BEFORE THE PUBLIC UTILITIES COMMISSION OF THE

STATE OF CALIFORNIA

Application of San Diego Gas & Electric Company (U 902 E) For Approval Of Distribution Resource Plan	))))	A.15-07-___

APPLICATION OF SAN DIEGO GAS & ELECTRIC COMPANY (U 902 E) FOR APPROVAL OF DISTRIBUTION RESOURCES PLAN

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Dated: **July 1, 2015**

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APPLICATION OF SAN DIEGO GAS & ELECTRIC COMPANY (U 902 E) FOR APPROVAL OF DISTRIBUTION RESOURCES PLAN

Pursuant to California Public Utilities Code Section 769, the Rules of Practice and Procedure of the California Public Utilities Commission ("CPUC" or "Commission"), and the Assigned Commissioner Ruling in Rulemaking ("R.") 14-08-013 issued on February 6, 2015, San Diego Gas & Electric Company ("SDG&E") hereby files its Application for approval of its Distribution Resources Plan ("DRP").

I. INTRODUCTION

This proceeding, in SDG&E's view, marks an important step forward in establishing a new framework for utility distribution planning. This effort is but one of a number of important initiatives that SDG&E believes have the potential to achieve major reductions in Greenhouse Gas Emissions and help to usher in a more sustainable energy future. SDG&E welcomes the opportunity be a partner in achieving these important goals. Toward that end, SDG&E supports placing greater emphasis in its planning process on the strategic, cost-effective deployment of Distributed Energy Resources ("DERs"), as it has committed in its DRP, to address customer energy needs, promote customer choice, and advance important policy objectives.

At the same time, however, it is important to recognize that the new procedures and planning framework adopted in this proceeding will not exist in a vacuum. SDG&E is particularly concerned that its existing rate structure serves to distort the price signals being sent to customers and DER developers. While not a part of this proceeding, SDG&E believes that comprehensive rate reform that is fair, transparent, and avoids cost shifts, is critically important to promoting universal access for all customers, across all types, of cost-effective DERs. Simply put, SDG&E believes that the continuation of policies allowing a subset of customers to avoid paying for the value they receive undermines investor confidence and therefore the financial health of the distribution system.

Make no mistake; investor confidence is critical to the success of the new framework for utility distribution planning that will be established here. For a substantial number of SDG&E's customers, service levels and finances currently limit opportunities for participation in the burgeoning distributed energy future. Accordingly, as illustrated in the DRP, investments of various kinds will be necessary to promote not only higher levels of DER penetration but, indeed, participation in that opportunity by a broader spectrum of customers, all while preserving the service reliability and safety that customers rightly expect.

II. PROCEDURAL BACKGROUND

On August 14, 2014, the Commission issued its *Order Instituting Rulemaking Regarding Policies, Procedures and Rules for Development of Distribution Resources Plans Pursuant to Public Utilities Code Section 769* in Rulemaking ("R.") 14-08-013 (the "DRP OIR"). The purpose of the R.14-08-013 proceeding is to establish policies, procedures, and rules to guide California investor-owned electric utilities ("IOUs") in developing DRP proposals to be filed by July 1, 2015, as required by Assembly Bill ("AB") 327, subsequently enacted, in part, as Public Utilities Code §769. In general, the rulemaking is addressing the IOUs' existing and future electric distribution infrastructure and planning procedures as it pertains to incorporating DERs into the planning and operation of the utilities' electric distribution systems.

The Assigned Commissioner Ruling ("ACR"), issued in that proceeding on February 6, 2015, includes a document setting forth guidance for content and structure of the IOUs' DRPs (the "Guidance" document). The ACR states (at p. 2) that the IOUs' DRPs "should be consistent with each other in structure and content so they may be more easily compared and analyzed." The ACR requires the IOUs to file their DRPs as applications and states that such applications may be consolidated with R.14-08-013.

III. SUMMARY OF PLAN

The Guidance document attached to the ACR says (at p. 3) that it "is intended to define a framework for the [DRPs] that has three major sections: 1) the framework section that describes the structure and intended content of the DRPs, 2) the description of phasing of next steps and 3) the definitions section which defines certain terms in PUC §769 and how the Utilities will interpret these terms in the DRPs." The framework section, in turn, includes nine topic areas that the utilities' DRPs must address. The manner in which SDG&E's DRP addresses these nine topic areas is summarized below.

A. Integration Capacity Analysis and Locational Value Analysis

SDG&E's DRP explains that the utility's annual Distribution Planning Process ("DPP") involves analyzing all aspects of the distribution system to identify where modifications and/or capital projects are necessary to ensure continued safe, reliable, and cost effective operation of the distribution system to meet current and forecasted load growth. SDG&E's DRP proposes to expand this existing process to include advanced analytics that will help better identify where a DER can interconnect with minimal impact and/or add value to the grid. The Guidance directs the IOUs to develop three analytical frameworks to address 1) the potential integration capacity for DERs (the Integration Capacity Analysis or ICA), 2) quantification of locational benefits, and 3) future DER growth.

With respect to the ICA, SDG&E's DRP explains that it and the other IOUs have developed a common methodology that assesses the capability of their respective systems to integrate DER within applicable thermal ratings, safety standards, protection system limits, and power quality parameters.[1] In the limited time available, SDG&E has performed this analysis for a substantial percentage of its distribution system but has not yet had the time to conduct the analysis for the entire system. Concurrent with the filing of this Application, SDG&E is publishing via online maps the initial results for the ICA performed to date. SDG&E is committed to continuing the analysis and publish the remaining results as they become available.

To address the quantification of locational benefits of DERs, the Guidance instructs the utilities to develop a Locational Net Benefits Methodology ("LNBM") that specifies the net benefits that DERs can provide in a given location. The IOUs have developed a locational net benefit methodology building on the E3 Distributed Energy Resources Avoided Cost Model, with additional inputs and considerations described in the DRP, including recommendations from the More Than Smart working group to produce what SDG&E believes are more accurate locational values. In general, SDG&E's analysis shows that DER integration is likely to be most effective in locations where the installation of DERs will not require significant upgrades, and DER projects are more likely to be chosen over traditional upgrade projects where the benefits to consumers are greater than the costs to consumers of installing the DER project.

As required by the Guidance, SDG&E's DRP reflects three 10-year (2016-2025) forecasts of peak demand and growth of DERs. Initial forecasts of DER capacity values were made on a system-wide level and then allocated to SDG&E's substations and then individual circuits. The three growth scenarios reflect increasingly aggressive assumptions and include

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1 The IOUs use parameters that differ for design and operational reasons.

expected geographic dispersion at the distribution level and impacts on distribution planning. SDG&E's ICA and LNBM runs thus far do not reflect the peak demand and DER values generated by these forecasts, but SDG&E will incorporate them upon approval by the Commission. The primary impact of the growth scenarios SDG&E anticipates may be a reallocation in capital projects due to the large growth in energy efficiency targets.

B. Demonstration and Deployment

As required by the Guidance, SDG&E's DRP discusses six DER-focused demonstration and deployment projects designed to validate integrating locational benefits analysis into utility planning or operations. In the first, SDG&E will perform the ICA on each circuit in SDG&E's service territory for thermal, voltage and protection limits, pursuant to the methodology the Commission approves in this proceeding. As committed above, SDG&E will make the results available online as they become available. The second demonstration project tests the functioning of the LNBM in connection with traditional, capacity-related distribution investments deferred or avoided through DER deployment.

The remaining demonstration projects described in the DRP involve physical installation and interconnection of DER assets to the distribution grid to demonstrate the benefits achievable with deployment of DERs. In general, SDG&E has designed its proposed demonstration projects to show how DERs can meet defined grid planning and operational objectives. Where feasible, these proposed projects leverage ongoing utility activities and are coordinated with SDG&E's smart grid deployment plan and Electric Program Investment Charge activities and/or conducted in collaboration with third-party DER providers and technology vendors.

The DRP explains that SDG&E does not anticipate incurring incremental costs in connection with the ICA and LNBM, although SDG&E may file an advice letter requesting approval for a Memorandum Account to track unexpected costs of these projects. In this

Application, SDG&E proposes to establish a Memorandum Account to track the costs associated with the other demonstration projects, with recovery of such costs to be addressed in SDG&E's next General Rate Case ("GRC").

C. Data Access

SDG&E recognizes the value of sharing information relevant to improving the safety, reliability and security of its distribution system. Much of the data SDG&E uses in distribution planning and operations activities is or can be made public. However, the utility also believes that reasonable safeguards and restrictions should be implemented in connection with access to non-public data. SDG&E believes that sharing some of the data that the DRP Guidance states third parties indicate is important to furthering the goals of the DRP process may compromise some of SDG&E's data security policies. In general, SDG&E also believes that any data sharing policies and procedures resulting from the CPUC's approval of the respective DRPs should align with and not expand existing state approved and utility industry supported philosophies, policies, and procedures related to data sharing. SDG&E's DRP addresses examples within the respective data security sub-sections.

D. Tariffs and Contracts

Consistent with the Guidance, SDG&E's DRP describes a variety of existing tariff and contractual mechanisms that govern or incent DERs, and describes the utility's views regarding incorporating locational values into such existing mechanisms. The DRP describes the inherent tension between the two approaches: tariffs, being of general applicability, promote transparency and broad reach, but contracts may be a more effective means of providing incentives related to benefits at a specific location and in a given moment in time. SDG&E believes that the question of whether the value of locational pricing is more appropriately translated though tariffs or contracts is best addressed after the Commission has made a determination of what values should be incorporated in defining locational benefits.

E. Safety Considerations

SDG&E prides itself on being a nationwide leader in the delivery of clean, reliable power at reasonable rates through a safety-first culture. As explained in the DRP, SDG&E's policy is to implement safety practices that comply with local, state, and federal electric safety codes to ensure system reliability and a safe environment for utility electrical workers, community emergency responders, and the public. Moreover, SDG&E is committed to investing in new and innovative technologies that advance important policy decisions in California.

The integration of DERs with an advanced utility grid offers opportunities to improve system reliability and public safety. However, increased use and deployment of distributed energy resources on the SDG&E electric distribution system—with associated increased two-way complex power flow, and the proximity of low voltage, high voltage, and AC and DC sources—presents significant challenges with respect to ensuring public and worker safety and system reliability. In this connection, SDG&E believes that the integration of a range of devices on the advanced utility power grid will be facilitated by consistent and/or compatible equipment standards and specifications, periodic inspection, and performance verification. Moreover, improved power flow, analysis, equipment control enhancements, and communication network advances will enhance the integration of new technologies and advanced power grid devices, thereby improving customer service and reliability. However, in SDG&E's view, investments in system protection, controls, standards, and training are necessary to achieve identified and desired benefits.

F. Barriers to Deployment

As required by the Guidance document, SDG&E's DRP identifies and categorizes a variety of barriers to the deployment of DERs, focusing on five categories of barriers. SDG&E notes that while many of the barriers described in its DRP are cross-cutting in nature and affect multiple factors, the method of categorization of the barriers, in SDG&E's view, improves readability and accessibility of the information provided. Each barrier is addressed in a template format, which describes: (1) the specifics of the barrier itself; (2) the issue that the barrier poses to the successful implementation of the plan; (3) SDG&E's perspective regarding the barrier; and, finally (4) SDG&E's proposal(s) for addressing the identified barrier.

G. DRP Coordination with Utility General Rate Cases

The GRC process reflects known projects at the time of filing that will be necessary to meet SDG&E's load and reliability forecasts. SDG&E proposes to continue this process, with those projects being approved through the GRC filing under the default that they will be cost-estimated and constructed as traditional utility projects. As part of its annual DPP, which will incorporate the new analytical tools described in the DRP, however, SDG&E recommends that it identify those traditional investments that can be potentially deferred or replaced by appropriate DERs. SDG&E will include those types of investments in future GRCs. Additionally, SDG&E proposes to establish a Memorandum Account in order to track costs associated with designing, procuring, installing, operating, and maintaining demonstration projects. Another Memorandum Account would be used to track expenditures on potential new investments, such as in infrastructure or software, that may be necessary to ready SDG&E's electrical distribution system for—and, indeed, to promote—much higher DER penetration levels than SDG&E experiences today.

H. DRP Coordination with Utility and CEC Load Forecasting

SDG&E uses a top down approach for developing its electricity demand forecasts, in which various factors, such as county-wide economic and demographic drivers and regional weather data, are used to produce a system level forecast of energy and peak demand. SDG&E considers DERs at the service territory level but, initially, not at or below the substation level. SDG&E resource planners use the foregoing system level forecast, and it is also provided to the California Energy Commission in connection with the biennial Integrated Energy Policy Report ("IEPR").

Going forward, SDG&E believes it will be necessary to segregate DER impacts between, on the one hand, system-level forecasts used primarily by resource planners and, on the other, more granular, substation and circuit-level data, used primarily by distribution planners. SDG&E proposes that the system-level DER growth scenario analyses should become a deliverable of the IEPR stakeholder initiative. The level of stakeholder participation and transparency available during the state-level IEPR process should help ensure that the initial DER growth scenarios developed for inclusion in the various forecasting and planning functions are consistent with regard to assumptions and estimates and are as detailed as possible.

I. Phasing of Next Steps

The Guidance reflects a belief that the effectiveness of a utility's DRP depends not on a one-time exercise of developing it in the first place, but rather its integration into the utility's distribution planning, operations and investment. The Guidance therefore requires rolling updates to DRPs on a biennial cycle, at a minimum, over a ten-year period, and sets forth a proposed phasing for the initial framework development and subsequent refinements to the framework.

SDG&E agrees with the Guidance concerning the importance of integrating the DRP into the utility's distribution planning, operations and investment. SDG&E is committed to doing that. However, as discussed in the DRP, SDG&E believes that much of the content in this DRP filing is one-time in nature, and does not lend itself to meaningful repetition in futures filings. SDG&E suggests that implementing a biennial DRP Status Report will be an effective means of providing the status of DER development, while updates to the DRP itself can be made on a biennial cycle if necessary to incorporate revisions to methodologies or consideration of emerging DER technologies that were not contemplated in the initial DRP. Moving forward, SDG&E proposes to establish a Procurement Review Group-like body, an important distribution planning process refinement described in the DRP.

IV. RELIEF REQUESTED

SDG&E respectfully requests that, in accordance with the proposed schedule, the Commission issue a decision that:

1. Accepts SDG&E's DRP;

2. Authorizes SDG&E to file Tier 1 advice letters with respect to the proposed Memorandum Accounts;

3. Grants such other relief as is necessary and proper.

V. PROCEDURAL REQUIREMENTS

A. Rule 2.1 (a) – (c)

In accordance with Rule 2.1 (a) – (c) of the Commission's Rules of Practice and Procedure, SDG&E provides the following information.

1. Rule 2.1 (a) - Legal Name

SDG&E is a corporation organized and existing under the laws of the State of California. SDG&E is engaged in the business of providing electric service in a portion of Orange County and electric and gas service in San Diego County. SDG&E's principal place of business is 8330 Century Park Court, San Diego, California 92123. SDG&E's attorney in this matter is Jonathan J. Newlander.

2. Rule 2.1 (b) - Correspondence

Correspondence or communications regarding this Application should be addressed to:

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3. Rule 2.1 (c)

a) Proposed Category of Proceeding

In accordance with Rule 7.1, SDG&E requests that this Application be categorized as quasi-legislative because this proceeding will establish policy or rules affecting a class of regulated entities and, because it is mandated by, and may be consolidated with, the R.14-08-013 proceeding, involves the Commission's investigation of practices for an entire regulated industry or class of entities within the industry.

b) **Need for Hearings**

SDG&E does not believe that approval of this Application will require hearings. SDG&E believes the proposed schedule set forth below will afford ample opportunity to examine SDG&E's DRP and provide the Commission with a sufficient record upon which to grant the relief requested.

c) **Issues to be Considered**

The issues to be considered are described in this Application and the DRP.

d) **Proposed Schedule**

SDG&E proposes the following schedule:

ACTION	DATE
Application filed	July 1, 2015
Initial Comments	August 3, 2015
Reply Comments	August 17, 2015
Workshops	September-October, 2015
Opening Briefs	November 13, 2015
Reply Briefs	December 18, 2015
Proposed Decision ("P.D.")	February 10, 2016
Initial Comments on P.D.	March 1, 2016
Reply Comments on P.D.	March 7, 2016
Final Decision	March 24, 2016

B. Rule 2.2 – Articles of Incorporation

A copy of SDG&E's Restated Articles of Incorporation as last amended, presently in effect and certified by the California Secretary of State, was filed with the Commission on September 10, 2014 in connection with SDG&E's Application No. 14-09-008, and is incorporated herein by reference.

C. Rule 1.9 – Service and Notice

This application will initiate a new proceeding, although SDG&E anticipates that the Commission may consolidate this with R.14-08-013. Accordingly, SDG&E is serving this application on all parties in that proceeding. Pursuant to Commission Rule 1.9, service will be accomplished via a Notice of Availability, which is attached below.

VI. CONCLUSION

SDG&E respectfully requests that, in accordance with the proposed schedule, the Commission issue a decision: (1) accepting SDG&E's DRP; (2) authorizing SDG&E to file Tier 1 advice letters with respect to the proposed Memorandum Accounts; and, (3) granting such other relief as is necessary and proper.

Respectfully submitted,

SAN DIEGO GAS & ELECTRIC COMPANY

/s/ David L. Geier

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San Diego Gas & Electric Company
Vice President – Electric Transmission & System Engineering

/s/ Jonathan J. Newlander

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July 1, 2015

OFFICER VERIFICATION

David L. Geier declares the following:

I am an officer of San Diego Gas & Electric Company and am authorized to make this verification on its behalf. I am informed and believe that the matters stated in the foregoing **APPLICATION OF SAN DIEGO GAS & ELECTRIC COMPANY (U 902 E) FOR APPROVAL OF DISTRIBUTION RESOURCES PLAN** are true to my own knowledge, except as to matters which are therein stated on information and belief, and as to those matters I believe them to be true.

I declare under penalty of perjury under the laws of the State of California that the foregoing is true and correct.

Executed this 1st day of July, 2015, at San Diego, California.

/s/ David L. Geier

David L. Geier
San Diego Gas & Electric Company
Vice President – Electric Transmission & System Engineering

Distribution Resources Plan

July 1, 2015

SDGE

A Sempra Energy utility

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Introduction

Pursuant to Assembly Bill (AB) 327, subsequently enacted, in part, as Public Utilities Code (P.U. Code) §769, the California Public Utilities Commission (CPUC or Commission) issued an *Order Instituting Rulemaking Regarding Policies, Procedures, and Rules for Development of Distribution Resources Plans Pursuant to Public Utilities Code Section 769* (DRP OIR) on August 14, 2014. This rulemaking (R.14-08-013) was developed to establish policies, procedures, and rules to guide California investor-owned electric utilities (IOUs) in developing Distribution Resources Plan (DRP) proposals to be filed by July 1, 2015. The CPUC issued the Assigned Commissioner Ruling (ACR) on February 6, 2015 that provided the final guidance[1] for content and structure of the filed DRPs. Accordingly, this DRP addresses the IOUs' existing and future electric distribution infrastructure and planning procedures as it pertains to incorporating distributed energy resources (DERs) [2,3] into the planning and operation of the utilities' electric distribution systems.

Policy and Leadership

California energy policy is sharply focused on achieving major reductions in Greenhouse Gas Emissions (GHG). Through electrification, including the optimal use of DERs, the state's IOUs are uniquely positioned to lead the way to a more sustainable energy future. Leadership is nothing new for SDG&E. In addition to leading in safety, reliability and service, SDG&E is a strong leader in clean energy. We are on track to achieve the state's 33% renewable portfolio standard by year-end, the first of any utility and a full five years ahead of the required schedule. In addition, our electric vehicle charging program is an important first step in addressing the need for critical infrastructure required to decarbonize California's transportation sector. This is particularly important given that transportation accounts for far more GHG emissions than any other sector (37.3%) and the state cannot achieve its goals without significant reductions in transportation related GHGs. As with RPS and clean transportation, SDG&E welcomes the opportunity to be a strong partner in the state's efforts to achieve strategic, cost effective deployment of distributed energy resources**.**

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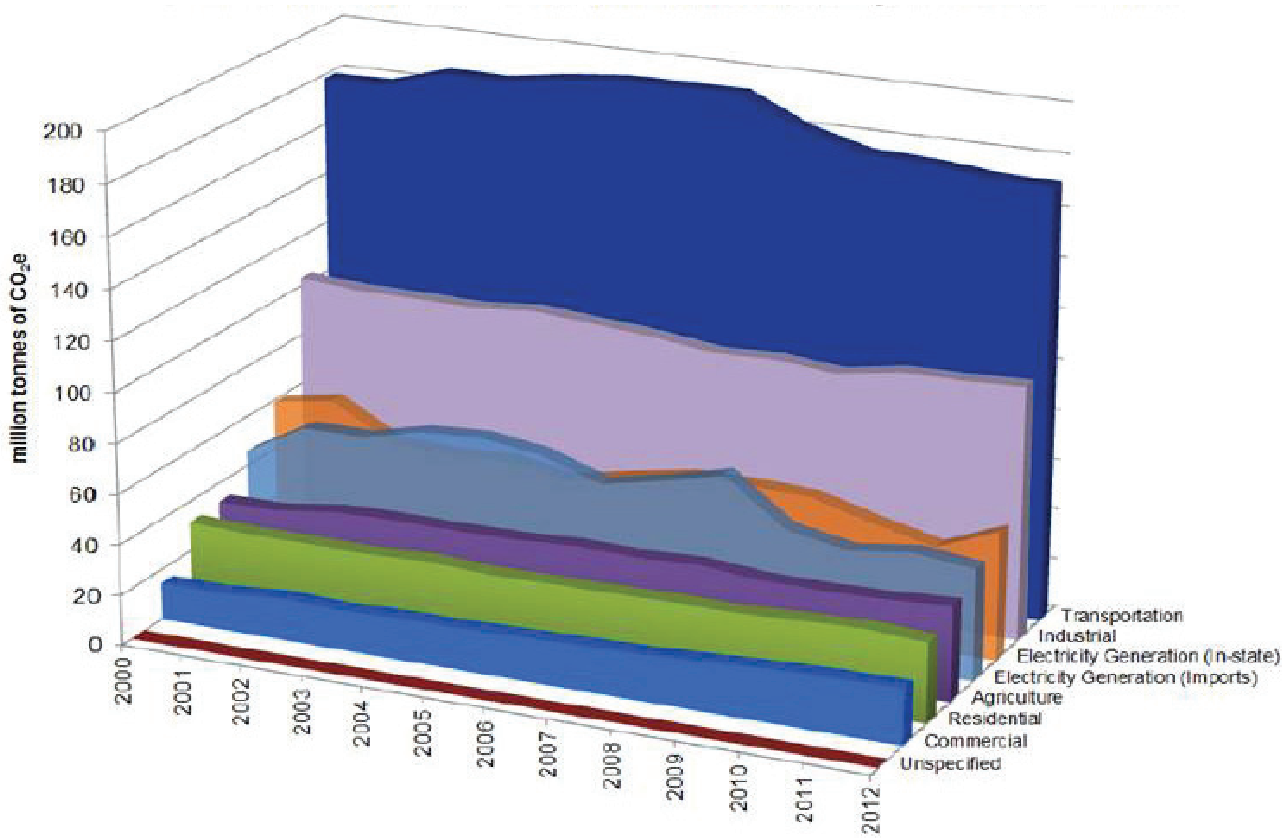
[1] SDG&E refers to the pages in the ruling containing the final guidance language as either the Guidance or the DRP Guidance.

[2] While PUC Section 769 uses and defines the term "distributed resources", the CPUC OIR, the ACR, and SDG&E's DRP Proposal interchangeably use the terms "distributed resources" and "distributed energy resources" and in the context as defined in PUC 769.

[3] AB 327 and PUC Section 769 define distributed resources to include distributed renewable generation resources, energy efficiency, energy storage, electric vehicles, and demand response technologies.



Source: California Environmental Protection Agency - Air Resources Board
California Greenhouse Gas Emission Inventory: 2000-2012, May, 2014 Pg. 7
http://www.arb.ca.gov/cc/inventory/pubs/reports/ghg_inventory_00-12_report.pdf

Essential Foundations

The electric grid is a critical enabler of the state's policy agenda. Beyond ensuring the safe and reliable services that all customers demand, strategic investments in the grid will support; increasing levels of RPS, integration of DERs including battery storage, electrification designed to displace transportation emissions, demand response programs and more. An advanced and financially healthy grid is foundational to achieving GHG reductions. Policies that allow a subset of customers to avoid paying for the value they receive from the grid undermine the foundation on which it was built. Should investors or credit agencies lose faith in the financial underpinnings of this essential resource, California risks losing the platform required to achieve its important policy objectives. It is imperative that policy makers ensure a rational rate structure that is fair, transparent, avoids cost shifts and moves in the direction of cost-based service.

The Massachusetts Institute for Technology (MIT) report The Future of the Electric Grid, reinforces the importance of aligning climate change objectives and utility regulatory policies; "*The California feed-in tariff for small-scale renewable generation, particularly rooftop solar, is perhaps the most visible of "net metering" programs, which compensate end users for generating their own energy at the retail electricity rate rather than the wholesale cost of energy. The difference between these rates is mainly the fixed cost of distribution (and, sometimes, transmission), which is typically recovered by per-kWh charges. When an end user increases generation, the system saves only the wholesale cost of energy. Under net metering, however, the end user saves both this wholesale cost and the per-kWh charge used to recover fixed network costs. Thus net metering provides an additional subsidy to distributed generation of all sorts that may encourage uneconomic penetration."*[4]

The concept of universal service is also an important element of consideration with the state's objective of broader deployment of DERs. SDG&E supports universal access for all customers, across all types, of cost-effective DERs. SDG&E believes that a large percentage of the utility's residential customers may lack the necessary electric service levels or viable financial options to participate in sustainable DER or electric vehicle opportunities. The distribution system of the future will need additional investments to upgrade electrical service levels to facilitate participation, customer choice and greater adoption of PEVs.

SDG&E believes that the DRP must leverage the IOUs' institutional knowledge to develop a rigorous framework to analyze and implement DERs throughout the distribution system. The IOUs have more than a century of experience in providing safe, reliable, reasonably priced power. Our expertise can and should be instrumental in developing the most effective path to full DER integration.

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[4] The Future of the Electric Grid - An Interdisciplinary MIT Study. Massachusetts Institute of Technology, 2011 Pg.16; http://mitei.mit.edu/publications/reports-studies/future-electric-grid

Guiding Principles

To achieve the state's policy objectives of reducing GHG emissions through adoption of DERs, as well as fulfilling the requirements set forth in the ACR, SDG&E has established a set of governing principles to guide the utility's vision of the future distribution system. These principles include the following:

1) Ensuring both public and employee safety, enhancing reliability, and optimizing the use of the existing grid in order to optimize value to all customers.
2) Enabling access to DERs for all customers and alignment with California energy policy goals, which include GHG reduction, DER growth, and capacity-related least cost / best fit DER solutions.
3) Promoting a rational rate structure that is fair, transparent, and avoids cost shifts with a view toward cost-based service.

