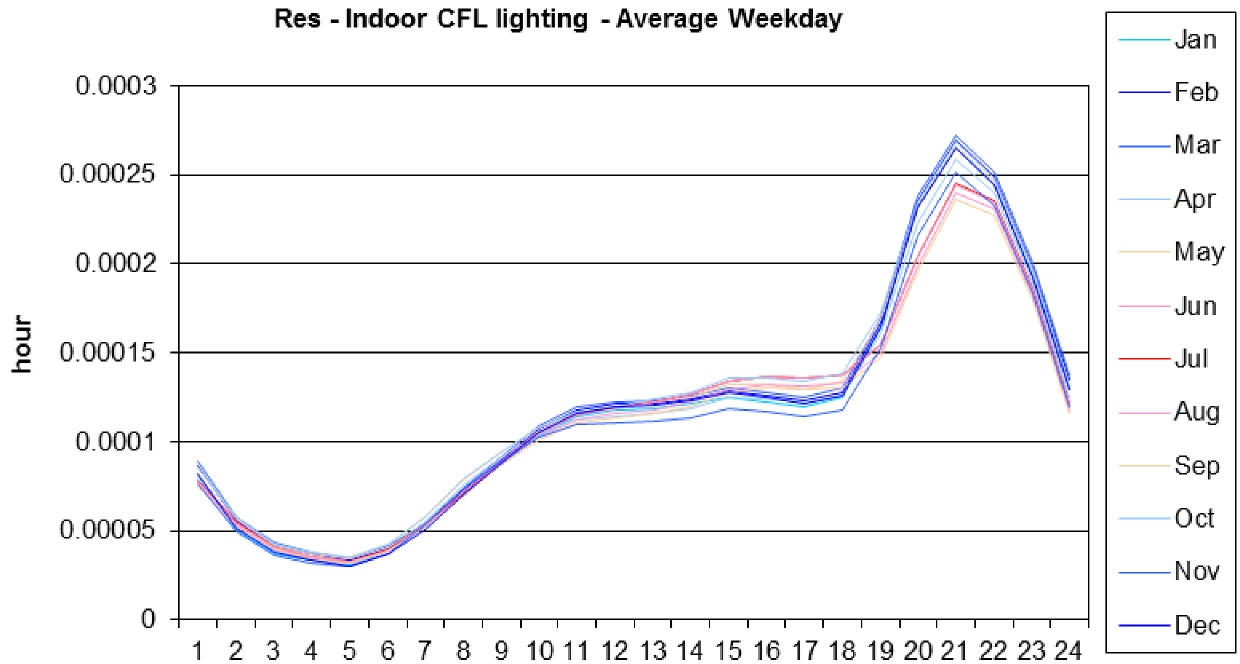

FIGURE 1-1
RESIDENTIAL INDOOR CFL LOAD SHAPE INCLUDING THE PORTION OF SAVINGS OCCURRING BY HOUR AND MONTH

1.c. Results

The results are provided at a high level of granularity. With close to 1,400 buses, 4 sectors (residential, commercial, industrial, agricultural), 2 resources (EE programs, codes and standards), 10 years of data, and 3 scenarios, the result is ~360,000 data points. This level of granularity takes previous work to an even greater level of detail with sector level splits.

Figure 2-2 shows system-level results by scenario, which provides a sense of the substantial differences between the three cases, with the highest case being almost three times greater than the expected case in 2025. The second figure is a table at the county level. As would be expected, counties that contain large population centers (e.g., Alameda, Contra Costa, Fresno, and Santa Clara Counties) have the greatest level of savings. It is also important to note that the results agree at the aggregated level with the AAEE scenario results. This was by design, as explained in Section 1.b.

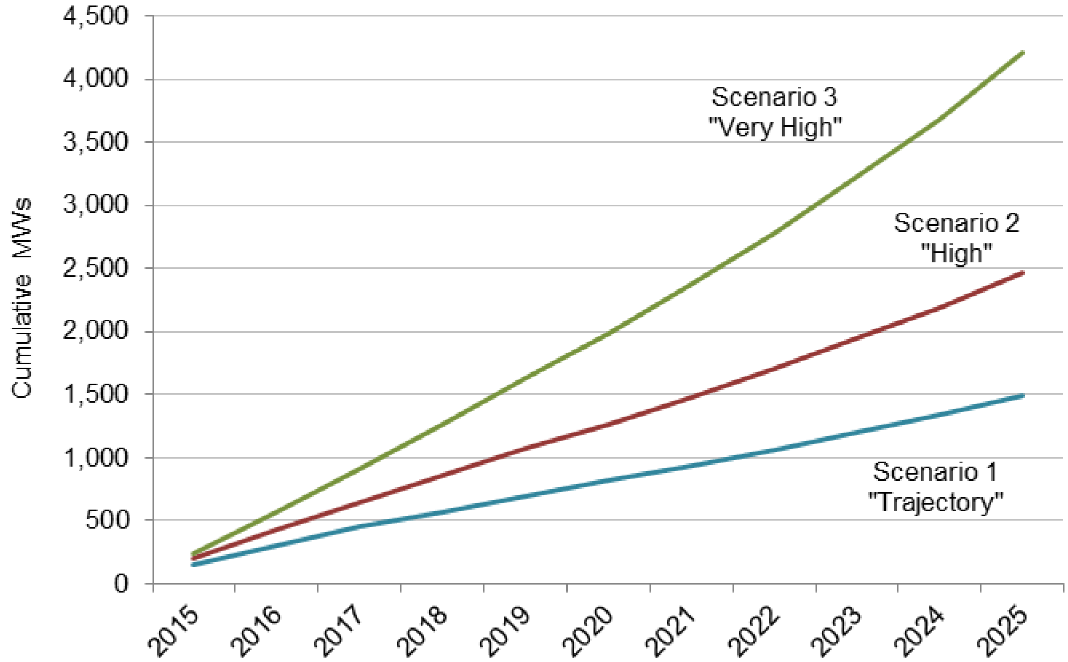

FIGURE 1-2
CUMULATIVE EE MW CAPACITY ADDITIONS POST 2014 AT SYSTEM LEVEL BY SCENARIO

TABLE 1-1
SUMMARY OF EE GROWTH SCENARIO ASSUMPTIONS

Cases	Emerging Tech	Building Stock	Retail Prices	Avoided Costs	Unit Energy Savings	Incremen tal Costs	Incentive Level	TRC Threshold	ET TRC Thres- hold	Measure Densities	Word of Mouth Effect	Marketin g Effect	Implied Discount Rate	Standards Com- pliance	Title 24 Updates	Title 20 Updates	Federal Standards
Scenario 3 – “Very High” (CEC High-Mid)	150% of model results	Mid IEPR Case	Mid IEPR Case	Mid IEPR Case	Estimate +25%	Estimate - 20%	50% of incremen- tal cost	0.75	0.4	Estimate +20%	47%	3%	14%	No Com- pliance Enhance- ments	2016, 2019, 2022	2016-18	Future Federal Standards
Scenario 2 – “High” (CEC Mid)	100% of model results	Mid IEPR Case	Mid IEPR Case	Mid IEPR Case	Best Estimate	Best Estimate	50% of incremen- tal cost	0.85	0.5	Best Estimate Costs	43%	2%	18%	No Com- pliance Enhance- ments	2016, 2019, 2022	2016-18	Already Adopted
Scenario 1 – “Trajectory” (CEC Low-Mid)	50% of model results	Mid IEPR Case	Mid IEPR Case	Mid IEPR Case	Estimate - 25%	Estimate +20%	50% of incremen- tal cost	1	0.85	Estimate - 20%	39%	1%	20%	Com- pliance rates reduced by 20%	None	None	Already Adopted

TABLE 1-2
CUMULATIVE EE MW CAPACITY AT SYSTEM PEAK (AUG HE 17) ADDITIONS POST 2014 BY COUNTY
(EXPECTED CASE)

County	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Alameda	17.16	34.36	51.96	64.14	78.51	91.60	104.32	117.49	132.94	148.32	165.53
Alpine	0.03	0.06	0.09	0.12	0.15	0.18	0.20	0.23	0.25	0.28	0.31
Amador	0.63	1.26	1.91	2.41	2.98	3.51	4.03	4.57	5.20	5.83	6.53
Butte	2.84	5.73	8.70	11.13	13.83	16.42	18.96	21.57	24.43	27.33	30.58
Calaveras	0.42	0.84	1.27	1.60	1.97	2.31	2.63	2.97	3.35	3.74	4.18
Colusa	0.47	0.95	1.45	1.83	2.27	2.68	3.10	3.52	4.00	4.48	5.01
Contra Costa	19.62	39.27	59.26	74.75	91.99	107.99	123.30	138.98	156.62	174.32	194.07
El Dorado	2.56	5.14	7.76	9.89	12.19	14.30	16.34	18.44	20.80	23.17	25.83
Fresno	10.66	21.48	32.65	41.33	51.25	60.70	70.03	79.66	90.39	101.22	113.36
Glenn	0.37	0.75	1.14	1.47	1.83	2.17	2.51	2.86	3.23	3.61	4.04
Humboldt	1.31	2.62	3.97	4.91	5.99	6.95	7.90	8.91	10.15	11.38	12.77
Kern	7.23	14.55	22.10	27.89	34.54	40.87	47.13	53.61	60.83	68.12	76.29
Kings	0.76	1.52	2.31	2.94	3.64	4.32	4.98	5.67	6.42	7.18	8.03
Lake	1.03	2.06	3.11	3.96	4.88	5.72	6.54	7.38	8.33	9.28	10.35
Lassen	0.05	0.09	0.14	0.17	0.21	0.25	0.28	0.32	0.36	0.40	0.45
Madera	1.49	3.01	4.57	5.81	7.21	8.55	9.87	11.23	12.73	14.24	15.94
Marin	3.92	7.84	11.84	14.69	17.99	21.01	23.90	26.87	30.32	33.77	37.62
Mariposa	0.27	0.53	0.81	1.03	1.27	1.50	1.71	1.93	2.18	2.43	2.71
Mendocino	0.88	1.75	2.65	3.35	4.12	4.83	5.51	6.21	7.02	7.84	8.75
Merced	1.98	3.98	6.05	7.76	9.65	11.46	13.24	15.06	17.05	19.06	21.32
Monterey	3.92	7.86	11.90	14.77	18.12	21.22	24.28	27.45	31.14	34.82	38.94
Napa	1.86	3.72	5.62	7.03	8.64	10.13	11.58	13.07	14.79	16.50	18.42
Nevada	1.71	3.44	5.19	6.61	8.16	9.59	10.97	12.40	14.00	15.62	17.42
Placer	2.95	5.93	9.01	11.49	14.25	16.85	19.39	22.01	24.95	27.94	31.28
Plumas	0.17	0.34	0.51	0.63	0.77	0.90	1.02	1.15	1.31	1.47	1.65
Sacramento	0.18	0.37	0.56	0.72	0.90	1.06	1.22	1.39	1.57	1.76	1.97
San Benito	0.40	0.80	1.21	1.54	1.90	2.24	2.56	2.90	3.27	3.64	4.05
San Francisco	4.26	8.54	12.96	15.62	19.02	22.06	25.07	28.24	32.15	36.02	40.38
San Joaquin	7.29	14.67	22.27	28.13	34.79	41.02	47.16	53.54	60.79	68.11	76.32
San Luis Obispo	2.98	5.97	9.02	11.29	13.89	16.29	18.64	21.06	23.82	26.59	29.69
San Mateo	10.05	20.14	30.47	37.34	45.61	53.10	60.39	67.98	77.00	85.97	96.02
Santa Barbara	0.72	1.44	2.18	2.73	3.35	3.94	4.51	5.11	5.79	6.47	7.23
Santa Clara	20.31	40.73	61.68	76.10	93.25	108.94	124.41	140.50	159.51	178.42	199.63
Santa Cruz	1.96	3.92	5.92	7.35	9.00	10.50	11.95	13.45	15.18	16.91	18.85
Shasta	0.89	1.80	2.72	3.55	4.43	5.28	6.10	6.95	7.84	8.75	9.77
Sierra	0.02	0.03	0.05	0.06	0.08	0.09	0.10	0.12	0.13	0.15	0.16
Solano	5.34	10.69	16.12	20.48	25.26	29.73	34.03	38.42	43.30	48.19	53.66
Sonoma	3.91	7.83	11.84	14.80	18.19	21.32	24.36	27.51	31.12	34.73	38.77
Stanislaus	0.06	0.12	0.18	0.23	0.28	0.34	0.39	0.44	0.50	0.56	0.63
Sutter	1.05	2.12	3.22	4.12	5.12	6.07	7.01	7.98	9.04	10.11	11.31
Tehama	0.62	1.25	1.89	2.41	2.99	3.55	4.09	4.65	5.28	5.90	6.61
Tulare	0.09	0.19	0.29	0.38	0.47	0.56	0.65	0.74	0.83	0.93	1.04
Tuolumne	1.07	2.15	3.25	4.14	5.10	5.98	6.83	7.70	8.69	9.68	10.79
Yolo	2.94	5.92	9.00	11.24	13.86	16.29	18.70	21.22	24.16	27.12	30.45
Yuba	0.23	0.46	0.69	0.90	1.12	1.33	1.54	1.75	1.98	2.21	2.47
Grand Total	148.64	298.24	451.51	564.84	695.02	815.70	933.46	1,055.21	1,194.75	1,334.59	1,491.18

1.d. Key Findings

EE offers the potential for substantial levels of savings. Because EE has been producing relatively stable savings for many years. Much of what is included in the growth scenarios is already embedded in sales and peak growth scenarios used by PG&E.

1.e. Limitations and Caveats

Any projection 10 years in the future will have uncertainties. One is the accuracy of the potential study, which forms the basis of the figures included in the scenarios. This is partially mitigated by extensive IOU review and collaboration on the development of the study.

A second limitation is the amount of EE realized at the busbar level. This issue is that EE realized at the system level may not cascade to the local level as predicted. This is partially mitigated by regularly updating busbar class loads. Another mitigation is the use of the low-mid AAEE case as the expected case for local planning, as directed by the state agencies, as this allows for greater than anticipated activity in some areas, and less activity in others.

A third limitation is the uncertainty of growth scenarios of EE that depends upon voluntary actions or behavioral changes by customers or upon variable inputs into the economic efficiency of EE, such as financing, new housing starts, population growth, and turnover of existing building stock.

1.f. Recommendations for Future Planning

PG&E has three recommendations for refining the EE component of these growth scenarios: (1) cascading savings to the feeder level; (2) incorporation of load shapes; and (3) continued refinement over time. Disaggregating savings to the feeder level is currently under way in an Electric Program Investment Charge (EPIC) project that was recently approved in Q2 2015. Load shape data, as discussed above, is needed for energy (gigawatt-hour (GWh)) scenarios and more accurate incorporation of impact for feeders/busbars that don’t have peaks that coincide with the system peak. The CEC is pursuing work in this area through an EPIC project.[8] Lastly, continued refinement of the scenarios over time will be important for improved accuracy of this data.

[8] "Market Analysis of Trends in California Investor-Owned Utility Electricity Load Shapes," RFP-15-301, issued March 2015.

2. Demand Response

2.a. Introduction

PG&E has developed feeder-level projected capacity impacts for each of PG&E's Demand Response (DR) programs. These include the following programs:

- SmartAC™ Residential Direct Load Control Program
- SmartRate™ Residential Critical Peak Pricing Program
- Base Interruptible Program (BIP)
- Aggregator Managed Portfolio Day-Ahead (AMP-DA)
- Aggregator Managed Portfolio Day-Of (AMP-DO)
- Capacity Bidding Program Day-Ahead (CBP-DA)
- Capacity Bidding Program Day-Of (CBP-DO)
- Demand Bidding Program (DBP)
- Peak Day Pricing (PDP) Non-Residential Critical Peak Pricing Program
- Non-dispatchable incremental Time-of-Use (TOU) program for non-residential customers

CPUC Decision (D.) 08-04-050 provided detailed and rigorous DR evaluation protocols and established an annual compliance filing requirement.[9] During the six years since D.08-04-050 was issued, PG&E has developed a deep knowledge of the performance of individual DR customers and its DR programs as a whole.

As of June 2015, PG&E estimates 595 MW of potential load reductions for dispatchable DR programs and non-dispatchable incremental TOU program for non-residential customers, under

[9] CPUC Decision 08-04-050. Decision Adopting Protocols for Estimating Demand Response Load Impacts. Retrieved December 30, 2014 from http://docs.cpuc.ca.gov/PublishedDocs/WORD_PDF/FINAL_DECISION/81972.PDF.

August 1-in-10 year weather conditions. Dispatchable programs constitute nearly 583 MW (or 98%) of the available capacity.

2.b. Methods and Data Sources

2.b.i. Growth Scenarios and Geospatial Modeling

PG&E's feeder-level DR model is directly derived from PG&E's **April 2014** DR Load Impact compliance filing.[10] The source data for the model was developed pursuant to the Load Impact Protocols specified by D.08-04-050, Attachment A.[11] In accordance with the Load Impact Protocols, the load impact data was developed using rigorous econometric models and experimental design techniques. Official compliance filing reports documenting how the load impacts were developed for each program are publicly available[12] and can be provided by PG&E upon request. These reports provide highly detailed descriptions of how the source data was developed for each program as well as performance characteristics.

2.b.ii. Load Impact Modeling

An example of a DR load impact profile is shown in Figure 2-1. This figure shows the reference load and estimated load with DR of the BIP in August 2015 based on 1-in-10 year weather conditions, under Scenario 1. The estimated average load impact (reference load *minus* observed load) is 246 MW from 1 p.m. to 6 p.m. This represents an 80 percent average load reduction relative to the average reference load of 307 MW.

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[10] PG&E April 1, 2014 Demand Response Load Impact Compliance Filing. Retrieved December 30, 2014 from https://pgera.azurewebsites.net/Regulation/ValidateDocAccess?docID=300477.

[11] CPUC Decision 08-04-050, Attachment A. Protocols and Regulatory Guidance. Retrieved December 30, 2014 from http://docs.cpuc.ca.gov/PublishedDocs/WORD_PDF/FINAL_DECISION/81979.PDF.

[12] PG&E April 1, 2014 Demand Response Load Impact Compliance Filing. Retrieved December 30, 2014 from https://pgera.azurewebsites.net/Regulation/ValidateDocAccess?docID=300477.

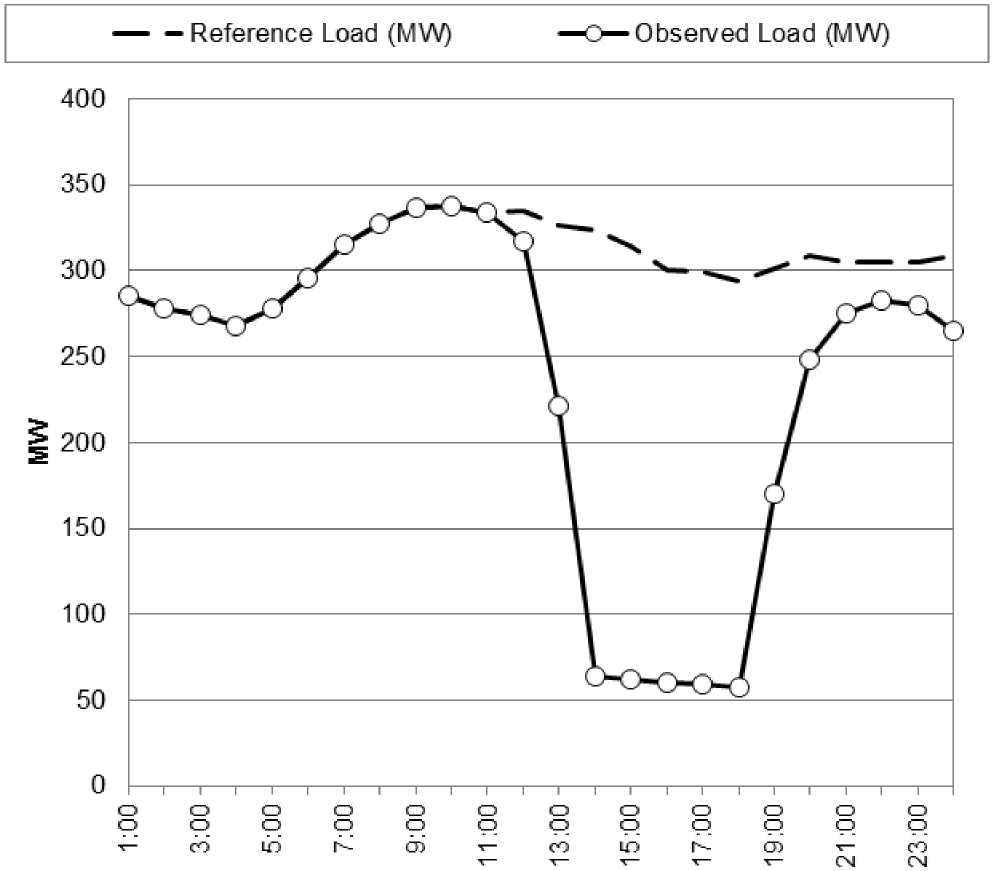

FIGURE 2-1
BASE INTERRUPTIBLE PROGRAM - AGGREGATE LOAD IMPACT IN AUGUST 2015 BASED ON 1-IN-10 YEAR WEATHER CONDITIONS. SCENARIO 1 ("TRAJECTORY")

2.c. Results

The source data developed in PG&E's April 2014 DR Load Impact compliance filing was used to determine the potential load impacts associated with each individual PG&E DR customer for each scenario and under August 1-in-10 peak weather conditions.[13] PG&E then mapped each individual customer and their load impact to the feeders in PG&E's territory. The load impacts were then aggregated by program and by feeder. Therefore, all DR load impacts are feeder-specific and account for the exact location of PG&E's DR customers.

[13] Note that the August 1-in-2 peak value is the value that is used in all regulatory proceedings (Resource Adequacy, Long Term Procurement Planning, Cost Effectiveness of DR, etc.).

Figure 2-2 presents system-level results by scenario. Each scenario includes combined potential load reductions from both dispatchable programs and non-residential incremental TOU.

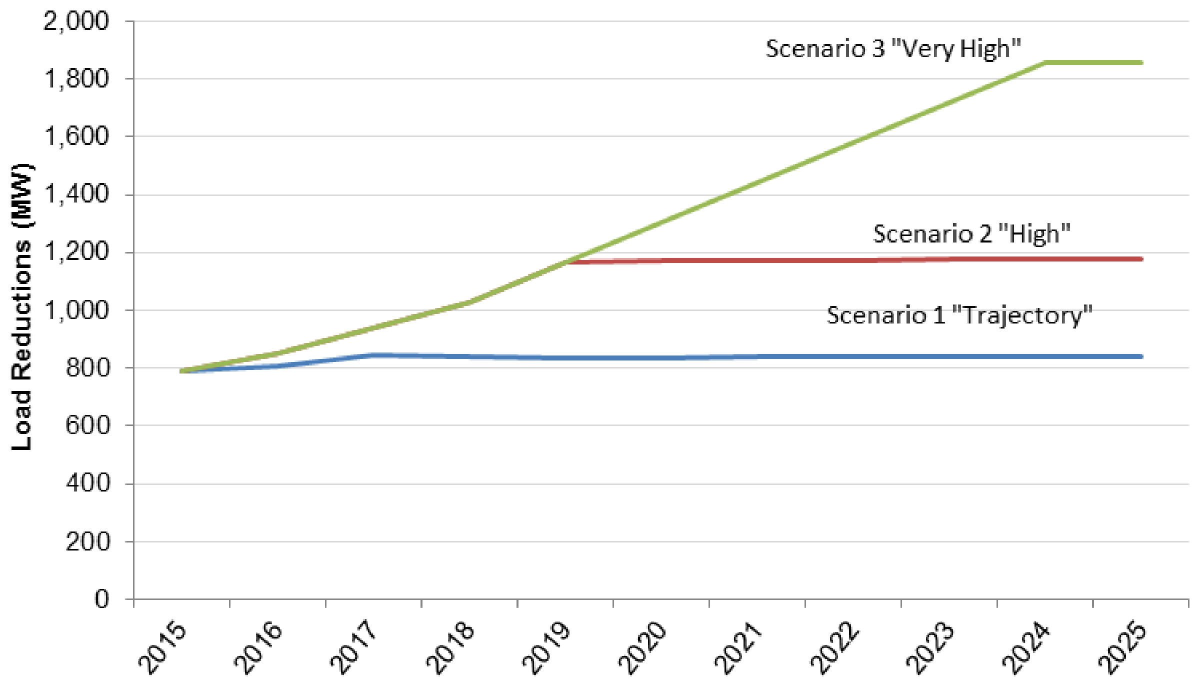

FIGURE 2-2
POTENTIAL LOAD IMPACT REDUCTIONS (MW) SCENARIOS AT SYSTEM LEVEL, AUGUST 1-IN-10 PEAK WEATHER CONDITIONS

Non-dispatchable TOU program load impacts constitutes nearly 120 MW (or 14 percent) of 841 MW total load reduction estimated for 2025, under Scenario 1. As illustrated in Figure 2-1, Scenario 3 is more than double than Scenario 1 in 2025.

The potential load reductions in the Trajectory Scenario align with the load impact filings of April 1, 2014. The High Growth Scenario assumes an aggressive but achievable increase in DR impacts that offset, by 2019, 5 percent of PG&E expected peak demand. The 5 percent growth scenario parallels with the Energy Action Plan (EAP) II and CPUC D.03-06-032. The Very High Growth Scenario assumes that DR can offset– by 2024–7.5 percent of PG&E highest system peak demand, a 50 percent increase to the EAP II.

2.d. Key Findings

Demand Response provides the potential for substantial peak shaving to help meet the supply and demand of the grid, avoid service interruptions, provide relief in congested nodes and defer investments for new generation and transmission needs. Increasingly, DR can balance the grid locally, reliably, flexibly and near real-time.

In order to capture the potential benefits of DR for distribution planning, the resource must be considered appropriately. DR is often available for a short duration—with predefined hours and time-of-year—and has a cap on the maximum of hours of dispatch in a given year. In addition, DR often requires longer notification than peaking generation which makes its operational characteristic atypical to that of a traditional generation unit.

2.e. Limitations and Caveats

PG&E has included only dispatchable programs and non-residential incremental TOU potential load reductions in its growth scenarios. PG&E excluded the non-residential SmartAC program as it remains closed to new participants. The Permanent Load Shifting (PLS) program remains under development, and enrollments in the residential TOU program may significantly change as a result of the Residential Rates Reform Order Instituting Rulemaking (R.) 12-06-013.

Dispatchable programs are those that elicit load impact in response to an event call. Each of these programs is available to be called according to the parameters in the 'Demand Response Operational Characteristics' document describing the operational characteristics of the programs. The primary drivers of the forecast based on the attribute of each program may include: customer class and size, geography, marketing plans, industry, economic forecast and regulatory policy.

The growth Scenario 1 aligns with PG&E's April 2014 load impact filings. The estimates represent the average system peak reductions across the resource adequacy window. PG&E measures the system peak reductions at hour ending 17 to equal the average system peak load reductions, thereby conservatively estimating the impacts. Methods allocating system peak impact at hour ending 17 in lieu of average system peak are being developed.

To avoid double counting of resources, PG&E used portfolio-adjusted load impacts. This means that customers that participate in multiple programs are assigned to only one program in this model. Note that this means that for any given program, the expected load response is at least as much as included in the model. Also note that if all programs were called simultaneously, the expected load impact would be equal to the total of all programs within the model.

2.f. Recommendations for Future Planning

In all regulatory proceedings, DR programs are assigned a gross up factor for avoided line losses to recognize that reduced usage not only avoids the energy that is not consumed, but also avoids the need to transmit that energy and the associated line losses. This factor is typically 10-12 percent. PG&E has not included those losses as the best judgment lies with distribution planners regarding the gross up factor from the customer’s meter to the particular system node being modeled.

3. Retail Distributed Generation (not including ZNE)

3.a. Introduction

In this section, PG&E describes the retail Distributed Generation (DG) growth scenarios that PG&E incorporated into the DRP for three technology categories: (1) solar PV, independent of Zero Net Energy (ZNE) compliance-driven PV adoption); (2) fuel cells, which may be operated in an electricity-only or in a Combined Heat and Power (CHP) configuration; and (3) combustion technologies less than 20 MWs in size, most of which are operated in a CHP configuration (combustion turbines, microturbines, internal combustion engines).[14] Solar PV on new construction associated with ZNE requirements is addressed in Section 4 of Appendix C.

PG&E first outlines the methods used to project growth and allocate projected technology adoption geospatially. We then present a summary of results and key findings and in closing present recommendations for future efforts.

PG&E includes scenarios for DG adoption (not including ZNE compliance-driven PV adoption) to the feeder level, but it is critical to consider that projecting adoption at this level of granularity is challenging, particularly for large-scale DG adopted by a limited number of customers, such as non-residential PV, non-residential fuel cells, or combustion technologies.

Adoption of distributed wind in PG&E's service area has been limited, and PG&E did not have an adequate sample size to project the geospatial adoption of this technology, so retail wind was not included in the geospatial analysis.

Since 2001, PG&E customers have installed approximately 1,700 MW of retail DG in PG&E's service area through End-of-Year 2014. Most (~1,360 MW) of the installed retail DG capacity in PG&E's service area consists of solar PV, though combustion technologies also comprise a significant portion of DG in the service area (~250 MW). This does not include CHP generation associated with California's implementation of the Public Utility Regulatory Policies Act of 1978.

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[14] For the purposes of this DRP, PG&E limited its analysis to DG less than or equal to 20 MW in size.

Most of this pre-2001 CHP capacity is larger scale and does not meet the criteria for distributed generation generally used (i.e., DG is less than 20 MW). Fuel cell installations have increased in recent years and now account for about 60 MW of capacity in PG&E's service area. Due to siting and other constraints, the amount of distributed wind installed in PG&E's territory has been relatively small at about 12 MW total. Of the DG technologies in PG&E's service territory, solar rooftop PV has experienced the fastest and most sustained growth trajectory with about a 30 percent Year-over-Year growth in cumulative installed capacity since 2009, and driven by very high growth (40-50 percent per year) in the residential PV market segment.

3.b. Methods and Data Sources

PG&E used historical adoption patterns and anticipated future market and policy developments to estimate future retail DG adoption. The data source used for historical DG technology adoption is PG&E's internal DG interconnection database.

3.b.i. Retail DG Growth Scenarios

For Scenario 1 of this DRP—the "trajectory" case—PG&E used the DG forecast we submitted on April 20, 2015 as part of the CEC's 2015 IEPR Forecast (Forms 3.3 and 6).[15] PG&E is concerned that the CEC's 2014 IEPR update (both the mid and high cases) under predicts likely retail solar PV adoption in PG&E's service area. For this reason, PG&E's chose to use its Form 3 IEPR submittal for the DRP trajectory scenario.

For Scenarios 2 and 3, the high and very high growth scenarios, PG&E evaluated policy changes and market developments that could lead to higher growth and estimated adoption scenarios based on these conditions.

PV accounts for the majority of PG&E's projected incremental growth for DG in our trajectory scenarios. By 2026, PV accounts for about 90 percent of Scenario 1 retail DG capacity. PG&E

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[15] PG&E Form 6 Submittal. April 20, 2015. http://docketpublic.energy.ca.gov/PublicDocuments/15-IEPR-03/TN204261-10_20150420T154647_Pacific_Gas_and_Electric_Company's_Form_6__Incremental_DemandSi.pdf

focused on variation in potential PV growth for the DG scenarios, as PV accounts for the majority of expected DG growth.

It should be noted that approximately 75 percent of the capacity in the scenarios developed for the “Wholesale (Feed-In Tariff) Combined Heat and Power” technology category is anticipated to serve on-site load, on the retail side of the meter, with the remaining 25 percent likely to be exported. The scenarios developed for this technology category are described in Section 9 of Appendix C.

Scenario 1

PG&E’s trajectory system level DG growth scenario is consistent with PG&E’s April 20 Form 3.3 IEPR submittal to the CEC. To estimate retail PV adoption, PG&E examined historical adoption rates, adjusted market growth projections based on anticipated policy developments, and referenced its growth assumptions to near-term growth rates and long term cost reductions predicted in a study by market research firm, Bloomberg New Energy Finance.[16] For non-PV technologies, PG&E used historical growth rates and trend analyses to estimate future adoption.

Scenarios 2 and 3

For the Scenario 2, PG&E included growth similar to the trajectory scenario through 2016 but higher growth rates in cumulative installed capacity from 2017-2025. In these scenarios, annual installed capacity levels off after 2018 as the residential market begins to become increasingly saturated and approaches constraints in residential market potential, though cumulative growth continues. PG&E estimated these constraints by examining housing characteristics and demographic data in its territory using proprietary purchased data sources. Under Scenario 3, annual PV capacity installed is assumed to be 25 percent higher than in Scenario 2.

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[16] Bloomberg New Energy Finance (BNEF) H1 2015 North American PV Outlook- wide-open throttle. January 16, 2015.

Factors that could drive adoption toward the installed capacities shown in the high (Scenario 2) and very high (Scenario 3) growth scenarios include increasing solar cost-effectiveness, and consolidation of solar provider activity to California due to constraints in other markets. Policy factors outlined for consideration in the DRP guidance that could drive higher retail DG adoption include:

- ZNE and building code requirements.
- Regulatory changes that mandate Governor Brown's renewable energy policy goal that calls for 50 percent renewable generation by 2030.
- Regulatory changes that mandate the Governor's Greenhouse Gas (GHG) emissions goals.

Impacts on total PV capacity associated with ZNE requirements are described in Section 4 of Appendix C. Higher renewable generation mandates could increase retail PV adoption if mechanisms were put into place to include rooftop renewable DG as part of statewide renewables goals. More aggressive GHG emissions goals may increase capacity additions from zero-carbon CHP, bottom-cycling Waste Heat-to Power (WHP) technologies, as further described in Section 8.

TABLE 3-1
COMPOUND ANNUAL GROWTH RATES (CAGR) IN CUMULATIVE INSTALLED PV BY GROWTH SCENARIO

	2007-2010	2010-2012	2012-2014		2014-2016	2016-2018	2018-2025
				Scenario 1 ***Trajectory***	33.8%	16.0%	9.1%
Historical	***39%***	***34%***	***33%***	**Scenario 2** ***High***	33.9%	24.1%	12.9%
				Scenario 3 ***Very High***	39.7%	25.5%	12.8%

3.b.ii. Geospatial Modeling

PG&E's approach to developing scenarios for geospatial DG technology adoption consisted of allocating the trajectory, high, and very high system level DG scenarios to a distribution feeder based on the probability of technology adoption on that feeder. The probability of PV adoption was estimated through regression modeling. While it is challenging to predict precisely which customers will adopt a given technology and where, historical information on technology adoption patterns and information on customer characteristics may provide an indication of what areas are more likely than other areas to see DG growth given current market conditions.

In PG&E's service area, over 176,000 customers have installed solar PV. This large sample size, combined with other studies on PV adoption patterns, allowed PG&E to produce a model to develop scenarios of where future adoption may be more likely to occur. For PV, we used a logistic regression model to estimate the probability of a given PG&E customer adopting PV based on housing and customer characteristics as well as customer usage data. PG&E then allocated the system level forecast for a given year to the feeders with customers that have the highest probability to adopt. Logistic regression is commonly used in marketing applications to predict who may be more likely to purchase a given product.

Far fewer customers have adopted non-PV technologies in PG&E's service area, approximately 800 installations at the end of 2014. PG&E used a linear regression model to estimate adoption by feeder using historical data on adoption by rate and non-residential customer type, as classified by PG&E's internal North American Industry Classification System (NAICS) information.

3.b.ii.1. Geospatial PV Forecast (not including ZNE)

To better understand where PV adoption may be likely to occur in PG&E's service area, an estimated probability of adoption was assigned to customers in PG&E's territory. This was done using logistic regression, a statistical method used to estimate the likelihood of binary outcomes, in this case, whether or not a PG&E customer adopts solar. It is a linear regression, in which the dependent variable is a measure of the probability of adoption based on the independent or explanatory variables. Models were developed for residential and non-residential customers, as the factors that drive adoption in different sectors are different.

A number of studies have demonstrated a statistically significant relationship between residential PV adoption and electricity usage, demographic variables, housing characteristics, as well as other factors. While PG&E does not provide a literature review here, a report by National Renewable Energy Laboratory (NREL) and academic researchers (Davidson et al., 2014)[17] provides a good overview of published research in this area.

Based on published research and PG&E's prior analyses, and constrained by data availability, PG&E used information on housing characteristics, demographics, electricity consumption, and geography as explanatory variables in the logistic regression model for residential adoption. For the non-residential logistic regression model, PG&E used information on the customer sector, electricity consumption, and electricity tariff as explanatory variables.

PG&E used the Wald Chi square statistic and Young's c-statistic to assess the goodness of fit for the two models. As is shown in Table 3-2, both models showed a statistically significant improvement in predicting adoption compared to the global null hypothesis (all parameters are zero).

Table 3-3 shows the Young's 'c' statistics for the two models. One would expect to have a 50 percent probability of predicting adoption for any given customer simply based on chance, like flipping a coin or any outcome that has only two options. The c statistic shows how much improved over this 50 percent probability the prediction of adoption is if using the models. C statistics above 0.7 are generally considered to represent a significant improvement in predictive capability.

TABLE 3-2
MODEL FIT STATISTICS FOR LOGISTIC REGRESSION USED TO ESTIMATE CUSTOMER'S PROBABILITY OF ADOPTING RETAIL SOLAR PV

Model	Wald Chi-Square	Pr>ChiSq
Residential	25,178	<0.0001
Non-Residential	4,394	<0.0001

[17] Davidson et.al., 2014. Modeling PV diffusion: and analysis of geospatial datasets. Environmental Research Letters (9) 2014.

TABLE 3-3
YOUNG'S C STATISTIC FOR LOGISTIC REGRESSION USED TO ESTIMATE CUSTOMER'S PROBABILITY OF ADOPTING RETAIL SOLAR PV

Model	c - statistic
Residential	0.861
Non Residential	0.804

3.b.ii.2. Estimating PV Technical Potential

The technical potential for installed PV by feeder was estimated to benchmark the feeder-level scenario to an estimated upper bound on PV adoption for a given feeder. Technical potential, as defined here, is constrained by the surface area available for PV installation. This is not to be confused with the technical potential of the distribution feeder to host PV. The technical potential estimates we used were based on the best available information PG&E has at this time.

For residential customers, rooftops are generally the most commonly used surface areas for PV, though homes with significant land available may install ground-mounted PV systems. The type of roof, orientation, and shading are key factors that affect the viability of PV for a given household.

For commercial customers, roofs are most commonly used for PV installation and the potential for installed PV capacity is constrained by space, orientation, and shading. Parking lot shade structures may be used for PV, but the supporting structures add significant cost and this type of capacity has not yet been widely adopted. PV potential associated with structures installed over parking areas was not included in estimating technical potential as part of this analysis.

Agricultural customers are generally not constrained by surface area, as the relationship between available land and electrical usage for agricultural customers is usually quite high. For the purposes of this analysis, technical potential for agricultural customers was defined as the capacity required to offset all onsite usage.

Approach to Estimating PV Technical Potential

To estimate available surface area for installation by residential and commercial customers, usage data by feeder and average energy use intensity (kilowatt-hour usage/square foot) for a given rate class were used to estimate the housing/building square footage associated with a given feeder. General estimates of building characteristics for residential and non-residential customers developed by Navigant Consulting for the NREL were used to translate building square footage into available roof space for PV.[18] Navigant provided updates to PG&E on their 2008 analysis which included slightly lower estimates for residential rooftop solar potential.

It should be noted that the usage data that was used to develop the technical potential estimates only captured about 90 percent of PG&E's reported usage, and so may somewhat underestimate technical potential. The usage data was based on Advanced Metering Infrastructure data that is not available for all customers.

Benchmarking PV Geospatial Forecasts against Technical Potential

To assess the quality of its retail PV technical potential estimates, PG&E examined the relationship between estimated PV technical potential by substation and the actual PV that has been installed on a given substation through 2014. As can be seen in Figure 3-1 , there is a positive linear relationship between the estimates and the actual installed PV capacity on a given substation, which suggests that the technical potential estimates are capturing physical factors that make solar more viable.

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[18] Paidipati et al. 2008. Rooftop Photovoltaics Market Penetration Scenarios. NREL Subcontract Report, NREL/SR-581-42306. Accessed December 15, 2014. http://www.nrel.gov/docs/fy08osti/42306.pdf.

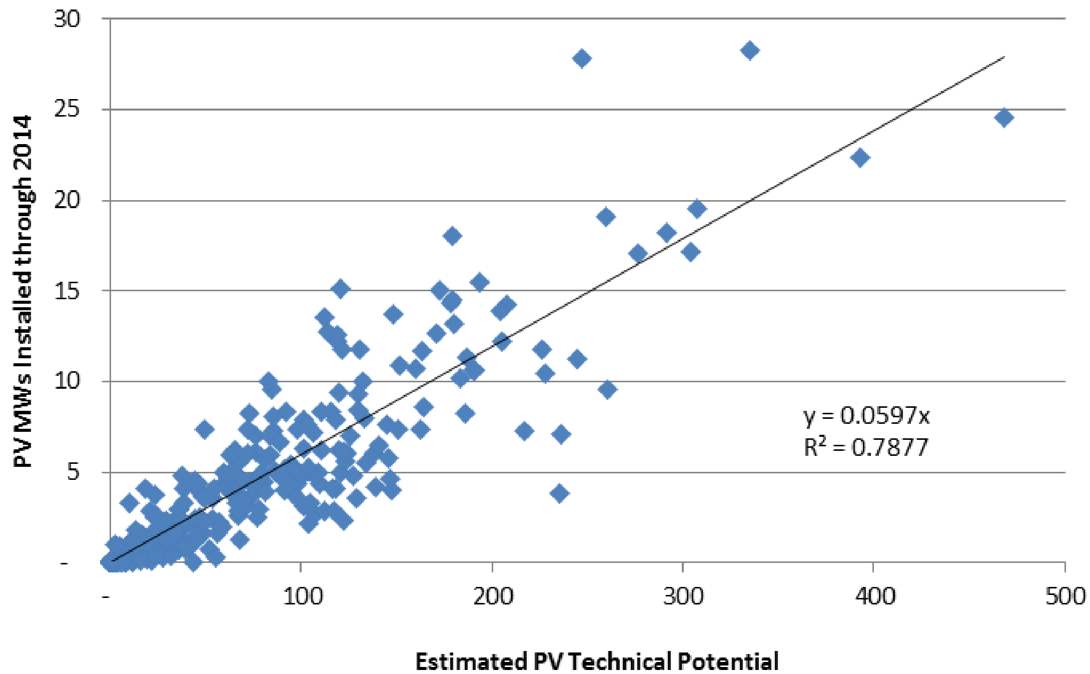

FIGURE 3-1
SCATTERPLOT OF ESTIMATED TECHNICAL RETAIL PV POTENTIAL AND INSTALLED PV THROUGH 2014 BY SUBSTATION

3.b.ii.3. Non-PV DG Geospatial Forecast

Non-PV DG technologies (fuel cells and combustion technologies), are used primarily in the non-residential sector and have not been as widely adopted as PV. While by the end of 2014 about 150,000 PG&E customers had installed distributed PV, under 300 customers had installed combustion technologies less than 20 MW in size, and only about 160 customers had installed fuel cells. It is thus very challenging to project with any confidence where adoption of these technologies will occur at a feeder level.

PG&E examined historical data to evaluate the tariffs used by, and sectors[19] that characterize, customers who have adopted non-PV technologies. PG&E developed growth scenarios for fuel cells and combustion technologies (gas turbines, microturbines, and IC engines) separately.

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19 As defined by the North American Industry Classification System (NAICS) code of the customer site.

An Ordinary Lease Squares (OLS) linear regression model was then specified to predict the MWs of each technology installed at a system level using tariff and NAICS code as explanatory variables. These system level parameters were then applied to each feeder to predict adoption given the proportion of load on that feeder served to customers on a given tariff and with a given NAICS classification. The annual system-level fuel cell and combustion technology forecasts were then allocated to each feeder using the parameters from the regression model and the information on load by tariff and NAICS code for each substation.

Low number of adopters and limited information on adoption drivers means that the model only explains about 10 percent of variability in adoption of combustion technologies.

TABLE 3-4
TESTS OF STATISTICAL SIGNIFICANCE FOR COMBUSTION TECHNOLOGIES REGRESSION MODEL

Combustion Technologies OLS Model		
Variables in Model	**P-value for F**	**Adj R squared**
Rate (Tariff) and NAICS	0.019	0.105

Feeder-level modeling of fuel cell adoption by rate and NAICS creates more statistically robust results, explaining approximately 40 percent of variability in adoption patterns.

TABLE 3-5
TESTS OF STATISTICAL SIGNIFICANCE FOR FUEL CELL REGRESSION MODEL

Fuel Cells OLS Model		
Variables	**P-value for F**	**Adj R squared**
Rate and NAICS	0.00077	0.426

3.b.iii. Load Impact Modeling

To develop a representative load profile for retail solar PV, PG&E used CSI PV incentive program data, PG&E PV interconnection data, and NREL's PV Watts tool to create an average load profile weighted by existing PV by CEC Climate Zone in PG&E's territory.

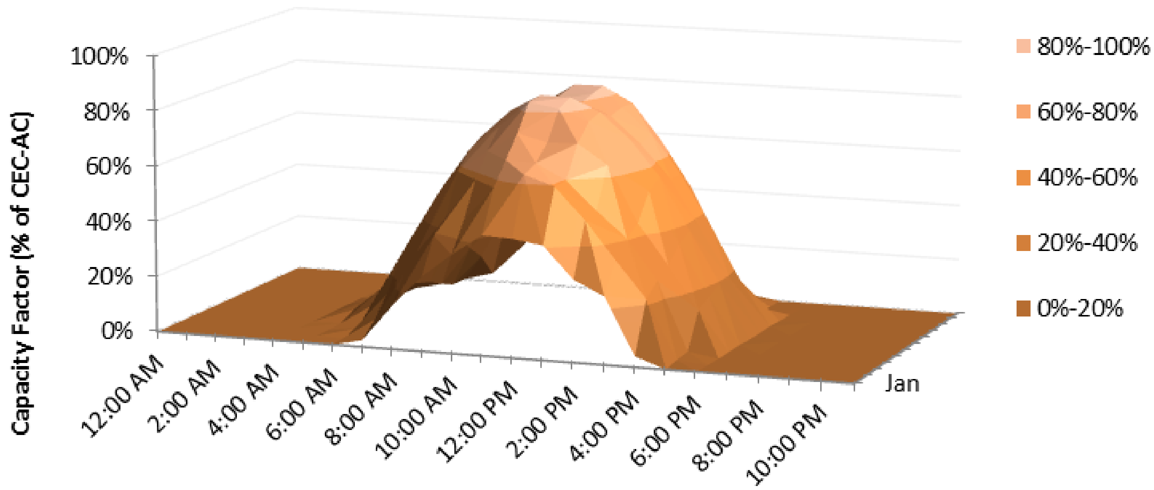

FIGURE 3-1A
AVERAGE GENERATION PROFILE OF A TYPICAL PG&E RETAIL PV SYSTEM

3.c. Results

3.c.i. DG Growth Scenarios

An important element of PG&E's PV growth scenario developed for the 2015 IEPR submission is that PG&E expects near-team DG growth to primarily be driven by PV adoption in the residential sector. In recent years, PV growth has been driven mostly by residential customers in PG&E's service area (Figure 3-2), with Year-over-Year growth rates in annual capacity additions of approximately 70 percent in 2013 and 2014 in PG&E's territory.

Decreasing PV costs and increased availability of little or no-money-down financing arrangements, such as solar leases, PPAs and loan products, have driven increasing adoption in the residential sector. This growth has also been bolstered by aggressive marketing by retail solar providers in advance of policy changes that are likely to reduce the financial incentives associated with Net Energy Metering (NEM) and the investment tax credit (ITC). PV growth in the residential sector has also been accelerated by access to abundant and low cost capital and greater standardization of residential PV contracts which has reduced transaction costs.