Public and employee safety, reliability, and affordable electric service for all customers are at the core of the utility compact and are part of SDG&E's foundational values. SDG&E strives to operate its distribution system under both normal and extraordinary conditions, with several primary objectives in mind:

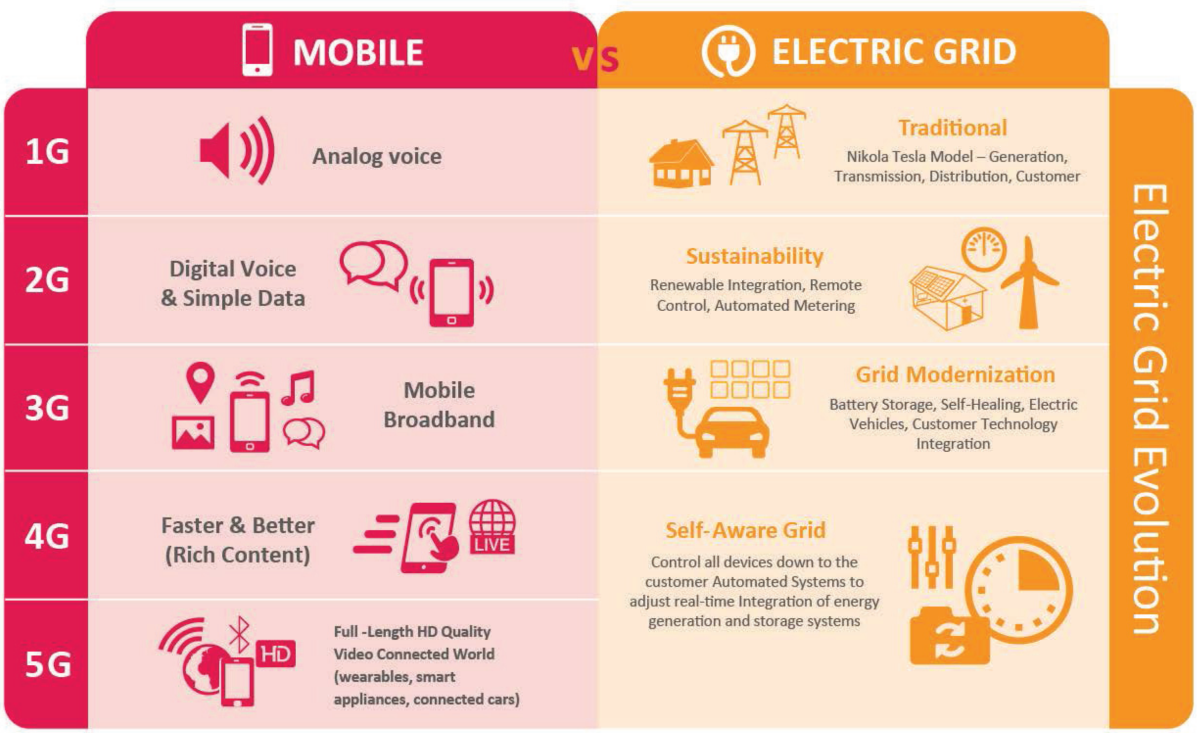
- Maintain a high level of public safety
- Maintain a high level of employee safety
- Maintain a high level of reliability
- Maintain a high level of service and customer satisfaction
- Operate in an efficient and effective manner

SDG&E stands ready to continue its leadership position by partnering to achieve the state's DER objectives and broader GHG goals. As the electric grid will play a central role, it is critical that assets are well maintained, periodically replaced, and monitored around the clock to ensure the level of safety and reliability that customers demand. SDG&E is the sole entity responsible in that regard and is tasked with performing numerous planning, design, operating and maintenance activities to keep the public and employees safe.[5] A future system where responsibility and/or expectations are not clearly defined can jeopardize the safety and reliability customers rely on today.

Evolution of the Distribution System

Implementing the DRP will fundamentally change the way the IOUs perform their annual distribution planning analysis and help define the future of the distribution delivery model. As illustrated Figure 1, SDG&E sees striking similarities between mobile phone evolution and the electric grid evolution.

Figure 1: Electric Grid Evolution



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[5] Pub. Util. Code §399.2(1)(2)- "…each electrical corporation shall continue to operate its electric distribution grid in its service territory and shall do so in a safe, reliable, efficient, and cost-effective manner". Each utility is "responsible for operating its own electric distribution grid, including . . . owning, controlling, operating, managing, maintaining, planning, engineering, designing, and constructing its own electric distribution grid."

There is a rapid, technology-driven revolution in the ways that utilities, DER providers, and end users integrate and interact with services they provide and/or consume. As the centralized, unidirectional distribution grid evolves into a flexible, multidirectional energy services platform, utilities, DER providers and customers will develop new capabilities to provide value. The decades-long transition from land line voice and data services to mobile communications offers lessons that can be applied to the deployment and integration of DER.

In the initial model for voice communications, the telephone was the standard communication medium, sending analog voice signals to a corresponding tethered device on "the other end". Similarly, the electric grid's traditional design has utilized a one-directional flow of power from the utility to the customer. These industries remained relatively static for decades with limited technological change, until recently. Through revolutionary technological improvements, the analog tethered phone has been replaced by the digital mobile device. Each new cell-phone generation has provided new capabilities such as voice, data, and video. The transition from one telephone per household (used simply to talk), to a world where almost every adult (and many children) stay connected via mobile, smart devices, has taken decades. These changes likewise provide a useful analogue for the electric grid's anticipated evolution, where the development of digital control systems, enhanced renewable generation, and energy storage devices are quickly changing the electricity industry.

During the first generation of mobile communications, the device was no longer tethered to a phone jack. People could receive calls from virtually any location that had cell service. Similarly, under the long-prevailing model of the grid, electricity was generated at a centralized source, transferred at a certain voltage level across the wire, and distributed to the customer. The power flowed in one direction from the respective generation source to the customer; providing basic electric services.

The second generation (2G) of mobile technology transformed an analog signal to digital, enabling not only voice but simple data traffic. At that point, a mobile customer could begin receiving text messages and emails. This allowed a person to be more connected and also provided simple data communication solutions for digital devices. The 2G electric grid was the beginning of a new digital age in terms of power. New digital equipment and standard technology protocols began replacing non-digital instruments, enabled automatied monitoring and control of the electric grid from a centralized location. Real-time information was presented to an operator to make immediate decisions. The 2G electric grid could use variable power from renewable energy to support basic customer loads, while smart meters measured use and automatically communicated consumption information to the utility for billing, and provided end users with detailed digital information on their energy consumption. The digitization of both cell phone and electricity transmission laid the foundation for significant technological advances to increase both availability and reliability for the customer.

Leveraging the digital foundation, the third generation (3G) cell phone began providing sophisticated broadband services such as video, music, applications, and internet services. Many commentators have called it the most important communication device in the information age. With this new generation, the mobile device has arguably become the most readily-available medium for accessing the internet. Information is at our fingertips; available anytime, anywhere. For the electric grid, the 3G analogue is grid modernization.

For the 3G electric grid, technology enhancements continue to increase with the development of energy storage, distributed energy management systems, and plug-in electric vehicles (PEVs). New electric grid sensors are placed to automate the control of electricity. Power flows bi-directionally. Customers are empowered with the ability to purchase customer generation solutions and PEVs. Utilities have introduced microgrids that utilize both renewable energy and energy storage to provide safe, reliable power to communities and customers. As the electric grid continues evolving its 3G technology, planning will leverage these distributed energy solutions for more system capacity and better reliability. Mobile technology has continued to evolve its latest technology while providing additional capabilities and better services to their customers, who have shown their willingness to pay more for higher-value services. Similarly, SDG&E believes the electric grid will also continue to transform and develop past our version of 3G. Changes implemented by the DRP will provide a foundation for continued growth.

The promise of an electric system that enables the reduction of GHG emissions through the integration of renewable energy sources, electric transportation, and data-driven management of energy use is exciting. SDG&E believes that the development of an energy services platform that reduces emissions and enables customer choice is an essential step towards achieving California's energy policy goals. The transition of telecommunications services from fixed line to mobile has positive parallels that can inform stakeholders as they manage change. Indeed, the convergence of wireless communications and information technology (IT) systems is a significant enabler of the modern electric grid, and distributed energy technologies are conversely improving reliability for the wireless network infrastructure.

As regulators and other policymakers manage the transition of the electric grid to an energy services platform that relies heavily on DER, they should ensure that investments in modernization do not leave vulnerable consumers exposed to increasing prices and diminishing reliability.

Figure 2 below shows a continuum with potential end states for the distribution grid, with one extreme being a back-up and the other fully integrated. SDG&E believes in order to achieve a safe, reliable, and affordable future for all customers, the distribution system will play an integral part. This integral role of the grid is supported by numerous studies[6] over the last few years that have tested the concept of grid defection, yet found very little support to demonstrate that this future will be economical, sustainable, safe, or reliable. These studies start with the basic premise that utility customers will defect from the grid because of declining costs of photovoltaics (PV) and energy storage. These studies come to the conclusion that cutting the cord, while technically feasible, is typically four-nine times more costly than utility rates today and for the foreseeable future.

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[6] The Economics of Grid Defection – Rocky Mountain Institute; http://www.rmi.org/electricity_grid_defection
The Economics of Load Defection – Rocky Mountain Institute;
http://blog.rmi.org/blog_2015_04_07_report_release_the_economics_of_load_defection
Residential Off-Grid Solar Photovoltaic and Energy Storage System in Southern California – EPRI;
http://www.epri.com/abstracts/Pages/ProductAbstract.aspx?ProductId=000000003002004462
Tesla Builds a Battery, Utilities Yawn – Bernstein Research; private subscription;
https://www.bernsteinresearch.com/brweb/view.aspx?eid=42n2NpXa4NVcfr4JtxFWszxKJweQjMLwTjC57fpZ5XXnHLWoWlHfhxz4%2beYEjvHb

The basis for comparing these studies is the levelized cost of electricity; however, the analysis varies by study. Each study utilizes some simplifying assumptions regarding customer loads, PV and energy storage costs, and cost reductions versus time. In all instances, they use simplified monthly average consumption numbers. SDG&E believes the Electric Power Research Institute (EPRI) report does the most thorough job of considering how an off-grid system would be designed, incorporated, and priced. The Bernstein Research report discusses off-grid issues but ignores them in the analysis. Finally, Rocki Mountain Institute (RMI) presents a yearly cost comparison versus time to determine the point at which grid defection would be cost effective. However, in a side bar note, RMI discusses that even though it is cost-effective for commercial customers in Hawaii to defect from the grid today, based upon their calculation, no commercial customers have done so given the other systems which need to be in place to perform the generation-load balancing functions.

In an earlier study[7], MIT looked at the future of the electric grid. This was a comprehensive view of the evolution of the grid over the next several decades. The goal was to provide an objective perspective on the challenges and opportunities that will occur in this future timeframe. The study recognized the existing grid which has served society well and will continue to serve and evolve to face serious challenges. It also recognized that these challenges will demand the intelligent use of new technologies and the adoption of more appropriate regulatory policies.

The MIT study has nine chapters covering the breadth of the electric grid that portend a number of the issues raised by the DRP, including a chapter on utility regulation that extensively discusses two critical elements for the future of the electric distribution system: the evolving nature of utility investments and rate design. Other chapters include:

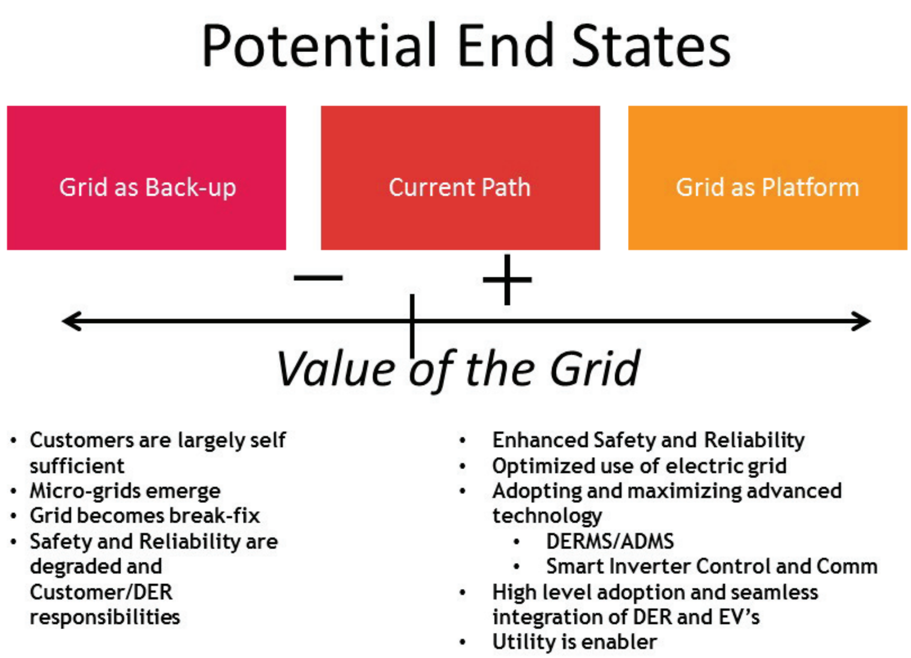
- Challenges, Opportunities, and Major Recommendations
- Enhancing the Transmission Network and System Operations
- Integration of Variable Energy Resources
- Transmission Expansion
- The Impact of Distributed Generation and Electric Vehicles
- Enhancing the Distribution System

[7] The Future of the Electric Grid – An Interdisciplinary MIT Study; http://mitei.mit.edu/publications/reports-studies/future-electric-grid

- Engaging Electricity Demand
- Utility Regulation
- Data Communications, Cybersecurity, and Customer Privacy

SDG&E believes that at high DER penetration levels, systematic change may be required in the planning and operation of the grid. DG standards will need to be changed to allow voltage regulation. Active distribution system management systems will be needed, as well as incentives to encourage off-peak battery and vehicle charging. In general, all these issues are raised as part of this DRP.

Figure 2: Potential End States



The future distribution delivery model must be an enabler of DER adoption and allow for all customers to have choice in their energy supply or the option to purchase a PEV. The distribution system of the future will leverage the existing infrastructure and become a universal services platform for a range of customer choices and DER provider transactions. Creating a future distribution platform that enables customer choice and DER integration will require strategic and cost-effective investment in DER enabling technologies, programs, and infrastructure by the utilities. While the benefits of new monitor and control technologies to enhance DER integration are generally recognized, other DER opportunities are often overlooked. In many cases, DER providers target candidates that meet certain qualifications, e.g., single-family homeowners with high energy usage, incomes, and credit scores. While this may make perfect sense for the business model, SDG&E believes that it may fall short of enabling the state to meet its GHG and policy goals because it fails to provide a majority of customers with a choice in their energy supply. Specifically, SDG&E believes that a large percentage of the utility's residential customers may lack the necessary electric service levels or viable financing options to purchase or lease a solar system, or plug in an EV where they live or work. The distribution system of the future will need additional cost-effective investments to upgrade electrical service levels to allow for widespread customer choice in energy and adoption of PEVs. SDG&E believes that cost-effective utility programs and investments that address customers who are *not* targeted by DER providers can help fill the gap in meeting the Commission's policy goals.

In order to create a future distribution system that provides universal service to all customers, SDG&E recommends reviewing the existing interconnection rules, such as Rules 15, 16, and 21. Enabling the utilities to make cost-effective investments to increase integration capacity of their respective distribution systems, which allows for increased customer choice, will provide benefits to both utility customers and DER providers.

Evolution of Distribution System Planning

Presently, the IOUs plan distribution circuits from the substation outward, as would be expected in a central source-to-point load system, and have traditionally used static steady state analysis that focused on peak system conditions. While SDG&E anticipates the power system's continued reliance on central generation sources, the expanding growth of DERs throughout the system changes the distribution planning paradigm. The very nature of renewable DERs requires that not only must a static load flow analysis be performed, but also a time series dynamic analysis to properly plan the distribution system. Given the current growth rate of DER and PEVs in San Diego, SDG&E has been proactive about upgrading its existing planning tools and processes to perform dynamic analysis, making substantial investments to improve its distribution planning tools. SDG&E is on track to have a fully integrated dynamic planning tool and process for its 2016 annual distribution planning cycle. Additionally, the need to improve customer load forecasting and adoption rates of DER is vital to a planning process and SDG&E has purchased new software to assist in this area.

While the DRP Guidance recommends that the CPUC and IOUs adopt a biennial DRP filing cycle, SDG&E proposes instead to incorporate the requirements for Integrated Capacity Analysis (ICA) and Locational Net Benefits Methodology (LNBM) into the annual distribution planning process. Results from the ICA and LNBM can then be made closer to real time and provide specific locations where DER can provide the most benefit. The ICA is the first step in the process to integrate DER. It will identify where there is existing capacity available on the distribution system where DER can connect with little or no upgrade costs. The next step is to use the LNBM layered on top of the ICA to determine where DER can potential provide additional value to the distribution system. The LNBM will use the E3 Distributed Energy Resources Avoided Cost Tool (DERAC) as the foundation and replace system values with locational values where appropriate. Finally, the growth scenarios will identify areas with a potential for a high adoption rate of DER where cost effective utility investment will be needed to achieve that adoption. SDG&E envisions that with the proper physical assurances, DERs will be able to play a role in capacity planning by deferring, and in some cases eliminating, traditional capital distribution, capital transmission, and/or utility-scale generation projects.

Existing Utility Distribution Operations

Although SDG&E's service area is segregated into various districts as described below, they are coherently integrated through coordination, communication, and teamwork. SDG&E maintains six geographically determined Construction & Operations Districts (Districts or C&O Centers) and two satellite operations centers to provide safe, reliable, and cost effective utility service to more than 3.2 million customers. Each District is staffed with a management team, administrative support staff, engineering and planning personnel, fleet and logistics support, and a variety of highly trained and qualified field technicians represented by Local 465 of the International Brotherhood of Electrical Workers. District personnel are primarily responsible for maintaining, operating, and upgrading the existing electric distribution systems. This includes routine maintenance and new construction work as well as responding 24/7 to routine outages and emergencies affecting SDG&E's customers. As circumstances warrant, Districts can team up and redeploy resources from areas that may be unaffected to locations in need of additional support or specialty equipment.

The Distribution Operations Department works around the clock and is responsible for the daily operation of the electric distribution system. Distribution Operations' primary activities include monitoring the status of the electric distribution system, coordinating planned outages, responding to unplanned outages, and overseeing any switching necessary for operations. Distribution Operations authorizes and schedules all planned outages. This organization is also the first to learn about forced interruptions and other emergencies and is responsible for dispatching appropriate District personnel as required. SDG&E averages six electric unplanned outages affecting approximately 3,000 customers per day. Most of these outages are fairly short in duration as they are usually the result of a localized problem that can normally be easily isolated and repaired.

Weather is the number one impact on the operation of the electric system. To that effect, Distribution Operations employs a team of three full-time meteorologists to assist in operating the nation's largest utility weather network, monitoring in-house weather forecast models and communicating adverse weather conditions that may impact SDG&E's electric distribution system. If an outage or emergency arises that is much broader or more severe in nature than Distribution Operations typically handles, the company will raise its response level and activate its Emergency Operations Center to take over some of Distribution Operations external coordination activities, and allow operations personnel to focus on the distribution system and field response activities.

Existing Utility Systems that Expedite Interconnection

SDG&E's Distribution Interconnection Information System (DIIS) has been verbally recognized by CPUC staffers at public workshops as a leading platform to process net energy metering (NEM) applications in both traditional and fast-track methodologies. SDG&E developed DIIS in response to the rapid adoption of rooftop solar PV in the San Diego service area, and it serves as the utility's main tool to allow an increasing number of customers to apply for the NEM tariff without burdening other ratepayers with additional staffing and administrative costs. With a focus on customer service and cost efficiency, DIIS was designed to help customers track applications and provide automated notifications to both customers and solar installation contractors during the application process.

However, DIIS also serves as a utility-wide database of all customer sited DER systems; including solar, wind, batteries, fuel cells, and other electricity generation and energy storage systems. DIIS integrates with the Geographic Information System (GIS) and Engineering Data Warehouse to provide data for analytics and efficient operations.

DIIS was developed with the primary goal of delivering excellent customer service by meeting multiple objectives, including:

- *Be connected with customers*
    - Continuing SDG&E ongoing efforts to connect with customers in multiple ways, DIIS was designed to provide a guided process to both contracted solar installers and customers self-installing solar to apply for the NEM rate and enact all agreements. DIIS was also designed to provide a single online location for an applicant to provide the numerous types of information required by the NEM application process.
- *Be transparent within every milestone under SDG&E control*
    - DIIS was designed to provide open access (to all qualifying outside parties) to applicable information within SDG&E's control. DIIS automatically generates emails to inform solar installers and customers of the status of their application and any milestones reached. DIIS also automatically verifies and validates entered data by cross-referencing data in SDG&E's primary billing and customer information system, thus ensuring that no NEM application is submitted with an invalid or erroneous account number and thereby avoiding unnecessary delays and re-work.
- *Reduced timeframe for authorization*
    - DIIS acts as a single data source which serves as the transactional interface for customers. It automatically routes information to SDG&E's billing system, customer generation team, and to external parties, thereby reducing the time for applications to proceed through each stage of the process. The internet accessibility of DIIS enables both customers and SDG&E employees to easily and efficiently remain informed regarding the next step for each application, which in-turn allows authorizations to proceed quickly and with minimal manual processes.

DER Capacity Value

SDG&E believes it is appropriate to install cost effective utility owned DERs that can provide capacity services to the distribution system. It is important to note that not all traditional infrastructure investment can be replaced either by investment in DER enabling infrastructure or investment in DER. The first step is to distinguish capacity services from reliability services; and then identify the reliability services DERs may potentially provide, the reliability services that only the IOUs can provide, and the appropriate regulatory oversight. The capacity services on the distribution system that a DER may potentially provide are straight forward: decreasing the loading on a circuit/substation through reliance on DER (e.g., serving the load locally may eliminate the need for additional circuit or substation capacity). This is not a new concept. The legislature and the Commission have already provided direction in P.U. Code § 353.5, and SDG&E has formalized processes to ensure compliance with this statue. In SDG&E's annual distribution planning process, DER solutions are evaluated as alternatives to traditional infrastructure for projects where they can meet specific criteria, e.g. right place, right size, right time, and right certainty.

Factors Potentially Limiting DER Integration Today

Several factors potentially limit more robust DER integration today, including:

- Difficulty providing or quantifying reliability services
- Uncertainty around resource adequacy eligibility and counting rules
- Rate reform
- Lack of standards or requirements addressing distribution-level voltage
- Power quality issues for DER resources

Reliability services on the distribution system that are reserved to the utility include system protection, system control, and service restoration. Utilities are best suited to detect and isolate distribution system faults, as well as restore the distribution system after an event. Utility-controlled devices such as Supervisory Control and Data Acquisition (SCADA), electronic relays, and service restorers make this possible. Additionally, utilities are best positioned to identify equipment that has high failure rates (such as certain vintages of underground cable) and then replace them ahead of time to reduce the frequency of forced outages.

While SDG&E does not support providing additional compensation to DERs for producing or absorbing reactive power within a minimum prescribed power-factor range, there could be instances when producing or absorbing reactive power outside the minimum-power-factor range would be helpful in ensuring the reliable operation of a distribution circuit. In these instances, a bilateral contract could be used to provide compensation for utility-directed production or absorption of reactive power outside the minimum prescribed range.

As noted elsewhere, DERs can be compensated for potentially avoiding or deferring planned distribution upgrades, including those designed to maintain acceptable voltages on the distribution circuit. But it is not appropriate to give credit to DERs for grid-support services unless the value of the service exceeds the costs in each specific instance for which the DER owner wants compensation. Such value assessments should compare the costs of providing the solution with DER versus using alternative solutions, such as switched-capacitor banks, dynamic (power electronic) voltage compensation, or line reconductoring.

Any DER that wants to provide Resource Adequacy (RA) capacity must follow the minimum operating and offer requirements that are set by the Commission's RA rules and CAISO Tariffs. Creating RA qualifying criteria and counting rules within the DRP that differ from the established protocols would create inconsistency among Commission decisions and could compromise the IOUs' ability to realize the full value of RA capacity. The CAISO could engage their backstop procurement mechanism if they believe that DRP derived RA capacity values are unlikely to be available when needed for reliability. Additionally, behind the meter DERs could potentially be used as load modifiers, thus reducing the amount of RA a utility needs to procure. Any determination of the appropriate RA credit, Net Qualifying Capacity or Effective Flexible Capacity applicable to a DER should be based on the scope, schedule, and decisions determined during the annual RA proceedings.

To realize the benefits of DERs, the IOUs' existing retail rate structures must be modified. If DERs are to be compensated for deferring or eliminating traditional infrastructure projects, DERs must have physical and contractual performance requirements with appropriate penalty provisions for non-performance. To enable customer choice and to realize benefits will require the right prices. To create the right economic incentives for DER performance, and to provide correct price signals for end-use consumers, SDG&E believes that price signals, whether they are rates or direct incentives, will need to reflect the value of the services being provided. Such price signals can be location-specific as well as time-differentiated.

However, providing accurate price signals for only DER will not be sufficient. To truly enable a distribution grid that is "plug-and-play" for DER will require that the prices for the utilities' resources also accurately reflect the services provided. SDG&E believes that it is necessary for traditional services and DER to be priced such that they accurately reflect the value of services provided in order for the most efficient resource be selected to meet a specific need. In the event that policy dictates that additional considerations are made for specific technologies or to meet specific needs, then these should be addressed through direct incentives that are outside of the rate structure in order to manage and mitigate resulting cost shifts.

While not part of this proceeding, rate reform is key to accomplishing much of what is envisioned in this OIR. As pointed out by stakeholders in this and other proceedings, the current ratemaking paradigm represents a fundamental challenge to the successful integration of DER into distribution system planning.[8,9] SDG&E could not agree more. Without comprehensive rate reform, including time of use and real time elements, it will be difficult to realize the Commission's vision of a fully integrated DER network.

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[8] IREC's September 5, 2014 Comments on the Order Instituting Rulemaking page 20.
[9] NY State Dept. of Public Service Staff Report and Proposal on Reforming the Energy Vision, http://www3.dps.ny.gov/W/PSCWeb.nsf/96f0fec0b45a3c6485257688006a701a/26be8a93967e604785257cc40066b91a/$FILE/ATTK0J3L.pdf/Reforming%20The%20Energy%20Vision%20(REV)%20REPORT%204.25.%2014.pdf

Responses to DRP Guidance

SDG&E formatted this document to align with the nine main sections contained in the DRP Guidance. As specified in the ACR, this DRP includes the results of an ICA SDG&E performed as well as a proposed LNBM. The ICA results will be displayed online and the LNBM will be used to guide future DER deployment. SDG&E will also provide various DER growth scenarios and demonstration projects.

Section 1: Integration Capacity Analysis and Locational Values Analysis

This section will detail SDG&E's three analytical frameworks related to the grid integration capacity of DER, the quantification of DER locational value, and the future growth of DERs. The intent is to create a set of mutually supportive tools that detail how much DER can be deployed under a business-as-usual grid investment trajectory, and build the capabilities to compare portfolios of DERs as alternatives to traditional grid infrastructure.

SDG&E performs its Distribution Planning Process (DPP) annually. The DPP involves analyzing all aspects of the existing distribution system to identify where modifications and/or capital projects are necessary to ensure continued safe, reliable, and cost effective operation of the distribution system to meet current and forecasted load growth per state mandates and industry practices. The DRP Guidance instructs the utilities to expand their existing DPP to include advanced analytics that will help better identify where a DER can interconnect with minimal impact and where interconnecting a DER can add value to the grid. Specifically, the Guidance directs the IOUs to develop three analytical frameworks to address 1) the potential integration capacity for DERs (the ICA), 2) quantification of locational benefits, and 3) future DER growth.[10] By incorporating these new additional analytics within the DPP, the intent is to expand upon historical DER incorporation practices and increase the ability to assess where and how DERs may be able to provide solutions to problems that have traditionally been addressed via new wires and new traditional equipment projects.

[10] The ICA results will be displayed online.

The following three sections outline SDG&E's proposed methodology for performing the 1) ICA, 2) the Locational Values Analysis, and 3) DER growth scenarios.

1.a Integration Capacity Analysis

The Guidance in 1.a.i. directs the utilities to utilize a common methodology to quantify the ICA and display available capacity on the distribution system down to the line section or node level. The IOUs have developed a common methodology that assesses the capability of their respective systems to integrate DER within applicable thermal ratings, safety standards, protection system limits, and power quality parameters. The parameters may differ slightly between utilities due to design standards and operating criteria, but the methodology used is common between the IOUs. Additionally, the Guidance in 1.a.i. required each IOU to both complete an "initial" ICA by July 1, 2015, as well as specify processes for regularly updating the ICA to reflect ongoing current conditions. Concurrent with this filing, SDG&E will publish via online maps the initial results for the ICA performed to date. SDG&E believes that should its methodology be deemed appropriate and upon Commission direction, SDG&E will publish the remaining results as they become available.

SDG&E has adopted a two-pronged approach to completing the ICA. The utility has simultaneously developed an in-house approach, and contracted with Integral Analytics (IA) to perform a parallel ICA for this filing. IA's analysis serves as a secondary check on SDG&E's methodology, and allows an advanced look at the entire SDG&E system, as well as a 10-year extended Integration Capacity estimate. While SDG&E and IA are unified in their approach, different data sets were used for each analysis.

SDG&E's current DPP involves using a simulation and analysis software tool call Synergi Electric (Synergi) to model and analyze the power distribution system. SDG&E is in the process of updating all of its power flow models to Synergi version 5 models, and is performing ICA using these new models.[11] To ensure that the most up to date numbers are readily available, SDG&E will be updating the IC values on its GIS maps based on its own analysis utilizing the Synergi 5 models. While not all

[11] IA has performed the ICA on Synergi version 4 models. This was done to ensure that an analysis was performed on all of SDG&E's 12 kV distribution circuits, as not all of SDG&E's circuits were modeled in Synergi version 5 before the July 1 filing date. The Synergi version 4 models do not have all of the functionality of the version 5 models, but it does provide an second look at what capacity might be available on each circuit.

circuits have yet been analyzed using SDG&E's proposed method for this filing, SDG&E expects that its system will be fully analyzed in Synergi version 5 by the end of 2015.

1.a.i. Methodology for a Distribution System ICA

Per the Guidance in 1.a.i., SDG&E's proposed methodology performs an ICA on each of SDG&E's distribution system circuits, and will provide the ICA's results on a GIS-based mapping system accessible on SDG&E's website. For the purposes of this DRP, "Integration Capacity" is the amount of DER capacity that can be installed on a distribution circuit without requiring significant distribution upgrades. SDG&E's ICA methodology starts with annually reviewing and forecasting the minimum daytime (9 a.m. – 6 p.m.) loading on each of SDG&E's distribution circuits. The minimum loads will be used to establish the maximum amount of IC allowed on the circuit, with the maximum amount defined as the last MW of DER capacity installed before the next incremental MW of capacity causes electricity to flow from the DER(s) back to the substation bus, an outcome also known as reverse power flow. It is important to note that this reverse flow restriction is only in place for this initial DRP filing, and that future ICA results will not be limited by the load on the feeder or substation bus. SDG&E believes that even with the reverse flow restriction, there is significant IC to be found on its distribution system. Table 1 shows that there are over 100 MW of IC available on the first 70 circuits analyzed on SDG&E's distribution system. Once analysis is complete for the remaining 12 kV circuits, SDG&E expects that number to climb to over 1,000 MW system-wide without removing the reverse flow limit. When SDG&E incorporates the ICA into its annual DPP, the reverse flow limit will be removed, and each circuit's IC will be determined solely by the results of power flow analysis performed as part of the ICA.

The forecasted load will be allocated throughout the circuit based on data collected from smart meters. As Synergi models each distribution circuit down to the service transformer, the smart meter data is used to determine what portion of the total circuit load should be allocated to each service transformer.

Once the forecasted load is allocated to the circuit, the ICA methodology will next identify an IC for different zones of each circuit along the main feeder backbone[12]. Additionally, each circuit will be grouped into one of two categories based on circuit length. This is intended to differentiate longer length rural circuits from shorter, load-dense urban circuits. Table 1 below identifies the criteria defining the zones and feeder groupings utilized in the ICA.

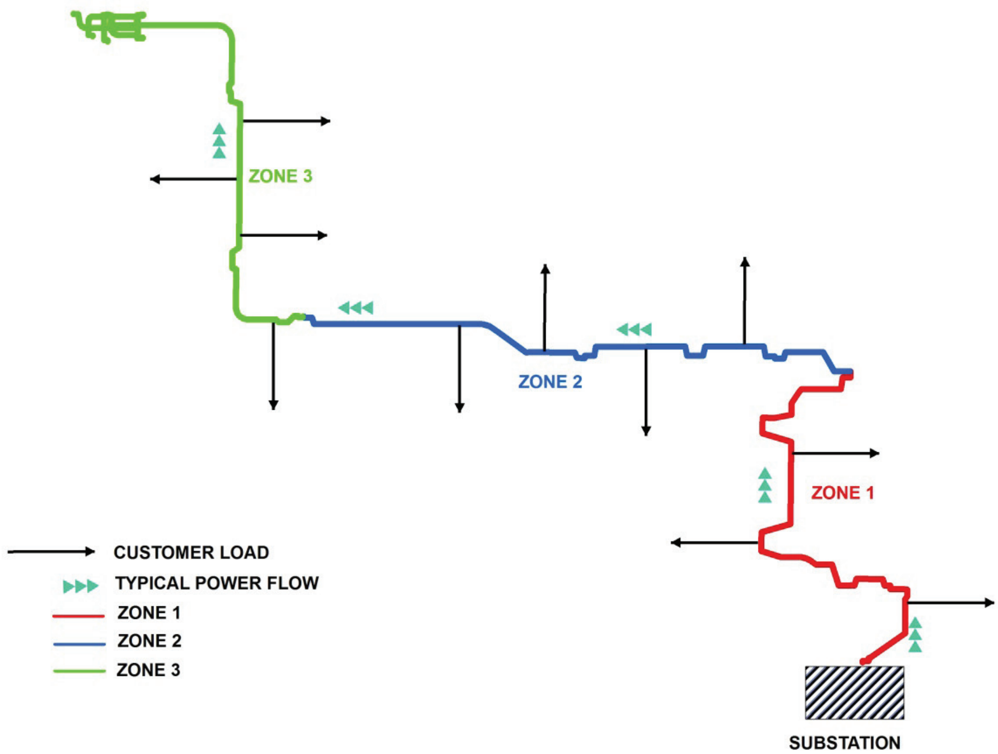
Table 1: Zones

	Group 1	Group 2
Circuit Length in Miles	0-10	10+
Zone 1 Impedance (Ohms)	0-1	0-15
Zone 2 Impedance	1-2	15-25
Zone 3 Impedance	2+	25+

Figure 3 below shows an example of a circuit divided into three zones, and how the load might be distributed throughout the circuit.

[12] A circuit may be divided into one to three zones, which are based upon the impedance along the main feeder backbone.

Figure 3: Example Circuit Map



The methodology involves dividing each distribution circuit into up to three zones and then simulating the addition of generation to each zone until one or more limits are exceeded. Starting with the highest impedance zone and finishing with the lowest impedance zone, the methodology next simulates connecting a single generator with the maximum allowable IC with a power factor (PF) of 1.0 to the respective zone, and then running a steady state power flow simulation with the newly connected generation, as well as existing generation on the circuit to determine if the new generation causes any of the following three limits identified below to be exceeded.[13]

The three identified limits represent system conditions which can result in the damage of electrical equipment, presenting a safety hazard. To maintain the safety of the SDG&E employees and the public, it is imperative that equipment be operated within these limitations. As SDG&E is the sole entity responsible for the safe and reliable operation of the electric system, the utility will continue to plan the system to rigorous safety standards.[14,15] Therefore, the operating limits identified below will

[13] The three limits comply with SDG&E's safety standards for distribution energized equipment.

[14] D.03-02-068, pg. 13 "The utilities indicate that if the utility is responsible for the safety, reliability and operation of the distribution system, it must have control over the planning and operation of the system. We reaffirm this today."

apply to the ICA, and DER integration beyond those limits will require upgrades to the distribution system to ensure safe operation.

- **Thermal Limits** – Thermal limits shall be the rated capacity of the conductor, transformer, or cable established from SDG&E standards. SDG&E designs and constructs the distribution system in accordance with General Orders (GO) 95 and 128.
- **Voltage Limits** – There are two voltage limits: the steady state limit and voltage fluctuation limit. The steady state voltage criteria requires the voltage to remain within either the Conservation Voltage Reduction (CVR) limits or already established and annually reported temporary non-CVR limits. Voltage fluctuation criteria limit permissible fluctuations to not exceed 3%.
- **Protection Limits** – The protection limit is a check on feeder breaker, switch, and recloser fault current interrupting rating. Once the DER is installed, the fault contribution of the generator is added to the existing fault current on the devices at the feeder and it is verified that the fault current remains below the fault current interrupting rating.

Violation of thermal limits can result in sagging conductors, damaged equipment, fires, and other public safety hazards. Violation of voltage limits can result in damaged utility and customer equipment, fires, and other public safety hazards. Violation of protection limits can result in catastrophic equipment failure, damaged customer equipment, fires, and other public safety hazards.

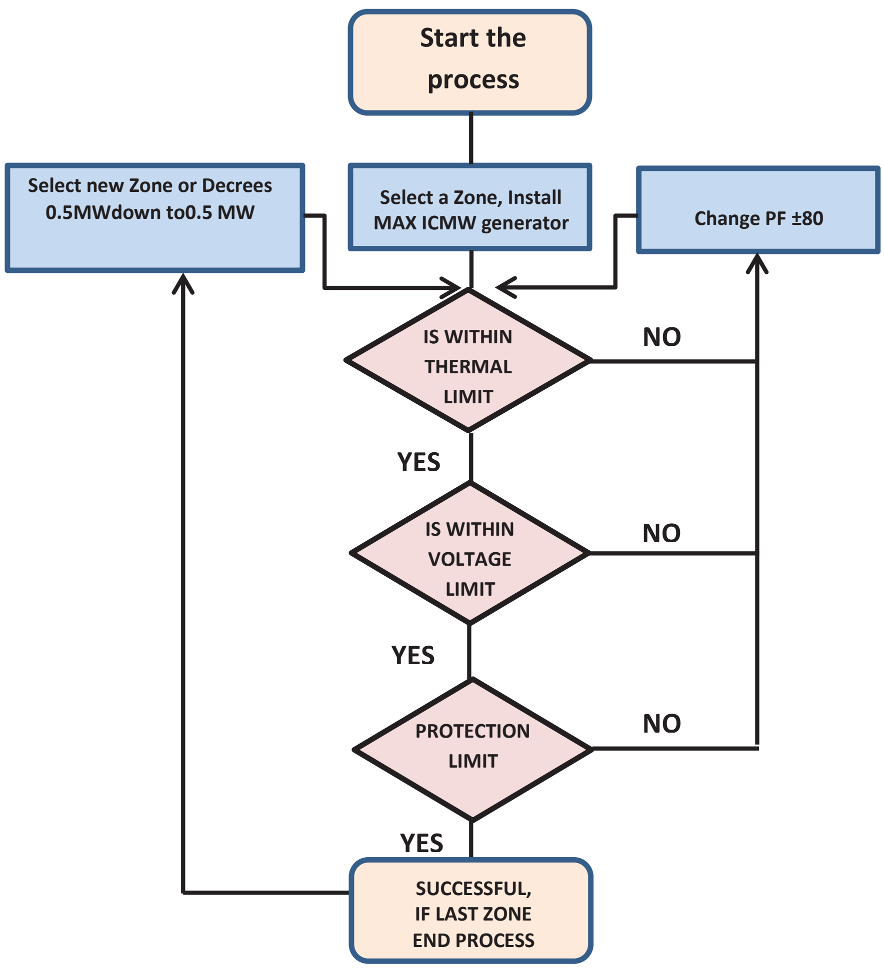
If the new generation exceeds any limit, the methodology will reduce the generation in 0.5 MW increments and rerun the full simulation until none of the three limits are exceeded. Additionally, if a limit is exceeded, the analytics will change the generator's modeled power factor and then rerun the steady state power flow simulation. If the simulation results still do not meet acceptable criteria, then the simulations will continue until either the simulation passes all three limit screens, or until the simulated generator drops to 0 MW, at which point the IC is reported as 0 MW

[15] R.01-10-024, pg.93 "The utilities themselves are the ones responsible and accountable for meeting the loads and energy requirements of the customers in their respective service areas. The utilities, not the CEC, are required to meet an obligation to serve under several sections of the Pub. Util. Code. We specifically cite here Section 451's requirement to "furnish adequate, efficient, just, and reasonable service…necessary to promote the safety, health, comfort and convenience of its patrons, employees, and the public." Therefore, regulatory clarity and appropriate placement of responsibility requires that the utilities should have the responsibility of estimating their own future needs.

for that circuit. The model will stop doing simulations for an impedance zone when the modeled PF is = +/- 0.80 and the results are still outside of the acceptable criteria. The reported IC is the maximum value of added generation with simulation results that are within acceptable criteria ranges.

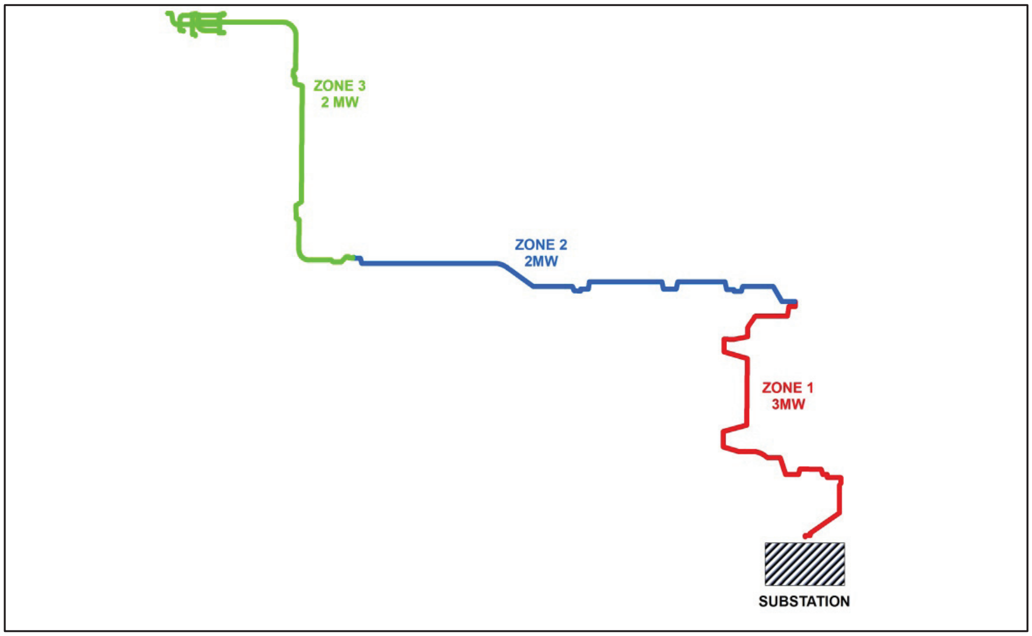
Once an IC value for one impedance zone is determined, the test generator on that zone is removed and the entire process is repeated on the next zone until all impedance zones on all distribution circuits have an IC value. See Figure 4 for a flow chart.

Figure 4: Flow Chart



The IC per zone is established upon the completion of this process. The entire process assumes that the interconnection point is on the circuit main feeder. Figure 5 below provides an example of the process using a a circuit with a minimum daily peak of 5MW.

Figure 5: Example Identifying the Zones Integration Capacity



In this example, the largest IC identified is 3 MW and is associated with zone 1, which happens to be the feeder section closest to the substation circuit breaker. The 3MW IC value is lower than the 5MW reverse flow limit at the substation bus. An IC value of 3MW means that a third party DER developer may interconnect a mix of different techology types and capacity sizes in any of the circuit's zones as long as the aggregate does not exceed 3MW (circuit's max IC), and the aggregrate of DER within and "below" any one zone exceed the IC of that specific zone. That is, zone 1 is the aggregation of DER in zones 1, 2 and 3; zone 2 is the aggregation of DER in zones 2 and 3; and zone 3 is the aggregation of DER in zone 3 only. In those situations where the IC value is based upon a voltage limit being exceeded, not all combinations of DER are plausible. Additional engineering studies will be necessary to evalute DER of different techology types being installed on a circuit which has at least one of its zones having an IC value that is based on voltage limits being exceeded.

To see the initial values for the ICA, as well as a 10-year forcast, please refer to appendix I.

1.a.ii. Distribution System Capability and Forecast Methodology

The Guidance in 1.a.ii directs the utilities to perform the initial ICA using current distribution system capabilities together with any planned investments over the next two years, and to clearly articulate forecasting methodologies and assumptions for load and DER growth. In compliance with this directive, SDG&E's ICA methodology includes both data representing the distribution system's capabilities today, as well as changes to the system due to planned investments during the next two years into a single analysis.

In regard to load forecasting methodologies and assumptions, SDG&E's current DPP includes preparing a 10-year annual peak demand forecast for each distribution circuit and substation power transformer. The forecast is developed by first validating the peak load values recorded during the most recently completed summer and winter periods. The validation includes, but is not limited to, confirming if the peak values reflect any of the following:

- New customer load being added or existing customer load being removed
- Load that was temporarily transferred to or from another circuit
- Load due to any system failures, unplanned outages, loss of resources, or temporary generation

The forecasted peak values are then developed by reflecting the following onto the validated previous year's peaks: load growth reflecting historic trending, load growth associated with specific new large-load customers, loss of load from specific large-load customers, and changes due to planned permanent load transfers. After the generation and loads are validated, weather factors are applied to establish a worst case scenario (1-in-10 scenario) on the distribution system to identify if the system will have adequate capacity.

SDG&E is currently developing localized irradiance curves for typical PV systems located throughout the service territory. Future peak forecasts will reflect a solar PV component based upon regional irradiance curve data instead of a system-wide default value. Additionally, SDG&E's use of a new forecasting tool to develop hourly geospatial load forecasting tool will improve the IC analysis.

Per the Guidance in 1.a.i, the ICA results reflecting current and planned capacity investments in the next two years are anticipated to be made available online in two separate formats: on SDG&E's GIS based mapping system, and in a tabular format as illustrated in Table 2.

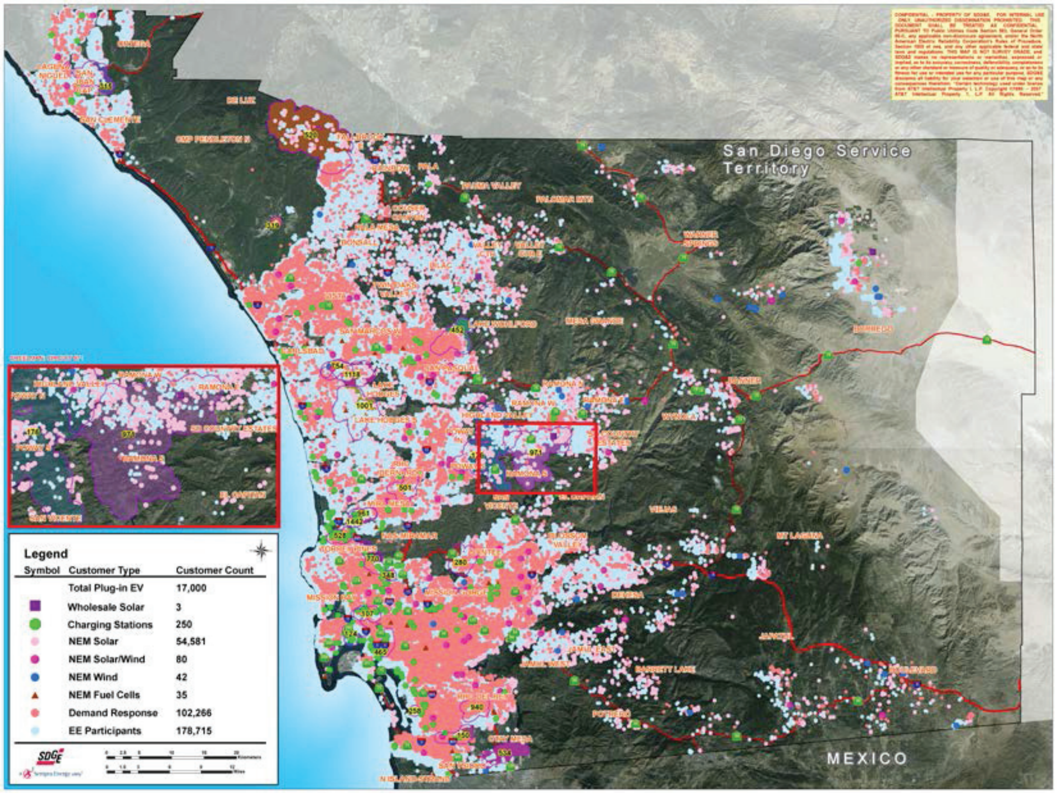
Table 2: Distribution System IC

Circuit	Maximum IC	No. of Zones	Zone 1	PF	Zone 2	PF	Zone 3	PF
CXXX	2.5 MW	3	1 MW	1.0	2 MW	1.0	1 MW	1.0

1.a.iv. State of DER and Technology Deployment

As a component of the ICA, the Guidance in 1.a.iv directs utilities to provide current levels of DER deployment territory-wide, with an assessment of geographic dispersion of DERs. As the graphics and tables below illustrate, SDG&E has experienced a rapid deployment of new technologies, including PV solar and one of the highest penetration areas of PEVs in the nation. SDG&E embraces the change in the electric system landscape, and is even now testing new technologies to expand the IC of the distribution system. To determine where future DERs might deploy, it is important to understand where DERs exist today. This map is also shown full size as attachment 1.

Figure 6: DER Penetration in SDG&E Service Territory



As can be seen from the figure, SDG&E has a significant spread of DERs throughout its distribution system. In particular, solar PV is enjoying widespread adoption, which is reflective in the utility's statewide lead in NEM penetration. San Diego is also among national leaders in PEV adoption, with an estimated 17,000 PEVs in SDG&E's service territory as of May 2015[16].

The table below indicates distribution circuits where the aggregate installed DER nameplate capacity is greater than 25% of the circuit's capacity.

[16] Footnote to Map in Appendix: Charging stations shown represent public charging stations where location data is publically available. It does not include private access or residential charging stations.

Table 3: High Penetration DG Circuits

Substation	Circuit	Installed Capacity (%)	Substation	Circuit	Installed Capacity (%)
AS	452	28.40%	MRM	958*	38.40%
AV	520	30.30%	MRM	961*	41.30%
BQ	754*	25.70%	MTO	1442*	54.20%
BQ	1118*	26.70%	MG	258*	73.60%
BD	534*	25.10%	OT	107*	25.30%
CP	315*	58.30%	OT	124	26.00%
CH	280*	42.40%	OY	150*	78.90%
CC	501	37.60%	PN	319*	28.40%
CRE	971	68.90%	PO	176	28.10%
GE	528*	36.70%	SF	1001	34.10%
KA	348*	40.50%	TC	940	25.30%
MSH	770*	68.50%	UB	465*	33.10%

**Represents circuits where the majority of distributed generators are qualifying facilities or combustion turbines.*

In response to the increasing penetration of DERs, SDG&E has been actively upgrading its distribution system with an increasing number command, control, and automation devices. At present, approximately 80% of SDG&E's 12 kV substations are fully SCADA enabled, allowing the utility to remotely monitor and control those substations. SDG&E is also deploying systems that will automatically locate and isolate faults on the distribution system, decreasing the time that it takes to troubleshoot and restore an outage. Smart, cost-effective investments in technologies such as these allow SDG&E to continue to provide safe and reliable electric service while simultaneously enabling the distribution system of the future.

1.a.vi. Updating the Integration Capacity Analysis

The Guidance in 1.a.vi requires the utilities to specify their process for regularly updating the ICA to reflect both current conditions and process improvements. As articulated more fully below, SDG&E is already implementing both near-and medium-term initiatives to improve its DPP to plan for and enable more robust DER growth. These initiatives include developing and incorporating dynamic ICA modelling, as well as a spatial load forecasting tool to more accurately model load growth at the substation, circuit, and small area levels. Once these improvements are tested and fully integrated, the ICA will evolve. The updated models and processes will perform power flow analysis in a more dynamic environment, including solar irradiance curves and other operating parameters of DERs as well as distribution equipment, and the improved forecasting software suite will allow SDG&E to perform hourly geospatial forecasting of customer demand and solar penetration, generating the curves that will be input into the improved dynamic modelling suite of software products. While not included in the demonstration projects, ultimately SDG&E will include smart inverter dynamic models as they become available.

Near Term Initiatives: The Future State of Integration Capacity Analysis

SDG&E's current DPP software provides static results, but not dynamic results required to robustly and appropriately plan for and enable rapid DER growth. SDG&E is working with its vendors to create a version that will execute the utility's dynamic ICA modeling of renewable DG production profiles and distribution circuit load profiles. The new version of Synergi will acquire customer demand from SDG&E's Advanced Metering Infrastructure (AMI), contain renewable DG profiles throughout the entire service territory, and capture time settings for all voltage regulating equipment (e.g., transformer's load tap changer, distribution capacitors, voltage regulators, inverter controls, etc). Each data point installed and distribution circuit uploaded within the new software version will entail troubleshooting as well as debugging before the new version is capable of being tested for dynamic functionality. Before the new dynamic ICA is ready for production, the results will require validation with real-time values to identify any outliers or inaccurate results. SDG&E expects that the time-series dynamic simulation results will cause ICA maximum values to be different than when calculated using static series simulation.

As reflected in the Next Phase text, the new tools and software to perform the first dynamic ICA are expected to be developed during the 2016-2017 time period (with the results demonstrated to the CPUC as demonstration project A) and incorporated within SDG&E's DPP during 2017-2018. SDG&E proposes the dynamic ICA will be updated regularly to reflect current conditions utilizing a similar process for the Renewable Auction Mechanism (RAM).