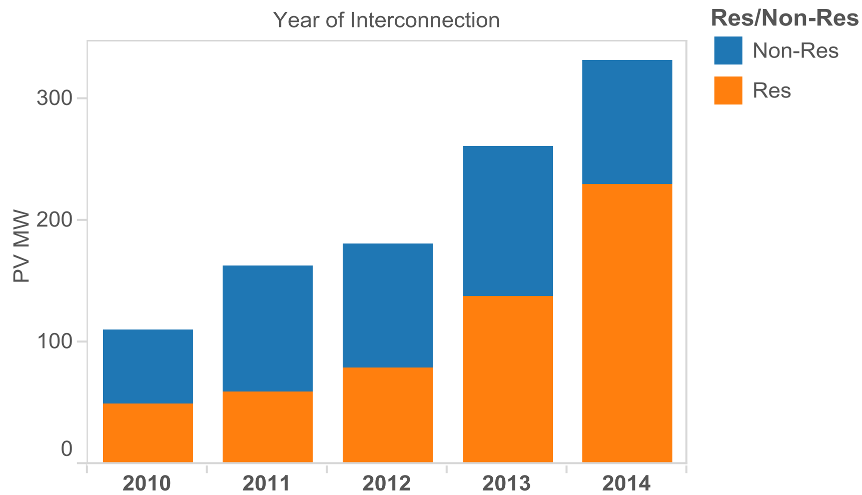

FIGURE 3-2
HISTORICAL ANNUAL ADOPTION (MW CEC-AC) BY SECTOR

In Scenario 1, by 2025, installed PV capacity in PG&E's territory increases over four-fold to 6,000 MW, up from about 1,400 MW installed at the end of 2014. Scenario 1 is nearly double the projection put forth by the CEC in their 2014 IEPR update. As of the end of March 2015, PG&E had about 1,500 MW of PV installed, just 100 MW shy of the CEC's forecast for the end of 2016. This underscores PG&E's concerns that the CEC's 2014 IEPR update PV forecast is under-forecasting PV adoption.

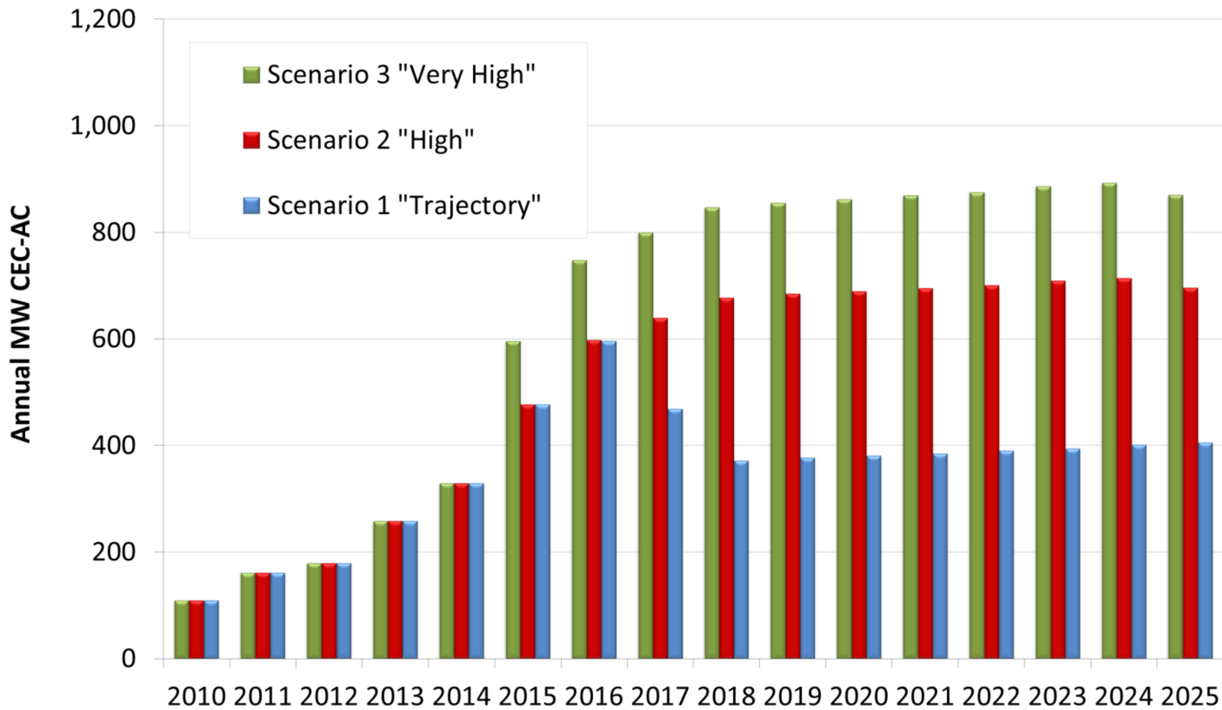

FIGURE 3-3
ANNUAL PV CAPACITY ADDITIONS (MW CEC-AC) UNDER
THE THREE DRP DER PLANNING SCENARIOS (NOT INCLUDING ZNE)

In Scenario1, high growth in PV installations occurs in 2015 and 2016 as customers and solar providers rush to install solar before implementation of the NEM successor tariff and the expiration of the federal ITC. Post 2016 in this scenario, a slow-down in the rate of growth in PV adoption occurs as adoption continues to grow but with incremental annual additions that are more commensurate with adoption prior to the “NEM 1.0/ITC rush” (Figure 3-3).

In Scenario 2, growth continues to accelerate post 2017 through 2020, after which growth continues but without acceleration as adoption starts to approach constraints in market potential. Under Scenario 3, PV adoption is 25 percent higher than in Scenario 2. A policy mandate outlined in the DRP guidance for consideration in Scenario 3 that could drive this additional growth would be regulatory or legislative mandating of Governor Brown’s 2030 renewable energy policy goal that calls for 50 percent renewable generation by 2030. If regulatory renewables mandates were put into place that include rooftop renewable distributed generation that could drive additional retail PV adoption.

TABLE 3-6
INSTALLED PV CAPACITY (NOT INCLUDING ZNE) BY DER GROWTH SCENARIO

In MW CEC AC	2010	2012	2014		2016	2018	2025
Historical	***430***	***772***	***1,360***	**Scenario 1** ***Trajectory***	2,400	3,300	6,000
				Scenario 2 ***High***	2,400	3,800	8,600
				Scenario 3 ***Very High***	2,700	4,300	10,500

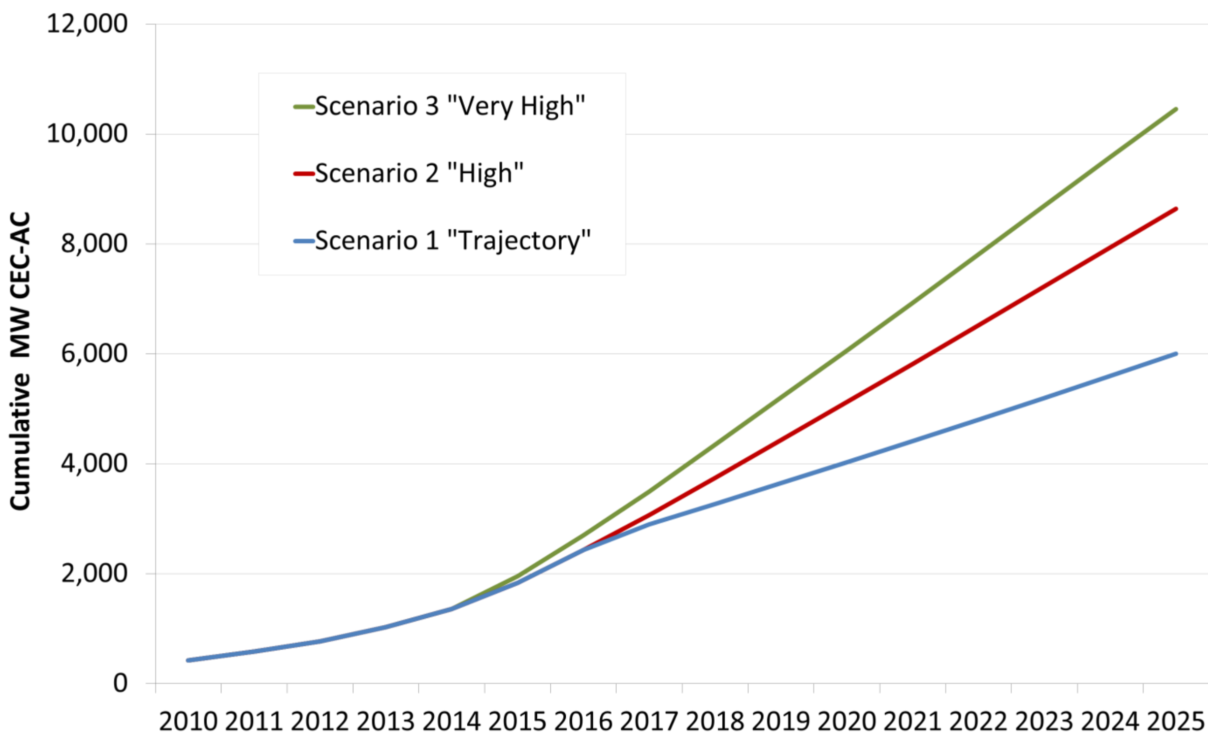

FIGURE 3-4
RETAIL NON-ZNE PV PLANNING SCENARIOS, CUMULATIVE MW CEC-AC INSTALLED

As mentioned in Section 3.b.i., PG&E focused primarily on variation in potential PV growth for the Distributed Generation (DG) growth scenarios, as PV accounts for the majority of expected DG growth. Across all scenarios, PG&E estimated growth in non-PV DG technologies to result in approximately 800 MW of installed nameplate capacity by 2025 (Figure 3-5).

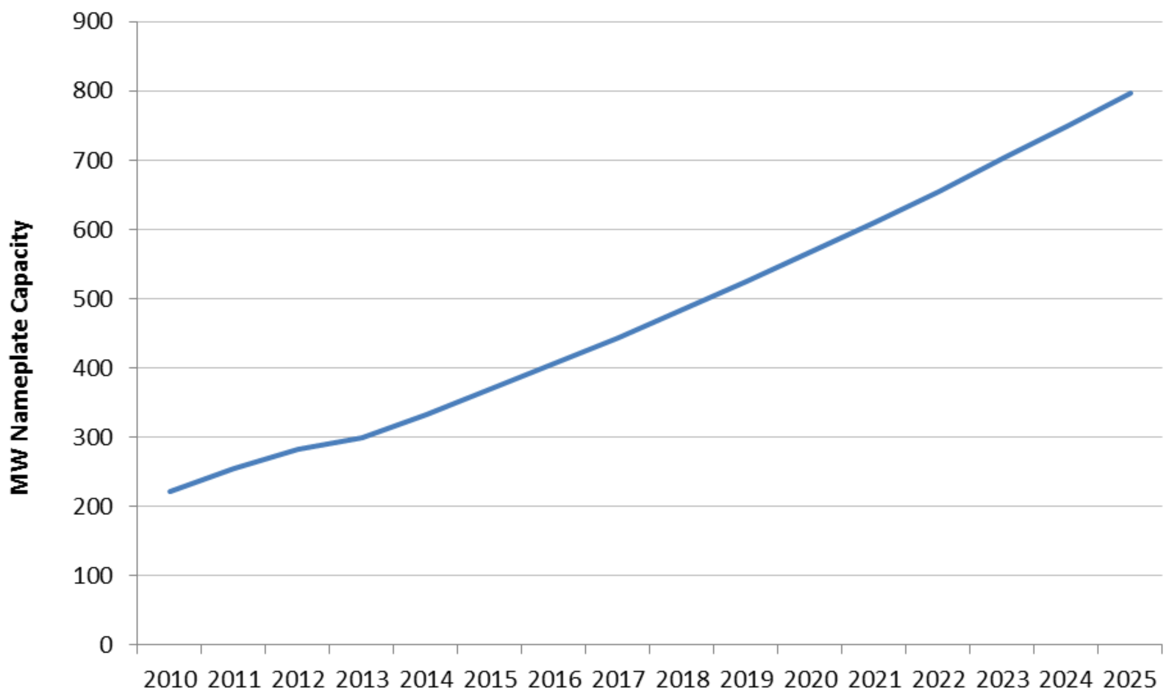

FIGURE 3-5
RETAIL NON-PV DG GROWTH SCENARIO, CUMULATIVE MWS INSTALLED

3.c.ii. Geospatial PV Forecast

PG&E's geospatial modeling estimates highest PV adoption in the South San Francisco Bay Area County of Santa Clara, in Fresno and Kern Counties in the Central Valley, and in the East Bay in Alameda and Contra Costa Counties (Figure 3-6). These are also the high population centers in PG&E's territory. Figures 3-6and 3-7 show historical and trajectory growth scenario PV capacity by feeder for the years 2008, 2014, 2020, and 2015. These figures illustrate that PV adoption is projected to be clustered in certain areas.

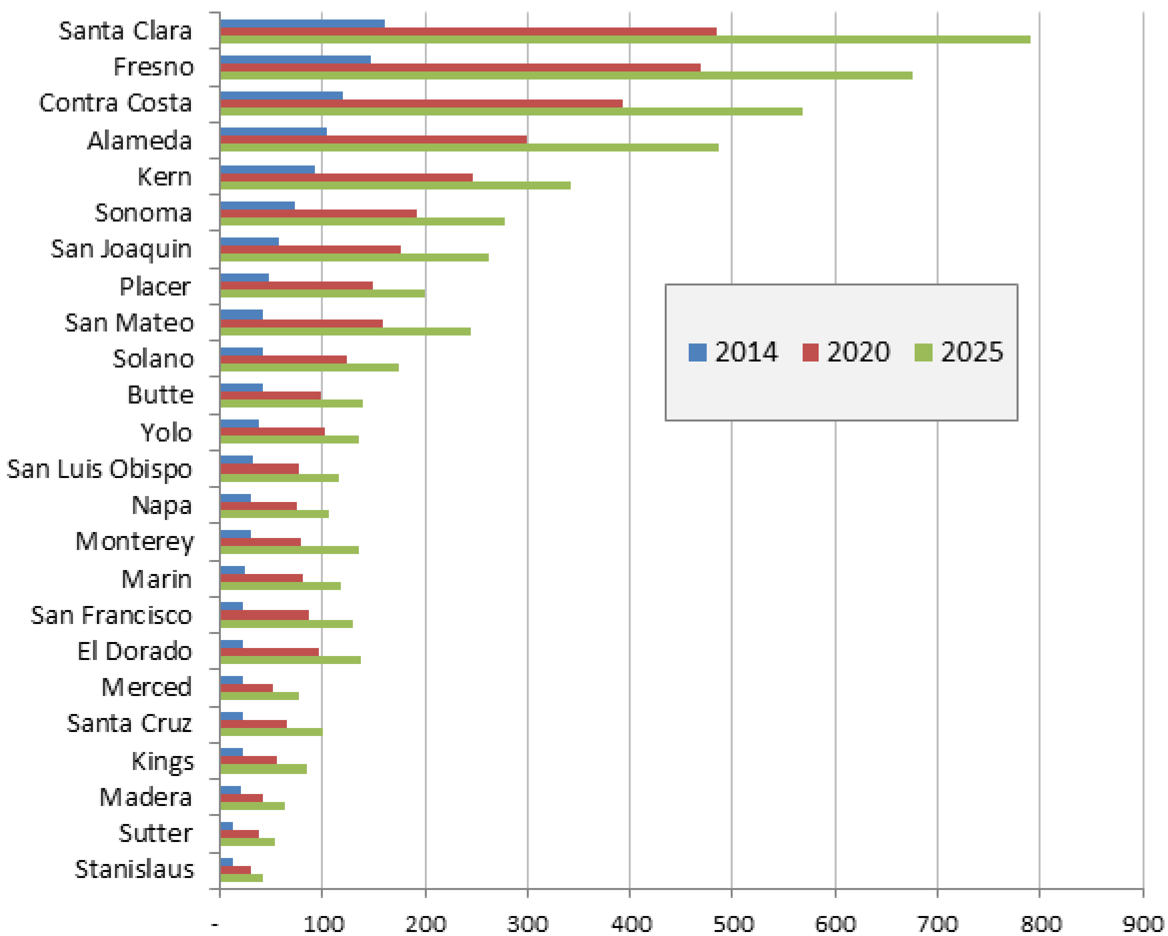

FIGURE 3-6
INSTALLED PV MWS BY COUNTY TO 2014, AND FORECASTED FOR 2020 AND 2025

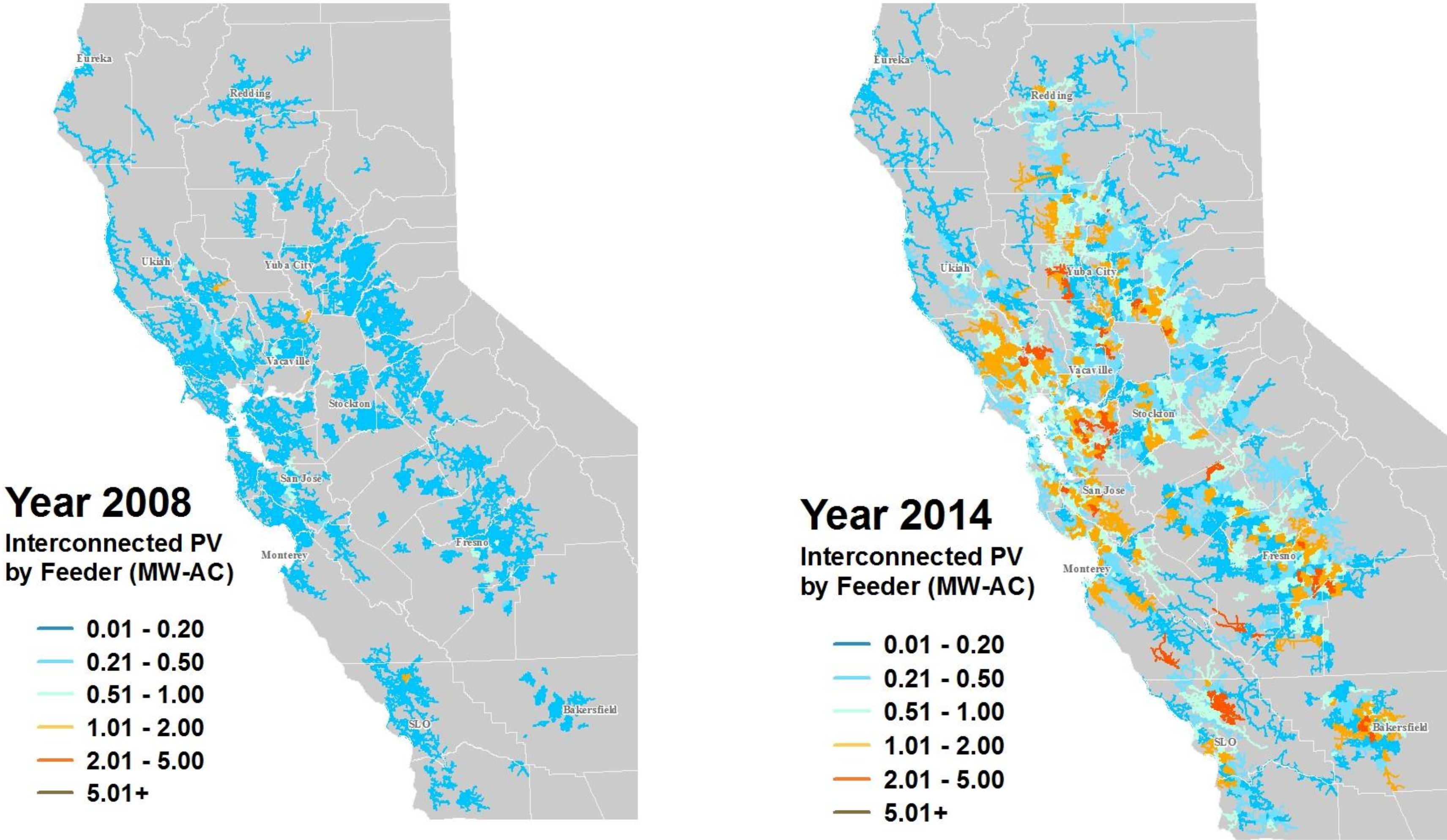

FIGURE 3-7
PG&E SERVICE AREA - INSTALLED PV CAPACITY (CEC-AC) BY FEEDER IN 2008 AND 2014

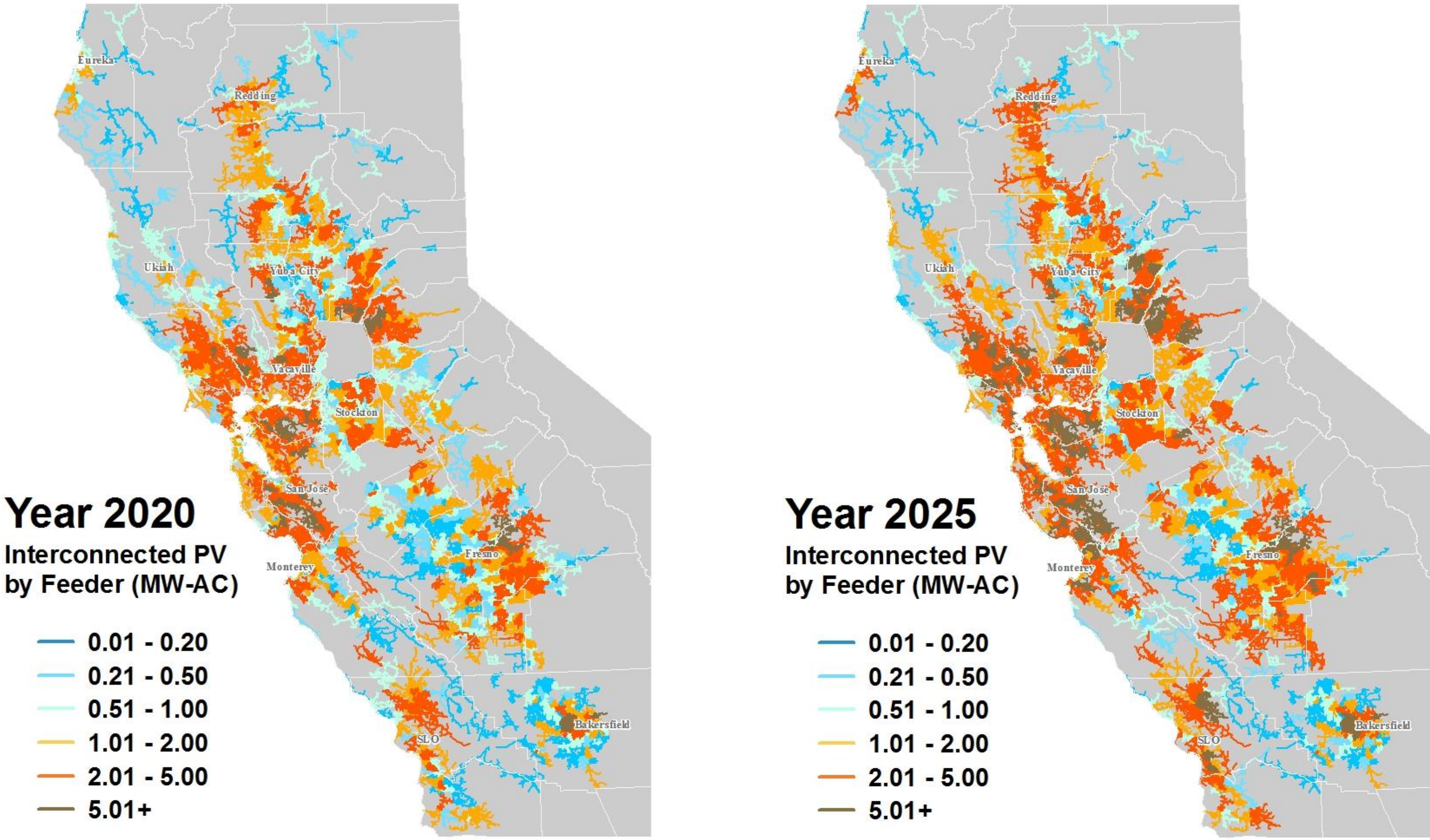

FIGURE 3-8
PG&E SERVICE AREA – SCENARIO 1 - ESTIMATED PV INSTALLED IN 2020 AND 2025

3.d. Key Findings

The geospatial models PG&E used for its PV adoption scenarios appear to have reasonably strong predictive power for determining where future adoption may be most likely to occur, with the caveat that historical patterns of adoption may not remain indicative of future adoption patterns, and other factors not considered within PG&E's modeling may affect actual adoption patterns.

The statistical tests of significance for models used to project geospatial adoption of combustion technologies and fuel cells indicate less confidence in the predictive capability of the models, in part due to limited historical adoption and information on key adoption drivers.

According to PG&E's modeling, distribution assets that serve higher income, single family, owner-occupied homes with above-average electricity usage may be the most likely to see significant growth in PV adoption over the next 10 years. Non-residential PV adoption is more likely among large customers with relatively high usage.

3.e. Limitations and Caveats

The trajectory scenario presented in this report is based on PG&E's best estimate of future patterns of DG adoption using certain available explanatory variables.

As with any technology diffusion forecast, there are a number of sources of uncertainty that must be considered for planning purposes. Key factors that lend uncertainty into future DG adoption are summarized in Table 3-7 below.

TABLE 3-7
LIMITATIONS AND UNCERTAINTY IN THE DG SYSTEM LEVEL AND GEOSPATIAL FORECASTS

Category of Uncertainty	Key Factors that Drive Uncertainty
Modeling Constraints & Data Availability	• Technical potential estimates were based on estimates of roof space using customer usage data. Feeder level data on home/building stories, shading was not available for this analysis • A number of studies have shown that "peer effects" contribute to consumers' willingness to adopt PV. To the degree that these effects are geographic (my neighbor has PV, so I am more likely to adopt) rather than social (my co-worker has PV), then incorporating peer effects may strengthen the predictive power of geospatial modeling • Later DG technology adopters may exhibit different consumer behavior than early adopters, so models based on historical adoption behavior may not accurately predict future behavior
CA Policy Outcomes	• The structure of the NEM successor tariff has yet to be determined and will affect PV cost-effectiveness • The Self Generation Incentive Program (SGIP) continues to support fuel cell and other non-PV technology adoption. SGIP funding is currently available through 2019
Federal Policy Changes	• The Federal 30% ITC is due to expire at the end of 2016. Grandfathering or extension of the ITC could foster more adoption if that incentive is passed through to customers through reduced prices.
Market Developments and Technology Innovation	• Business model/financing innovations • Growth positions by key market players • Disruptive technologies could change customers' options • Distributed storage may impact DG adoption patterns as storage technologies evolve

3.f. Recommendations for Future Planning

In this section, we outline possible areas in which the DG growth and geospatial scenarios could be strengthened.

For solar PV growth estimates, available surface area for installing customer-sited PV can be a significant limiting factor in metropolitan areas due to limited rooftop space or space for ground mounted systems. Better data on housing and building characteristics, such as the number of stories, would improve estimates of technical constraints to PV adoption in certain areas. Light Detection and Ranging remote sensing data that provides a three dimensional representation of building and land surfaces has been used to estimate solar availability and could enhance technical potential estimates.

Sales projections and information on marketing and project development strategies from DG technology providers could also enhance forecasting efforts for the DRP, because DG providers have the most current geo-spatial information on customer acquisition strategies.

4. Solar PV from Zero Net Energy

4.a. Introduction

PG&E's retail solar PV growth scenarios include compliance driven solar PV installations due to expected ZNE adoption in residential new construction. PV capacity additions due to ZNE adoption are estimated at the county level. Methods, data sources, and assumptions used to develop growth scenarios of PV adoption due to ZNE compliance (i.e., ZNE-PV) are described in this section.

CEC's EE Strategic Plan and 2007 IEPR adopted ZNE goals for new construction in California. The IEPR further defined ZNE buildings and laid out the necessary steps and renewables options to achieve ZNE goals.

The DRP Final Guidance points to the Road to ZNE (2012)[20] report when referencing the state's ZNE goals. This report focuses on the following two goals:

1 – All new residential construction in California will be ZNE by 2020

2 – All new commercial construction in California will be ZNE by 2030 (the impact of which is outside the EDRP load forecasting time horizon)

There is currently limited data available on ZNE adoption in new commercial buildings and commercial retrofits due to a high level of market uncertainty around commercial sector ZNE adoption. Therefore, PG&E's ZNE-PV scenarios include compliance-driven solar PV adoption due to new residential construction only.

Achieving ZNE in California is driven by new and proposed state building codes (Title 24, Part 6) and EE standards for appliances (Residential Appliance Saturation Study). To achieve ZNE goals, the triennial building standards update is assumed to increase the EE of newly constructed buildings by 20 to 30 percent in every triennial update. The next building standard code update will be provided in 2016.

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[20] Heschong Mahone Group, "The Road to ZNE: Mapping Pathways to ZNE Buildings in California," Main Report, CALMAC Study ID – PGE0327.01, December 20, 2012.

One of the major uncertainties of the ZNE-PV scenarios is the definition and future market adoption of ZNE homes. TRC[21] (2015) reports that although there are only 16 ZNE homes built in California, nearly 1,100 ZNE-type homes were identified. ZNE-type homes include ZNE-Ready, ZNE, and Near-ZNE homes. TRC (2015) characterized nearly 95 percent of ZNE-type homes as Near-ZNE, which have constructed onsite rooftop solar PV systems but did not meet the current ZNE code requirements. There is no market data available on how much solar PV (MW) capacity added due to ZNE-type residential new construction. PG&E's current ZNE-PV scenarios include not only ZNE but also Near-ZNE homes.

4.b. Methods and Data Sources

The step-by-step procedure PG&E used to develop ZNE growth scenarios was the following:

1. Identified the number of single and multi-family new residential housing starts by county in PG&E territory
2. Calculated ZNE-type residential housing starts in each county per year using estimated ZNE adoption curves (i.e., number of ZNE-type homes as a percentage of new housing starts)
3. Assigned each county to a primary climate zone based on the climate zone with the highest number of existing PG&E households
4. The Potential Study (Navigant 2013) provides PV system nameplate capacity (kW) per single and multi-family home to achieve minimized TDV values per climate zone. These PV system capacities were multiplied by the number of ZNE-type homes per county to obtain PV penetration per county due to ZNE adoption

Moody's Analytics (2014) quarterly residential housing permit forecasts for Single and Multi-family building types by county were used to estimate new ZNE homes added.

For counties where other utilities are present, a portion of the county's housing starts are allocated to PG&E using maps, census data, and PG&E's data on existing households. The number of housing starts used in the ZNE scenarios is shown in Figure 4.1.

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[21] TRC Energy Services, "Residential ZNE Market Characterization," Final Report, CALMAC Study ID – PGE0351.01, February 27, 2015.

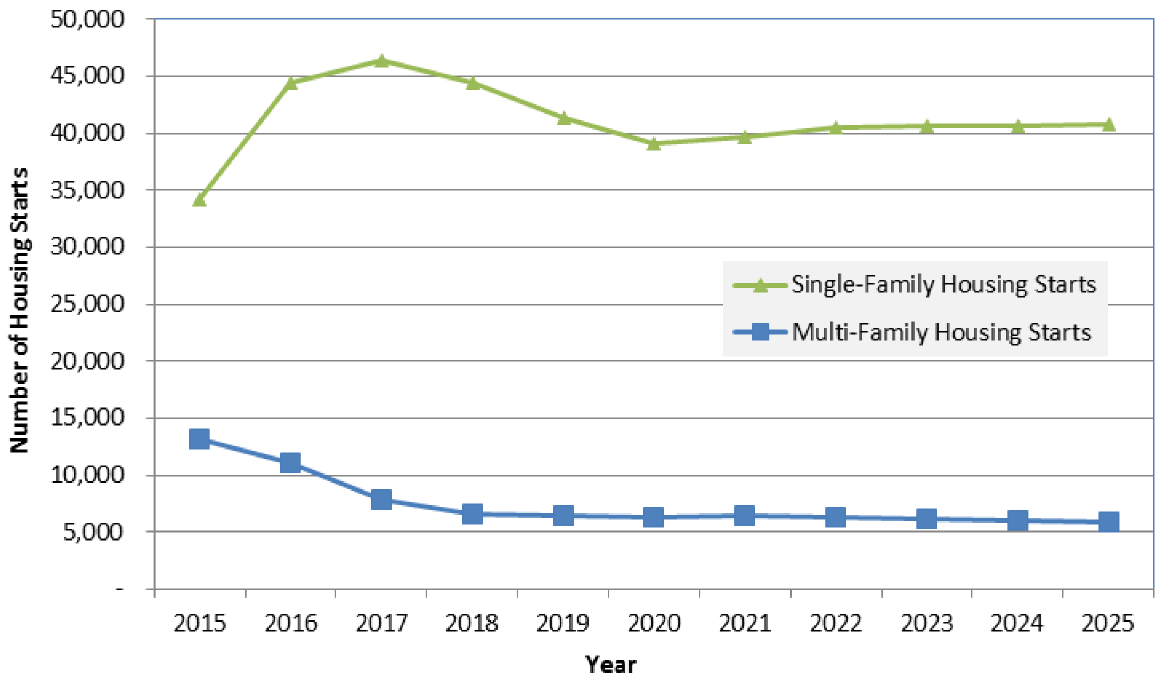

FIGURE 4-1
NUMBER OF HOUSING STARTS USED IN ZNE SCENARIOS

Three ZNE adoption curves were used to estimate number of ZNE-type homes as a percent of all new residential construction for each scenario. The methods and assumptions for each adoption scenario are described below:

- **Scenario 1 Trajectory Case:** The number of ZNE whole buildings was back-calculated by dividing total EE per year due to ZNE-type residential buildings in PG&E territory provided in the IEPR (2013) by the EE savings of a single residential house provided in the Potential Study (Navigant, 2013).[22] The number of ZNE-type homes in PG&E territory was divided by total housing starts in PG&E territory to obtain ZNE-type homes as a percent of total new construction. Based on this calculation, by 2023 approximately 30 percent of new homes adopt ZNE.

- **Scenario 2 High Case:** This case assumed an adoption scenario hybrid of Scenario 1 and Scenario 3 with approximately 53 percent of new home additions adopting ZNE beyond 2020.

[22] Navigant Consulting, "2013 California Energy Efficiency Potential and Goals Study," Final Report, February 14, 2014.

- **Scenario 3 Very High Case:** In Scenario 3, PG&E assumed that 100 percent of new construction will adopt ZNE by 2020 with a technical feasibility limitation of 77 percent per Arup (2012)[23] study mainly due to roof space limitations. The adoption curves for each scenario are shown in Figure 4.2.

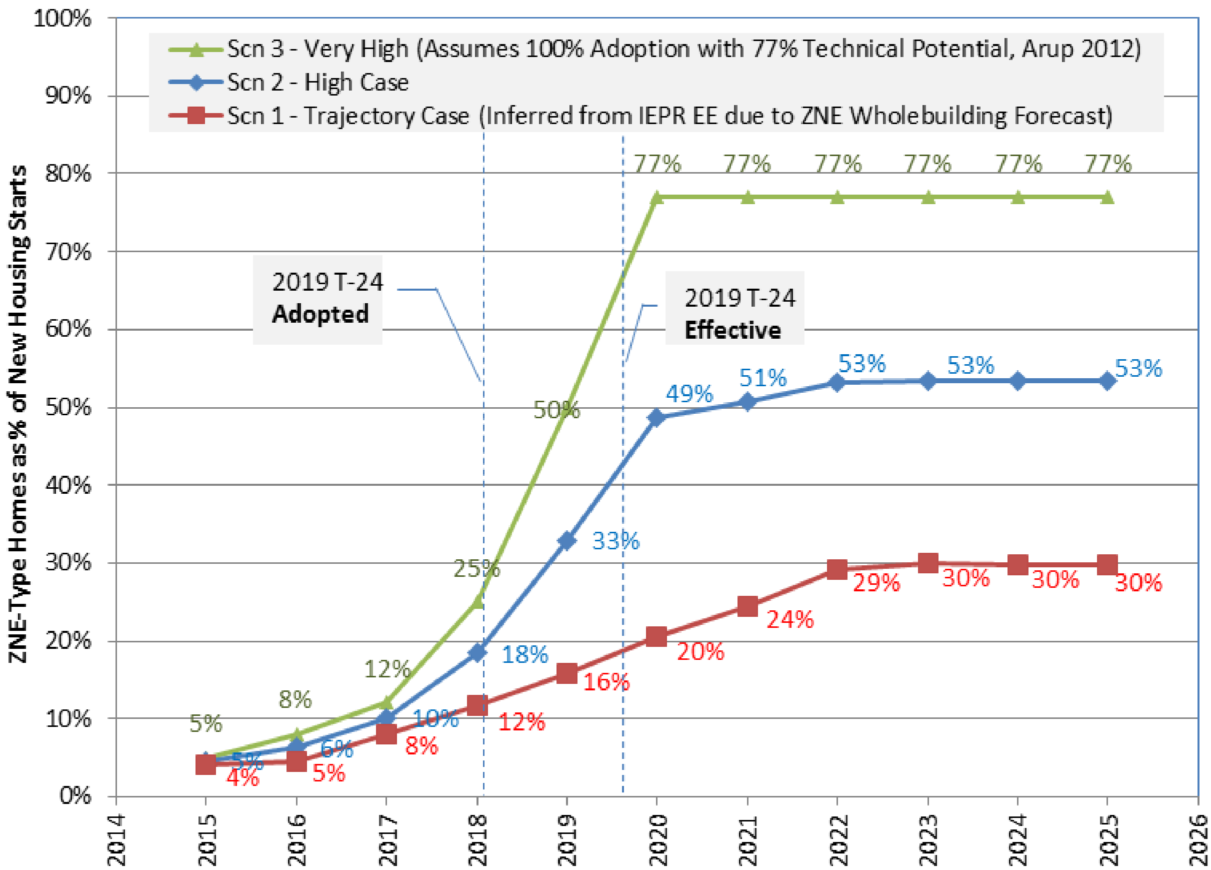

FIGURE 4-2
RESIDENTIAL ZNE PV ADOPTION CURVES

The differences in the three scenarios are mainly driven by the assumed adoption curves shown in Figure 4.2. The adoption curve inferred from IEPR (used in Scenario 1) results in more gradual ZNE-type home adoption, steadily increasing until 2022, whereas the very high scenario adoption curve assumes a dramatic ramp up to meet the state ZNE goals by year 2020.

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23 Arup, "The Technical Feasibility of Zero Net Energy Buildings in California," CALMAC Study ID – PGE0326.01, December 2012.

IEPR (2013) defines a ZNE Code Building as “the one where the net of the amount of energy produced by on-site renewable energy resources is equal to the value of the energy consumed annually by the building measured using the CEC’s Time Dependent Valuation (TDV) metric.”

PV system (kW) capacities to minimize TDV loads in single and multi-family homes per Climate Zone provided by Arup (2012) were used to calculate PV system capacity per ZNE type homes. System sizes for Climate Zone 12 (e.g., Central Valley) and Climate Zone 3 (Central Coast) are shown in Table 4-1 below.

TABLE 4-1
SOLAR PV SYSTEM (KW) SIZE FOR MINIMIZED TDV

House Type	Climate Zones 4, 11, and 12	Climate Zones 1, 2, 3, and 5
Single Family	3.3	2.5
Multi-Family(a)	2.9	2.5

(a) Multi-family PV capacities are for each unit of a Low-Rise Building with total of 12 units.

The kWh energy addition due to ZNE-PV is calculated using a capacity factor of 17 percent. This capacity factor assumes that the future ZNE-PV systems will be west-facing to maximize the TDV value. No PV panel degradation was assumed in the scenarios.

The ZNE-PV scenario model assumed 100 percent of the ZNE-type building loads (electric and gas) will be offset by on-site solar PV systems. No Electric Vehicle (EV) loads were included as a plug load that would be offset by renewable generation.

4.c. Results

For the trajectory case (Scenario 1), ZNE type new home additions are estimated to result in 305 MW cumulative PV nameplate capacity (MW_{ac}) additions which would generate 455 GWh of energy by 2025. Cumulative capacity additions and energy generation for various scenarios are summarized in Table 4-2.

TABLE 4-2
ZNE-PV CUMULATIVE-DRIVEN PV ADOPTION SCENARIOS

	Cumulative Capacity (MW) Additions by			Cumulative Energy (GWh) Additions by		
Scenarios	**2015**	**2020**	**2025**	**2015**	**2020**	**2025**
Scenario 1	6	98	305	9	146	455
Scenario 2	6	176	548	10	262	816
Scenario 3	7	256	798	10	381	1,189

Annual and cumulative incremental MW nameplate capacity additions per year for each scenario are shown in in Figures 4.3 and 4.4, respectively. Cumulative energy generation (GWh) is shown in Figure 4.5.

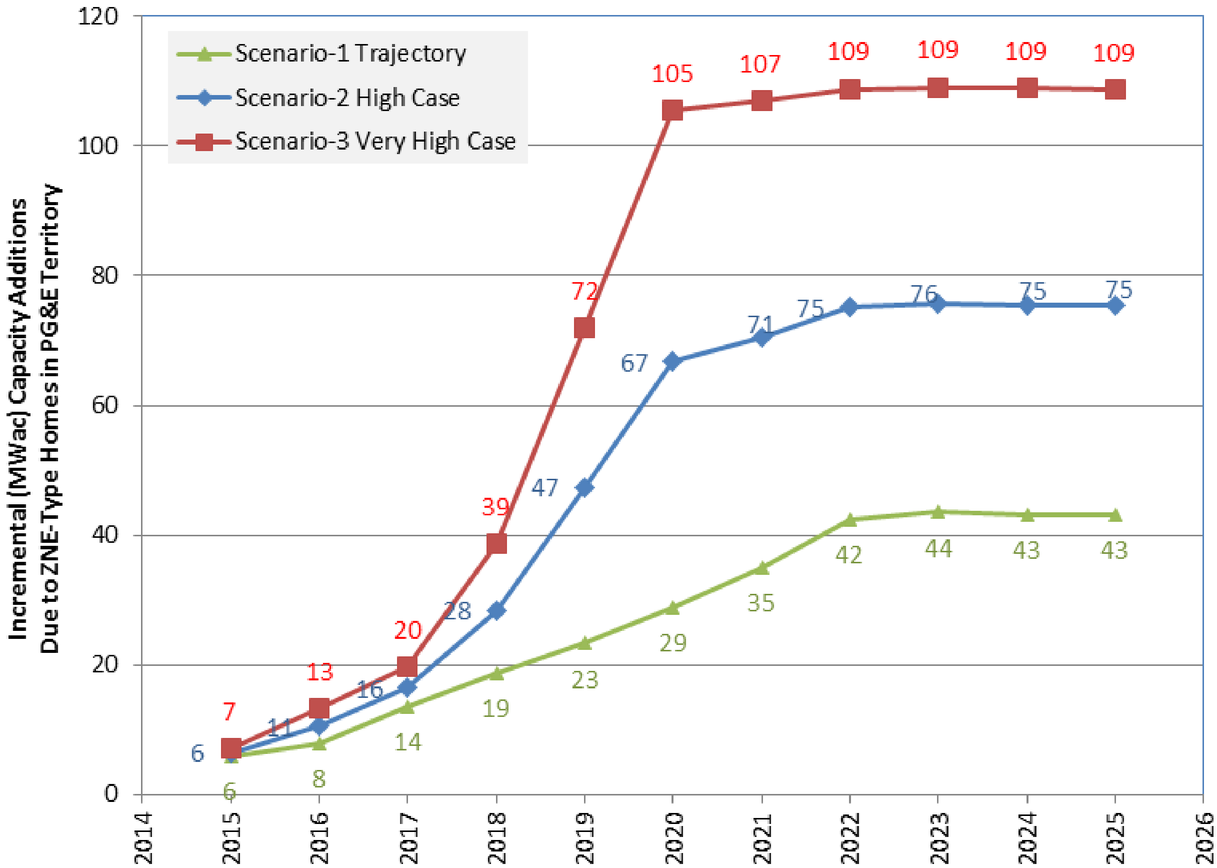

FIGURE 4-3
ZNE-PV INCREMENTAL CAPACITY (MW) ADDITIONS BY SCENARIO

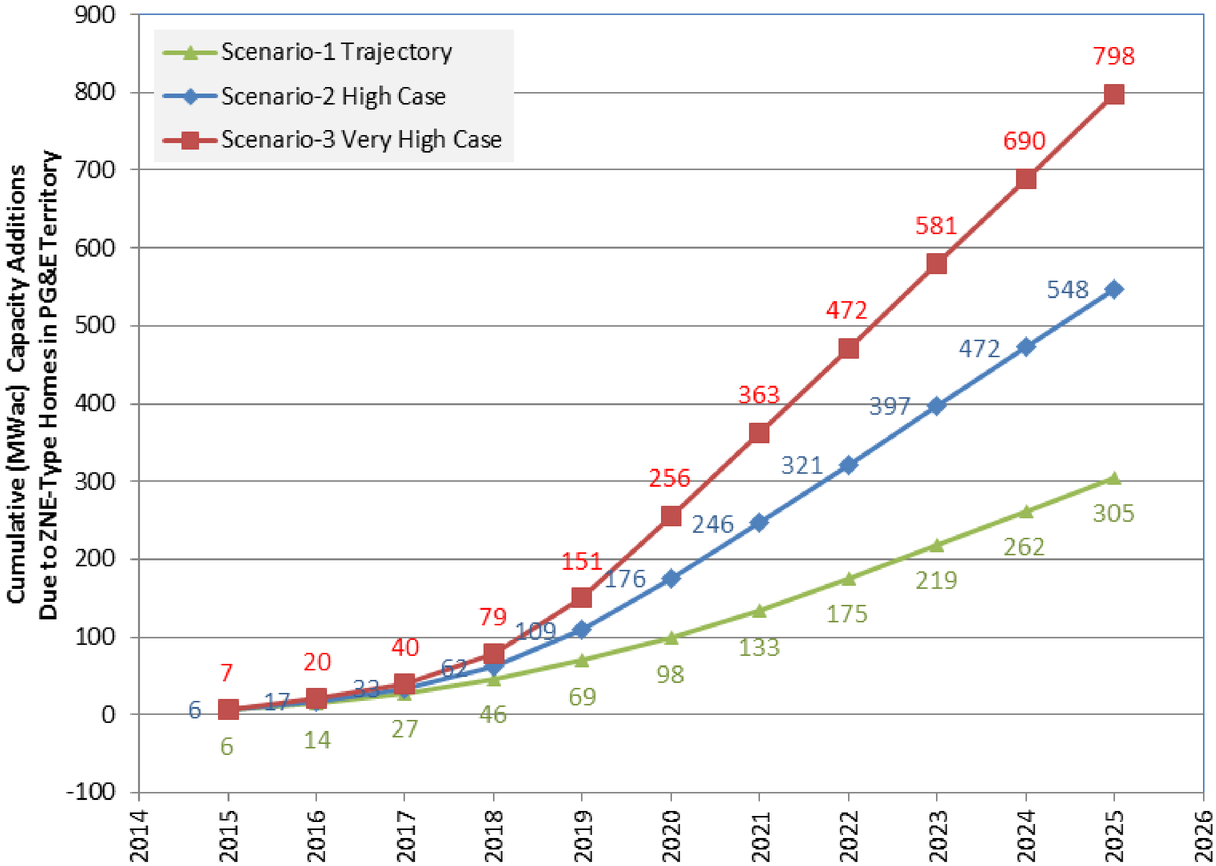

FIGURE 4-4
ZNE-PV CUMULATIVE CAPACITY (MW) ADDITIONS BY SCENARIO

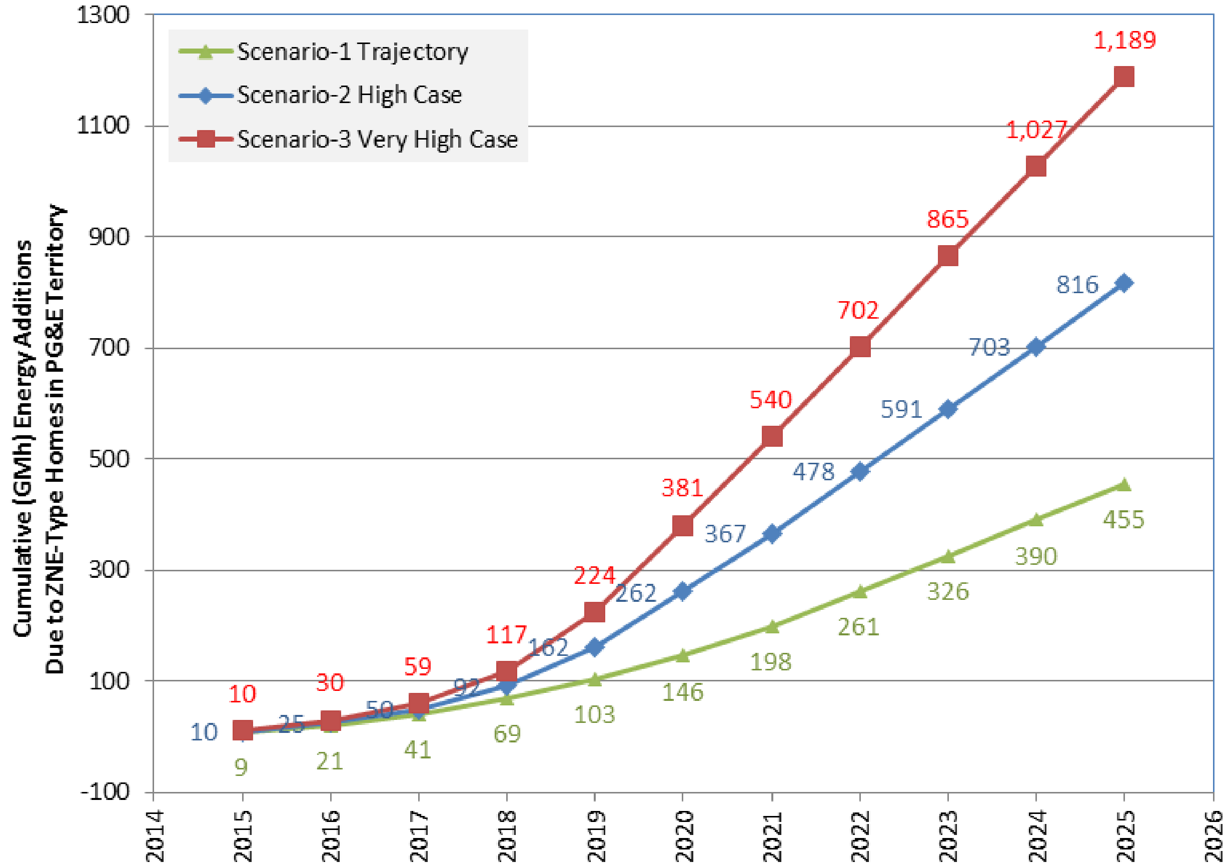

FIGURE 4-5
ZNE CUMULATIVE GWH ENERGY GENERATION BY SCENARIO

In Scenario 1, the top 15 counties with the highest cumulative ZNE-PV capacity additions by 2025 are shown in Table 4-3. Of the 47 PG&E counties considered, the top 15 counties account for 81 percent of the cumulative ZNE-PV capacity additions by 2025. Fresno, Santa Clara, Kern, San Joaquin, and Contra costa counties are estimated to have the highest ZNE-PV penetration by 2025.