Medium-Term initiatives: The Future State of Integration Capacity Analysis

One of the key initiatives in moving from the existing planning paradigm to DER focused planning is updating forecasting methodology. Forecasting will need to transition from a point-in-time analysis to a fully dynamic, hourly demand-curve type forecasting process. For this purpose, SDG&E

has procured the LoadSEER software package from Integral Analytics. LoadSEER, developed by Integral Analytics, is a spatial load forecasting tool which will be used by SDG&E distribution system planners to predict how much power must be delivered, where on the grid the load will occur, and when it must be supplied. LoadSEER spatial load forecasts address both short-term circuit trends and long-term grid expansion, while remaining consistent with the overall corporate load forecast for energy and peak demand. Due to the complexity of the forecasting challenge, LoadSEER employs multiple statistical methods including statistical modeling of peak load history, econometric modeling of energy, and a GIS-based land use simulation analysis which, taken together, increase the validity and reduce uncertainty associated with the forecasts. The resulting forecast provides SDG&E planners with substation, circuit, and small-area resolution load growth which is mapped and viewed within the tool. With this increased granular detail, SDG&E planners can more accurately predict growth as well as assess changes and risks on each circuit due to the LoadSEER information provided on acre-level load growth and/or distributed resource changes, including PEV adoption, solar power penetration, and load switching transfers. The LoadSEER tool also enables SDG&E to analyze specific future scenarios such as high speed commuter rail lines, new manufacturing, changes in solar penetration, plug-in electric vehicle adoption, and circuit-by-circuit analysis of the econometric drivers that are responsible for growth. All of these aid SDG&E planners in examining the reliability risk for each circuit.

LoadSEER utilizes two distinct modules, the FIT (Forecast Integration Tool) module and LoadSEER-GIS module. LoadSEER-FIT employs three methods for forecasting loads, is maintained within a web services user interface, and is the software platform where distribution planners perform most of their forecasting and data management tasks. The LoadSEER-GIS module houses the spatial data information and analytics. LoadSEER employs three different types of load forecasting including a regression of peak circuit loads on weather and economic variables, an econometric forecast of energy using these same or similar independent variables, and a spatial load forecast using GIS land use and geographic information. The use of three different methods provides increased convergent validity where two or more of the distinct forecasts produce similar forecast results. In addition, the distribution planner’s knowledge of the local load situation can be incorporated to further enhance the forecast accuracy of any of the three methods. LoadSEER also provides an option to statistically blend the three forecasts based on the statistical goodness of fit diagnostics for each method. Alternatively, if the distribution planner has unique, local knowledge that one of the three forecasts is likely to be more accurate than the others, more weight can be placed on that forecast.

All forecasts provide both weather normal and weather adjusted results. SDG&E planners may see value in utilizing either 1-in-10, 1-in-20, or 1-in-30 year peak weather occurrence forecasts to account for increasing risk due to extreme weather. Historically, regression analysis of just peak circuit loads on temperature was the industry standard for distribution planning forecasts.

However, the use of three independent and more sophisticated forecasting methods in LoadSEER can improve overall forecasting accuracy and increase confidence in the forecast. For example, if mild weather has historically coincided with depressed economic conditions, traditional regression results would be biased when only temperature related variables were used. The result would be artificially lower load forecasts and commensurate increases in planning risk. The economic crisis of 2008, which persisted over multiple years, highlighted the fact that the state of the economy can often be more influential on peak loads than just weather variability. Therefore, simultaneously forecasting peak loads using both weather and economic variables is a prudent and necessary next step to load forecasting, especially where the data histories on which the analysis is based include significant economic changes. As such, LoadSEER not only provides a weather normal forecast of loads, but also incorporates a forecast of circuit specific economic drivers as well. For example, one circuit might respond to changes in retail sales, while another might be more sensitive to employment, personal income, gross domestic product (GDP), personal bankruptcies, or other economic drivers. These weather and economic variables are taken from the same sources as those used for the overall corporate forecast to ensure forecasting consistency. Additionally, the same weather and economic sources are used in both the peak load history regression forecast as well as the econometric energy forecasting method. So, the first two of LoadSEER's three forecasting methods are assured of consistent inputs not only with each other, but with the overall corporate forecast as well.

LoadSEER's third forecasting method generates a spatial forecast that relies on a rich set of geospatial data layers and simulation algorithms to produce local area forecasts that in the aggregate are also required to maintain consistency with the overall corporate forecast. The forecasting algorithms in LoadSEER determine where growth will occur by analyzing factors such as regional influences (e.g., economic centers, airports, and roads), historic customer location preferences (e.g., proximity to other land uses, surrounding densities of other types of customers, land use availability, and restricted zones), and local geographic factors. Land availability wields significant influence on the overall forecast given local geography, terrain, and zoning law constraints. In addition to forecasting growth for areas that have already partially developed, the LoadSEER-GIS module can project growth for currently undeveloped areas based upon the previously mentioned regional influences, location preferences, and the overall economic forecast.

Analogous to regression based methods, spatial forecasts assume that the manner in which historical changes and trends have emerged will continue in the same way into the future. As such, separate forecasting methods are required to layer in new technologies and resources such as solar and PEVs, or any other load change where past data observations are sparse or of limited duration.

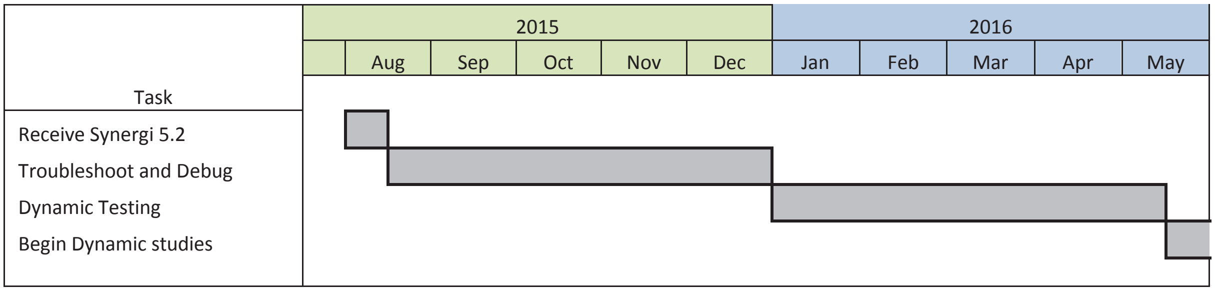
Using information and results from the foregoing three methods, LoadSEER allows the distribution planner to either accept LoadSEER's blended final forecast (weighted by the statistical goodness of fit values for each of the three forecasts) or establish a final forecast that is consistent with the planner's local knowledge of the area. In some cases, this local knowledge and experience is invaluable with respect to adjusting the load forecast via the addition of spot loads, known residential development, or other factors that LoadSEER cannot know. As SDG&E engineers include these known, or reasonably knowable, future loads into the local circuit forecast, LoadSEER subsequently will update the overall allocation of customer class loads generally across the other circuits. In this manner, the software grows increasingly accurate over time as the statistical forecasts are combined with local engineer knowledge of known changes.

Because LoadSEER operates under the premise that the integration of the planner's local knowledge is essential for a useful and accurate local forecasting, the software allows experienced engineering judgment and insights to be directly included within the forecasting process and results. LoadSEER can incorporate local knowledge relating to a region's socio-economic system, past and present trends, known construction, and future land policy. To ensure overall forecast quality and consistency with the total corporate forecast, LoadSEER requires planners to co-construct the intelligence housed in the database with the engineer's years of experience and intimate knowledge of local development, economics, politics, and other factors which contribute to peak loads. This helps guarantee the quality and accuracy of the forecast. When expert engineer judgment, experience, and local knowledge is integrated into the problem-solving and forecasting loop, this enhances the richness, detail, and accuracy of the forecast and provides the locational granularity required for the changing mix of resources and loads on the grid.

The LoadSEER-GIS module maps and provides visuals of each forecast, produces tabular and graphic results for each substation area, and summarizes the change in load and hourly load profiles for each area. LoadSEER's GIS simulation engine enables planners to run various growth scenarios created from sets of specific assumptions (e.g., changes in the economy, new manufacturing plants, commercial retail, residential housing, and transportation). Changes in one type of load class inevitably cause changes in location or magnitude for other customers. For example, construction of a new manufacturing facility or highway results in the eventual construction of other types of loads, such as residential housing, retail space, or other customer types. LoadSEER's GIS engine accommodates the prediction and likely placement of these multiplier effects, consistent with the overall corporate forecast in total. In this manner, various distributed energy resources can be analyzed in terms of their likely impacts given the likely placement of future loads, jointly. The LoadSEER tool represents a major improvement in the ability of SDG&E distribution planners to accurately model a DER integrated distribution system.

Once LoadSEER's forecast is complete, it will be an input to the updated Synergi power flow model. Synergi's new capabilities will enable more detailed analysis of DERs, including dynamic modeling of the daily demand and generation curves produced by LoadSEER. Synergi will perform power flow simulations utilizing both the demand and generation curves, and identify thermal, voltage, and protection limits following the same criteria as the initial phase of the DRP.

Figure 7: Dynamic ICA Schedule



1.a.vii. Recommendations for Utilizing the Integration Capacity Analysis

The results of the ICA will be published online[17] and made available for DER developers to use as a guideline to identify where available capacity may exist on the distribution system to allow installation of a DER within the Rule 21 interconnection process. SDG&E envisions that the results of the ICA will guide developers to areas of SDG&E's distribution system that DERs can connect with little to no distribution upgrades required.

DER developers and other stakeholders must remember that the ICA is not an all-encompassing interconnection analysis tool, and that interconnection facilities identified as part of the Rule 21 process are the responsibility of the developer/installer. Interconnection facilities are those facilities necessary to connect DERs to the distribution system, and will be required where an existing connection does not exist, or an existing connection is not adequate to connect the DER.

The Guidance in 1.a.vii directs the utilities to specify recommendations for changes to rules 15, 16, and 21. SDG&E believes that the DRP can be informative to proceeding R.11-09-011 which is currently underway to modify Rule 21. While the ICA is not a substitute for an interconnection study, the results of the ICA may be used to inform and potentially expedite the fast track process. The fast track process involves a set of screens that evaluate many different aspects of generation interconnections, which are key to ensuring the safety and reliability of the distribution system. SDG&E believes that the ICA may change the way the screens are applied, and certain screens may be avoided altogether for locations where SDG&E has identified sufficient IC. Further, for areas where

[17] SDG&E's online interconnection maps can be accessed at http://www.sdge.com/generation-interconnections/interconnection-information-and-map. To gain access to the online maps, parties must register and go through a screening process to validate eligibility.

SDG&E identifies proactive investment to accommodate DERs, there may be the opportunity for discussion about cost allocation principles for distribution upgrades under Rule 21. Even with the discussion outlined above, SDG&E believes that any modifications to the Rule 21 tariff should be explored and vetted in the Rule 21 proceeding.

Rules 15 and 16 contain specific provisions regarding the addition of new customer load, and care should be taken not to undermine those processes within this DRP. While the addition of EV charging load will be an important component of migration to an emissions-free California, the utilities existing processes are adequate to address PEV charging load. Should the need arise to change procedures and protocols for adding PEV charging load, or any new load, SDG&E will propose the necessary changes in the appropriate regulatory forum.

1.b Optimal Location Benefit Analysis

The Guidance instructs the utilities to develop a LNBM that specifies the net benefits that DERs can provide in a given location. To implement this analysis, the utilities have developed a consistent locational net benefit methodology using DERAC as a foundation, and supplemented by additional inputs and considerations as described in detail below.

An optimal location is dependent on a number of qualitative and quantitative factors, including the timing of the need for distribution system upgrades, and is affected by the extent to which a DER necessitates upgrades to interconnect to the distribution system (the cost of interconnection upgrades subtract from net benefits). An effective DER integration strategy identifies those locations where DERs fit seamlessly into the system without the need for significant upgrades. SDG&E's utmost responsibility is to its customers, therefore, DER projects will be chosen over traditional upgrade projects where the benefits to consumers are greater than the costs to consumers of installing the DER project.

Before describing SDG&E's LNBM in detail, it is important to clearly articulate the circumstances where optimally located DERs may provide an effective alternative to conventional distribution infrastructure investment, and circumstances where regardless of location, DERs are less likely to provide a suitable alternative to conventional distribution infrastructure investment. In its yearly DPP, SDG&E performs an analysis that identifies capacity deficiencies on the distribution system. These deficiencies can be at the substation, or along the distribution circuit. To address deficiencies that cannot be mitigated through reconfiguration of the distribution system, SDG&E will propose the lowest cost, optimal solution to resolve the deficiency. These options typically include new circuits, new substations, additional substation transformers, or reconductoring of existing circuits.

For the purposes of the LNBM, SDG&E proposes to group the distribution upgrade projects into two categories. The first category, where SDG&E believes optimally located DERs can play an important role, is providing an alternate to or possibly avoiding the capacity investments that increase load serving capability of the grid, such as new substations, transformers or distribution circuits, or the reconductoring of existing transmission and distribution lines. The second category, where DER solutions are less suited to replace traditional distribution system investment includes, but is not limited to: replacement of aging infrastructure (e.g., poles and wires), operation and maintenance of the existing system, and control and monitoring equipment.

In general, SDG&E believes that only the first category of projects is appropriate for deferral or replacement by a DER project. DERs are located close to load, and as such, will generally decrease power flows on the distribution system. With proper performance requirements and guarantees, DERs located in capacity-constrained areas on the distribution system could potentially allow SDG&E to defer the need to build capacity projects, such as new circuits or substations. On the other hand, reliability projects that replace aging vintages of cable cannot be mitigated by DER projects, as the high failure rate of such cable will still be a reliability risk to the system. Table 4 highlights some project examples and the potential for DER projects to defer the investment.

Table 4: Project Types and Potential for DER Deferral

Project Type	Purpose	Potential for DER Deferral?
New Circuit	Capacity	Yes, with performance requirements
New Substation	Capacity	Yes, with performance requirements
Reconductor	Capacity	Yes, with performance requirements
New Regulators/Capacitors	Voltage Regulation	Yes, with smart inverter installation
New SCADA/Controls	Reliability	No
Equipment Upgrade	Reliability	No
Equipment Replacement	Aging Infrastructure	No
Pole Replacement	Compliance	No

1.b.1 SDG&E's Locational Net Benefits Methodology

This section describes the LNBM that SDG&E is developing and proposing to include within its expanded DPP to calculate location-specific benefit of deferring traditional upgrades on its distribution system. As directed by the Guidance, SDG&E's LNBM utilizes DERAC as its foundation. Where appropriate, and as described in more detail below, SDG&E utilized additional recommendations from the More Than Smart (MTS) working group to augment and improve the DERAC foundation to more accurately reflect locational value. Lastly, the Guidance identified several additional values for utilities to consider when developing LNBM. As discussed below, SDG&E's proposed LNBM incorporates inputs to identify and calculate those values where appropriate.

Adopting and Evolving the DERAC Model

The DERAC model identifies seven different value components that may be impacted by the installation of DERs. Each of these value components and their treatment in the DERAC model are outlined in Table 5 below.

Table 5: Value Components in the DERAC Model

Component	Basis of Annual forecast	Basis of Hourly Shape
Generation Energy	Forward market prices and the $/kWh fixed and variable operation costs of a CCGT	Historical hourly day-ahead market price shapes from MRTU OASIS
Losses	System loss factors	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 shape
Avoided RPS	Cost of a marginal renewable resource less the energy market and capacity value associated with that resource	Flat across all hours

Several of the DERAC's value concepts are quantified at the system level. In contemplating a methodology to assess locational value concepts, the utilities created a unified methodology that modifies the DERAC model to replace system values with locational values where appropriate. This improvement in granularity from the system to local level is shown in Table 6 below.

Table 6: DERAC Model Modification

Component	Locational Value
Generation Energy	Generation energy replaced with locational marginal price
Losses	Location specific loss factors
Generation Capacity	Local Capacity Requirements (LCR) for resource adequacy
Ancillary Services	Percentage of generation energy value
T&D Capacity	Avoided Sub-Transmission, Substation and Feeder Capital and Operating Expenditures Avoided Distribution Voltage and Power Quality Capital and Operating Expenditures Avoided Distribution Reliability and Resiliency Capital and Operating Expenditures Avoided Transmission Capital and Operating Expenditures
Environment	Qualitatively describe the societal avoided costs by using the CalEnviro Screening tool
Avoided RPS	Cost of a marginal renewable resource less the energy market and capacity value associated with that resource

In addition to modifying the DERAC to include local factors where appropriate, SDG&E believes the values determined by its LNBM should also be directly tied to the services that DER projects provide to the distribution system. This connection between locational value and DER services is another area where the MTS working group has been instrumental in identifying the role that DERs can play in distribution system planning and operations. Table 7 below summarizes the distribution services identified by MTS which DER may play a role provided they meet technical and performance requirements.

Table 7: Potential Distribution Services Provided by DER Projects

Service	Description
Distribution Capacity	Load modifying or supply service capable of reliably and consistently reducing net loading on desired distribution infrastructure
Steady-state Voltage	Feeder level dynamic voltage management service
Power Quality	Transient voltage and/or power harmonics mitigation service
Reliability and Resilience	Load modifying or supply service capable of improving local distribution reliability and/or resiliency

The locational factors identified in Table 6, coupled with the services identified in Table 7, provide the basis for the modifications to the DERAC model that SDG&E will utilize for its LNBM. In sum, SDG&E will be adapting portions of the DERAC model, converting system values to locational values, and tying those values to the services provided by DER projects.

In addition to tying locational values to actual services, SDG&E notes here that the LNBM is a *net value* analysis. There will be locations on the distribution system where installing a DER will result in a negative value. It is imperative to institute a methodology that equally evaluates all values of DER against a traditional upgrade to find the cost-effective solution.

Incorporating the Guidance's Location Specific Values

The Guidance directs that the IOUs' LNBM specifically include additional, Commission-directed components designed to reflect location specific value. Table 8 below identifies those values from the guidance, inputs that SDG&E intends to use to calculate said values, and the output resulting from SDG&E's analysis.

Table 8: Locational Values and their Components

Values from the Guidance Document	SDG&E Inputs	Output
Avoided Sub-Transmission, Substation and Feeder Capital and Operating Expenditures	CapEx,$CapEx_{DER}$*, $CapEx_{INT,}$ O&M, $O\&M_{DER}$*	Capital and O&M cost for deferred substation and feeder projects
Avoided Distribution Voltage and Power Quality Capital and Operating Expenditures	CapEx, $CapEx_{DER}$*, $CapEx_{INT,}$ O&M, $O\&M_{DER}$*	Capital and O&M cost for deferred voltage projects
Avoided Distribution Reliability and Resiliency Capital and Operating Expenditures	CapEx, $CapEx_{DER}$*, $CapEx_{INT,}$ O&M, $O\&M_{DER}$*	Capital and O&M cost for eliminated projects to serve isolated load
Avoided Transmission Capital and Operating Expenditures	CapEx, $CapEx_{DER}$*, $CapEx_{INT,}$ O&M, $O\&M_{DER}$*	Capital and O&M cost for deferred transmission projects
Avoided Flexible Resource Adequacy Procurement	RA, FlexCap	Mitigated RA requirements
Avoided Renewables Integration Costs	Utilize DERAC Default Values	
Any societal avoided costs which can be clearly linked to the deployment of DERs	Gen	GHG reduction savings
Any avoided public safety costs which can be clearly linked to the deployment of DERs	Evaluated on a qualitative level	

**Only applicable as a separate element if the DER is utility owned; if owned by a third party, these values would be combined and generated by calculating the present value of the DER.*

An expanded explanation for each value component is included below.

Avoided Sub-Transmission, Substation and Feeder Capital, and Operating Expenditures

This category of avoided costs includes new distribution substations, new distribution transformers, new distribution circuits, and reconductoring circuits as identified in SDG&E's annual DPP to address a specific need on the distribution system. As mentioned previously in this DRP there is the potential for DER to defer or replace this type of investment.

Avoided Distribution Voltage and Power Quality Capital, and Operating Expenditures

This category of avoided costs includes capacitors, regulators, and substation transformer load tap changers to regulate the voltage on its distribution circuits within acceptable limits. DERs, properly implemented with smart inverters, can potentially eliminate the need for individual voltage support devices on a distribution circuit either by (i) providing a source of power that is close to load and thus decrease the overall voltage drop on the circuit, or (ii) absorbing or injecting reactive power. SDG&E will identify the voltage control characteristics (e.g., allowed voltage range at specific points on the system under steady state and contingency conditions) that a DER will have to provide in order to defer the upgrade that SDG&E otherwise plans to construct. As mentioned previously in this DRP there is the potential for DER to defer or replace this type of investment.

Avoided Distribution Reliability, Resiliency Capital, and Operating Expenditures

SDG&E believes that the overall impact to reliability by DERs will be minimal, and the most appropriate application of DERs for reliability will be for serving isolated distribution circuit loads that lose electric power as a result of a planned outage or a forced outage. SDG&E believes that the primary avoided reliability cost will be a deferred or eliminated project to serve an isolated load. This could take the form of new facilities, replacement facilities, or repair of existing facilities to serve that load.

Avoided Transmission Capital and Operating Expenditures

This category of avoided costs includes new transmission substations, new transmission transformers, new transmission lines and reconductoring transmission lines. The California Independent System Operator (CAISO) is responsible for the reliable and economic planning and operation of the bulk power system in California. As a Participating Transmission Owner (PTO), the SDG&E-owned bulk power system is studied on an annual basis by both the CAISO and SGD&E transmission planning personnel, in cooperation with the other PTO's (most notably Southern California Edison and Pacific Gas & Electric). This annual process is referred to as the TPP, and occurs over a span of about eighteen months. During the TPP process, the SDG&E bulk power system (69 kV through 500 kV) is thoroughly examined to ensure that it can reliably serve customer load growth over the next ten-year period by meeting specified criteria, such as that developed by the CAISO NERC (North American Electric Reliability Corporation) and WECC (Western Electricity Coordinating Council). Meeting reliability criteria is more than just good customer service – the CAISO and PTO's are required by federal law, as implemented by the Federal Energy Regulatory Commission (FERC), to meet applicable reliability criteria. Failure to do so can result in significant fines as well as unacceptable reduction in customer reliability.

Since the TPP process examines the electric system from a bulk power standpoint, DERs have not been directly considered as mitigations for specific transmission constraints. However, in scenarios where DERs can be effectively used to offset customer demand and reduce the loading on bulk power facilities, they can be an effective mitigation for transmission constraints. DERs in this manner can be considered during the TPP as alternatives for deferring or eliminating the need for bulk power system upgrades.

Defining the LNBM's Value Components and Inputs

As discussed above, SDG&E's proposed LNBM includes inputs from an evolved DERAC, and incorporates additional locational value components as directed by the Guidance. Below is a description of each of the value components and inputs that SDG&E will use in its LNBM. These inputs will in many cases be unique to each DER project, as they depend on size, location, and configuration of the project. Not all inputs will apply to every project, and in some cases the inputs can be positive or negative.

Generation Energy

SDG&E will use aggregated prices from SDG&E's single Default Load Aggregation Point (DLAP) as a proxy for generation energy value. In theory, using a nodal Locational Marginal Price (LMP) as a proxy value component would yield the most accurate comparison. However, in an area like San Diego where there is generally little difference between nodal prices and aggregated prices found at SDG&E's single DLAP, the question is whether the increased accuracy of nodal prices justifies the increased complexity, and higher cost compared to using the DLAP prices. SDG&E assessed several factors when deciding to use DLAP prices, including:

- Is there significant price dispersion between nodal prices and DLAP prices?
- Are price dispersions consistent over time?
- How long is price dispersion expected to exist?
- Are the borders of price dispersion stable and large enough for targeting?

The answers for these questions are different for each IOU. Geographically SDG&E's territory is compact with major transmission constraints only at the borders of the service area. No significant constraints exist within the service area. Effectively SDG&E is transmission rich within its service area and transmission constrained at its borders with the rest of the CAISO/WECC. Additionally, SDG&E has only a single Sub Load Aggregation Point (SLAP) while each the other IOUs has several SLAPs. Further, all of SDG&E's load is contained in a single local capacity area, while the other IOUs have several local capacity areas and load they serve outside of their local capacity areas.

Because of these factors, price dispersion between nodal prices and DLAP prices for SDG&E is far smaller than the other IOUs, a fact reflected in the CAISO's recent Load Granularity Refinements report. The CAISO's reported price dispersion for the IOUs found that the percent of load within $0.50/MWh of DLAP LMP for SDG&E was almost 80%, while only 57% for SCE, and significantly less - only 44% - for PG&E. This data indicates the impact of using nodal LMP instead of DLAP LMP is largely insignificant, for SDG&E.

The greater price dispersion and geographic diversity of the other IOUs may support their use of nodal LMPs to obtain a meaningful improvement. However, there is little likelihood that using nodal LMPs for LNBM in the SDG&E service area would cause a measureable improvement in LMP accuracy over using DLAP LMPs. Therefore SDG&E will be using the DLAP LMP for LNBM.

Losses

Due to the homogeneous nature of the SDG&E system, SDG&E intends to use its distribution system loss factor when computing potential decreased losses resulting from the installation of DER projects.

Generation Capacity

As described above, SDG&E's LNBM will replace the DERAC's default system generation capacity with values that reflect Local Capacity Requirements for RA. RA capacity credit will be assigned to DERs consistent with and contingent upon their demonstrated ability to meet the RA qualifying criteria as defined and continuously modified by both the CPUC and/or CAISO. In addition, the actual RA value for DER should reflect the current and forecasted resource adequacy situation e.g., the current and forecasted demand/supply balance in the load pocket. If the local area has more local resources than are needed, the local RA value should be based on market prices. If the local area is short of local resources, or forecasted to become short at some time in the future, then the value attributed to a DER solution capable of meeting RA eligibility criteria would be adjusted to reflect short conditions.

Ancillary Services

The DERAC model calculates an ancillary services value as 1% of the wholesale energy price, which, as discussed above, is typically flat throughout the SDG&E service territory. SDG&E intends to utilize the default values from the DERAC to calculate ancillary services benefits.

Transmission and Distribution Capacity

Per the discussion above, SDG&E will identify locations on either the distribution or transmission system where there is a need, and calculate a cost to install a traditional project to meet the identified need. The estimated cost will become the T&D Capacity value.

Distribution Voltage, and Power Quality

SDG&E will identify locations where there is a system need, and calculate a cost to install a traditional project to meet the identified need. The estimated cost will become the Distribution Voltage and Power Quality value.

Distribution Reliability, and Resiliency

SDG&E will identify locations where there is a system need, and calculate a cost to install a traditional project to meet the identified need. The estimated cost will become the Distribution Reliability and Resiliency value.

Environment

SDG&E intends to utilize the CalEnviroScreen 2.0[18] to qualitatively analyze the impact of DER projects in lieu of traditional projects.

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[18] CalEnviroScreen is a screening methodology that can be used to help identify California communities that are disproportionately burdened by multiple sources of pollution. More information available at: http://oehha.ca.gov/ej/ces2.html

Avoided RPS

In the DERAC tool, the renewable premium is calculated as the difference between the avoided cost of marginal renewables ($/MWh) less the sum of market energy value of renewables ($/MWh) plus the emissions cost ($/MWh) and the capacity value of renewables ($/MWh). These values are simply inflated annually at the inflation rate. SDG&E intends to use the default values from the DERAC tool in calculating this value.