TABLE 4-3
ZNE-PV CUMULATIVE MW FOR TOP 15 COUNTIES IN 2025, TRAJECTORY CASE

County	Cumulative Capacity (MW) by 2025	Running % of Total
Fresno County	39.6	13%
Santa Clara County	30.4	23%
Kern County	26.2	32%
San Joaquin County	24.7	40%
Contra Costa County	22.4	47%
Alameda County	16.8	52%
Solano County	12.1	56%
Placer County	11.8	60%
Monterey County	11.6	64%
Sonoma County	10.5	68%
San Luis Obispo County	10.2	71%
Butte County	9.9	74%
Yolo County	8.9	77%
Yuba County	6.3	79%
Merced County	6.0	81%

4.d. Key Findings

Based on the trajectory (Scenario 1) scenario, cumulative solar PV capacity additions due to ZNE-type homes could increase from 6 MW in 2015 to 305 MW in 2025. Cumulative ZNE-PV capacity is estimated to increase from 1 percent of total cumulative retail solar PV capacity in 2015 to 6 percent in 2025. Fresno, Santa Clara, Kern, San Joaquin, and Contra Costa counties account for nearly half of the ZNE-PV adoption by 2025.

The PV capacity additions are controlled by the number of new housing starts, the system size by climate zone, and the percent of the county that is served by PG&E. Based on Moody's data, single family houses represents 72 percent of new housing starts in 2015. The proportion of single family houses increases to around 87 percent by 2017 and stabilizes at that level. Therefore, the ZNE-PV adoption scenarios are primarily driven by number of single family houses, a variable that is highly dependent on general economic conditions and population growth.

4.e. Limitations and Caveats

PG&E's ZNE-PV scenarios represent its best estimate of future growth of solar PV capacity additions due to ZNE type residential new home additions in various PG&E counties. In addition to uncertainty in policy and market developments, the ZNE-PV scenarios are subject to uncertainty because they use broad system level assumptions, such as number of units per multifamily building, which are highly dependent on economic variables and may not accurately represent averages in PG&E's territory. Therefore, the ZNE-PV scenarios should be considered directional.

Market adoption of ZNE homes is the most significant source of uncertainty in the growth scenarios. The number of ZNE homes is not only influenced by building codes and regulatory considerations, but also by of the market choices homeowners and developers in the market.

4.f. Recommendations for Future Planning

PV capacity additions due to ZNE adoption are currently modeled at the county level. A more geographically granular housing permit forecast could be used as a foundation for a feeder level ZNE-PV modeling in the future. In addition to more granular geographic information for housing starts, refining the PV capacity factor assumptions by climate zone or geographic area could improve the accuracy of ZNE-PV energy generation.

Finally, sensitivity studies could be added to model potential future changes. For example, the TDV values could change with changes in peak load, electric vehicles may be included in building load, and off-site renewable generation may be assumed for buildings with limited rooftop space.

5. Electric Vehicles

5.a. Introduction

At the end of 2014, PG&E had approximately 58,000 Plug-in Electric Vehicles (PHEV)[24] in its service territory. The resulting load and peak capacity contributions of these EVs is estimated to have been approximately 182 GWh and 16 MW. It is difficult to develop EV growth scenarios given the nascent market and the rapid changes that are occurring in public policies. In order to respond to the CPUC guidance for DER Growth Scenarios PG&E's leveraged: (1) aggregated registration and rebate data available through the end of 2014; (2) policy goals declared through January 2015 as well as modeling of compliance for existing policy; and (3) EV adoption scenarios developed by ICF International in the California Electric Transportation Coalition (CalETC) Transportation Electrification Assessment.[25] The following describes the development of, and learnings from, the EV DER Growth Scenarios and their geospatial allocation.

5.b. Methods and Data Sources

5.b.i. Adoption Scenarios and Geospatial Modeling

To develop the EV inputs to PG&E's DRP, three EV adoption growth scenarios were developed in line with the CPUC's DRP guidance:

- Scenario 1 – "Trajectory"[26]
    - Reflects historical growth rates from recent years.
    - Out years adoption based on CalETC Transportation Electrification Assessment EV scenarios—midpoint between "ZEV Compliance" and "Aggressive Adoption" scenarios, these were chosen to sync with recent adoption growth rates.

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[24] Includes both PHEV and Battery Electric Vehicles (BEV).

[25] CalETC, "California Transportation Electrification Assessment, Phase 1 Final Report," September 2014, p. 8. http://www.caletc.com/wp-content/uploads/2014/09/CalETC_TEA_Phase_1-FINAL_Updated_092014.pdf.

[26] PG&E's growth scenario for EV load assumes approval and implementation of PG&E's EV Infrastructure and Education Program, currently pending before the CPUC. If PG&E's Program is not approved, the projected EV load is likely to be significantly less than provided in this growth scenario.

- Generally consistent with Governor Brown's goals in ZEV Action Plan which are driving current policy and regulatory decisions.
- Under this scenario, EV load aligns with 2014 IEPR Update mid case and therefore aligns with guidance to "adopt/adapt IEPR."

- Scenario 2 – "High Growth"
  - Adoption based on CalETC Transportation Electrification Assessment EV "Aggressive Adoption" scenario.
  - Under this scenario, EV load aligns with 2014 IEPR Update high case and therefore aligns with guidance to "adopt/adapt IEPR."
- Scenario 3 – "Very High Growth"
  - This scenario is based on Governor Brown's goal to "reduce today's petroleum use by cars and trucks by up 50 percent [by 2030]."[27]
  - PG&E modeled EV adoption if all petroleum reduction beyond existing regulations (which will currently create ~20% reduction by 2030) is achieved by EVs displacing internal combustion engines.
  - This is a -stress-test scenario because the goal has yet to be codified by legislation or regulations and because other measures could be used to help achieve petroleum reductions (e.g., reduce vehicle miles traveled with increases in public and shared transportation, increase internal combustion engine vehicle efficiency, and reduce carbon intensity of fuel by strengthening the Low Carbon Fuel Standard).

The methodology for converting the adoption into load and peak capacity contribution, explained below, remained consistent across all three scenarios. Figure 5-1 provides capacity contribution at system peak to indicate the overall magnitude of the impact of EVs at the PG&E total system level, however the system peak is not necessarily the hour of interest when evaluating a specific distribution circuit. Therefore, PG&E's distribution planning tools also utilize an average 24-hour load profile per EV in combination with the number of cars expected in each county in order to determine impacts at the distribution level.

[27] Edmund G. Brown Jr., Inaugural Address, Remarks as Prepared, January 5, 2015, http://gov.ca.gov/news.php?id=18828.

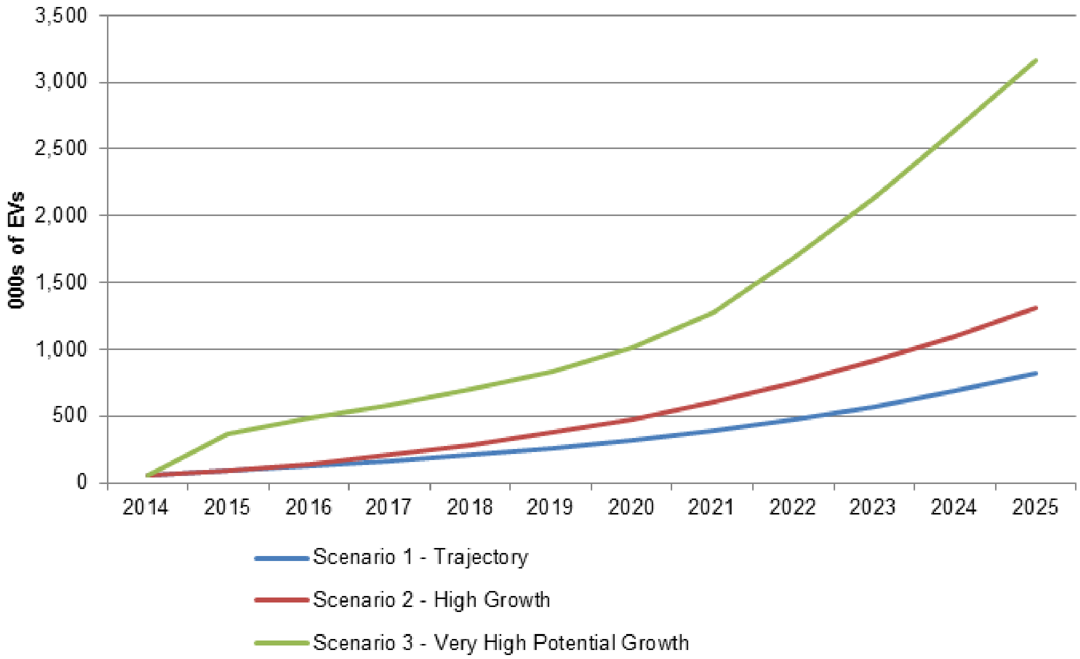

FIGURE 5-1
EV ADOPTION SCENARIOS FOR PG&E SERVICE TERRITORY

Once the system level growth scenarios were developed, the annual values were allocated to a county level based on data from the Clean Vehicle Rebate Project (CVRP). The 2014 CVRP data provides number of rebates issued for EVs by zip code[28] but because not all EV adopters apply for and receive CVRP rebates, this zip code level data set was aggregated at the county level to smooth out zip code level variability in the geospatial spread of the adoption scenarios (on a proportional basis). The proportion of rebates issued in a county to the total number of rebates issued was calculated. This proportion was multiplied by the systemwide adoption, peak capacity, and load estimated for each scenario in each year.

[28] Center for Sustainable Energy (2014). California Air Resources Board, Clean Vehicle Rebate Project, Rebate Statistics. Data last updated December 2014. Retrieved December 30, 2014 from http://energycenter.org/clean-vehicle-rebate-project/rebate-statistics.

The geospatial spread of the growth scenarios is assumed to be constant through 2025. It is not feasible at this time to estimate how demographics and locations of EV adopters will shift over time (see Limitations and Caveats).

5.b.ii. Load Impact Modeling

In order to determine the load and capacity characteristics of the growth scenarios, assumptions regarding driving behavior and vehicle technology need to be made. PG&E assumes charging behavior (e.g., home vs. non-home charging), driving behavior (e.g., miles per year), and vehicle technology (e.g., charging levels, miles/kWh efficiency) in line with current trends through the duration of the growth scenarios. According to PG&E's Electric Vehicle Load Research Report, on average, each EV uses 10 kWh/day or 3.65 MWh annually.[29] This is consistent with national data regarding average driving behavior and opportunity for electrifying vehicle miles traveled.[30] The energy use per EV is held constant through 2025. Decreasing electricity use resulting from efficiency increases in the electric engines is assumed to be offset by an increasing proportion of miles traveled in PHEVs being fueled by electricity as the typical battery size increases.

On the capacity side, PG&E developed an aggregate charging load profile by developing a weighted average of three load profiles that represent the vast majority of EV charging (Figure 5-2). PG&E assumed 80 of percent charging at occurs at home[31] (30% on the EV rate and 70% on non-EV rates[32]) and 20 percent of charging at occurs at work or in another public

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[29] "Joint IOU Electric Vehicle Load Research Report," Compliance Filing (pursuant to D.13-06-014 and D.11-07-029), December 23, 2014, p. 23. http://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M143/K954/143954294.PDF.

[30] Transportation Statistics Analysis for Electric Transportation. Electric Power Research Institute (EPRI), Palo Alto, CA: 2011. 1021848.

[31] CalETC, "California Transportation Electrification Assessment, Phase 1 Final Report," October 2014, p. 31, http://www.caletc.com/wp-content/uploads/2014/10/CalETC_TEA_Phase_2_Final_10-23-14.pdf.

[32] In 2014, the proportion of customers on PG&E's EV rate was approximately 30 percent of total EV registrations in PG&E's service territory according to Polk Registration Data and EPRI.

location. The aggregate charging profile has each EV, on average, contributing 0.32 kW at peak hour (Aug HE17).

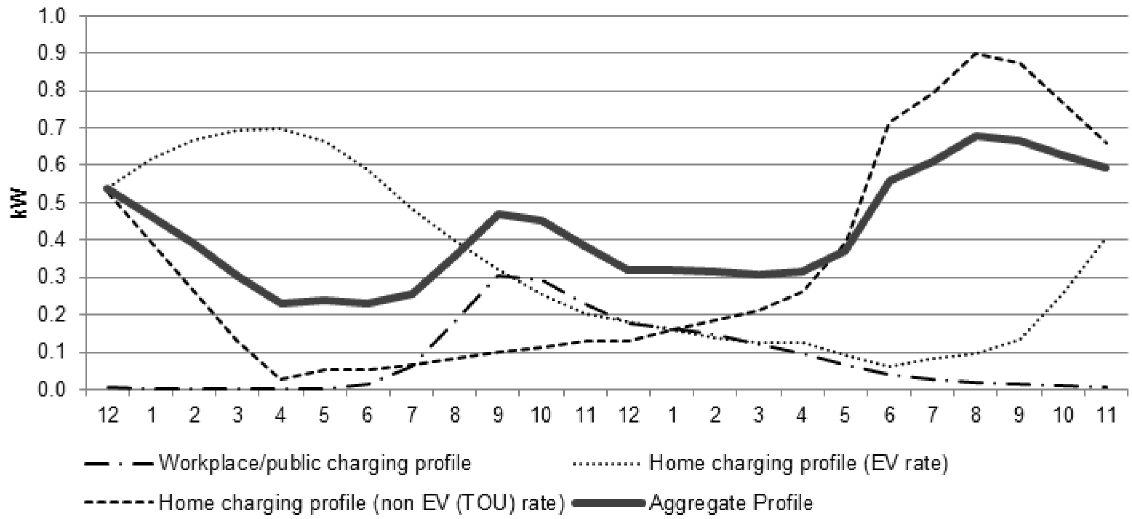

FIGURE 5-2
AVERAGE CHARGING LOAD PROFILE PER EV

The total contribution to system peak is calculated by multiplying the contribution to peak per car by the cumulative number of EVs expected in PG&E service territory through August of each year in the scenarios.[33]

5.c. Results

According to the CVRP data, EV adoption is concentrated in the Bay Area. The five counties with the most EVs, Santa Clara, Alameda, San Mateo, Contra Costa, and San Francisco Counties, account for over 75 percent of adoption.

Under Scenario 1, the load impact of EVs grows to around 2,800 GWh or around 3 percent of system load in 2025. Even under the very aggressive assumptions in Scenario 3, EVs would account for only around 10 percent of PG&E system load.

[33] PG&E analysis of monthly Polk vehicle registration data for 2010-2014 indicated that an average of 70 percent of each year's EV adoption had occurred by the end of August.

The capacity impact at a system level is low to moderate, currently EVs contribute around 0.1 percent to PG&E's system peak. In 2025 EV contribution to system peak capacity is only projected to be 1-5 percent across the three growth scenarios. However, given the geographically concentrated nature of EV adoption local distribution system impacts could be much more significant.

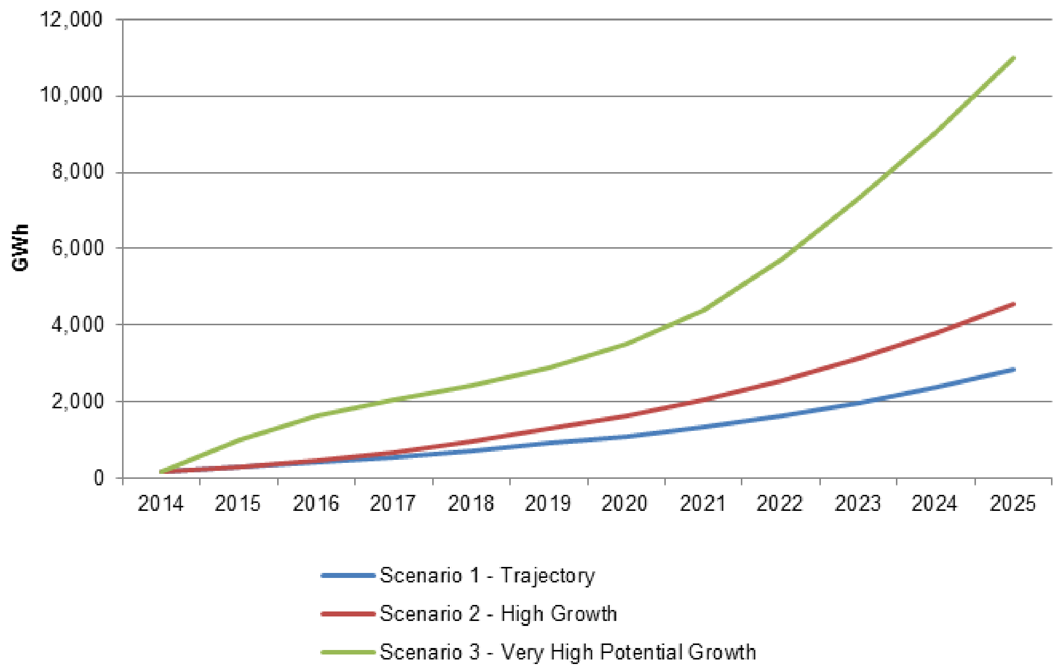

FIGURE 5-3
CUMULATIVE ADDITIONAL EV LOAD POST 2014

As a point of comparison, PG&E's load projection under Scenario 1 aligns fairly closely with the CEC's view of EV load in PG&E's service territory[34] (Figure 5-4).

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[34] California Energy Demand Updated Forecast, 2015-2025, Form 1.1 - PGE Planning Area, http://www.energy.ca.gov/2014_energypolicy/documents/demand_forecast_cmf/Mid_Case/.

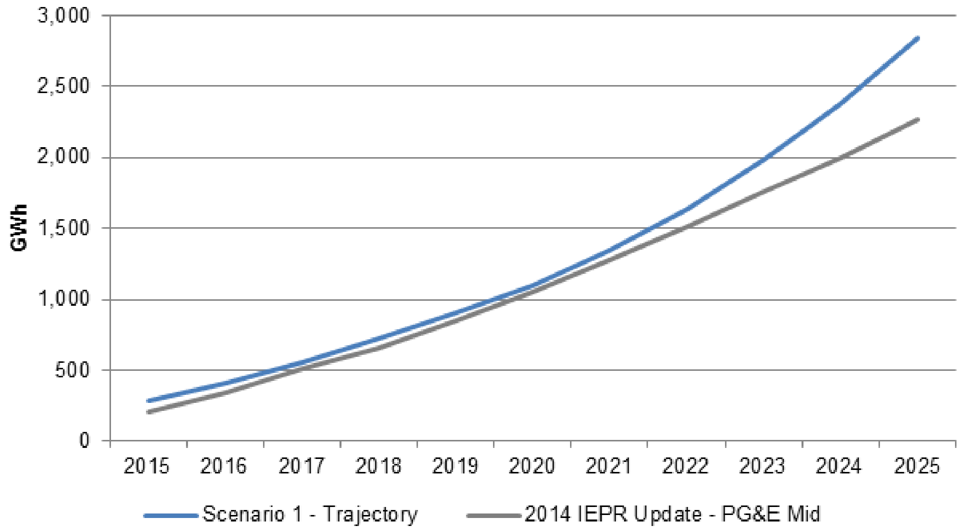

FIGURE 5-4
PG&E DRP SCENARIO 1 COMPARED TO IEPR FOR LOAD FROM EVS IN PG&E SERVICE AREA

The total contribution to system peak is calculated by multiplying the contribution to peak per car by the cumulative number of EVs expected in PG&E service territory through August of each year in the scenarios.[35] The resulting contribution to system peak capacity can be seen in Figure 5-5.

35 PG&E analysis of monthly Polk vehicle registration data for 2010-2014 indicated that an average of 70 percent of each year's EV adoption had occurred by the end of August.

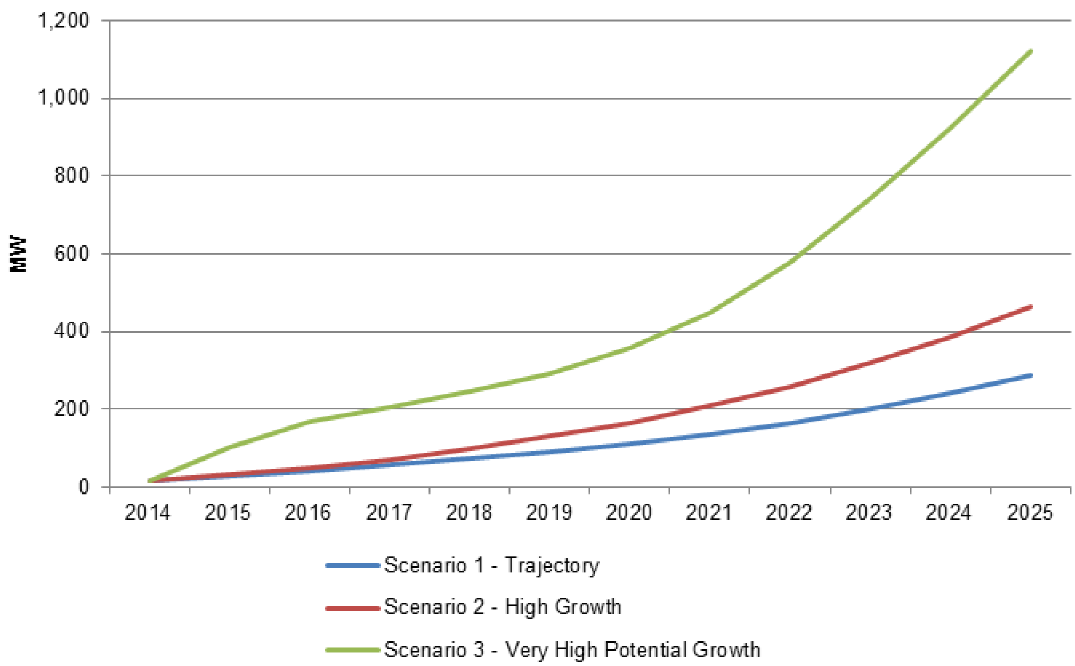

FIGURE 5-5
CUMULATIVE EV LOAD AT SYSTEM PEAK (AUG HE 17)

5.d. Key Findings

Electric Vehicles are different than many other DERs in that average EV load does not vary in a significant way as a result of the day, season or weather. The average EV load profile may shift over the horizon of these scenarios for many reasons: increases in the power level of charging technologies, proportion of customers on EV rates (and therefore more likely to charge off peak), and the proportion of PHEV versus BEV adoption. However, changes in these factors could also counterbalance each other and result in the average EV load profile remaining constant.

The methodology for developing EV load and capacity contribution at the PG&E system level is robust, however, PG&E's ability to model geographic dispersion of this load on the distribution system is less well developed. This is inherently difficult to estimate due to the fact that the vehicles may plug in at different locations throughout the day. Additionally, this geospatial scenario analysis is limited by data availability, for example, PG&E knows the aggregate number of EVs that have been registered but only knows the home location of less than a third of those vehicles (due to the customer being on an EV rate tariff).

5.e. Limitations and Caveats

Currently, EV data is available at aggregate levels that are well suited to development of total system-level growth scenarios, but more geospatial resolution is needed to model impacts on distribution assets.

The market for electric vehicles is in a relatively early stage of development, and subject to strong policy support that may drive adoption rates in California. Existing policies will likely be augmented by new policies in response to Governor Brown's Executive Order and stated goals that will combine with other adoption drivers to impact both the rate and geospatial dispersion of EV adoption. Additionally, when developing scenarios out to 2025, assumptions regarding driving behavior and vehicle technology need to be made. This report assumes charging behavior (e.g., home vs. non-home charging), driving behavior (e.g., miles per year), vehicle technology (e.g., charging levels, miles/kWh efficiency), and geographic patterns of adoption remain in line with current observations through the duration of the growth scenarios. Future iterations may incorporate refinements to these assumptions as new data becomes available.

5.f. Recommendations for Future Planning

As stated above, a key limitation in creating geospatial scenarios for EVs is data availability. The recommendations for future planning are all related to this issue:

- Increase the amount and geographic resolution of data available for planning; data improvements on EV adoption, charger type, charging profile, and location of non-primary charging, i.e., for a residential customer that charges 80 percent at home, even if PG&E knows the home location
- Develop estimates of geospatial and/or demographic shifts of EV adopters as market penetration increases
- Develop partnerships with commercial customers that are electrifying their fleets to best understand their charging load profiles and the precipitating factors

6. Retail Storage

6.a. Introduction

The retail distributed energy storage (DG storage) scenarios cover all energy storage devices that are or will be installed on retail customer sites, to serve customer load. This is distinct from any grid-connected energy storage that may be deployed to meet the statewide energy storage targets for distribution-connected and transmission-connected storage or that may be procured for other reasons. At the end of 2014, PG&E had 9.2 MW of DG storage interconnected,[36] primarily driven by retail rate arbitrage opportunities and support of DG storage through the SGIP. Almost all of the DG storage growth occurred between the years 2011 to the present.

PG&E included scenarios for retail energy storage according to DRP guidance provided by the CPUC, with the knowledge that DG energy storage deployment faces the following significant uncertainties:

- Retail storage is an emerging technology that has only been available on a limited basis for commercial scale use by customers since 2010.
- There are a low number of completed and queued projects as of April 2015, roughly 350 total in PG&E's territory.
- No CEC forecast for DG energy storage has been developed as part of the IEPR proceeding; therefore the guidance to "adapt" DER forecasts to the IEPR does not apply to DG energy storage.

PG&E made the following modifications to the DRP guidance to model potential DG storage deployment:

- Forecasted DG storage to the county level rather than the feeder level, since a feeder-level forecast would have an extremely high level of uncertainty.

[36] PG&E's Interconnection database (ENOS), retrieved February 1, 2015 from PG&E's Electric Generation and Interconnection Department.

- Divided the forecast into residential and non-residential, since different economic and market drivers exist for each of these categories.

6.b. Methods and Data Sources

As a first step to forming adoption scenarios, PG&E created a set of assumptions for the Trajectory, High and Very High growth scenarios as described below:

- Scenario 1 – "Trajectory"
    - The SGIP continues as the key driver for both Residential and Non-Residential energy storage
    - SGIP incentives cease after 2019, as currently planned. This creates a significant drop in growth rates starting in 2020
    - Non-residential energy storage grows faster in areas with peak shaving target customers on demand rates
    - There is no significant pairing of energy storage with PV systems beyond 2015 levels
- Scenario 2 – "High Growth"
    - The SGIP continues as the key driver for both residential and non-residential energy storage[37]
    - SGIP incentives cease after 2019, as currently planned. This creates a significant drop in growth rates starting in 2020 for residential energy storage. However, the economic drivers of non-residential economic drivers are expected to mature enough by this point that there is no real drop in non-residential storage growth rates
    - Overall growth rates for residential and non-residential storage are higher than the Trajectory case, because storage costs are expected to fall more aggressively
    - NEM policies are expected to change such that "banking" of renewable energy is allowed for later export, and so residential energy storage tracks the growth of PV installations (PV High case), as a "growth adder" to the expected growth of storage

[37] The SGIP database for PG&E, February 2015. Retrieved February 1, 2015 from https://www.selfgenca.com/.

- Scenario 3 – “Very High”
  - SGIP continues as the key driver for both residential and non-residential energy storage
  - SGIP incentives continue well into 2025, so aggressive growth rates continue for both residential and Non-Residential energy storage
  - NEM policy changes, along with more aggressive statewide Renewables Portfolio Standards (RPS) requirements cause both Residential and Non-Residential energy storage growth rates to track PV growth rates as an additional “growth adder” (Very High PV case)

Figure 6.2 shows the growth rates and adders assumed for each scenario.

PG&E expects retail storage adoption to fluctuate year over year but follow a steady growth trajectory over the next 10 years. The general method throughout the retail energy storage forecast is to assign a compound annual growth rate to the technology post 2016, with separate growth rates for the residential and non-residential sectors. For estimated growth in 2015, PG&E used SGIP and PLS installed and pending projects to estimate added capacity. The 2015 energy storage installations were calculated using the following methodology:

- All “Incentive Claim Form” and “Payment Complete” SGIP projects in queue will be installed in 2015: Late Stage Queue.
- All other queued projects are subject to an attrition rate: 45 percent residential, 40 percent non-residential (derived from actuals): Early Stage Queue.
- New Project Adoption based on actuals: 95 percent residential, 14 percent commercial.

  2015 Energy Storage Installations = (Late Stage Queue + (Early Stage Queue * attrition)) * New Project Adoption

After applying the above equation, the four queued PLS energy storage projects were added to their respective counties. Counties in PG&E territory with no energy storage in 2015 were assigned energy storage installations starting in 2017, scaled to population based on average MW of energy storage per population of other counties, and divided into residential and non-residential based on the average residential/non-residential ratio in 2015.

The non-residential energy storage compound growth rates post 2016 are lower than residential, because there has been greater past adoption of non-residential energy storage, whereas residential energy storage is just recently becoming established, mainly by pairing with residential PV systems.

Growth rates based on the SGIP database are not necessarily representative of future growth, because there were a number of policy factors, such as the timing of the NEM-paired storage decision (D.14-05-033) that caused developers to delay progress of their SGIP applications and therefore distorted the energy storage installation numbers.

Instead, energy storage growth rates were selected by benchmarking against industry reports,[38] while keeping the overall energy storage growth within the confines of the statewide energy storage targets (the lower bound). The energy storage growth rates also assume that residential energy storage will take on a more aggressive growth, primarily driven by PV pairing, whereas non-residential energy storage growth will be slower on a basis, and more tied to target customer segments: hotels, supermarkets and hospitals. In order to identify the counties that had the highest prevalence of these key customers, PG&E analyzed the total 2014 numbers of these businesses per county by NAICS codes in 2012 as well as hotel market penetration in 2014,[39] took an average, and then identified counties that had above-average prevalence of these businesses. PG&E also identified the counties that had the highest prevalence of Large and Medium Commercial customers. The reason that Large Commercial and Medium Commercial customers were chosen as the PG&E customer types to assign scalars

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[38] a) Manghani, Ravi; *U.S. Energy Storage Monitor Year in Review,* Greentech Media Research, December 2014.

b) Munsell, Mike; Commercial Energy Storage Market to Surpass 720MW by 2020, Greentech Media, Retrieved February 6, 2014: http://www.greentechmedia.com/articles/read/Commercial-Energy-Storage-Market-to-Surpass-720-MW-by-2020.

[39] a) Dean Runyan and Associates, *California Travel Impacts by County*, 1992-2012, prepared for the California Office of Business Development, Retrieved 2014 http://www.deanrunyan.com/doc_library/CAImp.pdf.

b) U.S. Census (2012), *2012 County Business Patterns* (NAICS) for California, Retrieved February 1, 2015 at: http://censtats.census.gov/cgi-bin/cbpnaic/cbpdetl.pl.

is because these types of customers are most like to be on demand rates, and peak shaving for non-residential customers on demand rates presents one of the most lucrative economic drivers for energy storage. PG&E then took averages of the percent prevalence of Medium and Large Customers, and noted the counties that emerged as above average. The additional growth scalars in Figure 6-2 were then added to the counties with the highest concentration of target customers by business type and/or by PG&E customer size.

The Trajectory case assumes that residential energy storage growth rates will decline by 50 percent after 2020, and that non-residential energy storage growth rates will decline by 5 percent after 2020, due to the cessation of the SGIP incentive. The High case assumes that only the Residential storage will decline by this amount, assuming that SGIP will not be needed to make the Non-Residential storage economically viable by 2020.

Finally, in all cases, energy storage is taken offline after ten years of operation (e.g., the incremental installations in 2020 subtract the energy storage installed in 2010). The true effects of this assumption in the forecast do not become apparent until 2020. outlines the detailed methodology.

TABLE 6-1
RETAIL ENERGY STORAGE GROWTH SCENARIO METHODOLOGIES

Scenario	Residential	Non-Residential	Additional Scalars	Sources
Trajectory	85% CAGR, 35% after 2020	10% CAGR, 5% after 2020	*Non-Res* • Counties above state averages for hotels, hospitals, supermarkets and E19/20 usage: 15% CAGR: Alameda, Monterey, San Francisco, San Mateo, Santa Clara • Alameda adjusted down to 12% because of early adoption distortion (Santa Rita Jail) • San Francisco adjusted to 25% CAGR because of hotel prevalence • Fresno above average on hospitals, supermarkets and E/19/E20 usage: 13% CAGR • Contra Costa and Sonoma are above on hospitals and supermarkets, close to average on E/19E/20, so 12% CAGR	Res CAGR projected as roughly half of historical rates (historical rates disrupted by regulatory and SGIP fits and starts) Non-Res CAGR positioned to keep non-res proportional to res as demonstrated in GTM reports 3) 2012 census data, NAICS data by county and PG&E feeder data for scalars
High	Traj. + Solar adders High case	20% CAGR	*Non-Res* • Above average counties for hotels, hospitals, supermarkets and E-19/E-20 usage boosted to 20% • Alameda adjusted down to 15% • Fresno adjusted to 25% • Contra Costa and Sonoma adjusted to 23% *Res* • Additional year-on-year growth adder from Solar PV forecast Trajectory to High case	All of the above, and: 1) Solar PV forecasts
Very High	Traj. + Solar adders Very High Case	20% CAGR + Solar adders High case	*Non-Res* • Same as High, except Solar PV growth adder based on Trajectory to High *Res* • Same as High except Solar PV growth adder based on Trajectory to Very High	All of the above, and: 1) Solar PV forecasts

6.c. Results

The Trajectory energy storage case very closely follows the PG&E statewide targets for Customer energy storage targets under Assembly Bill (AB) 2514. This result was not by design, but was a natural result of the growth rates, customer segment adders, and rate of retirement of energy storage put online. The High and Very High cases present more than twice and more than three times the energy storage adoption shown in the Trajectory case, respectively, though both of these cases show less than the assumed energy storage adoption for PG&E territory by key industry reports. These are not surprising results, since both the high and very high scenarios assume a growth adder reflecting the incremental growth of PV for each year, and PV is expected to continue very robust growth.

Interestingly, in all cases, the residential energy storage installations measured in MW begin to exceed the MW of installed non-residential energy storage starting in the year 2020. PG&E believes that this is a reasonable result, because the installations of residential energy storage have historically been closely tied to PV installations, whereas non-residential energy storage installations have been driven by very specific customer segments on demand rates. It is reasonable to assume that the most appealing target customers on the non-residential side will have already installed energy storage by 2020, and that residential energy storage will continue to follow PV growth, regardless of the viability of residential rate arbitrage opportunities, because residential customers place a high value on back-up and resiliency uses of energy storage. In addition, the cumulative growth of non-residential energy storage begins to slow after 2020 simply because energy storage devices installed 10 or more years prior begin to come offline at that point.

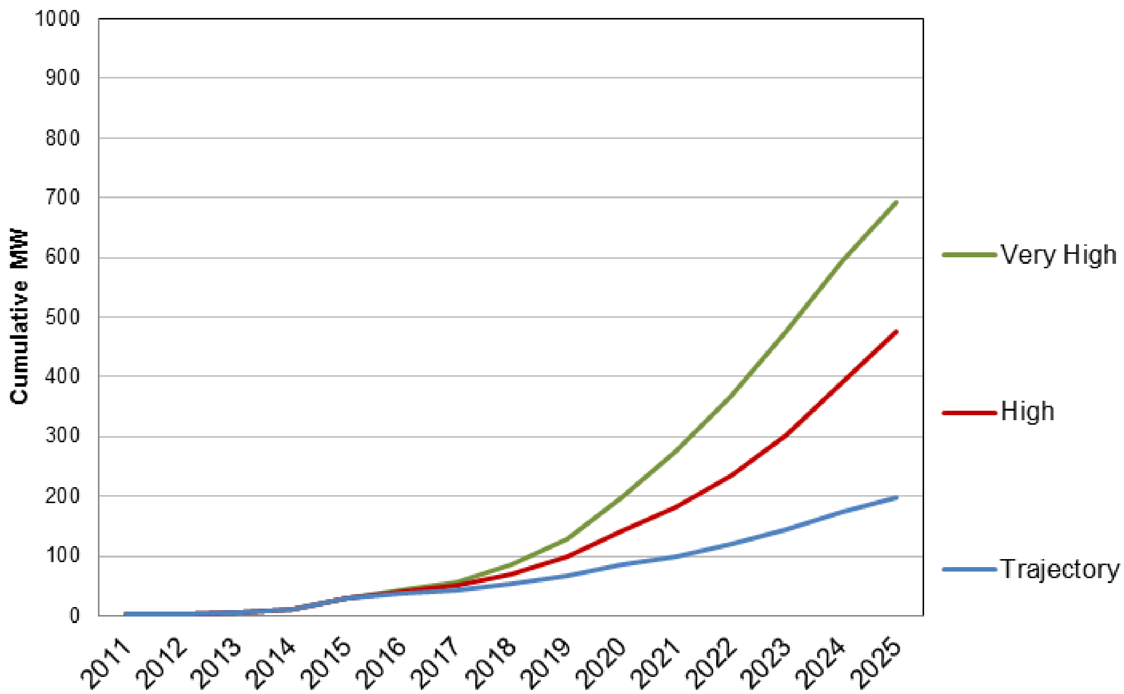

FIGURE 6-1
RETAIL ENERGY STORAGE GROWTH SCENARIO RESULTS

6.d. Key Findings

One of the primary key findings of this analysis is that storage installations vary widely by location. In general, energy storage has been installed in places of high population and high commercial activity, as well as in places with high current and expected PV installations. These findings are not surprising, since the economics of energy storage are the strongest for customers on demand rates, and these customers tend to be located in areas of high commercial activity. Since energy storage is currently being offered as a package deal with PV systems,[40] it is also not surprising the energy storage is following PV installations, especially on the Residential side.

40 http://www.solarcity.com/residential/backup-power-supply.

Another key finding is the fact that in the estimated growth scenarios, storage comes offline after 10 years of useful life as the adoption curves follow a typical "S" curve pattern of technology adoption. However, the storage market is not yet commercial scale and therefore not near saturation, as the inflection point of the "S" curve tends to indicate. As the economics of energy storage become clearer and commercial scale markets emerge, the ability to assess the longer-term deployment of DG storage should improve.

6.e. Limitations and Caveats

Several key limitations and caveats in the retail storage geospatial forecast must be considered. First and foremost, the current level of energy storage installations at fewer than 500 projects and only five years of installations does not yet create a basis for a robust, statistically significant bottom-up geospatial forecast. In addition, the growth of energy storage is closely tied to economic drivers, and there is still uncertainty about the future of key economic drivers that will affect the growth of both Residential and Non-Residential energy storage. The key policy drivers that also may undergo changes that will affect the drivers of energy storage are:

- Net Energy Metering policy
- DR policy
- Time-of-Use rate policy
- Self-Generation Incentive Program changes
- PLS Program changes
- CAISO wholesale market opportunities

As such, this geospatial forecast reflects PG&E's current understanding of the policies, programs and market opportunities for storage over the next 10 years, but this understanding may change as these key drivers evolve.

6.f. Recommendations for Future Planning

Because this is a first effort for PG&E to create a bottom-up, county level geospatial growth scenario for retail energy storage, and there is significant uncertainty regarding future market and policy drivers that will affect storage adoption, these growth scenarios presented here should be considered a 'first pass.' As more projects are installed and policies emerge, PG&E and the other IOUs may gain a better understanding of adoption drivers and can make a more informed assessment of retail energy storage growth scenarios.

7. Wholesale DG (Solar, Bioenergy and Small Hydroelectric)

7.a. Introduction

For the purposes of the July 2015 DRP, PG&E developed 10-year county-level growth scenarios of wholesale renewable generation ("wholesale DG") capacity additions, less than or equal to 20 MW, that will interconnect to PG&E's distribution grid.[41] Results are produced under three DER growth scenarios—"trajectory growth," "high growth," and "very high growth"—per Commission guidance issued under Rulemaking 14-08-013. Technology types included in these scenarios include solar photovoltaic (solar PV), small hydroelectric, and bioenergy resources. This mix of technologies represents the predominant wholesale renewable generation technologies interconnected to PG&E's distribution grid.[42] These scenarios also provide annual generation estimates associated with these capacity additions over the same 10-year time period using generic capacity factors, by technology. While Commission guidance on the DER growth Scenarios 1 and 2 ("trajectory" and "high growth") requests alignment with the CEC's IEPR forecast cases, forecasts for wholesale DG have not been developed as part of the IEPR proceeding. Therefore, alignment with the IEPR does not apply to the wholesale DG growth scenarios. PG&E included distribution-connected wholesale resources in its DER growth scenarios as they impact distribution planning requirements.

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[41] For the purpose of these scenarios, wholesale DG is defined as electric generation resources less than or equal to 20 MW, interconnected to PG&E's distribution grid, on the utility-side of the meter.

[42] Wind and geothermal resources, although eligible under the Renewable Auction Mechanism (RAM) program, are not included in these growth scenarios given the limited number of projects in PG&E's bundled electric portfolio which have been procured under the RAM program and are interconnected at the distribution-level. While wind and geothermal resources are not included in these growth scenarios, PG&E recognizes the possibility that both wholesale wind and geothermal projects may interconnect to PG&E's distribution grid in the future.

At the end of 2014, PG&E's bundled electric portfolio included approximately 232 MW of distribution-connected solar PV, 29 MW of distribution-connected bioenergy, and 41 MW of distribution-connected small hydroelectric resources.[43]

7.b. Methods and Data Sources

7.b.i. Growth Scenarios

The basis for the "trajectory" DER growth scenario is achieving full subscription under existing CPUC wholesale DG procurement programs, namely the Renewable Market Adjusting Tariff (ReMAT) Program, the Renewable Auction Program (RAM), the Solar Photovoltaic Program (PV Program), the Green Tariff Shared Renewables Program (Green Option) and the Bioenergy Market Adjusting Tariff (BioMAT).

[43] These figures include capacity additions through 2014 associated with all active contracts as of May 14, 2015.

TABLE 7-1
EXISTING PG&E PROCUREMENT PROGRAMS, WHOLESALE DISTRIBUTED GENERATION

Procurement Program	Program Description	Eligible Project Size
Renewable Market Adjusting Tariff (ReMAT)	ReMAT is a renewable energy Feed-In Tariff (FiT) established by the Commission in 2013. ReMAT offers 10-, 15- or 20-year PPAs to procure wholesale power generated from small renewable energy projects sized up to 3 MW.	≤3 MW
Renewable Auction Mechanism (RAM)	RAM is a simplified market-based procurement mechanism for renewable DG projects greater than 3 MW and up to 20 MW.	3 – 20 MW
Photovoltaic Solar Program (PV Program)	PG&E's Solar PV Program grants authorization to develop up to 500 MW of solar PV, from projects ranging from 1 to 20 MW in size. Development of Solar PV under the program may include up to 250 MW of utility-owned generation.	1 – 20 MW
Green Tariff Shared Renewables Program (Green Option)	SB 43 establishes the Green Tariff Shared Renewables Program, a 600 MW statewide program that will allow the customers of investor-owned utilities—including local governments, businesses, schools, homeowners, municipal customers, and renters—to purchase up to 100 percent of their electricity from a renewable energy facility.	≤20 MW
BioEnergy Market Adjusting Tariff (BioMAT)	SB 1122 establishes a requirement that investor-owned utilities must collectively procure at least 250 MW of generation eligible for the California RPS from bioenergy generation projects that commence operation on or after June 1, 2013.	≤3 MW

Under the "high growth" and "very high growth" scenarios, PG&E projects incremental growth of distribution-connected solar PV using generic scale factors of 120 percent and 150 percent of Scenario 1 capacity additions respectively.[44] Incremental capacity additions attributed to the generic solar PV scale factors are allocated evenly over years 2022 through 2025.

[44] Scale factors were applied exclusively to the solar PV component of this forecast given the cost competitiveness demonstrated by distribution-connected solar PV projects over other distribution-connected technologies included within the scope of this forecast.

7.b.ii. Geospatial Allocation of Incremental Capacity Additions

Capacity additions associated with PG&E's growth scenarios for wholesale distributed renewable generation are geospatially allocated at the county-level under various siting assumptions attributed to each individual wholesale DG procurement program. A summary of county-level siting assumptions applied in the growth scenarios is outlined below. Energy deliveries associated with annual capacity additions are approximated using generic capacity factors, by technology, consistent with assumptions used by PG&E in the Integrated Energy Policy Report (IEPR) and Long Term Procurement Plan (LTPP) proceedings.

ReMAT: New project development is assumed to occur in across three procurement product types—As-Available Peaking, As-Available Non-Peaking, and Baseload—as specified under the ReMAT program. Under each product type, new project development will reflect the technology type and geographic distribution of existing contracts already procured by PG&E under the ReMAT program, and its predecessor FiT program, AB 1969. Given the requirements of the ReMAT program, it is assumed that all ReMAT projects will be interconnected at the distribution-level.