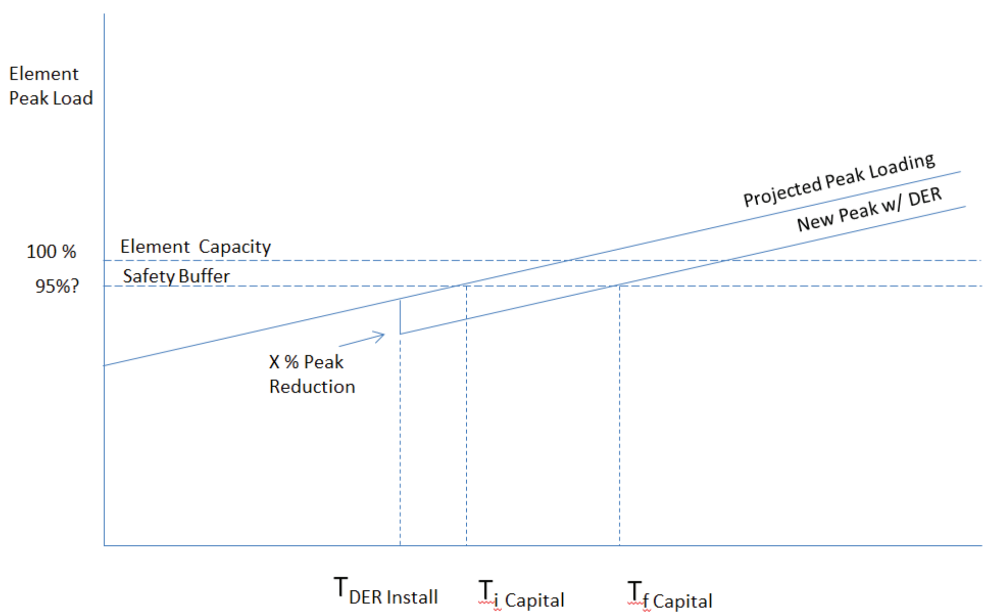
Avoided Renewables Integration Costs

SDG&E will determine if the DER avoids any renewable integration costs. The DERs ability to reduce utility costs associated with renewable integration will be coordinated with the CPUC's efforts to update the RPS Calculator and the Renewables Integration Charge. It should also be noted that the DER could result in an increase in integration costs, in which it could receive a negative credit in this section.

Present Value & Deferral Value Formulas

SDG&E provides following figures and formulas to further clarify how SDG&E plans to estimate the cost savings for deferring a capital project.

Figure 8: Deferral Graph



The present value calculation will allow SDG&E to identify the time relative cost of the normally constructed capital improvement. Once this is calculated SDG&E can calculate the actual deferral value realized by installing a DER.

The deferral value along with the expected life of the capacity project will be used as the CapEx portion of the $\mathbf{DER_{Benefit}}$ equation (defined below). One can see from the figure above that estimating the deferral time will play a significant role in the deferral value formula and that the probability of greater time deferral will be higher in slower load growth areas.

Societal Avoided Costs Linked to the Deployment of DERs

Societal benefits related to GHG reduction will be captured by using energy prices that fully reflect the GHG costs imbedded in the cost for both the DER energy production and market power.

Avoided Public Safety Costs Linked to the Deployment of DERs

SDG&E believes that in some cases, DER may actually increase costs related to safety. For example, if a large number of DERs interconnect to a single circuit, back-feeding is a concern during outages and extreme care will have to be taken by utility personnel during outage restoration. While the anti-islanding provisions of Rule 21 ameliorate this issue for installations utilizing the newer inverter technology, there is still the risk of equipment malfunction, and risks presented by legacy equipment that may not have the full complement of safety features. SDG&E will qualitatively evaluate the safety impacts of DER projects on the distribution system.

Inputs

The following definitions describe the specific inputs into SDG&E's proposed LNBM.

CapEx represents the net present value (NPV) of the traditional capital project identified by SDG&E necessary to maintain grid services/capacity but that may be deferred or replaced by a DER project providing the required services/capacity. Present value calculations for an IOU owned project typically include three main components: the present-day cost to design and build a project, the anticipated rate of return on that project, and the anticipated financing costs associated with the project. In those situations where a DER may defer rather than replace an IOU capital project, the NPV will reflect this deferral rather than a replacement. Factors that impact these values include anticipated service life of the project and SDG&E's weighted cost of capital. The deferral is upgrade-specific and the **CapEx** value will be offset based on the life of the upgrade project and scaled appropriately. For example, if a DER solution with a 10-year life is expected to replace a project with a 30-year book life, the DER solution will require replacement two times during the normal operating life of the traditional project. The **CapEx** value for the initial DER with a 10-year life will only be one third of the total cost of the proposed project (in real dollar terms).

DERs installed in optimal locations could potentially defer the need for the following types of traditional capital projects:

- Conductor upgrades, aka increasing the capacity of a circuit
- Installing voltage regulating equipment or maintaining existing equipment
- Circuit extensions
- New distribution circuits
- New substation equipment
- New substations
- New transmission lines

$CapEx_{DER}$ represents the NPV of the DER. In those cases where SDG&E requests bids from third parties to design and build a DER project that SDG&E will own, this cost will be based upon the costs represented in the received bids.

$CapEx_{INT}$ represents the cost of interconnecting the distribution energy resource into the distribution grid. These costs are in addition to components that derive the ***$CapEx_{DER}$*** value, are unique to each point of interconnection and are often associated with requirements located outside the footprint of the DER project. Examples include the cost for the following:

- Conductor upgrades
- Fusing changes
- Switch additions

- Circuit reconfigurations
- New structures
- New conductor
- New communications equipment
- New transformers/replacements
- New voltage regulating devices
- Voltage regulators operational changes
- New conduit
- Other upgrades as required

O&M represents the un-incurred costs of not having to operate and maintain the traditional utility project that is deferred or replaced by a DER. Because some but not all O&M costs will be deferred or eliminated by a DER, the O&M value will be based on the cost savings of deferred or eliminated maintenance or replacement cycles. For example, a DER that eliminates the need for a switch will result in savings associated with not needing to performing inspections and test operations; however, the resources required to perform these functions would not have been eliminated.

$\boldsymbol{O\&M_{DER}}$ represents the added cost of operating and maintaining the DER.

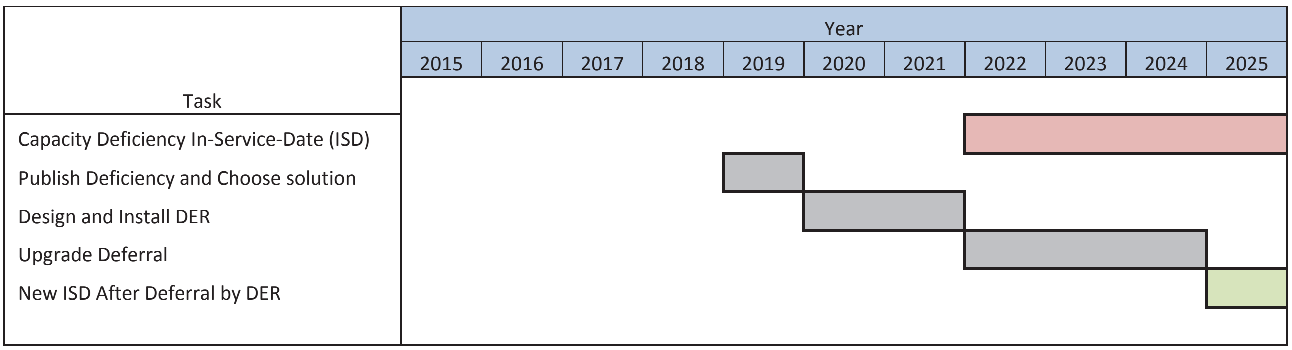
Gen represents the value of the electricity that SDG&E will not need to procure because of the electricity provided by the DER (wind, solar, discharging battery) or the energy curtailment associated with the DER. SDG&E will utilize the E3 Cost-effectiveness calculator to establish the $/MWh for a given resource. The viability of using the E3 calculator is well documented in other proceedings.

RA represents the value of local resource adequacy capacity that SDG&E will not need to procure because of the local capacity provided by the DER. To obtain this value, the DER must adhere to the qualifying criterion applicable to all RA resources as adopted and modified by both the CPUC and the CAISO.

The ***FlexCap*** (Flexible RA capacity) component of the $\boldsymbol{DER_{Benefit}}$ equation will credit or debit the DER in the cases where it increases or decreases SDG&E flexible RA capacity requirements. One the one hand, the operational characteristics of some DERS may exhibit higher intermittency, potentially resulting in an increase in flexibility needs. This would equate to a negative valuation in this section. On the other hand, energy storage or other DER that can potentially meet the increased flexible RA requirements caused by increased renewable penetration. This contribution to satisfying or avoiding flexible RA costs would be positively valued.

An example of the schedule SDG&E would use to propose and implement a distribution or DER project is shown in figure 9 below.

Figure 9: Sample of an Optimal Location Schedule



How LNBM Can Be Integrated Into Long-Term Planning Initiatives

SDG&E proposes that DER growth scenarios discussed in detail below and the LNBM should be integrated into long-term planning initiatives is through its inclusion in various forecasting processes. LNBM can impact SDG&E's forecast of the load the utility needs to serve as well as load-side and supply-side resources it can count on for distribution operations. These changes to the various forecasts will have an impact on long-term planning initiatives such as the CAISO's TPP, the LTPP and the CEC's IEPR.

Applying the LNBM to Future Processes and Operations

SDG&E proposes to incorporate both the ICA and the LNBA into its annual DPP.

1.c DER Growth Scenarios

As instructed within the Guidance, SDG&E has developed three 10-year scenarios that project forecasted peak demand and growth of DERs through 2025, including expected geographic dispersion at the distribution level and impacts on distribution planning. Each scenario reflects increasingly more aggressive DER growth to meet system needs, with Scenario 1 having the least amount of DER capacity and Scenario 3 containing the most amount of DER capacity. DER growth scenarios 1 is considered the base-line scenario and reflects the peak demand and DER values contained in The *California Energy Demand Updated Forecast, 2015 – 2025 (*CEC's 2014 IEPR updated forecast) – mid energy demand case scenario; DER growth scenario 2 represents a high peak demand and DER growth scenario and reflects the peak demand and DER impact values contained in the CEC's 2014 IEPR updated forecast– high energy demand case scenario modified to include updated forecasts of DER growth; DER growth scenario 3 represents a very high DER penetration growth scenario and reflects the values in the 2014 IEPR updated forecast– high energy demand case scenario modified to include DER growth assumptions discussed and included in various state energy and climate based goals and plans.

The DER capacity values were initially forecast on a system-wide level, which is consistent with traditional IEPR and LTPP forecasting methodologies, and then allocated on a more granular level first across all the substations in SDG&E's service territory and then further allocated to the individual circuit level. For the purposes of this initial DRP, the values generated by the growth scenarios were not included in the ICA and LNBM. Once approved by the Commission, these peak demand and DER values developed in the DER growth scenarios will be used as input values to both the ICA and the Optimal Locational Benefit Analysis. SDG&E expects that the primary impact of the growth scenarios will be a potential reallocation in capital projects due to the large growth in energy efficiency targets as defined in the IEPR.

The background associated with the state's mandated process that developed the starting point peak demand and DER growth projections used to develop the DER growth scenarios is provided below as well as a description of how the impacts of the DER growth values associated with each scenario differ. The reader should be aware that the DER growth scenarios developed forecasted impacts, in MW, on SDG&E's peak demand associated with the different DER growth scenarios. These impacts, while correlated to the nameplate capacity (MW) of the respective DER technologies, do not necessarily equate to a 1:1 correlation, and the correlation ratio will differ between DER technology types and locations depending upon how well the DER's operation's profile aligns with SDG&E's peak demand period.

Background: California's Integrated Energy Policy Report Process

California's Integrated Energy Policy Report Process

The California Energy Commission (CEC) is required per state statue to prepare a biennial integrated energy policy report (IEPR) that assesses major energy trends and issues facing the state's electricity, natural gas, and transportation fuel sectors and provides policy recommendations to conserve resources; protect the environment; ensure reliable, secure, and diverse energy supplies; enhance the state's economy; and protect public health and safety. Preparation of the IEPR involves close collaboration with federal, state, and local agencies, and a wide variety of stakeholders in an extensive public process to identify critical energy issues and develop strategies to address those issues.

During the 2013 IEPR process, staffs from the CEC, the CPUC, and the CAISO met frequently to develop a "process alignment" calendar. The effort was structured around a two phased, biennial LTPP proceeding, with the CEC and CAISO providing critical annual inputs to the procurement proceeding out of their IEPR demand forecasting and Transmission Planning Processes, respectively. The result of this process alignment was the agreement for the CEC's IEPR process to include a full review of assessments and associated policy recommendations every two years (odd years) and to update the demand forecasts associated with the IEPR process every alternate year (even years). At the time of preparing the DRP Filing, the 2013 IEPR for years 2013 - 2024 was the CEC's most recently approved biennial report and the 2014 IEPR Update, for years 2014 – 2025 was the CEC's most recently approved alternate year update report.

The 2014 IEPR update provides the results of the CEC's assessments of a variety of energy issues currently facing California. These issues include the role of transportation in meeting state climate, air quality, and energy goals; the Alternative and Renewable Fuel and Vehicle Technology Program; current and potential funding mechanisms to advance transportation policy; the status of statewide PEV infrastructure; challenges and opportunities for PEV infrastructure deployment;

measuring success and defining metrics within the Alternative and Renewable Fuel and Vehicle Technology Program; market transformation benefits resulting from Alternative and Renewable Fuel and Vehicle Technology Program investments; the state of hydrogen, zero-emission vehicle, biofuels, and natural gas technologies over the next 10 years; transportation linkages with natural gas infrastructure; evaluation of methane emissions from the natural gas system and implications for the transportation system; changing trends in California's sources of crude oil; the increasing use of crude-by-rail in California; the integration of environmental information in renewable energy planning processes; an update on electricity reliability planning for Southern California energy infrastructure; and an update to the electricity demand forecast.

Through the spring and summer of 2014, the CEC hosted numerous public workshops to solicit the views and recommendations about the Alternative and Renewable Fuel and Vehicle Technology Program from a wide array of technology, business, finance, and policy experts from state and federal government, academia, not-for-profit organizations, and industry. The goals for these workshops were to assess the CEC's progress, efficacy, and achievements in administering the Alternative and Renewable Fuel and Vehicle Technology program, the vision of the state Legislature in reauthorizing program funding, the technologies currently available and over the next decade that will be needed to achieve a low-carbon transportation system, and the challenges that still need to be surmounted before low-carbon, low-emission fuels, and vehicles can become a standard and integral part of California's transportation system. The CEC also hosted workshops to review the reliability of the electricity system in Southern California, to review the integration of environmental information in renewable energy planning processes and to review the demand forecast prepared the previous year, e.g., the California Energy Demand Final Forecast 2014-2024. The CEC's 2014 IEPR update, which is the basis for values in SDG&E's DER growth scenarios, reflects the input received at those workshops and in comments timely filed in response to those workshops, as well as staff and contractor analysis and policy direction from Commissioners.

California Ten Year Energy Demand Forecast

The integrated energy policy report process results in the CEC approving and publishing various documents. In addition to the published IEPR document, which contains an all-encompassing review and analysis of the numerous energy issues facing California, the CEC also approves and publishes, specific to the electric utility industry, a 10-year CA Energy Demand Forecast Report and corresponding spreadsheets containing the annual peak demand and DER values for each utility (associated with three different case scenarios: a low-energy demand case, a mid-energy demand case and a high-energy demand case). The IEPR process also includes each utility developing a 10-year demand forecast utilizing their respective in-house forecasting tools and assumptions. Aspects of the utility provided demand forecasts and associated assumptions are discussed within the IEPR stakeholder process, and to the extent agreed upon by the CEC, are incorporated within the CEC's approved demand forecast. A draft version of the 2014 IEPR updated forecast was reviewed and discussed with stakeholders during a CEC sponsored public workshop in December 2014. Reasonable and applicable comments were incorporated into the final version of the 2014 IEPR forecast update which was adopted during the CEC's business meeting held in January 2015 and the report was published in February 2015. The 10-year electric energy demand forecast associated with the 2014 IEPR update is entitled the California Energy Demand Updated Forecast, 2015 – 2025.

2014 IEPR Update Forecast

As detailed within the 2014 IEPR updated forecast report, the values (for low, mid, and high energy demand case scenarios) in the 2014 IEPR updated forecast reflect modeling the most current (at the time) economic and demographic assumptions, and adjustments, relative to the 2013 IEPR forecast, for an additional year of actual data, including electricity consumption, peak demand, temperatures, electricity rates, and self-generation technology adoptions and pending adoptions. As per the alternate year update protocols, the forecasts do not include updates to demand-side programs (including additional achievable energy efficiency), or factors that impact the forecast of PEVs and other electrification programs. The low energy demand case includes lower economic/demographic growth, higher assumed rates, and higher efficiency program and self-generation impacts. The high energy demand case incorporates relatively high economic/ demographic growth, relatively low electricity and natural gas rates, and relatively low efficiency program and self-generation impacts. The mid case uses input assumptions at levels between the low and high cases.

SDG&E Peak Demand Forecast

The forecasts developed in the IEPR process pertain to each utility's planning area, which includes the respective utility's bundled retail customers and customers served by various energy service providers using the respective utility's distribution system to deliver electricity to end users. Therefore the values reflected in the 2014 IEPR updated forecast report represent SDG&E planning area. The CEC also publishes utility system level values that reflect the peak demand and DER forecasts for only bundled retail customers. SDG&E's DRP analyses are based upon the values reflected in the CEC's 2014 IERP updated forecast for SDG&E's system level bundled customers.

For additional background, as further explained within the 2014 IEPR updated forecast report [pg 31 – 34], the growth in peak demand is slower in the 2014 IEPR updated forecast mid demand case than was forecast the previous year due to slower growth in personal income, commercial employment, and population. By 2024, consumption and peak demand in the updated mid case are around 1.5% and 2.6% lower, respectively, than had been forecast in the previous report. The larger difference for peak demand is the result of using an updated (lower) estimated weather-normalized peak for 2014.

SDG&E's understanding is that because the peak demand and DER forecasts developed as part of the CEC's biennial IEPR process are used in various proceedings, including the CPUC LTPP and the CAISO's TPP, and the assumptions used to develop the IEPR values are already familiar with many stakeholders, the DRP Guidance selected the IEPR forecasts to be the base source of the DER growth scenarios assumptions as a way to enable as many stakeholders as possible to already be familiar with the assumptions used to develop the DER growth scenarios.

1.c.i DER Growth Scenario 1 – IEPR Trajectory

As stated within the DRP Guidance, SDG&E's DER growth scenario 1 is based upon adapting the IEPR 'trajectory' case for DER distribution planning at the feeder level, down to the line section. SDG&E's understanding is that by using the term trajectory case, Scenario 1 is intended to be a sort of base-line in that the values reflect those contained in the 2014 IEPR updated forecast mid-energy demand case without any modifications[19].

[19] http://www.energy.ca.gov/2014_energypolicy/documents/demand_forecast_cmf/Mid_Case/

The 2014 IEPR update report also discussed and identified, but did not include the effects of additional achievable energy efficiency (AAEE) initiatives within the peak demand forecasts. SDG&E's understanding per the DRP Guidance is that these AAEE values are to be included in the Scenario 1 base-line values and therefore, as also seen on Table 9, SDG&E's DER growth scenario 1 peak demand impacting values reflect netting out the impacts of AAEE initiatives.

As part of the DRP process, these system-wide peak load and DER impact values are then disaggregated and allocated to each of SDG&E's substations and then additionally disaggregated and allocated to each of SDG&E's distribution circuits. While disaggregating the system-wide peak load values down to the circuit level is part of the typical distribution planning process, disaggregating and allocating system-wide level DER values down and across the distribution circuits on SDG&E's system is new specific to this initial DRP process. The forecast of DER on each distribution circuit is a key input variable to determining how much additional DER can be connected to any circuit without requiring infrastructure upgrades.

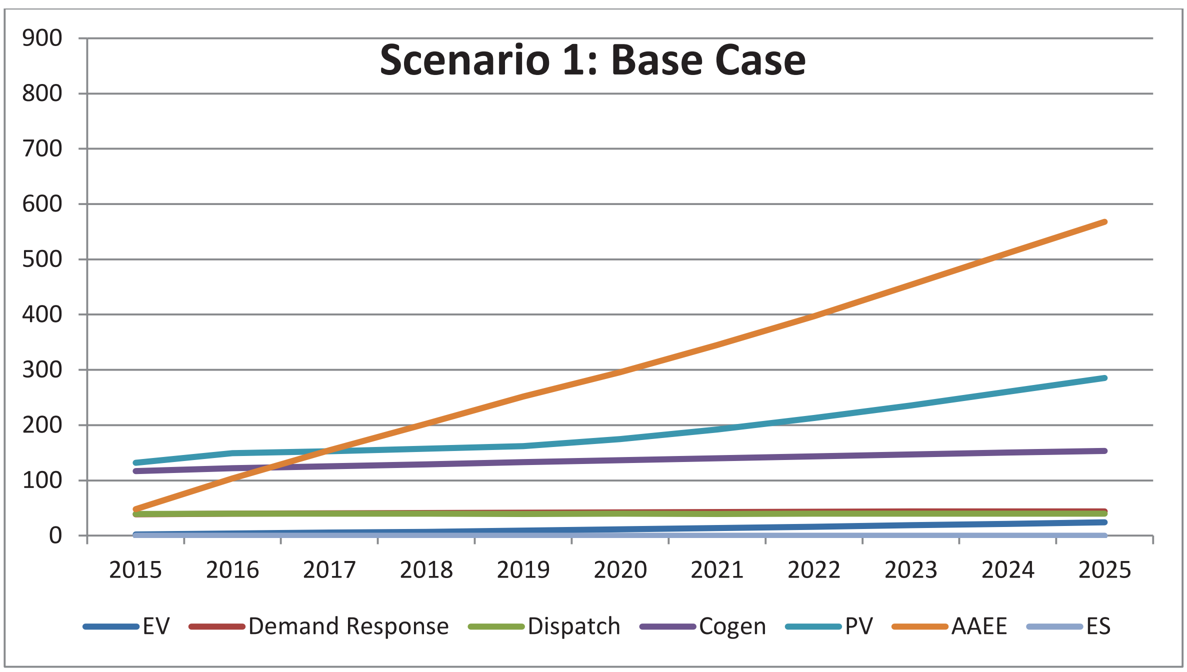
Six DER technology types are included in scenario 1: PEV, Dispatchable and non-dispatchable demand response (DR), cogeneration, PV, and AAEE.

Table and graph of forecast DER impact used in DER growth scenario 1.

Table 9: Growth Scenario 1

Scenario 1: Base-Case DER Growth

		Demand Response					
	PEV	Non-Disp.	Dispatched	Cogen	PV	AAEE	ES
2015	2	39	39	117	132	48	0
2016	4	40	40	122	149	103	0
2017	6	40	40	125	153	154	0
2018	7	41	40	129	157	203	0
2019	9	42	39	133	162	252	0
2020	11	42	40	137	175	296	0
2021	14	43	39	140	192	345	0
2022	16	43	40	144	213	397	0
2023	19	44	40	147	236	454	0
2024	21	44	40	150	260	511	0
2025	24	44	40	153	285	568	0



1.c.ii DER Growth Scenario 2 – High Growth Scenario:

Per the DRP Guidance, the 2014 IEPR updated forecast is again to be used as the starting point for developing the scenario values, but this time the peak demand and DER values are to come from the high energy demand case scenario[20]. However, unlike scenario 1 which was developed using the IEPR forecast values without modifications, the DRP Guidance instructs the utilities to develop scenario 2 by modifying the 2014 IEPR updated forecast values to reflect additional and more recent DER growth projection information from Load Serving Entities (LSEs), third party DER owners, and DER vendors. SDG&E developed DER growth scenario 2 by incorporating updated DER information from two sources: The DER forecast contained in SDG&E's 2015 IEPR demand forecast, and the responses to a joint IOU solicitation to third party DER owners and/or vendors requesting non-confidential DER growth forecast data.

SDG&E's 2015 IERP Demand Forecast

As requested by the CEC to assist in their 2015 IEPR process, and in compliance with CEC provided forms and instructions[21], SDG&E prepared and submitted forecasts for the 2015 – 2026 period for peak demand, impacts of DR, EE, cogeneration, PV, and impacts from new or expanded programs to achieve broad goals established by regulatory agencies[22].

As shown in Table 10, energy storage is a new DER category included in scenario 2 and the values are based upon procurement target information in the CPUC's Storage OIR (D 13-10-040). Because SDG&E's 2015 IEPR demand forecast does not evaluate the impacts of AAEE, and to reserve the CEC's high case AAEE values for scenario 3, the impact values for AAEE in Scenario 2 are the same as those in scenario 1.

Request for DER Growth forecasts

The joint IOUs posted a solicitation on the DER service list requesting third party DER owners and/or vendors to provide any non-confidential DER growth forecast data for consideration in the

[20] http://www.energy.ca.gov/2014_energypolicy/documents/demand_forecast_cmf/High_Case/
[21] http://www.energy.ca.gov/business_meetings/2014_packets/2014-12-10/Item_10_Electricity_Demand_Forecasts/CEC-200-2014-006-SF.pdf
[22] 2015 IEPR Electricity Demand Forecast for the San Diego Gas & Electric Service Area (2015-2026), filed with the California Energy Commission, April 24, 2015.

respective IOU's DER growth scenario 2. SDG&E received only one response, but the information provided was not applicable to use within the scenario 2 parameters defined in the DER Guidance.