PV Program, Green Option Tariff, RAM: It is assumed that solar PV projects procured under the RAM program, the PV Program, and the Green Option Tariff will be similar with respect to size, technology, project design and project location due to the similarity of program requirements, Power Purchase Agreements (PPA), and offer evaluation methods. Therefore, incremental capacity additions associated with these procurement programs are geospatially allocated using the same approach. It is assumed that new capacity procured under the each of these programs will reflect the geographic distribution of distribution-connected solar PV project offers received under the RAM 4 and 5, the most recent RAM solicitations as of January 1, 2015. Given the project size limitations and other program requirements under RAM, the PV Program, and Green Option, capacity additions associated with each of these procurement programs are adjusted to account for distribution-connected projects within PG&E's service territory only.

BioMAT: New project development will be categorized by feedstock – green waste biogas, dairy and agriculture bioenergy, and forest waste bioenergy – as specified under the BioMAT program. Under each category of feedstock, new project development will reflect the geographic distribution of small-scale bioenergy resource potential within PG&E's service territory.[45] Given the requirements of the BioMAT program, it is assumed that all BioMAT projects will be interconnected at the distribution level.

7.b.iii. Data Sources

Data utilized to develop the scenarios were gathered from publicly-available sources including CPUC filings and independent studies. Specific data utilized in various components of these scenarios are shown in Table 7-2 and attributed to individual procurement programs which drive the deployment of wholesale distributed renewables interconnected to PG&E's distribution grid.

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[45] Small-scale bioenergy resource potential within PG&E's service territory was assessed and quantified in a 2013 study by Black & Veatch.

TABLE 7-2
SOURCES OF DATA, WHOLESALE RENEWABLE DISTRIBUTED GENERATION

Procurement Program	Data Utilized	Source of Data
ReMAT	Executed contracts, ReMAT Executed contracts, AB 1969	ReMAT 10-day Reporting Requirement[46] IOU 33% RPS Compliance Report Filing[47]
RAM, PV Program, Green Option	Project offer locations, RAM 4 and 5	RAM 4 Advice Letter (4313-E)[48] RAM 5 Advice Letter (4539-E)[49]
BioMAT	Bioenergy resource potential in California	Black & Veatch Consultant Study, Bioenergy Resource Potential (*Table B-2*)[50]

7.c. Results

A summary of the cumulative capacity additions interconnected to PG&E's distribution system, by technology, under each DER growth scenario are provided in Tables 7-3, 7-4, 7-5 and Figures 7-1, 7-2, 7-3 below. Notably, in years 2016 through 2021, results do not deviate across DER growth scenarios, and instead show full subscription under existing CPUC wholesale DG procurement programs. In years 2022 through 2025, distribution-connected solar PV is scaled up to show incremental growth beyond existing CPUC procurement programs that may be

46 Pacific Gas and Electric Company (2014). ReMAT Feed-In Tariff (Senate Bill 32). Retrieved January 9, 2015 from: http://www.pge.com/en/b2b/energysupply/wholesaleelectricsuppliersolicitation/ReMAT/index.page.

47 California Public Utilities Commission (2014). California Renewables Portfolio Standard (RPS). Retrieved January 9, 2015 from: http://www.cpuc.ca.gov/PUC/energy/Renewables/.

48 Pacific Gas and Electric Company (2014). Advice Letter Filing of PG&E's Fourth Renewable Auction Mechanism Power Purchase Agreements. Retrieved January 9, 2015: http://www.pge.com/nots/rates/tariffs/tm2/pdf/ELEC_4313-E.pdf.

49 Pacific Gas and Electric Company (2014). Advice Letter Filing of PG&E's Fifth Renewable Auction Mechanism Power Purchase Agreements. Retrieved January 9, 2015 from: http://www.pge.com/nots/rates/tariffs/tm2/pdf/ELEC_4539-E.pdf.

50 California Public Utilities Commission (2014). SB 1122: Bioenergy Feed-In Tariff. Retrieved on January 9, 2015 from: http://www.cpuc.ca.gov/PUC/energy/Renewables/hot/SB_1122_Bioenergy_Feed-in_Tariff.htm.

attributable to changes in market conditions, regulatory requirements, policy drivers and other factors.

TABLE 7-3
DISTRIBUTION-CONNECTED WHOLESALE SOLAR PV, CUMULATIVE CAPACITY ADDITIONS (MW) 2016-2025

SCENARIO	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	Total
Trajectory (*Base Case*)	16	67	118	147	176	219	219	219	219	219	**219**
High (*Scale Factor: 1.2x*)	16	67	118	147	176	219	234	249	263	278	**278**
Very High (*Scale Factor: 1.5x*)	16	67	118	147	176	219	255	291	327	363	**363**

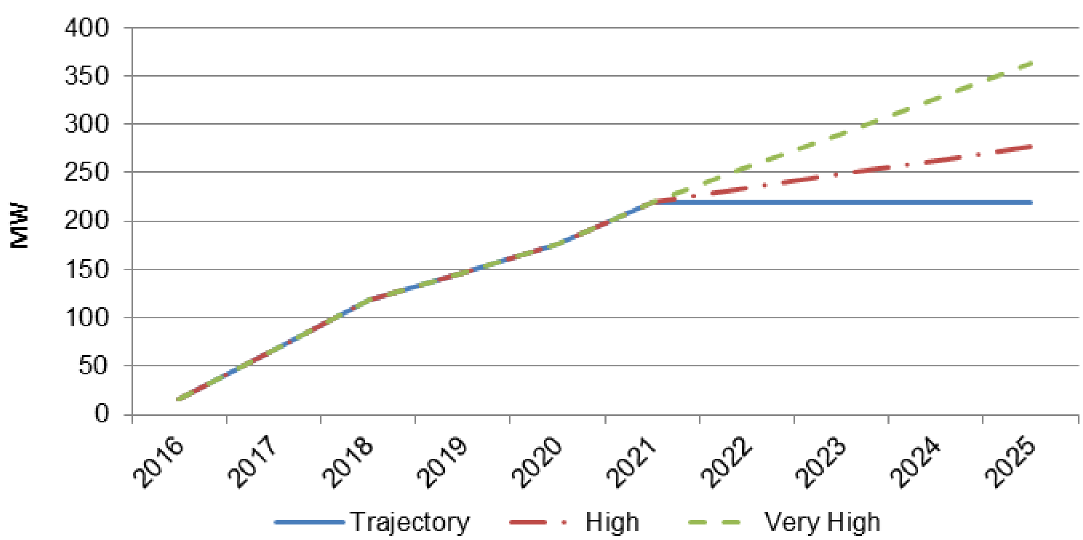

FIGURE 7-1
DISTRIBUTION-CONNECTED WHOLESALE SOLAR PV, CUMULATIVE CAPACITY ADDITIONS (MW), 2016-2025

TABLE 7-4
DISTRIBUTION-CONNECTED WHOLESALE BIOENERGY, CUMULATIVE CAPACITY ADDITIONS (MW), 2016-2025

SCENARIO	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	Total
Trajectory (*Base Case*)	11	51	88	114	140	157	157	157	157	157	**157**
High (*No change*)	11	51	88	114	140	157	157	157	157	157	**157**
Very High (*No change*)	11	51	88	114	140	157	157	157	157	157	**157**

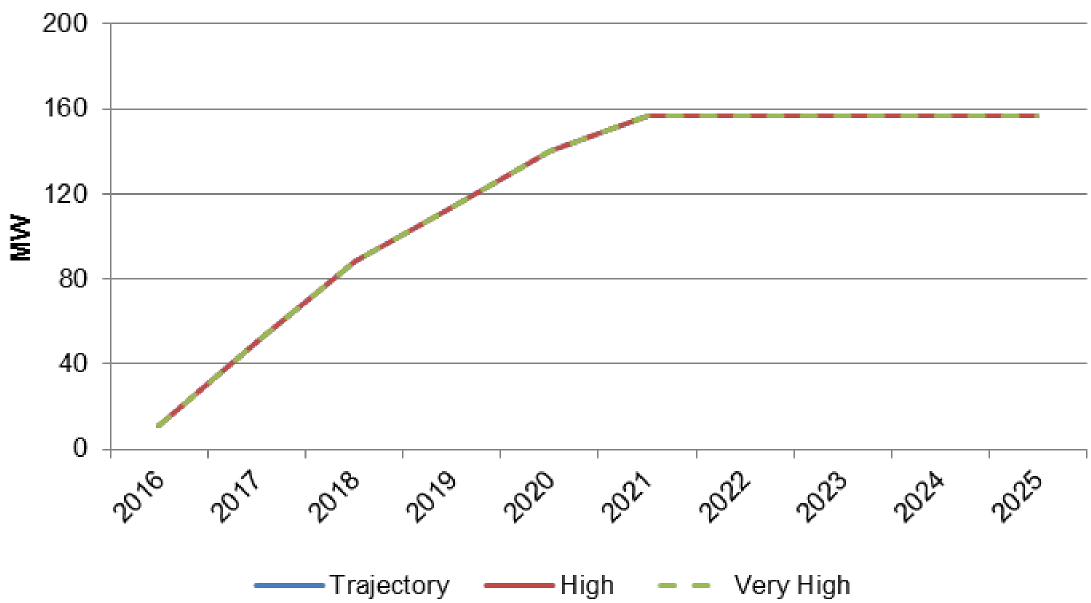

FIGURE 7-2
DISTRIBUTION-CONNECTED WHOLESALE BIOENERGY, CUMULATIVE CAPACITY ADDITIONS (MW), 2016-2025

TABLE 7-5
DISTRIBUTION-CONNECTED SMALL HYDRO, CUMULATIVE CAPACITY ADDITIONS (MW)

SCENARIO	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	Total
Trajectory (*Base Case*)	9	24	39	39	39	39	39	39	39	39	**39**
High (*No change*)	9	24	39	39	39	39	39	39	39	39	**39**
Very High (*No change*)	9	24	39	39	39	39	39	39	39	39	**39**

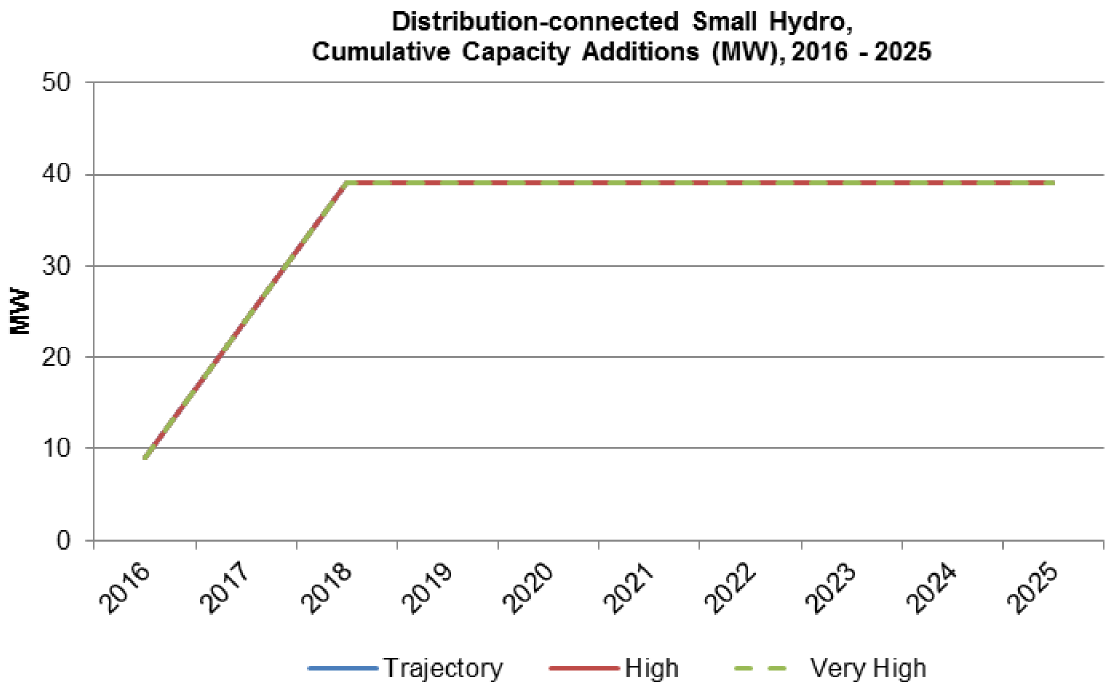

FIGURE 7-3
DISTRIBUTION-CONNECTED SMALL HYDRO, CUMULATIVE CAPACITY ADDITIONS (MW)

7.d. Key Findings

Given the requirements of existing CPUC procurement programs, as well as current market conditions, solar PV is anticipated to represent the fastest growing wholesale DG technology type in PG&E’s bundled portfolio. Within PG&E’s service territory, Kern, Kings, Fresno, and Merced counties are projected to experience the fastest growth of distribution-connected wholesale solar PV, all of which would be located in the southern half of California’s central valley, with further capacity additions distributed broadly across counties within PG&E’s service territory.

Bioenergy capacity additions are projected to represent the second fastest growing of wholesale DG technology type, driven primarily by PG&E procurement under the BioMAT and ReMAT programs. Given the diverse program requirements of BioMAT, as well the resource potential identified throughout the state of California,[51] bioenergy capacity additions are widely distributed across all counties in PG&E's service territory with Santa Barbara, Fresno, San Joaquin, Marin and Napa Counties estimated to experience the highest capacity additions through 2025.

7.e. Limitations and Caveats

The following assumptions, limitations, and caveats apply to the wholesale DG growth scenarios presented in Section 7:

- These scenarios are intended to represent wholesale renewable DG resources physically interconnected to PG&E's distribution grid
- These scenarios do not account for development of wholesale renewable DG resources interconnected to PG&E's distribution grid by parties other than PG&E
- Development of wholesale renewable DG resources will continue to be driven by mandated procurement programs
- These scenarios do not assume any regulatory change to existing CPUC procurement programs
- Executed contract data, as well as publicly-available project offer data, serve as proxy indicators for the location of future projects, by accounting for factors such as site suitability (*by technology*), ease of permitting, interconnection costs, and overall project economics
- These scenarios assume that future procurement of wholesale renewable DG resources will generally reflect the geographic distribution that has materialized over 6 years of wholesale renewable DG procurement in PG&E's service territory
- These scenarios assume that recent contract execution data and project offer data is most indicative of future project offers, while acknowledging that market conditions change over time

[51] Black and Veatch (2013). Small-scale Bioenergy: Resource Potential, Costs and Feed-In Tariff Implementation Assessment. Retrieved on January 9, 2015 from: http://www.cpuc.ca.gov/PUC/energy/Renewables/hot/SB_1122_Bioenergy_Feed-in_Tariff.htm.

- Solar projects procured under the RAM program, the PV Program, and the Green Option Tariff will be similar with respect to size, technology, project design and project location due to the similarity of program requirements and offer evaluation methods
- These scenarios do not predict levels of customer support for the Green Option program, and therefore do not attempt to site Green Option projects near participating customers
- This analysis assumes new projects will be online and operational approximately 30 months after contract execution
- These scenarios assume that the average project size under each program will favor the maximum size limitation, assuming project economics generally improve with scale
- Annual energy deliveries associated with new projects are estimated using generic capacity factors, by technology, consistent with the assumptions used in long-term planning proceedings include the IEPR and the LTPP (Table 5)

TABLE 5
GENERIC CAPACITY FACTOR BY TECHNOLOGY

Line No.	Technology	Generic Capacity Factor
1	Solar PV	25%
2	Bioenergy	85%
3	Small Hydro	25%

7.f. Recommendations for Future Planning

Procurement of wholesale DG is influenced by a diversity of factors including changes in economic, market, policy, and regulatory conditions. Therefore all wholesale DG growth scenarios are subject to significant uncertainty.

8. Wholesale (Feed-In Tariff) Combined Heat and Power

8.a. Introduction

PG&E developed growth scenarios—at the county-level—of distribution-connected wholesale CHP capacity additions (< 20 MW) interconnected to PG&E's distribution grid over the years 2016 through 2025. Projections are produced under three DER growth scenarios—"trajectory growth," "high growth," and "very high growth"—per Commission guidance issued under Rulemaking 14-08-013. While Commission guidance on the DER growth Scenarios 1 and 2 ("trajectory" and "high growth") requests alignment with the CEC's IEPR forecast cases, no dedicated IEPR forecast for wholesale CHP has been developed as part of the IEPR proceeding. Therefore, alignment with the IEPR does not apply to wholesale CHP growth scenarios. PG&E included distribution-connected wholesale resources in its DER growth scenarios as they impact distribution planning requirements. PG&E procurement of new CHP resources that meet the definition of wholesale DERs is primarily done through CHP FiT Program—AB 1613. As of April 2015, PG&E has executed one PPA—totaling approximately 9 MW capacity—under the AB 1613 program.

8.b. Methods and Data Sources

8.b.i. Growth Scenarios and Geospatial Modeling

8.b.i.1. Trajectory Scenario

The basis of the "trajectory growth" scenario is continued availability of existing CHP procurement programs through 2025. PG&E procurement of new CHP resources that meet the definition of wholesale DERs is primarily done through CHP FiT Program AB 1613 (*Table 1*). PG&E has three *proforma* AB 1613 PPAs available for new exporting CHP.[52] As of April 2015, PG&E has executed one PPA under the AB 1613 program. Additional capacity additions may

[52] PG&E AB 1613 *proforma* PPAs: one for projects less than 20 MW, one for projects less than 5 MW, and one for projects less than 500 kW. http://www.pge.com/en/b2b/energysupply/qualifyingfacilities/AB1613/index.page.

come online under the CHP FiT program.[53] Capacity additions are then geographically distributed at the county-level using publicly available data for similar size projects under previous CHP procurement programs in the state of California.

8.b.i.2. High Growth Scenario

This growth scenario is identical to the trajectory scenario. The Commission ruling refers to the CEC IEPR assumptions. The IEPR forecast focuses primarily on the CHP for self-generation (i.e., customer-side of the meter) and does not provide a dedicated forecast for wholesale CHP resources.

8.b.i.3. Very High Growth Scenario

To date, most of the CHP deployments in the state have been natural-gas fueled. However, over the long-term, carbon neutral forms of CHP such as Waste Heat to Power (WHP or bottoming-cycle CHP) and biomass/biogas CHP resources are better suited to be deployed, aligned with the state of California's objectives of achieving long-term GHG reduction targets. The Commission ruling also directs the IOUs to primarily consider potential growth of carbon neutral forms of CHP technologies. In 2014, PG&E retained ICF International (ICF)[54] to study technical and expected market potential of these cleaner forms of CHP by 2030. In this scenario, PG&E has utilized a 2025 expected capacity (MW) market potential estimate. The ICF study also provides the county-level distribution of the locations for these expected projects. Most of these projects will be sited primarily to meet onsite load (i.e., customer-side of the meter). Therefore, the majority of the electricity produced is expected to serve onsite load first and the remaining will be exported to the grid on as-available basis. PG&E estimates that about 25 percent of the capacity growth from the bottom-cycling WHP projection that is part of the wholesale CHP growth scenario would be exported and the remainder would serve on-site load.

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[53] Consistent with PG&E 2014 Bundled Procurement Plan (BPP) CHP assumptions.

[54] http://www.icfi.com/.

8.b.ii. High-level Assumptions

Scenarios 1 and 2 – Trajectory Growth

- Future procurement of wholesale DG CHP resources under the CHP FiT program (AB 1613) will continue to reflect the geographic distribution that has materialized over past 30 years of wholesale CHP (<20 MW) in California.
- Executed contract data serve as proxy indicators for the location of future projects, by accounting for factors such as site suitability, ease of permitting, interconnection costs, and overall project economics.
- Estimated annual generation is calculated using a generic capacity factor consistent with the assumptions used in PG&E's long-term forecasting, including the LTPP (Table 1).

Scenario 3 – Very High Growth

- Carbon neutral forms of CHP (i.e., WHP and biomass/biogas CHP) are better suited to support the State's objective of long term GHG reductions.
- Assumes incremental growth in capacity of 2.9 MW/yr., in years 2016-2025, beyond trajectory scenario.[55]
- New WHP and biomass/biogas CHP projects will be sited at existing industrial locations. Capacity additions will reflect the geographic distribution of resource potential identified in a 2014 ICF CHP study.
- Majority of the electricity produced is expected to serve onsite load first and remaining will be exported to the grid on as-available basis.

TABLE 1
GENERIC CAPACITY FACTOR, WHOLESALE CHP

Technology	Generic Capacity Factor
CHP	80%

[55] Incremental capacity additions of 2.9 MW/year are calculated as a pro-rata share of the total market potential for carbon-neutral CHP through 2030, 44.3 MW, as determined by an ICF International study of CHP resource potential in the state of California.

8.b.iii. Sources of Data

Data utilized to develop these geospatial scenarios has been compiled in the table below (Table 8-1).

TABLE 8-1
SOURCES OF DATA, DISTRIBUTION-CONNECTED WHOLESALE CHP

Scenario	Data Utilized	Source of Data
Trajectory	Total generic CHP capacity additions via CHP FiT AB 1613	PG&E 2014 Bundled Procurement Plan (BPP) CHP AB 1613 assumptions
	Geographic county level distribution of existing CHP PPAs less than 20 MW PPAs	PG&E Semi-Annual Cogeneration and Small Power Production Report, July 2014
Very High Growth	Total capacity additions and geographic county-level distribution for carbon-neutral forms of CHP	2014 ICF International WHP and Biomass/Biogas CHP Potential Study

8.c. Results

Table 3 summarizes the capacity additions (MW/year) for the three DER Wholesale CHP scenarios. Notably, results are held constant across the “trajectory” and “high growth” scenarios, while the “very high growth” scenario is consistent with total carbon-neutral CHP resource potential in PG&E’s service area, as identified in the ICF International 2014 study commissioned by PG&E.

TABLE 8-2
DISTRIBUTION-CONNECTED WHOLESALE CHP, CUMULATIVE CAPACITY ADDITIONS (MW), 2016-2025

Line No.	SCENARIO	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
1	Trajectory	8.4	16.8	25.2	33.6	42	50.4	58.8	67.2	75.6	84
2	High Growth	8.4	16.8	25.2	33.6	42	50.4	58.8	67.2	75.6	84
3	Very High Growth	12.0	24.1	36.1	48.1	60.1	72.2	84.2	96.2	108.2	120.3

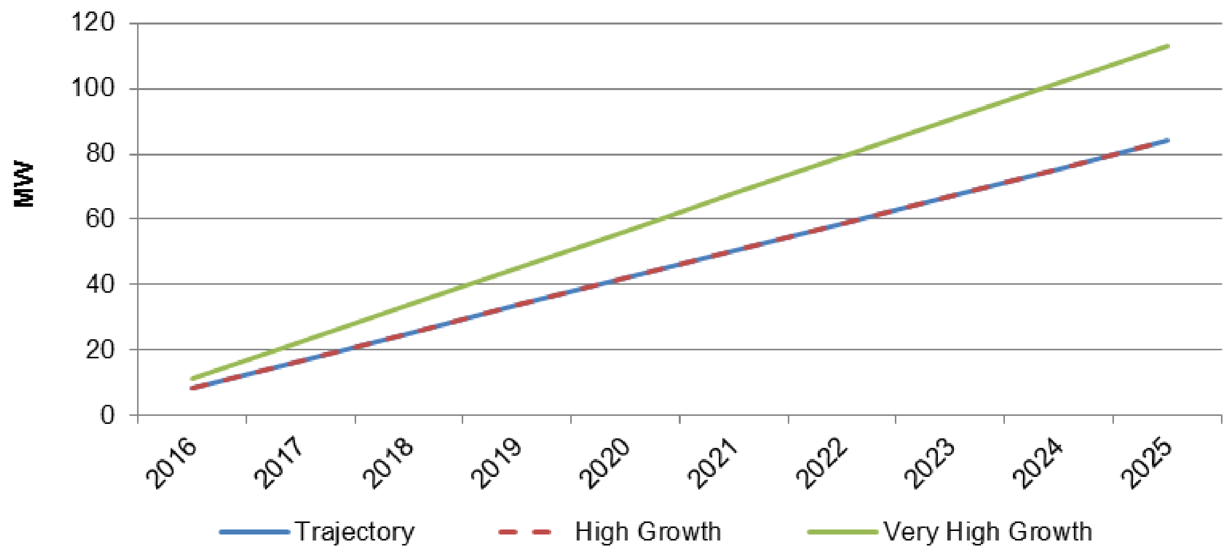

FIGURE 8-1
DISTRIBUTION-CONNECTED WHOLESALE CHP, CUMULATIVE CAPACITY ADDITIONS (MW), 2016 2025

8.d. Key Findings

Given the methodology used to develop the geospatial distribution under the trajectory scenario, Kern and Fresno counties are projected to experience the largest growth of wholesale CHP. The geographic distribution for the very high growth scenario is more geographically diverse, and is intended to target locations where carbon neutral forms of CHP may be sited to serve light and heavy industrial customers.