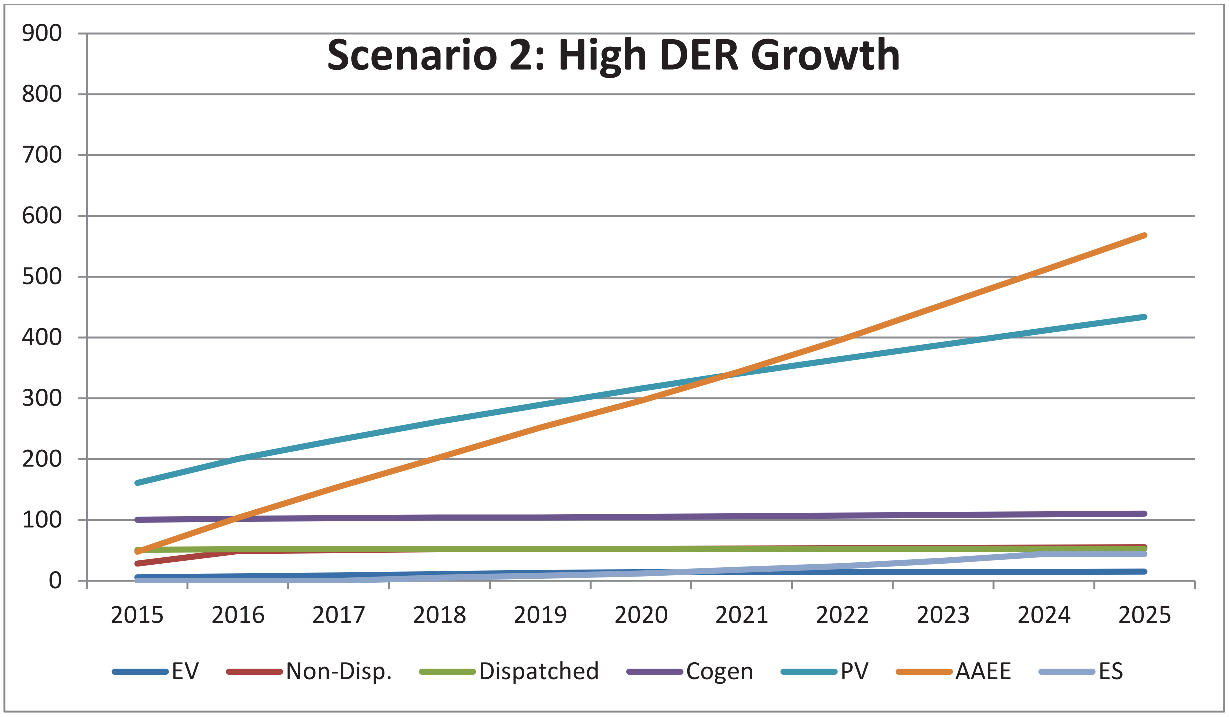
SDG&E developed Scenario 2 values by removing and replacing the effects of PEVs, cogeneration (cogen), PV, and demand response programs from the 2014 IEPR updated forecast – high energy demand case with the effects of PEV, cogen, PV, and demand response programs from SDG&E's 2015 IEPR Demand Forecast. Impacts of energy storage (ES) were developed to align with the procurement targets set out in the CPUC's Storage OIR.

Table 10 shows the yearly values included in SDG&E's DER growth scenario 2 and graphs the values.

Table 10: Growth Scenario 2

Scenario 2: High DER Growth

		Demand Response					
	PEV	Non-Disp.	Dispatched	Cogen	PV	AAEE	ES
2015	6	28	51	100	161	48	0
2016	7	49	52	102	200	103	0
2017	9	50	52	103	232	154	0
2018	11	52	52	104	262	203	5
2019	13	52	52	104	289	252	8
2020	14	53	52	105	316	296	12
2021	14	53	52	106	341	345	18
2022	15	53	52	107	365	397	24
2023	15	54	52	108	388	454	33
2024	15	54	52	109	411	511	44
2025	15	55	52	110	434	568	44

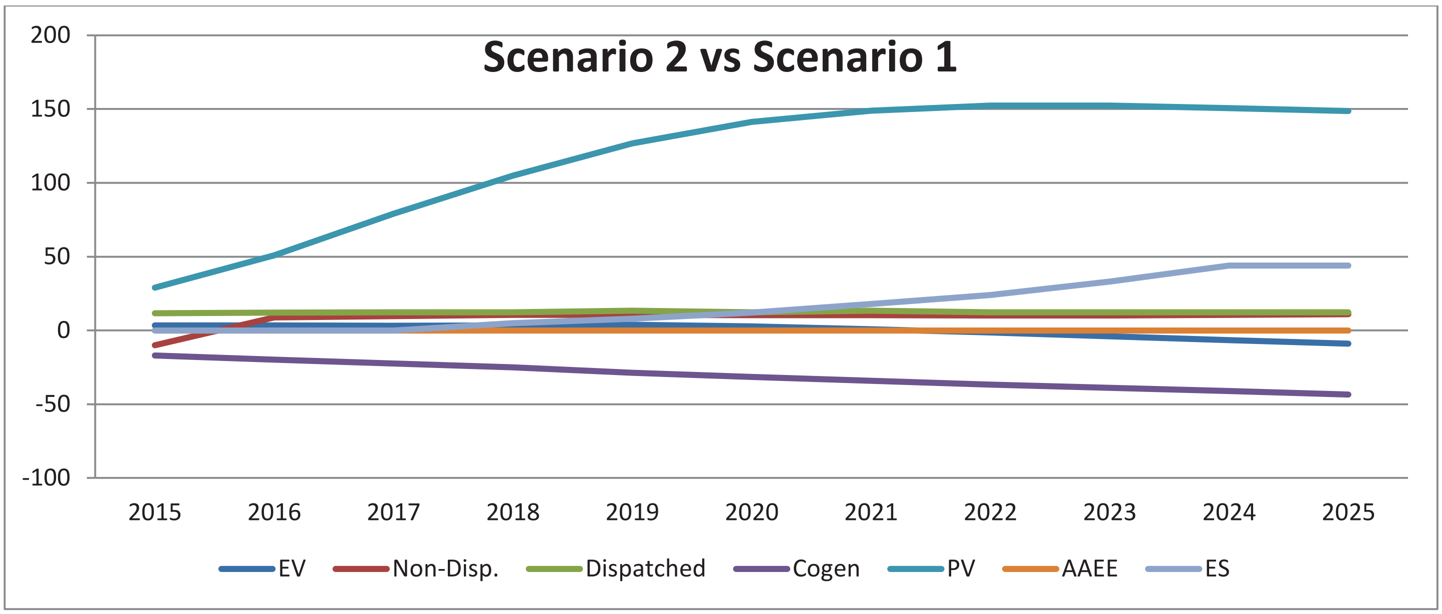


Scenario 2 vs Scenario 1

The impact in MW on SDG&E's peak demand attributed to DER in scenario 2 is generally 15% - 20% higher (55 MW in 2016 increasing to 164 MW by 2025) than in scenario 1. The largest impact increase is associated with PV (over 90% of the total impact), and cogeneration accounts for the smallest impact. The impact on SDG&E's peak demand attributed to cogeneration is actually projected in Scenario 2 to decrease by about 25% each year (20 – 40 MW).

As mentioned earlier, the IEPR process requires each utility to develop a 10-year peak demand and DER impacts on peak demand forecasts which will possibly be incorporated within the CEC's approved demand forecast. However, because a) the modeling techniques and software used to develop the CEC approved forecasts are different than those used by the utilities, b) the IEPR process does not include discussing nor preparing a line-by-line comparison of the extent that the CEC incorporates a utility's demand forecasting assumptions, and c) the DER assumptions used in Scenario 2 are those included in SDG&E's 2015 IEPR demand forecast which are 12-18 months more recent than assumptions used in the compared IEPR demand forecasts, SDG&E is not able to provide detailed explanations as to why the DER impact values in DER growth scenario 2 differ from the impact values in DER growth scenario 1.

	DER Growth Scenario #2 (High Growth) vs. DER Growth Scenario #1 (Base-Line)																					
	PEV			DR - Non-Dispatchable			DR - Dispatchable			Cogen			PV			AAEE			ES			Total Delta
	#2	#1	Delta	#2	#1	Delta	#2	#1	Delta	#2	#1	Delta	#2	#1	Delta	#2	#1	Delta	#2	#1	Delta	
2015	6	2	3	28	39	-10	51	39	12	100	117	-17	161	132	29	48	48	0	0	0	0	17
2016	7	4	3	49	40	9	52	40	12	102	122	-20	200	149	51	103	103	0	0	0	0	55
2017	9	6	3	50	40	10	52	40	12	103	125	-22	232	153	79	154	154	0	0	0	0	82
2018	11	7	3	52	41	11	52	40	12	104	129	-25	262	157	105	203	203	0	5	0	5	111
2019	13	9	4	52	42	10	52	39	13	104	133	-29	289	162	127	252	252	0	8	0	8	134
2020	14	11	3	53	42	10	52	40	12	105	137	-32	316	175	141	296	296	0	12	0	12	147
2021	14	14	1	53	43	10	52	39	13	106	140	-34	341	192	149	345	345	0	18	0	18	157
2022	15	16	-1	53	43	10	52	40	12	107	144	-37	365	213	152	397	397	0	24	0	24	161
2023	15	19	-4	54	44	10	52	40	12	108	147	-39	388	236	152	454	454	0	33	0	33	165
2024	15	21	-7	54	44	10	52	40	12	109	150	-41	411	260	151	511	511	0	44	0	44	170
2025	15	24	-9	55	44	11	52	40	12	110	153	-43	434	285	149	568	568	0	44	0	44	164



1.c.iii DER Growth Scenario 3 – Very High Growth Potential

As required by the DRP Guidance, DER growth scenario 3 represents a very high potential DER growth case to meet transmission system needs, resource adequacy, distribution reliability, resiliency, and long-term greenhouse gas (GHG) reductions. SDG&E referenced various state goals and plans pertaining to energy and climate issues to develop key input assumptions used in this scenario.

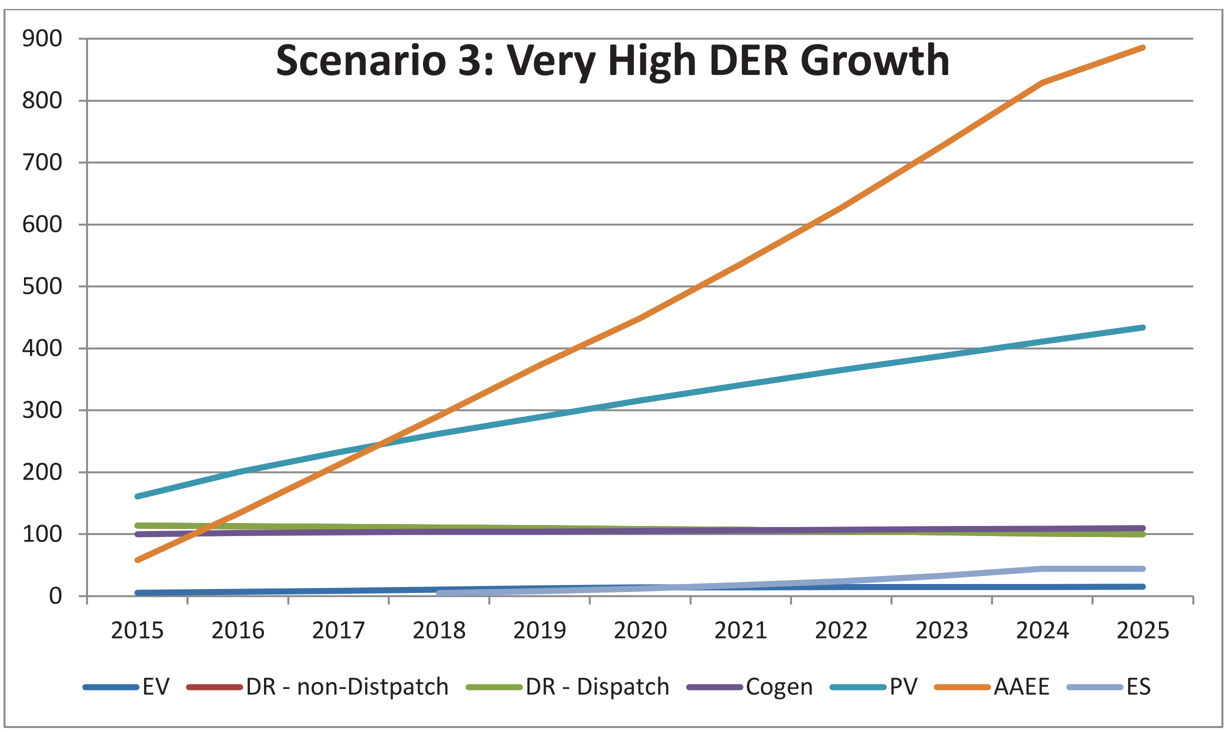
SDG&E's DER growth scenario 3 reflects incorporating the AAEE values from the CEC's 2014 IEPR updated forecast – high energy demand case and also increasing the total impact of demand response to equal 5% of SDG&E's peak demand net of the impacts associated with the other DERs. This 5% was split evenly between dispatchable and non-dispatchable DR. SDG&E kept the impact on peak demand caused by PEV, Cogen, PV and ES the same as in scenario 2.

Scenario 3 vs Scenario 2

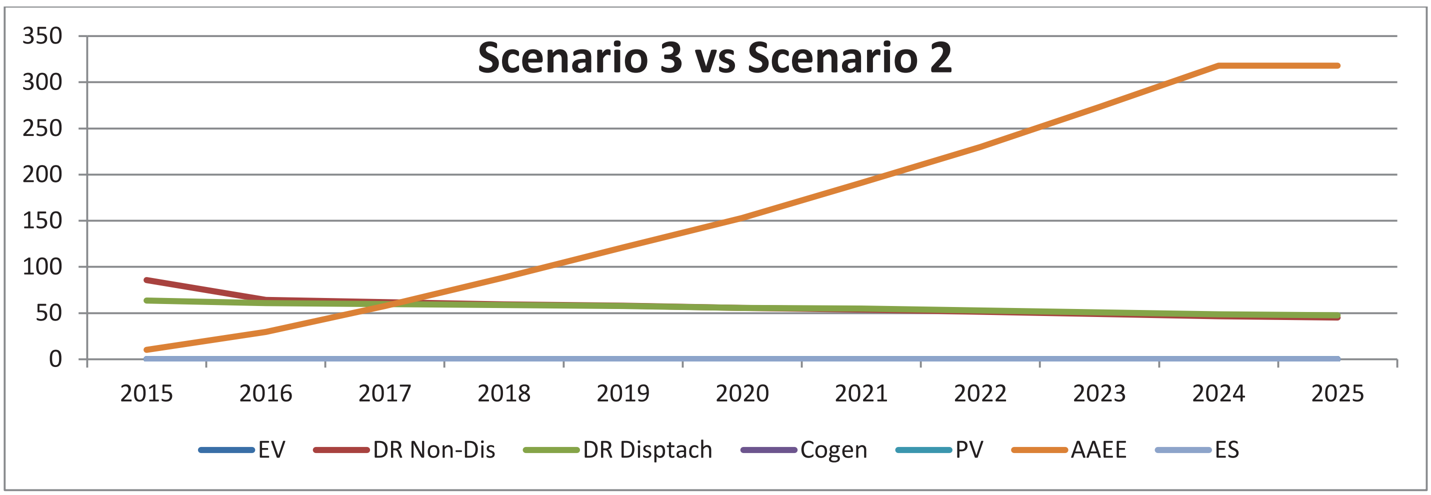
The impact in MW on SDG&E's peak demand attributed to DER in scenario 3 is generally 30% higher (150 MW in 2016 increasing to 400 MW by 2025) than in scenario 2. The increased impact due to Demand Response is ~ 100 MW in every year and the impact due to AAEE increases steadily from an initial 10 MW in 2015 to 300 MW in 2025.

Scenario 3: Very High DER Growth

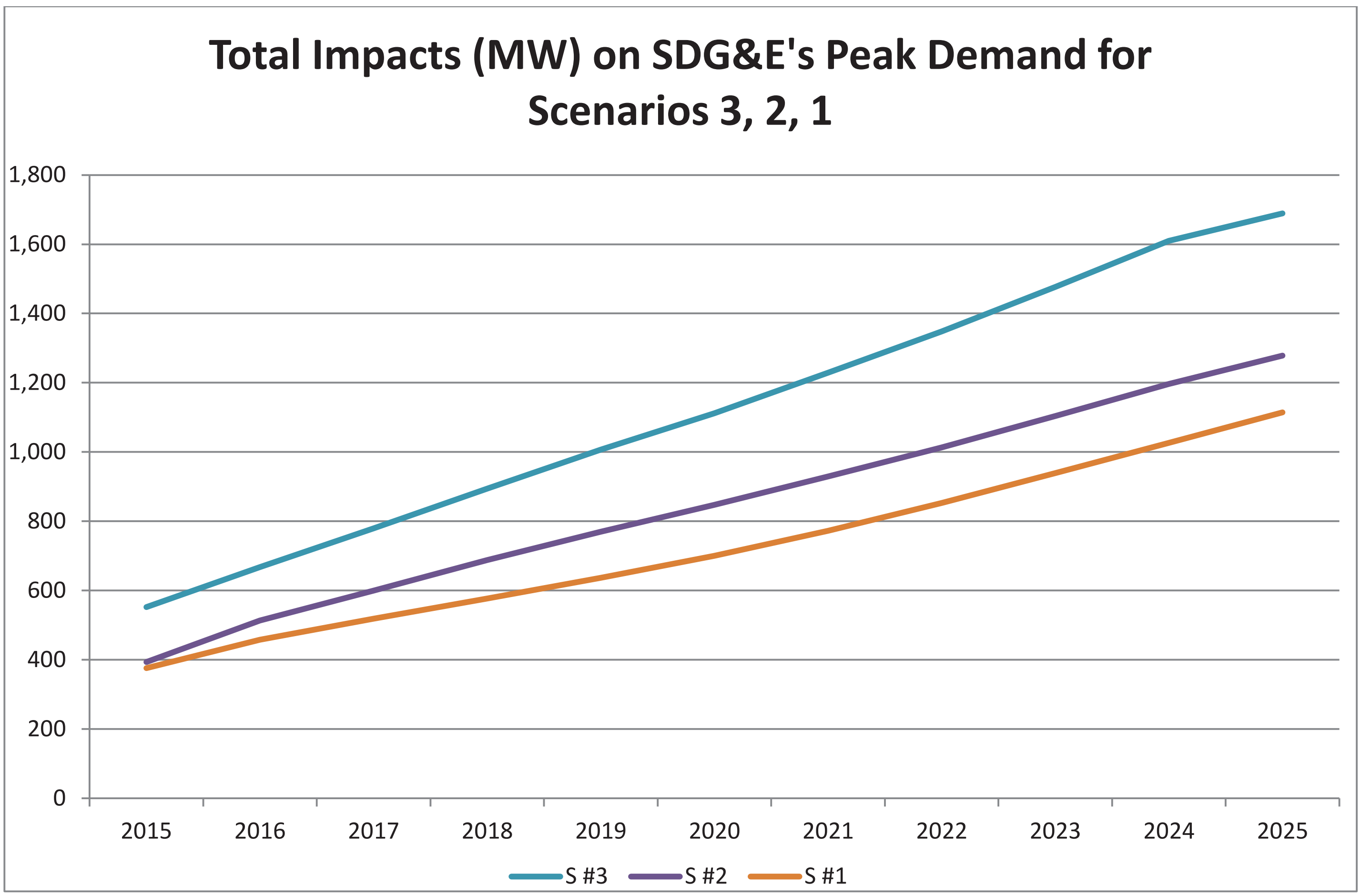
	PEV	DR - non-Dispatch	DR - Dispatch	Cogen	PV	AAEE	ES
2015	6	114	114	100	161	58	
2016	7	113	113	102	200	133	
2017	9	112	112	103	232	212	
2018	11	111	111	104	262	291	5
2019	13	110	110	104	289	373	8
2020	14	108	108	105	316	449	12
2021	14	107	107	106	341	536	18
2022	15	105	105	107	365	627	24
2023	15	103	103	108	388	727	33
2024	15	101	101	109	411	829	44
2025	15	100	100	110	434	886	44



	DER Growth Scenario #3 (Very High Growth) vs. DER Growth Scenario #2 (High Growth)																					
	PEV			DR - Non-Dispatchable			DR - Dispatchable			Cogen			PV			AAEE			ES			Total Delta
	#3	#2	Delta	#3	#2	Delta	#3	#2	Delta	#3	#2	Delta	#3	#2	Delta	#3	#2	Delta	#3	#2	Delta	
2015	6	6	0	114	28	86	114	51	63	100	100	0	161	161	0	58	48	10	0	0	0	159
2016	7	7	0	113	49	64	113	52	61	102	102	0	200	200	0	133	103	30	0	0	0	155
2017	9	9	0	112	50	62	112	52	60	103	103	0	232	232	0	212	154	58	0	0	0	179
2018	11	11	0	111	52	59	111	52	59	104	104	0	262	262	0	291	203	88	5	5	0	207
2019	13	13	0	110	52	58	110	52	58	104	104	0	289	289	0	373	252	121	8	8	0	237
2020	14	14	0	108	53	55	108	52	56	105	105	0	316	316	0	449	296	153	12	12	0	264
2021	14	14	0	107	53	54	107	52	55	106	106	0	341	341	0	536	345	191	18	18	0	300
2022	15	15	0	105	53	52	105	52	53	107	107	0	365	365	0	627	397	230	24	24	0	334
2023	15	15	0	103	54	49	103	52	51	108	108	0	388	388	0	727	454	273	33	33	0	373
2024	15	15	0	101	54	47	101	52	49	109	109	0	411	411	0	829	511	318	44	44	0	413
2025	15	15	0	100	55	45	100	52	48	110	110	0	434	434	0	886	568	318	44	44	0	411



	Impact (MW) on SDG&E's Peak Demand of DER in each Scenario																								
	PEV			DR - Non-Dispatchable			DR - Dispatchable			Cogen			PV			AAEE			ES			Totals		
	#3	#2	#1	#3	#2	#1	#3	#2	#1	#3	#2	#1	#3	#2	#1	#3	#2	#1	#3	#2	#1	#3	#2	#1
2015	6	6	2	114	28	39	114	51	39	100	100	117	161	161	132	58	48	48	0	0	0	553	393	377
2016	7	7	4	113	49	40	113	52	40	102	102	122	200	200	149	133	103	103	0	0	0	668	513	458
2017	9	9	6	112	50	40	112	52	40	103	103	125	232	232	153	212	154	154	0	0	0	780	600	518
2018	11	11	7	111	52	41	111	52	40	104	104	129	262	262	157	291	203	203	5	5	0	895	688	577
2019	13	13	9	110	52	42	110	52	39	104	104	133	289	289	162	373	252	252	8	8	0	1,007	770	637
2020	14	14	11	108	53	42	108	52	40	105	105	137	316	316	175	449	296	296	12	12	0	1,112	848	701
2021	14	14	14	107	53	43	107	52	39	106	106	140	341	341	192	536	345	345	18	18	0	1,229	930	773
2022	15	15	16	105	53	43	105	52	40	107	107	144	365	365	213	627	397	397	24	24	0	1,348	1,013	853
2023	15	15	19	103	54	44	103	52	40	108	108	147	388	388	236	727	454	454	33	33	0	1,477	1,104	939
2024	15	15	21	101	54	44	101	52	40	109	109	150	411	411	260	829	511	511	44	44	0	1,610	1,196	1,027
2025	15	15	24	100	55	44	100	52	40	110	110	153	434	434	285	886	568	568	44	44	0	1,689	1,278	1,115



Disaggregating System Level Values to Distribution Circuit Level Values

For all three scenarios, SDG&E used the same approach when disaggregating system level values down to the circuit level. The disaggregation SDG&E used was determined by the DER resource type. Each of the resource types were allocated evenly across the service territory, or geographically based on weather zones. This method was used to mirror past adoption patterns where known. In the case of nascent technology, such as energy storage, the DER adoption was spread evenly due to a lack of data on adoption rates.

See appendix III for worksheets used to calculate system-wide values and annual disaggregation for all the DER growth scenarios.

Section 2 –Demonstration and Deployment

This section will detail SDG&E's DER-focused demonstration and deployment projects. These projects are intended to demonstrate integration of locational benefits analysis into utility distribution planning and operations.

Introduction

The Guidance directs the utilities to propose five separate DER-focused demonstration and deployment projects designed to validate integrating locational benefits analysis into utility planning operations. Where practical, utilities are directed to collaborate with third-party DER providers and DER technology vendors, and to coordinate demonstration projects with their on-going smart grid deployment activities and Electric Program Investment Charge (EPIC) projects. Lastly, the Guidance requires the utilities to describe expected cost recovery for these demonstrations, and to include specific cost-recovery proposals in their filed DRPs.

SDG&E's five DER-focused demonstration and deployment projects are described in detail below. The projects are designed to uniquely show how DERs can meet the grid planning and operational objectives described within this filing. Where feasible, these proposed projects leverage on-going utility activities and are coordinated with SDG&E's smart grid deployment plan and EPIC activities. By way of brief introduction, the first demonstration project demonstrates how the CPUC-approved methodology for performing a dynamic integration capacity analysis will analyze each circuit in SDG&E's service territory for thermal, voltage and protection limits. The second demonstration project will demonstrate the CPUC-approved LNB methodology will work in practice to traditional, capacity-related distribution investments deferred or avoided through DER deployment. The third, fourth and fifth demonstration projects differ from the first two in that they will physically install and interconnect DER assets to the distribution grid to demonstrate, singularly or as a group, the various benefits that deployed DER can provide.

Demonstration Costs and Cost Recovery

SDG&E does not anticipate incurring any incremental costs to deploy the two initial pilot projects demonstrating the ICA and the LNB methodologies. SDG&E, however, reserves the option to subsequently file and request approval for a Memorandum Account to track currently unforeseen costs that may arise to complete these projects. SDG&E is seeking approval in this DRP to establish a Memorandum Account for the costs associated with the remaining demonstration projects for subsequent recovery in the next GRC. The cost for each of the demonstration projects is listed below and a further discussion regarding the Memorandum Account is included in Section 7, DRP Coordination with Utility General Rates Cases.

2.a Demonstrate Dynamic Integrated Capacity Analysis

The Guidance directs SDG&E to craft a demonstration project that applies the utility's proposed integration capacity analysis methodology to all line sections within it planning territory. As outlined below, SDG&E will undertake a dynamic ICA of each line section – defined as a segment of a circuit, reflecting impedance along the main feeder – in its service territory. This demonstration project will analyze each circuit based on thermal, voltage, and protection limits. SDG&E will perform the ICA utilizing Synergi power flow software and its suite of automation tools, including the new dynamic modeling module. Below are the necessary steps identified and their descriptions.

1. Determine the three segments on each feeder by identifying the start and end of each impedance zone on the main feeder.
    a. SDG&E will run a scan in Synergi to determine the maximum impedance of each feeder. Once the maximum impedance is determined, the feeder will be divided into three segments.
2. Synthesize the circuit demand profile from AMI, SCADA, or other data, and input into Synergi.
3. Conduct power flow analysis to determine thermal and voltage limits on each line section utilizing Synergi.
    a. SDG&E will place a 1MW generator at different points along each segment, and perform a power flow analysis to determine if the generator violates thermal or voltage limits anywhere along the feeder. If no violations are identified, the

capacity of the generator will be increased and the power flow analysis rerun. This process will continue until a violation is identified.

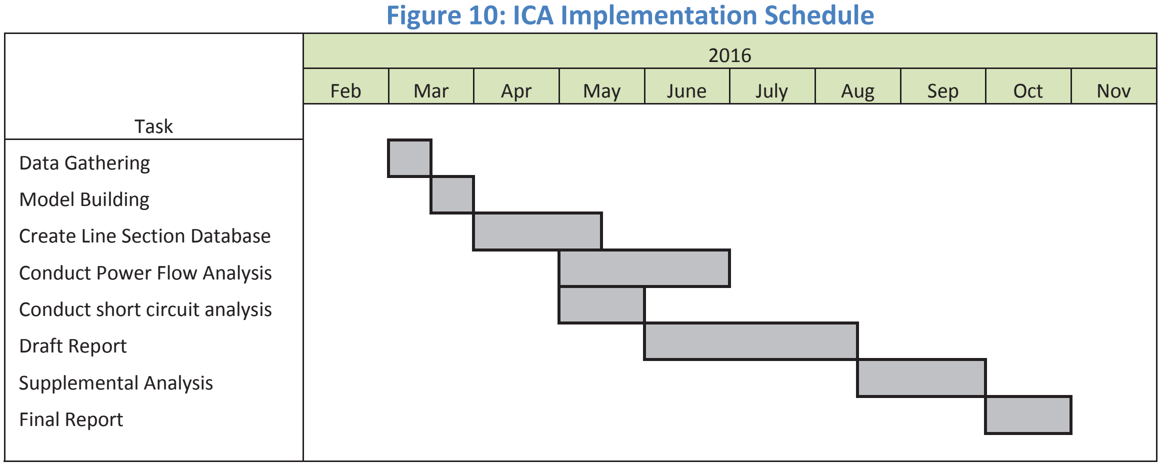
4. Conduct short circuit analysis to determine protection limits on each line section.
   a. Similar to the power flow analysis, SDG&E will model a 1 MW generator at different points along each segment and perform a short circuit analysis to determine if the generator violates protection limits anywhere along the feeder. If no violations are identified, the generator's capacity will be increased and the short circuit analysis rerun. This process will continue until a violation is identified.
5. Once a violation is identified, the integration capacity will be the largest generation capacity that passed the analysis without any violations.