8.e. Limitations and Caveats

The following limitations and caveats apply to these scenarios:

- These scenarios were developed to support PG&E's 2015 DRP. Other use cases for these scenarios may require alternate assumptions that would produce different scenario results
- The trajectory scenario does not consider possible changes to existing CHP programs. PG&E has to date observed limited participation under the CHP FiT program
- The geospatial numbers assume that future procurement of wholesale DG CHP resources under the CHP FiT program (AB 1613) will continue to reflect the geographic distribution that has materialized over past 30 years of wholesale DG CHP

procurement in California. This approach has its limitations as the existing industrial load in California already be too saturated to drive adoption of new CHP systems

- The capacity assumed for the very high growth scenario is based on a 2014 ICF International study commissioned by PG&E
- These scenarios include annual electricity generated using a generic capacity factor. The percentage of electricity that would be used onsite and the percentage that would be exported to the grid varies for each CHP unit based on site-specific electrical and thermal host demand. On average, PG&E expects these smaller CHP systems to use the majority of the electricity produced onsite and to export to the grid on an as-available basis. PG&E estimates that approximately 25 percent of the electricity would be exported and 75 percent would be used on site
- These scenarios do not account for any procurement of wholesale CHP interconnected to PG&E's distribution system by parties other than PG&E

8.f. Recommendation for Future Planning

These geospatial scenarios of distribution-connected wholesale CHP are developed based on various levels of subscription under the existing CHP FiT program and potential capacity additions of carbon-neutral forms of CHP aligned with State's objectives of achieving long-term GHG reduction targets. However, to date PG&E has observed limited participation from these technologies under existing procurement programs. As such, these scenarios should be refreshed periodically based on procurement experience and to reflect changes in market conditions over time.

9. Wholesale Storage

9.a. Introduction

For the purposes of the 2015 DRP, PG&E developed county-level growth scenarios of distribution-connected wholesale energy storage capacity additions that will interconnect to PG&E's distribution grid over a 10-year time horizon, 2015 through 2025. Results are produced under three DER growth scenarios—"trajectory growth," "high growth," and "very high growth"—per Commission guidance issued under R.14-08-013. Notably, while Commission guidance on the DER growth Scenarios 1 and 2 ("trajectory" and "high growth") requests alignment with IEPR forecast cases, no energy storage forecast has been developed as part of the IEPR proceeding, and therefore, alignment with the IEPR does not apply to distribution-connected wholesale energy storage growth scenarios. PG&E included distribution-connected wholesale resources in its DER growth scenarios as they impact distribution planning requirements. At the end of 2014, PG&E had 6 MW of distribution-connected wholesale storage; consisting of two utility-owned sodium sulfur batteries.

9.b. Methods and Data Sources

9.b.i. Growth Scenarios

The basis of all three DER growth scenarios is achieving compliance with CPUC requirements as established by decision (D.13-10-040), pursuant to the Energy Storage R.10-12-007. Notably, it is assumed that any variation in distribution-connected wholesale energy storage procurement across the three DER growth scenarios would result in an equivalent and opposite variation of transmission-connected energy storage procurement, such that the sum total of distribution- and transmission-connected energy storage procurement remains constant across all three scenarios.

Scenario 1 – "Trajectory Growth"

- 54 percent of PG&E's distribution-connected wholesale energy storage procurement targets as established by CPUC D.13-10-040

- Remaining capacity under the distribution-connected procurement target is assumed to be added to PG&E's transmission-connected energy storage target

Scenario 2 – "High Growth"

- 76 percent of PG&E's distribution-connected wholesale energy storage procurement targets as established by CPUC D.13-10-040

- Remaining capacity under the distribution-connected procurement target is assumed to be added to PG&E's transmission-connected energy storage target

Scenario 3 – "Very High Growth"

- 100 percent of PG&E's distribution-connected wholesale energy storage procurement targets as established by CPUC D.13-10-040

9.b.ii. Geospatial Allocation of Incremental Capacity Additions

PG&E's growth scenarios of distribution-connected wholesale energy storage are allocated geospatially at the county-level assuming three distinct types of energy storage projects: PG&E-specified projects, co-location with power generation, and stand-alone energy storage projects. Each project type is assigned a weighting factor based on PG&E assumptions made independent of project offer data received under the PG&E's 2014 Energy Storage Request for Offers (RFO).

PG&E-specified Projects: PG&E-specified energy storage projects will target distribution deferral or co-location with existing utility-owned power generation and are assumed to represent approximately 15 percent of energy storage capacity procured through 2025. PG&E-specified energy storage projects were publicly identified in PG&E's 2014 Energy Storage RFOs.[56] Distribution deferral projects target locations on PG&E's distribution grid with a high penetration of solar PV capacity and/or locations with a rapid change in load. Energy storage projects co-located with utility-owned generation may be sited with any of PG&E's existing

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[56] Pacific Gas and Electric Company (2014). Energy Storage Request for Offers, 2014 Solicitation Participants' Conference. Retrieved January 9, 2015 from: http://www.pge.com/includes/docs/pdfs/b2b/wholesaleelectricsuppliersolicitation/Energy_Storage/2014_EnergyStorage_ParticipantsConference.pdf.

power generation, most likely its solar PV projects, all of which are interconnected at the distribution-level.

Colocation with Power Generation: This type of project targets energy storage co-located with electric generating resources with which PG&E has an existing PPA, and is assumed to represent approximately 25 percent of energy storage capacity procured through 2025. For the purpose of these scenarios, new capacity additions co-located with power generation will be distributed across ten counties within PG&E's service territory with the highest density of RPS-eligible generation using a weighted average methodology.

Stand-alone Energy Storage Projects: This type of project targets stand-alone energy storage that can be sited anywhere in PG&E's service territory, and is assumed to represent approximately 60 percent of energy storage capacity procured through 2025. Stand-alone energy storage projects may include a diversity of projects that vary by technology-type, size, and discharge duration. To ensure sufficient locational diversity, this segment of energy storage procurement is distributed across counties which comprise the seven Local Capacity Areas (LCA) – as designated by the CAISO – within PG&E's service territory.[57] Within each LCA, projects are allocated using two variables, land acquisition cost and available feeder capacity, as a proxy for relative project cost.[58]

9.b.iii. Data Sources

Data utilized to develop these growth scenarios was gathered from non-proprietary sources including publicly-available records, CAISO technical studies, and other resources. Specific sources data utilized in these scenarios are shown in Table 1.

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57 California ISO (2012). Final Manual, 2012 Local Capacity Area Technical Study. Retrieved on January 9, 2015 from: http://www.caiso.com/Documents/2012FinalLCRManual.pdf.

58 Feeder capacity was selected as a representative measure of relative interconnection cost.

TABLE 9-1
DATA SOURCES, DISTRIBUTION-CONNECTED WHOLESALE ENERGY STORAGE FORECAST

Data Utilized	Source of Data
PG&E energy storage procurement targets CPUC minimum project size requirements 2014 PG&E-specified distribution deferral project requirements 2014 PG&E-specified project requirements for energy storage at utility-owned solar PV sites	2014 Energy Storage RFO Participant's Conference[59]
CAISO definition of Local Capacity Areas	CAISO Local Capacity Area Technical Study, 2012[60]
Survey of land acquisition cost, by county	PG&E Land Acquisition Department
Survey of feeder capacity, by county	PG&E RAM Map (Accessed December 2014)[61]

9.c. Results

A summary of the wholesale energy storage cumulative capacity additions interconnected to PG&E's distribution system-level capacity additions projected in these scenarios is included in Table 9-2. Based on the methodology used to develop these scenarios, capacity additions of wholesale energy storage come online in years 2018 through 2024, in compliance with existing energy storage procurement requirements.

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59 Pacific Gas and Electric Company (2014). Energy Storage Request for Offers, 2014 Solicitation Participants' Conference. Retrieved January 9, 2015 from: http://www.pge.com/includes/docs/pdfs/b2b/wholesaleelectricsuppliersolicitation/Energy_Storage/2014_EnergyStorage_ParticipantsConference.pdf.

60 California ISO (2012). Final Manual, 2012 Local Capacity Area Technical Study. Retrieved on January 9, 2015 from: http://www.caiso.com/Documents/2012FinalLCRManual.pdf.

61 Pacific Gas and Electric Company (2014). Solar Photovoltaic and Renewable Auction Mechanism (RAM) Program Map. Retrieved on January 9, 2015 from: http://www.pge.com/en/b2b/energysupply/wholesaleelectricsuppliersolicitation/PVRFO/pvmap/index.page.

TABLE 9-2
DISTRIBUTION-CONNECTED WHOLESALE ENERGY STORAGE
CUMULATIVE CAPACITY ADDITIONS (MW), 2016-2025

Scenario	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	Total
Trajectory	–	–	16	16	38	38	65	65	100	100	100
High Growth	–	–	23	23	53	53	91	91	140	140	140
Very High Growth	–	–	30	30	70	70	120	120	185	185	185

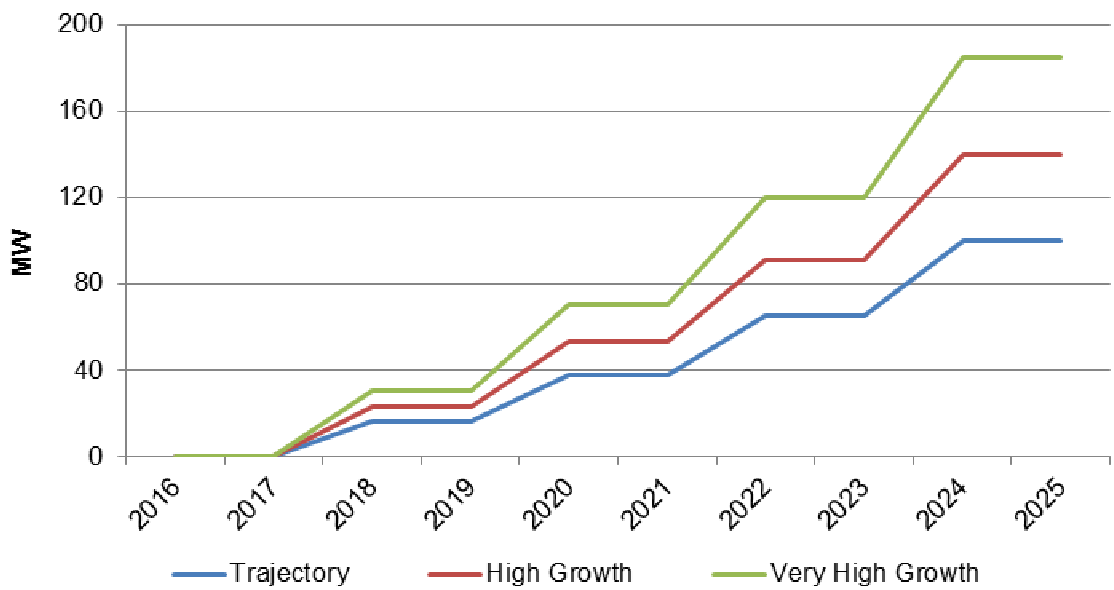

FIGURE 9-1
DISTRIBUTION-CONNECTED WHOLESALE ENERGY STORAGE

9.d. Key Findings

Given the methods and assumptions used to develop these scenarios, Kern, Fresno, Kings, San Luis Obispo, and Humboldt Counties would experience the fastest growth of distribution-connected wholesale energy storage; however, capacity additions would be interconnected broadly across counties included in PG&E's seven LCAs. Notably, these scenarios were developed independent from PG&E's ongoing commercial activities associated with its 2014 Energy Storage RFO. As such, future scenarios should be refined to reflect for practical experience and market conditions gained from energy storage solicitations.

9.e. Limitations and Caveats

The following assumptions, limitations, and caveats apply to the wholesale storage growth scenarios:

- These scenarios were developed to support PG&E's 2015 DRP. Other use cases for these scenarios may require alternate assumptions that would produce different scenario results
- These scenarios assume that procurement of distribution-connected wholesale energy storage will primarily be driven by compliance with CPUC procurement requirements established in D.13-10-040
- These scenarios do not consider possible regulatory changes to existing CPUC energy storage procurement requirements
- These scenarios were developed prior to any procurement of energy storage resources in compliance with CPUC Decision 13-10-040
- Assumptions included in these scenarios were developed independently of project offer data received under PG&E's 2014 Energy Storage RFO
- These scenarios do not account for any procurement of wholesale energy storage interconnected to PG&E's distribution system by parties other than PG&E

9.f. Recommendations for Future Planning

Procurement of wholesale energy storage is influenced by a diversity of factors including changes in market, policy, and regulatory conditions. Therefore, these wholesale energy storage growth scenarios are subject to significant uncertainty and should be updated periodically to reflect changes in conditions over time.

Appendix D

Summary of DER Tariffs and Rate Schedules

RELEVANT PG&E TARIFFS AND RATE SCHEDULES THAT GOVERN AND/OR INCENT DERS

PG&E Electric Rules		
Rule	**Title**	**Description**
Rule 2	Description of Service	Describes voltages and other conditions for basic service with PG&E.
Rule 15	Distribution Line Extensions	Describes rules and cost recovery for distribution line extensions. Since cost recovery is usage based, generation which offsets usage can impact this.
Rule 16	Service Extensions	Describes facilities from PG&E's Distribution Line facilities to Service Delivery Point; and covers physical and electrical requirements for the service. Since cost recovery is usage based, generation which offsets usage can impact this. Generating facilities are often interested in multiple services.
Rule 18	Supply to Separate Premises and Sub metering of Electric Energy	Describes sub metering and service to multiple premises; applicable to generators on rates such as NEMV and NEMA.
Rule 21	Generating Facility Interconnections	Describes requirements for CPUC jurisdictional generating facility interconnections (including for net energy metering, non-export, and qualifying facility "QF" selling to PG&E as a QF).
Rule 22	Direct Access	Customers on Direct Access with generators will be subject to requirement from the ESP and PG&E. Rule 22 describes these requirements generally.
Rule 23	Community Choice Aggregation Service	Customers on CCA with generators will be subject to requirement from the CCA and PG&E. Rule 23 describes the requirements generally.

Rule 25	Release Of Customer Data To Third Parties	Describes rules that apply to PG&E's automated, ongoing provisioning of electric SmartMeter™ interval usage data, ("Customer Data,") to customer-authorized third-parties using an electronic platform known as the Customer Data Access (CDA) platform.
Rule 27	Privacy and Security Protections for Energy Usage Data	Describes Pacific Gas and Electric Company's policies concerning customer energy usage data to the Rules Regarding Privacy and Security Protections for Energy Usage Data adopted by the California Public Utilities Commission as Attachment D to Decision (D.) 11-07-056.
Rule 27.1	Access to Energy Usage and Usage-Related Data While Protecting Privacy of Personal Data	Similar issues to Rule 25.
Other	The above listed rules occur relatively frequently with DER programs. However, any of PG&E's other Rules (Gas and Electric) can have impacts on DER program account setup and administration as well.	
PG&E Gas Rules		
Rule	**Title**	**Description**
Rule 1	Definitions	
Rule 2	Description of Service	Describes options and conditions for service.
Rule 14	Capacity Allocation and Constraint of Natural Gas Service	Describes when PG&E may reduce, interrupt, or allocate natural gas transportation, storage or supply services for operational reasons or to comply with regulatory requirements in the event of projected or actual supply or capacity shortages.

Rule 15	Distribution Line Extensions	Describes rules and cost recovery for distribution line extensions. Since cost recovery is usage based, generation can impact the cost recovery calculation for customers who install gas-fired generators.		
Rule 16	Service Extensions	Describes facilities from PG&E's Distribution Line facilities to the Service Delivery Point; and covers physical and electrical requirements for the service. Customers with gas fired Generating Facilities are required to have a dedicated gas meter. Since cost recovery is usage based, generation can impact the cost recovery calculation for customers who install gas-fired generators.		
Rule 21	Transportation of Natural Gas	Describes the general terms and conditions that apply whenever PG&E transports Customer-owned gas over its system.		
PG&E Electric Rate Schedules				
1. Non-Export[1]				
Rate Schedule	**Description**	**Size**	**Technology**	**Credit**
Non-Export	Rule 21 Non-Export • Requires anti-exporting facilities or verification load exceeds generation • Subject to Standby and Departing Load	no MW limit		n/a

[1] PG&E's electric rate schedules for residential and non-residential customers using DERs also affect the cost-effectiveness and equitable pricing of DERs and DER exports to the grid. See, e.g., PG&E application and testimony in R.12-06-013, Residential Rate Design Reform rulemaking.

2. Net Energy Metering & Other Retail				
Rate Schedule	**Description**	**Size**	**Technology**	**Credit**
NEM	Net Energy Metering Service – • Generator behind usage meter. • Nets kWh imports and export monthly – requires netting meter. • Credits based on otherwise applicable rate schedule energy charges. • Credits may only be carried over for 1 year (true-up period). • 2nd crediting mechanism provides credit for net annual net generation (net surplus compensation). • Allows for load aggregation for the same customer on contiguous and adjacent property. • NEMMT – Provision allow behind the same meter, provision for a generator to receive NEM treatment, and either another net energy metering rate schedule treatment or Rule 21 non-export treatment. • NEMA – Load aggregation provisions. Per Public Utilities Code (Pub. Util. Code) Section 2827	1 MW	RPS Eligible[2]	Full Retail

[2] RPS, Renewables Portfolio Standard eligible; includes Biomass, photovoltaic, wind, solar thermal, fuel cells using renewable fuels, geothermal, small hydro, digester gas, municipal solid waste conversion, landfill gas, ocean wave, ocean thermal, tidal current.

NEMBIO	Net Energy Metering Service for Biogas Customer-Generator • Requires separate in/out metering • Has annual true-up • Allows for load aggregation for a single customer on contiguous and adjacent property Allows for NEMMT (see NEM) (Closed to New Customers) Per now rescinded Pub. Util. Code Section 2827.9.	1 MW	Manure Methane CHP	Gen Comp
NEMCCSF	Schedule NEMCCSF – Net Energy Metering Service For City and County of San Francisco Municipal Load Served By Hetch Hetchy At-Site Photovoltaic Generating Facilities Per Pub. Util. Code Section 2828	15 MW	All	Gen Comp
NEMFC	Net Energy Metering Service for Fuel Cell (with non-renewable fuel sources) Customer-Generators • Requires separate in/out metering • Has annual true-up • Allows for load aggregation for a single customer on contiguous and adjacent property • Allows for NEMMT (see NEM) Per Pub. Util. Code Section 2827.10	1 MW	Fuel Cell	Gen Comp
NEMV	Virtual Net Energy Metering for a Multi-tenant or Multi-meter property served at the same service delivery point	1 MW	Solar/Wind Renewable except Solar/Wind	Full Retail Full Retail
NEMVMASH	Virtual Net Energy Metering For Multifamily Affordable Housing (MASH/NSHP) With Solar Generator(s)	1 MW	Solar (Low Income only) – Single Service	Full Retail

			Delivery Point	
		1 MW	Solar (Low Income only) – Multiple Service Delivery Point	Full Retail
RES-BCT	Schedule for Local Government Renewable Energy Self-Generation Bill Credit Transfer Per Pub. Util. Code Section 2830	5 MW	RPS eligible Gen	Gen Comp
3. Wholesale (export)				
Rate Schedule	**Description**	**Size**	**Technology**	**Credit**
CHP (PURPA PPA)	Exporting Generating Facilities under a PURPA PPA Section 2840.2(b)	No limit	QF eligible Gen	PPA
PURPA (Legacy Qualifying Facility)		No limit	QF eligible Gen	PPA
E-REMAT	Renewable Market Adjusting Tariff. This schedule implements the renewable resource Feed in Tariff program pursuant to Pub. Util. Code Section 399.20 and Commission Decision (D.) 12-05-035, D.13-01-041, and D.13-05-034.	1.5 MW	RPS eligible[3]	PPA
E-SRG	Small Renewable Generator Power Purchase Agreement (Closed to new applicants – replaced by E-REMAT)	1.5 MW	RPS eligible	PPA

[3] Is an Eligible Renewable Energy Resource, as defined in Section 399.12 and California Public Resources Code Section 25741, as either code provision may be amended from time to time.

E-PWF	Public Water Facilities Power Purchase Agreement (Closed to new applicants – replaced by E-REMAT)	1.5 MW	RPS eligible	PPA
CHP	Based on Rulemaking (R.) 08-06-024 to implement the provisions of Assembly Bill 1613 (codified in California Pub. Util. Code Section 2840 et. seq.), which establishes the Waste Heat and Carbon Emissions Reductions Act (the "Act").	20 MW	PURPA Qualifying Facility	PPA
PV USA	Special Contract with the City of Davis described under Pub. Util. Code Section 2826.5.	Existing solar facility	Solar	Special Contract

4. Other Rate Schedules with Specific Relevance to DER

Rate Schedule	Description	Size	Technology	Credit
S	Schedule S – Standby Service • SOLAR GENERATION FACILITIES EXEMPTION: Customers who utilize solar generating facilities which are less than or equal to one megawatt to serve load and who do not sell power or make more than incidental export of power into PG&E's power grid and who have not elected service under Schedule NEM, will be exempt from paying the otherwise applicable standby reservation charges. • DISTRIBUTED ENERGY RESOURCES EXEMPTION:	Under CPUC program and Rule 21 require-ments	Any	n/a
E-DCG	Departing Customer Generation		Any except NEM	

Various	Demand Response	Varies	Specific to DR programs	No double crediting under generation programs
PEVSP	Plug-In Electric Vehicle Sub metering Pilot – Phase 1			
Option R	(pending approval)	No limit	Solar	Lowers Demand charges for E19v, E19, and E20
E20 Demand Adjustment	Solar or Fuel Cell Generation Demand Adjustment: A customer who installs a solar electric generation facility on or after January 1, 2007, or fuel cell electric generation facility may be eligible to receive a Generation Demand Adjustment. A customer will qualify for a Generation Demand Adjustment if both of the following conditions are met: (1) either the customer's solar electric generating facility was installed after January 1, 2007, or the customer's fuel cell electric generation facility was installed (and approved for interconnection by PG&E); and (2) the electric generation facility reduces the customer's maximum demand to the point that the customer would no longer be eligible for service under this schedule. The Generation Demand Adjustment will be the fixed reduction in demand as determined by PG&E from the customer's interconnection agreement, and will be added to the customer's	No specified size limits	Solar Or Fuel Cell	Reduces demand charges

	maximum demand for the sole purpose of determining the customer’s eligibility for Schedule E-20. The Generation Demand Adjustment does not specifically guarantee the customer’s continued eligibility for service under this schedule nor will it be applied to the customer’s maximum demand for purposes of calculating the monthly maximum demand charge. The Generation Demand Adjustment for solar generating facilities will terminate on December 31, 2016.			
E19	Solar Pilot Program: Customers who exceed 499 kW for at least three consecutive months during the most recent 12-month period and must otherwise take service on mandatory Schedule E-19 may elect service under Schedule A-6 under the terms outlined in the Solar Pilot Program section of Schedule A-6. This program is closed to new applications effective.	No specified size limits	Solar	Reduces demand charges
G-EG	Gas Transportation Service to Electric Generation	Not specified	CHP must meet certain efficiency goals	Reduced gas prices through eligibility for G-EG

G-SUR	Customer-Procured Gas Franchise Fee Surcharge • Includes additional efficiency requirements for generation, in order to be eligible.	Not specified	CHP must meet certain efficiency goals	Includes an exception for generation Customers, for that quantity of natural gas billed under Schedule G-EG
PU Code 218	Over-the-fence arrangements	Not specified	Includes different provisions for different generation technologies	Defines when a generator can be used to serve other account load, without being deemed an electrical corporation