For the initial analysis, DER generation shall remain below the minimum load on each circuit, ensuring no power flow back to the substation. For those circuits that have an IC that does not reach a limit below the backflow limit, further analysis will be performed to determine the maximum integration capacity regardless of the backflow into the substation.

Implementation Schedule

As required by the Guidance, SDG&E will commence this project no later than six months after the Commission approves SDG&E's DRP. Once commenced, SDG&E will require approximately eight months to complete the ICA demonstration. Below is the detailed implementation schedule for the project.

Figure 10: ICA Implementation Schedule



2.b Demonstrate the Optimal Location Benefit Analysis Methodology

The Guidance requires SDG&E to scope a demonstration project that performs the utility's proposed optimum locational net benefits analysis within its distribution planning area. In compliance with this directive, SDG&E's proposed demonstration will focus on performing the proposed LNB analysis in selected area(s) with previously identified distribution capital projects. For this demonstration project, SDG&E intends to analyze the Oceanside area, where SDG&E has identified the need to build a new distribution substation to serve growing demand. SDG&E believes that given the proper specifications, a DER project could potentially defer the substation project. SDG&E will determine what portfolio of DERs is appropriate to meet the capacity need for the Oceanside area and utilize the LNBM to determine the value of the DER portfolio versus the traditional substation project.

If additional projects are identified, they may be circuits, substations, or voltage control projects. For circuit and voltage projects, a DER solution may result in a deferral or replacement of the capital project. For a new distribution substation, a DER solution will typically be a deferral of the project, as load growth in the area will eventually require a substation. The net benefits for the DER project will be calculated utilizing the proposed methodology outlined in section 1b, as approved and/or modified by the Commission. SDG&E's proposed project will focus on distribution infrastructure projects with at least a three-year lead time. Since SDG&E must address distribution deficiencies in a timely manner, the utility will continue to propose traditional infrastructure projects for near-term deficiencies.

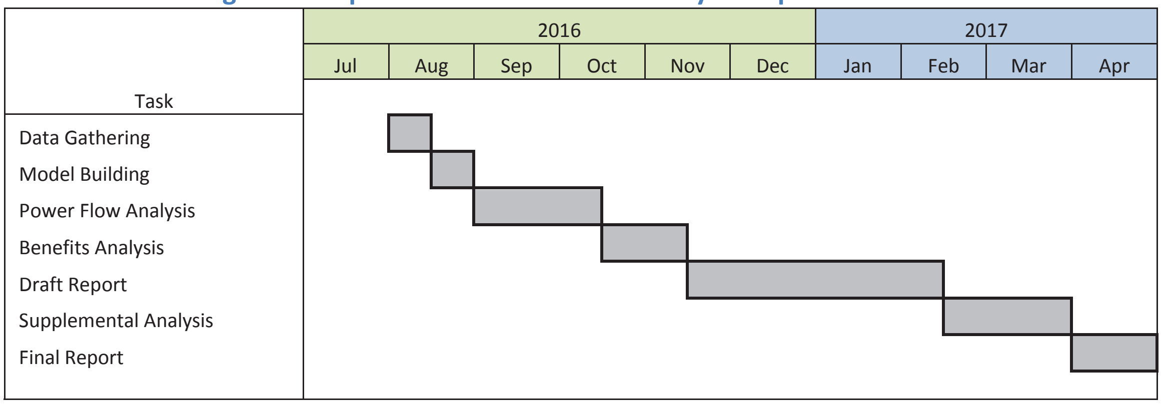
The demonstration project will accomplish several objectives:

1. Identifying traditional projects that can be deferred by DER
2. Identifying the operating characteristics of a DER project that can defer/eliminate a traditional project
3. Determinining length of deferral achieved by DER
4. Calculating net benefits resulting from installation of the DER project

Implementation Schedule

As required by the Guidance, this demonstration will commence within one year of the Commission's approval of SDG&E's DRP. SDG&E will require approximately nine months after commencement to complete the LNBM demonstration. Below is a detailed implementation schedule for the project.

Figure 11: Optimal Location Benefit Analysis Implementation Schedule



2.c *Demonstrate DER Locational Benefits*

The Guidance instructs the utilities to propose a pilot that demonstrates how multiple DER types can act in concert to achieve net benefits consistent with the optimal net benefits analysis. The project should strive to demonstrate how a minimum-cost portfolio of DER providing defined functions could operate in concert with existing infrastructure and defer or displace future investment. The Guidance requires the utilities to specify the products and services DERs would be required to provide to achieve the identified benefits, and also identify the transactional method (e.g., contract, tariff, etc.) the utility will use to attract customers and/or third parties to provide those defined services. Finally, the pilot must incorporate at least three of the Guidance's DER avoided cost categories for which only normative value data currently exist.

In response to these directives, SDG&E proposes a demonstration pilot to validate the locational benefits of DER by identifying, modelling, and installing DER on a capacity-constrained circuit to address power quality issues, and possibly avoid future distribution capital investment and operating expenditures. Specifically, and as described in detail below, the project will install smart inverters on existing and new PV installations, on utility owned and controlled battery storage assets both at the distribution level and behind the meter on circuit(s) with current (or forecasted) high PV adoption and high-load levels. SDG&E believes piloting this configuration of DER provides an opportunity to evaluate several potential DER avoided cost categories, including:

1. Avoided feeder capital and operating expenditures – The coordinated operation of PV systems and storage systems may reduce the feeder loading during times of peak, resulting in the deferral of circuit upgrades (reconductor or new circuit extensions)
2. Renewable Integration costs – DER with smart inverters will mitigate the impacts of PV ramping and intermittency and allow for higher penetration of renewables
3. Avoided distribution voltage and power quality capital and operating expenditures – Smart inverter operations of PV systems and storage systems will stabilize voltage by injecting or absorbing reactive power as required by the feeder
4. Avoided local RA costs – The discharge of aggregated, customer-owned storage during system peak hours could potentially lower the overall local RA requirements

Project Narrative

SDG&E will analyze candidate circuits based on historical data and projected load growth to identify the circuits with the most potential for DER-based benefits. The ideal circuit for this demonstration would be one that has high load levels and a high PV penetration. The selected circuit will be reviewed to establish the as-is circuit behavior (baseline) prior to the addition of smart inverters or storage systems. More detailed analysis of the circuit will be performed to identify the problem areas in the circuits (feeder segments with overloads or voltage problems) and determine the type, size, quantity, and location of DER devices needed to resolve the problems. Computer-based models of the circuits will be built and hardware-in-the-loop testing will be conducted to validate predicted DER performance and its impact on circuit operations. This testing will involve hardware (e.g., smart inverters) connected into virtual models of the circuit that allows for their operation under various loading scenarios.

SDG&E will attempt to work with third parties to install the DER equipment at the optimal locations in the distribution circuit. For example, SDG&E will work with third-party developers to install smart inverters for new rooftop PV systems where possible and to retrofit specific inverters as needed. The utility will work with customers in the identified circuits to install SDG&E-owned storage systems both at the distribution level as well as behind-the-meter. Once installed, SDG&E will control the storage system's charge and discharge functions for peak-shaving purposes as well as other modes of operation, such as those discussed above, that provide benefits to the distribution system. To encourage customer participation, these could be moved to dynamic rates to lower current electric bills. Other potential options to account for round-trip energy conversion inefficiencies inherent in battery storage systems include SDG&E offering an incentive or sub-metering the battery usage and adjusting the customer's consumption accordingly.

Demonstrations will be conducted and data collected over several months to capture data pertaining to the performance of the various DER operations. This data will be analyzed to validate the net benefits resulting from the installation of the DER and compare them to the predicted performance from the hardware-in-the-loop testing. Additionally, these net benefits be compared to the benefits identified in the original locational net benefit analysis. These results will be documented in a final report.

As described above, project activities will include:

- Reviewing historical and forecast load data
- Identifying candidate circuits
- Establishing baseline operations
- Modeling behavior of intelligent DER
- Installing equipment
- Conducting demonstrations
- Analyzing data
- Documenting results

DER to be Evaluated

As described above, the project will involve the installation and operation of PV systems with smart inverters as well as behind-the-meter storage systems with smart inverters on the identified circuit. PV systems with smart inverters can provide voltage regulation benefits by operating at power factor levels that can help keep the system voltage within the acceptable range, operating at a lagging power factor (consuming VARs) if the voltage is too high and needs to be lowered, or operating at a leading power factor (supplying VARs) if the voltage is too low. Additionally, the fast reaction times of smart inverters can help mitigate the quick changes in voltage associated with intermittent PV output when clouds are present. Lastly, if the circuit peak occurs at a time of the day when the sun is still shining, the PV systems can help reduce the peak on the circuit.

Storage systems with smart inverters offer what is known as four-quadrant operation. This functionality allows the storage system to operate in all four quadrants of the watt/VAR vector relationship. In physical terms, this means the storage system can supply or absorb real power (watts), supply or absorb reactive power (VARs), and do any combination of watts and VARs up to the rating of the system.

The ability of the storage system to charge and discharge real power (in watts) can be used to change the daily load profile of a circuit by charging at a time of low demand (and corresponding low energy cost) and discharging at a time of high demand. This use case provides the opportunity to lower the circuit peak demand and eliminate a circuit overload. By properly sizing the storage system's power capability (in kilowatts) and energy capability (in kW-hrs) the storage system can "ride through" a circuit overload. This operation can be repeated for all days an overload is expected to occur. Typically, this potential circuit overload might occur a finite number of times during the summer months. One of the most effective functions of a smart storage system is called "peak shaving." This refers to the system's ability to monitor a reference load (local or remote) and only discharge the system if a set point has been reached. The magnitude of the discharge will then be equal to the amount of load by which the monitored load exceeds the set point. As the reference load changes, the battery output will correspondingly change to maintain the set point. This use case can extend the battery life by only supplying the power necessary to maintain the set point. The ability of the storage system to supply and absorb reactive power means that the system can offer the same voltage regulation and power factor benefits that the PV smart inverter can provide, as mentioned above.

Controllable DER devices that act in a coordinated fashion have the ability to operate in reaction to a local condition or in response to a remote signal. This demonstration will attempt to evaluate both modes depending on actual field conditions.

Table 11: Implementation Schedule

Activity	*Duration*	*Start*	*Finish*
Approval of DRP plan	TBD		7/1/16
Review data and identify candidate circuits	3 months	7/1/16	9/30/16
Establish baseline operations	3 months	10/1/16	12/31/16
Model and simulate DER operations	3 months	1/1/17	3/31/17
Customer acquisition and equipment installation	18 months	4/1/17	9/30/18
Demonstrations and data analysis	6 months	10/1/18	3/30/19
Final report	3 months	4/1/19	6/30/19

Estimated Cost and Potential Funding Sources

Project is estimated at $6.4 million. Cost breakdown is as follows:

1. Engineering: $200k
2. Customer acquisition: $750k
3. Installation of smart inverters: $450k
4. Installation of storage systems: $4.6M
5. Modeling and simulations: $250k
6. Engineering (data analysis and results): $150k

Table 12: Projected Cash Flows

Activity	Cashflow ($000) 2015	2016	2017	2018	2019	Total
Engineering		$ 150	$ 50			**$ 200**
Install Smart Inverters			$ 225	$ 225		**$ 450**
Install storage systems			$ 2,300	$ 2,300		**$ 4,600**
Customer Incentives			$ 375	$ 250	$ 125	**$ 750**
Modeling and simulation			$ 125	$ 125		**$ 250**
Data Analysis and Results					$ 150	**$ 150**
Total	**$ -**	**$ 150**	**$ 3,075**	**$ 2,900**	**$ 275**	**$ 6,400**

2.d Demonstrate Distribution Operations at High Penetrations of DERs

The Guidance directs the utilities to scope pilot that demonstrates analysis of the potential locational benefits associated with high DER penetration in a relatively confined geographic area. Specifically, the analysis should be conducted at the substation level, involve up to five circuits, and expressly seek to demonstrate how multiple DER types, controlled by both the utility and third-parties, can be optimally coordinated. In response, SDG&E proposes a demonstration project that deploys multiple DER solutions on a distribution substation having five circuits with high PV penetration. SDG&E's proposed pilot will demonstrate advanced, coordinated operations of four DER types – smart inverters, dynamic voltage controllers (DVC), community energy storage systems, and power regulating transformers – with existing distribution infrastructure.

Project Narrative

As described in demonstration C, SDG&E will analyze candidate circuits based on historical data for PV penetration relative to circuit loading to identify the circuits with the most potential for DER-based benefits. The ideal circuit for this demonstration would be one that has low load levels and a high PV penetration. Selected circuits will be reviewed to establish the as-is circuit behavior (baseline), prior to the addition of the DER. The configuration of the circuits chosen will determine the types and combinations of DER devices that will be used. These operations will be modeled and simulated to determine the best solution for each circuit. Computer-based models of the circuits will be built and hardware-in-the-loop testing will be conducted to predict DER performance and its impact on circuit operations. This testing will involve hardware (e.g., smart inverters) connected into virtual models of the circuit that allows for their operation under various loading scenarios.

SDG&E will attempt to construct the installations as close as possible to the optimal locations identified in the modeling. SDG&E will attempt to work with third-party developers to install smart inverters for new rooftop PV systems where possible and to retrofit specific inverters as needed.

Table 13: Sample Breakdown of Potential DER Installations

Circuit	***PRT Units (50 kVA)***	***DVC Units (240 kVAR)***	***CES Units (25 kW)***	***Smart Inverters (5 kW)***
Circuit 1	50			100
Circuit 2		12		100
Circuit 3			20	100
Circuit 4		6	10	100
Circuit 5	25	6	10	100

Demonstrations will be conducted and data collected over several months to capture data pertaining to the performance of the various DER operations. This data will be analyzed to validate the net benefits resulting from the installation of the DER and compare them to the predicted performance from the hardware-in-the-loop testing. Additionally, these net benefits will be compared to the benefits identified in the original locational net benefit analysis. These results will be documented in a final report.

Project activities will include:

- Reviewing historical data for PV penetration information
- Identifying candidate substation/circuits
- Establishing baseline operations
- Evaluating potential DER solutions
- Modeling behavior of intelligent DER
- Installing equipment in the field

- Conducting demonstrations
- Analyzing data
- Documenting results

DER to be Evaluated

To achieve the various desired distribution system benefits, the project will involve the installation and operation of PV systems with smart inverters, dynamic voltage controllers (DVCs), community energy storage (CES) units, and voltage-regulating transformers on the identified circuits. These technologies and their capabilities are described in detail below.

1. Smart Inverters – Inverters that are capable of providing additional functionality such as voltage regulation and PV smoothing
2. DVCs – Inverter-based device capable of sinking or sourcing VARs to stabilize voltage. This device is connected to the secondary side of a distribution transformer and is typically operated by giving a reference set point. The DVC will monitor its input voltage and react as needed to try to maintain that voltage set point. If the voltage drops below the set point, the DVC will inject VARs and conversely, if the voltage goes above the set point, the DVC will absorb VARs to attempt to bring the voltage down.
3. CES – This secondary voltage, field-connected storage device is capable of four-quadrant operation (sinking or sourcing real and reactive power). The CES can inject or absorb real power in response to the intermittent power output of a PV system in an effort to "smooth out" high-frequency fluctuations which can negatively impact the distribution system. The CES can also inject or absorb reactive power in response to voltage changes.
4. Power Regulating Transformer (PRT) – The PRT is a 50 kVA-rated, integrated transformer and power regulator that regulates voltage +/-10%, dynamic reactive power compensation +/-5 kVAR and harmonic cancellation. This device is remote control capable, allowing for data aggregation in a back office setting as well as remote control over set points.

Combinations of these DER devices will be installed on the five circuits chosen for this demonstration. It is anticipated that all circuits will have some quantity of smart inverters. This project will evaluate the independent operation of the devices, the operation of a fleet of similar devices working simultaneously, and the interaction of different types of devices operating on the same distribution circuit. Various DER control methodologies will be evaluated for effectiveness. Devices can be dispatched on prearranged schedules based on historical circuit load and PV output. They can also be set to react to actual voltages. A fleet of devices can be made to react to local conditions (voltage, load, power factor) or react to a signal from a remote location, such as a substation or a data center.

Table 14: Implementation Schedule

Activity	*Duration*	*Start*	*Finish*
Approval of DRP plan	TBD		7/1/16
Review data and identify candidate circuits	2 mo	7/1/16	8/30/16
Establish baseline operations	3 mo	9/1/16	11/30/16
Circuit analysis and simulations	6 mo	12/1/16	5/31/17
Install DER equipment	24 mo	6/1/17	5/31/19
Demonstrations and data analysis	6 mo	6/1/19	11/30/19
Final report	3 mo	12/1/19	2/28/20

The project is estimated at $9.4 million. Cost breakdown is as follows:

1. Engineering: $250k
2. Modeling and simulation: $400k
3. Data analysis and results: $250k
4. Field installations: $8.5M

Table 15: Projected Cash Flows

	Cashflow ($000)					
Activity	***2015***	***2016***	***2017***	***2018***	***2019***	***Total***
Engineering		$ 150	$ 100			**$ 250**
Install Field Devices			$ 2,750	$ 3,000	$ 2,730	**$ 8,480**
Modeling and simulatino			$ 200	$ 200		**$ 400**
Data Analysis and Results					$ 250	**$ 250**
Total	**$ -**	**$ 150**	**$ 3,050**	**$ 3,200**	**$ 2,980**	**$ 9,380**

2.e Demonstrate DER Dispatch to Meet Reliability Needs

In response to the Guidance's requirement to include a pilot demonstrating how multiple third-party and utility owned DERs can be coordinated and controlled via a dedicated control system, SDG&E will undertake a demonstration project in which it will serve as the distribution system operator of a microgrid where DERs serve a significant portion of customer loads and reliability services. SDG&E will leverage the existing microgrid in the community of Borrego Springs for this demonstration project.[23]

Project Narrative

SDG&E designed the Borrego Springs microgrid to demonstrate the benefits of operating utility and third-party-owned DER in both a grid-connected and an islanded state. Borrego Springs is a small, desert community in the northeast corner of the SDG&E service territory, and was selected as a microgrid site after a thorough investigation of potential sites, which included factors such as historical reliability, PV penetration, land availability, and community acceptance. The community is served by a single substation with three distribution feeders. The peak demand of the substation is approximately 12 MW. The geographical location, isolation, rugged terrain, and preponderance of severe weather events around this community has presented reliability challenges over the years. Local DER presented an opportunity to improve the reliability.

SDG&E has established the as-is circuit behavior (baseline) prior to the addition of the DER. These operations will be modeled and simulated to determine the best solution for the microgrid. Computer-based models of the microgrid will be built and hardware-in-the-loop testing will be conducted to predict DER performance and its impact on circuit operations. This testing will involve hardware (e.g., smart inverters) connected into virtual models of the microgrid that allows for their operation under various loading scenarios.

[23] The construction of the existing Borrego Springs microgrid has been partially funded through grants from both the U.S. Department of Energy (DOE) and the CEC. The microgrid was designed to demonstrate the benefits of the operation of utility and third-party owned DER in both a grid-connected and an islanded state.

SDG&E is currently developing an enterprise-wide DERMS that will be capable of monitoring, controlling, and optimizing the dispatch of DER. This software will be used in this project to create optimal DER portfolios for various loading scenarios. These portfolios of resources will be scheduled, dispatched, and monitored in real time.

Demonstrations will be conducted and data collected over several months to capture data pertaining to the performance of the various DER operations made in response to this pilot's directives. This data will be analyzed to quantify the benefits and compare them to both the baseline and the predicted performance from the hardware-in-the-loop testing. These results will be documented in a final report, which will include both a technical and economic evaluation of the DER solutions.

Project activities will include:

- Defining microgrid area
- Determining outage history of microgrid
- Determining potential benefits (SAIDI, SAIFI, etc.)
- Devising strategies for dispatching microgrid assets under various outage scenarios (loss of distribution feeder, loss of substation bank, loss of transmission line, etc.)
- Conducting simulations to confirm microgrid operations
- Determining best combination of utility and third-party asset deployment to mitigate the various outage scenarios
- Deploying DERMS to monitor, control, and optimize the operation of the microgrid
- Conducting demonstrations and collect data
- Analyzing data
- Documenting results

<u>DER to be Evaluated</u>

To achieve the various described distribution system benefits desired, SDG&E anticipates that the project will involve the installation and operation of substation energy storage, CES, distributed generation, merchant PV and customer PV.

- Substation energy storage – 1.5 MW/4.5 MWh of storage located at the microgrid yard

- CES – Three 25kw/50kWh units located on one of the distribution feeders
- Distributed generation – 3.6 MW of distributed generation located at the microgrid yard
- Third-party-owned PV system connected to substation – 26 MW PV facility connected to the substation at the 69 kV level
- Third-party-owned PV system connected to distribution feeder – 6.3 MW PV generating facility connected at the 12 KV level to one of the distribution circuits
- Customer-owned PV systems – An aggregated rooftop PV output of more than 1.0 MW

To further improve the reliability to the microgrid, new SCADA switches will be deployed at key locations on the distribution feeders to enhance the ability to sectionalize the circuits and improve service to the high-priority loads. Additionally, the existing line capacitor stations, currently operated on a time clock with voltage bias, will be converted to SCADA control for better control of the primary voltage.

DERMS – SDG&E's DER control platform – is currently under development and will be deployed to manage the operation of the DER devices. DERMS will be integrated into key distribution operations systems including the Distribution Management System (DMS), demand response, and weather.

Table 16: Implementation Schedule

Activity	*Duration*	*Start*	*Finish*
Approval of DRP plan	TBD		7/1/16
Engineering analysis	3 months	7/1/16	9/30/16
Microgrid construction activities (SCADA switches and SCADA capacitors)	15 months	6/1/15	3/31/16
The deployment of the DERMS software	12 months	9/30/15	9/30/16
Demonstration of microgrid operations	6 months	10/1/16	4/30/17
Data analysis and results	3 months	5/1/17	7/31/17

The project is estimated at $14.7M. The cost breakdown is as follows:

1. Engineering tasks (define and execute test plan): $0.3M
2. Install microgrid equipment: $5.8M
3. Deployment of DERMS software: $8.4M
4. Data analysis and results: $0.2M

Table 17: Projected Cash Flows

	Cashflow ($000)					
Activity	***2015***	***2016***	***2017***	***2018***	***2019***	***Total***
Engineering		$ 300				**$ 300**
Install Microgrid Equipment	$ 3,800	$ 2,000				**$ 5,800**
Deployment of DERMS solution	$ 4,600	$ 3,800				**$ 8,400**
Data Analysis and Results			$ 200			**$ 200**
Total	**$ 8,400**	**$ 6,100**	**$ 200**	**$ -**	**$ -**	**$ 14,700**

2f. Demonstrate New Business Utility Model for DER Integration

In addition to the five pilots responding directly to those required by the Guidance, SDG&E proposes this optional sixth pilot designed to test new utility business models that foster increased collaboration between the customer and the utility and enable increased DER integration. While not fitting squarely into the structured format of the five identified pilots, SDG&E believes this optional demonstration addresses a key requirement for fostering and enabling robust DER integration going forward, namely how the existing utility business model intersects and interacts with increased participation at the distribution edge by customers and third parties.

This pilot provides an opportunity to test the ability of customer-owned, behind-the-meter storage assets to potentially defer circuit upgrades (e.g., re-conductor or new circuit extensions). In addition, the project will provide the opportunity to pilot a new residential energy storage rate, as well as test a new business and revenue model for third-party ownership of distribution infrastructure. This model differs from the proposed utility owned, behind-the-meter storage solution piloted in demonstration 2.c (DER Locational Benefits) above, and provides an opportunity to contrast two different approaches for integrating DER to defer a traditional capital infrastructure project, provided it meets the specific requirements.

Project Narrative

In this pilot, SDG&E will identify a specific location on the distribution system where 1) a capacity-related upgrade is needed, has been identified, and is currently included in SDG&E's distribution plan and capital budget (e.g., a re-conductor project, or new circuit extension) and 2) an aggregation of behind-the-meter storage resources with sufficient control mechanisms could potentially provide a suitable substitute for the conventional upgrade project.

Once identified, this pilot will provide customers at the specified location with cash incentives to purchase residential or small commercial energy storage systems. The cash incentives would be in addition to those available through the self-generation incentive program, and would be structured so that the combination of incentives nearly, and in some cases, completely defers the customer's out-of-pocket expense for the storage resources.

Customers taking advantage of the incentive will 1) accept a new dynamic rate that more acutely aligns charging and discharging with specific grid needs and 2) allow SDG&E to directly control the storage system's charge and discharge functions during a limited number of high-load hours annually. This limited control function will ensure the assumed deferral benefits are realized. The financial incentives offered to customers would be tiered, with customers agreeing to the minimum required utility control receiving the lowest incentive, and customers authorizing increased levels of receiving a higher incentive. When coupled with some measure of limited, direct utility control, behind-the-meter storage targeted and deployed in these high-value locations could be aggregated to potentially defer conventional capital upgrades. This provides the opportunity to create a potentially lower-cost, forward-thinking solution to the conventional upgrade that benefits all ratepayers. In tandem, customers accepting the incentive will have the opportunity to utilize their new storage system to both increase their own reliability and add a new level of control over their energy costs.

New Business Model for DER Integration

A key objective of this pilot is to test new utility business models that address the evolving nature of the distribution system. By using a DER solution to defer or displace traditional infrastructure investments, this pilot potentially creates fewer distribution-level infrastructure projects on which utilities like SDG&E would earn a traditional return. Therefore, for this pilot to be successful and scalable, it is necessary to incorporate and validate a new, performance-based utility incentive that partially replaces lost earnings and enables utilities to be active partners in identifying and incenting optimal location of DER solutions on the distribution grid. The performance-based revenue model SDG&E would test in this pilot has the following high-level elements:

- The established budget for the conventional upgrade solution – e.g., the circuit upgrade identified and currently included in SDG&E's distribution plan and capital budget – sets the ceiling. For ease of example, assume that conventional solution's budget was $1.8M.
- This amount is then removed from SDG&E's approved distribution capital budget and reallocated to a Memorandum Account for tracking purposes. Using some portion of $1.8M, SDG&E funds customer storage incentives and designs and implements a solution that enables utility control of the battery systems in a limited number of critical load hours annually. Assume the incentives plus control solution total $1.6M
- Once the solution is installed and proven to be operationally effective, ratepayers and shareholders equally share all savings, if any, between the cost of the identified conventional solution and the DER solution. In the above example, the delta is $200K (total cost of the budgeted upgrade at $1.8M minus total costs of the DER incentive solution at $1.6M = $200K). Ratepayers would receive $100K in the form of reduced project costs and revenue requirement relative to the conventional solution. Shareholders would receive $100K as an incentive for identifying and implementing a forward-thinking DER solution to a traditional distribution system capacity issue.

Implementing this pilot in tandem with the Locational Benefits pilot proposed in 2.c above provides an opportunity to contrast the efficacy of a customer-owned storage system with a distributed, utility-controlled storage system on a separate, similarly sized capacity. Constrained circuit data from the performance of this installation will be contrasted with data from the performance of the utility owned solution and will be used in future cost-effectiveness evaluations. Additionally, the pilot will help answer questions regarding the necessary or appropriate level of direct utility control required to realize a deferral benefit provided by behind-the-meter resources.

Implementation Schedule

SDG&E anticipates initiating this demonstration project within six months of the CPUC's approval of the DRP, with installation beginning one year after approval. For both the customer-owned and utility owned solutions, SDG&E anticipates needing approximately six months to identify a specific comparable location on the distribution system where 1) a capacity-related upgrade is needed, has been identified, and is currently included in SDG&E's distribution plan and capital budget (e.g., a re-conductor project, or new circuit extension) and 2) an aggregation of either behind-the-meter or front-of-the-meter storage resources with sufficient control mechanisms could potentially provide a suitable substitute for the conventional upgrade project. In parallel, SDG&E will develop a marketing strategy to solicit customer participation and work with vendors to enable the limited utility control function necessary to ensure the deferral benefit is realized.

Section 3 – Data Access

Many of the above sections require various amounts and types of data to be transferred between the utilities and third parties. This section will detail SDG&E's policies and procedures for data access and sharing.

3.a Proposed Policy on Data Sharing

SDG&E recognizes the value of sharing information relevant to improving the safety, reliability, and security of its distribution system. This section of SDG&E's DRP describes its policies and procedures regarding the sharing of company public, proprietary, and customer information. These procedures outline the physical security, cyber security, and customer privacy efforts that SDG&E undertakes to maintain a safe and reliable electric system. SDG&E believes that any third party that participates in data sharing as a result of this DRP should follow similar stringent guidelines.

While some of the data SDG&E uses in distribution planning and operations activities is considered public and is/can be made available to interested third parties, the utility also believes that some data is inappropriate for public consumption and reasonable safeguards and restrictions should be implemented when sharing any non-public data. The data that is shared may be subject to a qualification process when requested by interested parties. The DRP Guidance references just one of the many data sharing and privacy-related proceedings that have been litigated before the CPUC. SDG&E points out that privacy and data sharing discussions and decisions have also occurred in various other state, federal, and industry forums. SDG&E believes that any data sharing policies and procedures resulting from the CPUC's approval of the respective DRPs should align with and not expand existing state-approved and utility industry-supported philosophies, policies, and procedures related to data sharing.

SDG&E takes the privacy and safety of its customers and the security of its infrastructure very seriously. DER owners and operators should become familiar with and implement industry-recognized privacy, physical and cyber security frameworks and best practices before requesting data from SDG&E.

SDG&E's effective and proactive security programs, which include varying levels of confidential information, have been vetted by both the private and public sector. SDG&E believes that data and data gathering assets associated with the DRP should be subject to similarly vetted security programs, including the adoption of confidentiality measures.

Consistent with the outcome of various data access litigations or the philosophies associated with these decisions, SDG&E believes that sharing some of the data identified in the DRP Guidance, considered by various parties as important to furthering the goals of the DRP process, may compromise some of SDG&E's data security policies. Specific examples will be expanded upon within the respective data security subsections.

Physical Security

Utilities have long recognized that the safe and reliable operation of the electrical system depends upon establishing and maintaining a sufficient level of physical security to prevent and minimize threats to both electrical and information-providing assets. As the ownership and location of electrical distribution assets expands associated with an increasing penetration of DER, existing physical security threats will be exacerbated and new threats introduced.

Information assets have become a vital link to the safe, efficient, and reliable operation of the electrical distribution grid, and having physical access to an information-providing asset increases the likelihood that the asset can be exploited. SDG&E's physical security program recognizes that as information-providing assets are increasingly located beyond the security coverage embodied by well-protected data centers and into the field, more robust and faster-responding physical security controls must also be established and applied by all stakeholders involved in the gathering, storing, and sending of information.

SDG&E's corporate security department performs investigations of physical security incidents, site security reviews, and vulnerability assessments throughout Sempra Energy's U.S. operations. SDG&E's corporate security policies include, but are not limited to:

- Onsite guard patrol and monitoring of critical facilities

- Real-time remote monitoring of facilities
- Technical security and monitoring measures including real-time and recorded surveillance video, door, and gate alarms and various methods of intrusion detection

A central electronic access management system is used to limit facility access to only authorized personnel. Security awareness training provides personnel with the tools needed to identify threats and vulnerabilities and to take proper action. Local, national, and global threats are monitored through various methods, including classified briefings by federal security and law enforcement agencies.

SDG&E believes that the proposed data sharing of "GIS maps and power flow models of the entire distribution system to the substation level" raises high concern in regards to maintaining a necessary level of physical security. Making this information available to a third party, even under a non-disclosure agreement, could be problematic in terms of the physical security of the electric transmission and distribution system because this information could allow identification of critical infrastructure assets, including locations. Access to this information would increase the risk of physical attack on those assets. SDG&E deploys extensive physical security systems and resources to establish and maintain a required minimum level of infrastructure protection, and this minimum level of security needs to be implemented and maintained for non-utility owned assets as well in order to ensure continued confidentiality of the location of the most critical components of SDG&E's electrical distribution system.

Information Security

SDG&E utilizes a risk-based model for the management of information security that includes a value and impact-based methodology to ensure protections are commensurate with the value of the asset being protected. The company uses a security framework based on controls described in NIST 800-53 and ISO 27002. Third parties, including DERs, that wish to access SDG&E's sensitive information will be expected to show compliance with these and other applicable protocols.

Information used by SDG&E is classified based upon its value and risk of loss to the company, with the level of risk being higher or lower depending on the efficiency and which controls are in place to protect that information. Sharing sensitive information without a risk assessment to determine how that information will be received, used, shared, and stored by third parties can expose the company to risk of non-compliance with company policy and state and federal laws.

SDG&E's security posture of company information and information systems is influenced by many elements, some of which extend beyond specific information technology protocols and include physical security, administrative processes, insurance, and contractual agreements. Systems, facilities, processes, legal agreements, and insurance are security features and controls that ensure that the information is available, correct, and appropriately disclosed or that the risks associated with information security failures are understood and accepted.

Threats constantly evolve, and information systems change to accommodate new requirements. The result is that the security posture of an information asset or a system in the field can be degraded if no action is taken to ensure that security controls accommodate current and projected threats.

Periodic reassessment of the security levels assigned to information assets helps to reduce exposures to risks that result from evolving threats and changing control systems and information system configurations. Measurement of the effectiveness of controls verifies with the efficacy of the risk mitigations.

SDG&E's information security department is critical in helping the company maintain a clear and current view of the security posture of SDG&E-owned and operated information assets by providing tools to assess and address emerging threats, support change control processes, and support the company's information technology product lifecycle. Information security is also invaluable to DERs and other third parties who express an interest in accessing SDG&E sensitive information, or in connecting information assets to the utility's distribution system.

SDG&E believes that all data shared as a result of the CPUC-approved DRPs will be data that can be classified as static, e.g., data that has already been collected and stored by SDG&E from data-providing assets. No data will be transmitted near real-time, in real-time, nor directly from an SDG&E-owned, operated, or controlled asset.

Customer Privacy

SDG&E's customer privacy policies and practices comply with all state and federal laws and regulations regarding the privacy of customer information and rigorously protect all customer information that is measured, recorded, transmitted, collected, and/or stored using any aspect of SDG&E-owned, controlled, or operated equipment. An unassailable principle for SDG&E is dedicated to protecting and acting as a custodian of customer information, and to fostering customer privacy. Accordingly, SDG&E has implemented a comprehensive privacy program that incorporates high national and international standards.

SDG&E uses the Generally Accepted Privacy Principles (GAPP) and elements of Privacy by Design in its customer privacy framework and privacy controls and expects third parties, including DERs, to demonstrate that they have implemented similarly protective privacy controls before any customer information is shared.

SDG&E's policy regarding sharing customer data includes a consultation with the requesting third party to ensure an understanding of the reason for and type of data being requested and to determine what customer data will best help to answer the requesting party's questions or stated problem. Third parties must realize that access to customer information carries risk, as the collection and analysis of customer information could lead to discovery – intentional or otherwise – of behaviors and activities the customer believes to be private. To that end, in order to best protect customer privacy when information sharing becomes necessary, SDG&E always seeks to provide aggregated information whenever possible, and anonymized over customer-identifiable information when aggregated data will not suffice.

SDG&E defines aggregated information as data that has been summed or otherwise grouped to prevent any one individual customer from being identified. SDG&E may aggregate data based on a timeframe (e.g., monthly, annually, etc.), a geographic location (e.g., a zip code, town code, etc.), and/or by other criteria related to the customer (e.g., customer type, such as commercial or residential, or other factors). Data may be aggregated to different levels depending on the nature of the data and the laws that govern that data. Anonymized information is considered to be customer data that has had all metadata that can be used to identify the customer; such as names, service addresses, meter IDs, etc.; removed. While anonymized data is sometimes assumed to be protective of customer privacy, research[24] has demonstrated that individuals can often be identified when anonymized data is combined with other available data sets. All other customer information is considered to be customer-identifiable and is subject to the company's strictest protections.

SDG&E conducts Privacy Impact Assessments (PIAs) of projects that process customer information in order to determine the level of risk the project presents to customer privacy and to define the privacy controls required to minimize that risk. As a part of the risk calculation, PIAs take into account the results of information security assessments performed by the Information Security department on the project.

i. *Types of data that will be shared, including, but not limited to, all data fields referenced herein.*

   The following table describes the types of information that SDG&E plans to share as a part of its DRP. For purposes of the DRP, SDG&E has grouped company information into two categories: public and sensitive. Public Information is information that the company is able to share with DERs with little or no privacy or security controls in place. Sensitive Information is information that the company may be able to share with DERs that have met specific criteria, including contractual, administrative, and technical controls described later in this section.

[24] Data Privacy Lab, Personal Genome Project http://dataprivacylab.org/projects/pgp/index.html

Table 18: Types of Data Shared

Data Type	Data Field	Data Category
System	EV charging stations	Sensitive
	DG population	Sensitive
	CHP population	Sensitive
Planning	Capital project plan	Public
	DER adoption forecasts	N/A, Public
SCADA	Historical circuit load	Sensitive
	Historical substation load	Sensitive
	Coincident peaks - sub/circuits	Sensitive
	Non-coincident peaks - sub/circuits	Sensitive
Operational	Historical outage data	Public
	AMI data	Sensitive

Information Category	Required Controls
Public	No specific controls are required for sharing Public Information.
Sensitive	• Signed contract between DER and SDG&E. • Signed NDA between DER and SDG&E. • Review of DER security controls by SDG&E's information security department or an agreed-upon third party. • PIA (for projects processing SDG&E customer information) by SDG&E's office of customer privacy or an agreed-upon third party.

Requirements for Receiving Data from DER Owners (DER Owners/Operators)

SDG&E may be in a position to receive data from DER developers, owners, and operators in an effort to refine the various DRP-related analyses. Such data may include market sensitive data (e.g., operations and marketing plans pertaining to growth scenarios), technology sensitive (e.g., generation profiles associated with DER types), and customer sensitive (e.g., net and gross DER generation values at end-use customer sites). Any customer data received by SDG&E from DER developers, owners, and/or operators will be handled by SDG&E using the same privacy policies that apply to internally owned and generated data. In addition, DER developers, owners, and operators should coordinate with SDG&E to identify any additional information security policies that are necessary to safeguard DER-provided data.

3.b Procedures for Data Sharing

SDG&E proposes that procedures and protocols currently in place for non-DRP-related data sharing should be utilized for data shared as part of the DRP process.

3.b.i Proposed Process for Sharing Data with Customers and/or DER Owner/Operators

1. SDG&E will build a website that explains the process for customers and third parties to request company information for DRP purposes and describe the criteria they will need to meet in order to obtain the data. Requests for customer information will be routed to SDG&E's privacy GreenLight process, which is based on the rules described in the CPUC energy data access decision (D.2014-05-016). For other company data, a request form will be made available by SDG&E on its website for customers and third parties to request other company data for DRP purposes. The form may be web-based in PDF or other formats depending on the technology available.
2. When a customer or third party wishes to request company information for DRP purposes, they will complete the form and submit it to the contact provided in the form
3. After the form is received, SDG&E will review it for completeness, determine whether such information can be provided, and validate that the requestor is authorized to receive the information they are requesting. Depending on whether the request is for public or sensitive data, the requestor may be asked to demonstrate compliance with the required controls described in the table in section *3.a.i* above. SDG&E may contact the requestor to consult with them about the request on matters such as aggregation levels, report formats, and delivery methods and to provide guidance on how to best ensure the request can be fulfilled.
4. If all required controls are satisfied, SDG&E will ship the requested information to the requestor via reasonably secure and cost-effective channels
5. If the requestor cannot be validated, the requested information is not available, or the requestor cannot satisfy the required controls, the request will be denied

3.b.ii Availability of Data on a Real-Time Basis

From an operational, market risks and logistical standpoint, SDG&E is not prepared to provide or make real-time data available to a third party at this time. Creating the potential for SDG&E's safe, reliable, and customer-focused operations to be compromised is not an acceptable option. Additionally, the infrastructure is not in place to deliver real-time or near real-time data, and SDG&E questions the full benefits of expending the extensive time and resources to create the needed infrastructure. SDG&E intends to provide historical load data to qualified parties updated at regular intervals. The data can be accessed following the protocols outlined above.

3.b.iii Proposed Process for Sharing Market Data from DER Owners/Operators with Utilities

SDG&E believes that data from DER owners and operators can play a valuable role in planning the distribution system but also recognizes that in some cases, the data that SDG&E would request is market sensitive. Data about the physical installation of the DER system, such as nameplate capacity, inverter specifications, etc., is typically provided during the interconnection process, and is entered into SDG&E's GIS system upon the DER being energized. This data is key in properly modeling the existing distribution system and the impact that DERs have on it. This data does not, however, help SDG&E forecast the future development of DER deployment. To accurately forecast DER development, SDG&E would need access to marketing and other business plans of DER developers to better understand where DERs might mitigate the need for traditional wires projects. Projections based on past DER growth in an area can be misleading as DER installers may have left the neighborhood due to saturation, resulting in little or no future growth. Conversely, DER installers may be targeting a low-penetration area, which would result in larger than average near-term growth in DER resources for that area. SDG&E could then incorporate these growth plans into its demand forecast, which could affect the analysis of the distribution system.

In order for DER developers to share this type of data, SDG&E believes that a process similar to that required for transfer of utility data is appropriate. Data exchange would be limited in scope and subject to confidentiality rules.

3.c Grid Conditions Data and Smart Meters

i. *Process for making public feeder-level grid conditions data; such as what is provided by distribution sensor networks and substation automation systems, including coincident & non-coincident peaks, capacity levels, outage data, real and reactive power profiles, impedances and transformer thermal and loading histories; and projected investment needs over the next 10 years*

SDG&E looks forward to working with all stakeholders to discuss and ensure the proper levels of privacy, physical, and cyber security are identified, developed, and maintained for all assets contributing to the safe, efficient, and reliable delivery of electrical services to SDG&E's customers.

ii. Description of the utility's current plans for obtaining data from smart meters, beyond interval billing data, that reflect power quality and other factors. This data potentially includes voltage, frequency, and reactive power/power factor

SDG&E does not presently receive power quality and other data from smart meters due to budgetary and technical constraints. Any change to the data that is retrieved and stored from smart meters will require a significant IT investment. SDG&E can formulate a plan and propose it in the next GRC filing, but believes that the cost to do so may be prohibitive at this time.

iii. Process for making data from new sources; such as sensor systems, SCADA systems, and substation automation systems; available in a form where it can be analyzed and correlated with existing data sources

Historical SCADA data will be made available to interested parties upon completing a qualification process. This qualification process is intended to ensure that applicants for such data have proper data controls in place, and are authorized to receive this historical data. After applicants are qualified, they will receive historical data for the local area requested in a tabular format. As part of its annual DPP, SDG&E will identify distribution system investments over the 10-year forecast period. DER solutions will be considered for investments that are three or more years into the future. SDG&E notes that system needs that identified in the out years (eight to 10-year window) are often subject to change, as changes in the distribution system forecast and configuration can often accelerate or delay project in service dates. For this reason, incorporating DRP activities into the annual DPP is imperative, in order to capture those changes to better inform DER developers about the state of the distribution system. SDG&E is committed to working diligently and proactively to provide authorized customers and third parties access to company information that enables the DRP in a manner that protects customer privacy as well as the safety, reliability, and security of company infrastructure

iv. *Plan for how Utilities can leverage DER owner/operator data*

Certain types of data from DER can help to inform the utilities' planning processes, such as DER system capabilities and specifications. Weather correlated output curves from DER systems will help in developing more accurate ten year forecasts. Real time status will help distribution operators when formulating switching plans, ensuring that load on the distribution system can be reliably served when a DER system is switched between distribution circuits. Further data points may prove useful to utilities, and this topic is being explored in detail by the Smart Inverter Working Group.

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Section 4 – Tariffs and Contracts

The DRPs may propose or identify standard tariffs, contracts, or other mechanisms for the deployment of cost-effective distributed resources that satisfy distribution planning objectives. For the purposes of these DRPs, discussion of new or modified tariffs and contracts should be limited to their applicability in demonstration projects. To implement this guidance, the utilities shall include the following in their DRP filings:

4.a Outline Existing Tariffs that Govern/Incent DERs (e.g., NEM, PEV-TOU, Rule 21)

Net Energy Metering: For customers who install small (1MW or less) solar, wind, biogas, and fuel cell generation facilities to serve all or a portion of onsite electricity needs. NEM allows a customer-generator to receive a financial credit for power generated by their onsite system and fed back to the utility. The credit for generation valued at the full retail energy rate results in differing benefits depending upon the rate structure in the otherwise applicable tariff. The existing tariffs include the following:

- NEM
- VNM-A (Virtual Net Metering for Multi-Family Affordable Housing)
- NEM-V (Virtual Net Metering for Multi-Tenant and Meter Properties)
- NEM-FC (Net Energy Metering for Fuel Cell Customer Generators)
  - Sunset for NEM, NEM-V, VNM-A: These schedules shall be available to eligible customer-generators, upon request, on a first come, first served basis until the earlier of July 1, 2017 or when SDG&E reaches its NEM program limit. Pursuant to Assembly Bill 327, PU Code Section 2827(c)(4)(B)(i), SDG&E will reach its program limit when the combined total peak demand of all electricity used by eligible customer-generators in SDG&E's service area, furnishing net energy metering to eligible customer-generators, receiving service under schedules NEM, NEM-V and VNM-A, exceeds 5% of SDG&E's aggregate customer peak demand.
  - Sunset for NEM-FC: Pursuant to PU Code Section 2827.10, this schedule is available on a first come, first served basis for the operating life of the eligible fuel cell electrical generating facility. It will be closed to new customers once the utility reaches a level equal to its proportionate share of a statewide limitation of

500MW as calculated by a ratio of the utility's peak demand compared to the total statewide peak demand. This ratio is calculated to be 37MW for the utility.

Feed-in Tariffs (FiT): FiT is a wholesale renewable energy procurement program through which small renewable generators (sized up to 3 MW, provided that they are strategically located) execute a standard offer contract to export renewable energy to one of California's IOUs. These tariffs are not available for facilities that have participated in the CSI, SGIP RPS, or other ratepayer funded generation incentive program, including NEM tariffs. The existing tariffs include the following:

- CRE (Customer Renewable Energy)
- WATER (Water Agency Tariff for Eligible Renewables)
- ReMAT (Renewable Market Adjusting Tariff)
    - Sunset for CRE & WATER: Closed to new customers. Service under these schedules were on a first come, first served basis and closed to new customers once the Advice Letter to implement ReMAT was approved on July 24, 2013.
    - Sunset for Re-MAT: The maximum combined contract capacities of participating facilities under SDG&E's Re-MAT, Water Agency Tariff for Eligible Renewables (WATER), and Customer Renewable Energy (CRE) schedules is 48.8 MW (Program Cap), which represents SDG&E's allocated share of the total statewide program cap of 750 MW, as provided for in PUC Section 399.20 and CPUC D.12-05-035.
- Combined Heat and Power (CHP): For CHP systems that are small (less than 20 MW), new (in operation after January 1, 2008), and highly efficient (operating above a 62% total efficiency); California IOUs must procure a minimum of 3,000 MW of CHP for the entire QF/CHP Program and reduce GHG emissions consistent with the ARB scoping plan.

Time-of-Use Rates: Instead of a single flat rate for energy use, time-of-use rate plans are intended to provide price signals that are higher when costs of meeting electricity demand are higher. The existing tariffs include the following:

- DR-SES (Residential Domestic Time-of-Use for Households with a Solar Energy System)
- DG-R (Residential Distributed Generation Renewable – Time Metered)
- PEV-TOU (Residential Domestic Time-of-Use for Electric Vehicle Charging) – PEV only
- PEV-TOU-2 (Domestic Time-of-Use for Households with Electric Vehicles) – Home and PEV

PEV: Vehicle-Grid Integration (VGI) has the potential to harness the charging flexibility of electric vehicles (e.g., rate of charge by location, time of day, and duration). Through rate design with enabling charging equipment and related operating systems, the charging of electric vehicles helps to optimize the use of grid assets, thereby helping to offset investments in grid capacity to the benefit of all ratepayers. As the ownership level of PEV continues to increase, VGI will become a valuable means for the efficient integration of PEV charging on the grid. The existing tariffs include the following:

- *PEV-SP (Plug-In Electric Vehicle Sub-metering Pilot (Phase 1; through 8/31/16)*
  - Sunset for PEV-SP: On a first come, first served basis, a maximum of 500 sub-meters may be enrolled in each phase of the pilot. Of the 500 sub-meters, a limit of 100 sub-meters may be related to NEM accounts. The metered PEV charging is subtracted from the primary meter and billed on the PEV-TOU rate.
- *Rules 15 and 16 (Distribution Line and Service Extensions):* These rules include the provisions for extensions of electric Distribution Lines (less than 69 kV) and service extensions applicable to all utility customers. Both Rules contain standard contracts, which are required (and approved and on file with the CPUC). They both also have exceptional cases sections to allow for special conditions contracts when the application of these rules appears impractical or unjust to either party or ratepayers.

Others: Any schedule involving electric generation, including:

- *RES-BCT:* Local government renewable energy self-generation bill credit transfer
  - *Sunset for RES-BCT:* Available to eligible customers, upon request, on a first come, first served basis, until the combined rated generating capacity of eligible renewable generating facilities within SDG&E's service territory reaches SDG&E's

share of 8.1% of the statewide 250 MW limitation, based on the ratio of SDG&E's peak demand to the total peak demand of all electrical corporations within California.

- *Schedule S (Standby) and S-I (Standby – Interruptible):* Service to customers with an electric generator that is operated in parallel with the utility. Currently, solar customers taking service under NEM tariffs and solar customers that are 1 MW or less to serve load and who do not sell power are exempt from standby charges.
- *Gas Schedule EG:* Natural gas interstate transportation service for electric generation customers
- *CGDL-CRS:* Customer Generation Departing Load Cost Responsibility Surcharge
- *E-DEPART:* Departing Load – Non-bypassable charges, when all or part of the customer's electrical requirements are supplied by a generation source, other than the utility, located on the customer's premises. Not applicable to customers who have chosen to sell power to the utility on a simultaneous purchase/sale basis.

4.b Recommendations for How Locational Values Could Be Integrated Into the Above Existing Tariffs for DERs

The DRP is looking to take the pricing of utility services to the next level to provide price incentives that will allow the potential benefits of DERs to materialize. SDG&E strongly supports this direction but believes that it is important to take a thoughtful approach when determining the best mechanism. The concern is that if stakeholders rush into this process prematurely and insufficiently informed, the result may create distorted market incentives and result in unintended cost shifts. A key challenge is how best to implement prices and/or incentives to translate potential locational benefits to DERs.

The question of whether the value of locational pricing is more appropriately translated though existing tariffs or contracts is best addressed after the Commission has made a determination of what values should be incorporated in defining locational benefits. SDG&E has included a discussion regarding the issues of locational benefits. In addition, SDG&E provides a discussion below about some issues related to the difference between tariffs and contracts for consideration in future discussion about locational benefits.

When considering how to best provide customers with locational benefits and price signals, the discussion should not be limited to tariffs but should consider both tariffs and contracts. According to General Order 96-B (General Rule 3.15), tariffs refer collectively to the sheets that a utility must file, maintain, and publish as directed by the Commission and that set forth the terms and conditions of the utility's services to its customers. Tariffs may also refer to the individual rates, tolls, rentals, charges, classifications, special conditions, and rules of a utility. A standard contract is a legally binding agreement between two parties with fixed terms and conditions, offered almost always on a take it or leave it basis.

Generally, a tariff has broad customer applicability, is applied consistently to all customers, and has the ability to reflect changes or updates in a single document that is applicable to all customers, both at the time of implementation and for future customers. This provides for a high level of transparency and ensures all customers receive like treatment at any given time, while a contract has the flexibility to be more customer-specific and can result in differences in timing.

When considering the use of tariffs as the vehicle to provide customers with locational price signals, this generally implies providing customers with prices that differ by location. This raises potential concerns regarding the implications this kind of rate design may have on customers. For instance, consider two identical stores located on two different circuits, Circuit A and Circuit B. Circuit A is more constrained than Circuit B, resulting in higher prices at Circuit A than at Circuit B. This difference in utility pricing could result in a competitive advantage between these two stores. Alternatively, consider two identical shopping centers on the same two circuits. The difference in utility pricing could result in a business choosing to locate at the Circuit B location rather than the Circuit A location. Over time, due to the increase in load on Circuit B because of ability to offer the lower prices, which result in lower electricity bills, Circuit B becomes the relatively higher priced circuit and results in a change in competitive advantage between the two locations. Such shifts could also occur in the event DER investments were to occur at a constrained location. This has the potential to create uncertainty for SDG&E customers.

Given these implications, direct incentives through contracts may be a better mechanism for providing incentives related to benefits at a specific location in a given moment in time.

However, if the intent is to provide a price signal to modify behavior in a way that is responsive to the needs of the local distribution system, SDG&E has pending before the Commission a pilot rate design as part of its VGI pilot program application (Application (A.) 14-04-014) that provides pricing levels to encourage PEV charging during hours that are compatible with other demands on the grid. The proposed VGI rate will provide PEV owning customers, on a day-ahead basis, an hourly rate that offers a dynamic price signal related to both system and circuit peak conditions, as well as the changes in energy prices throughout the day. It is expected that in addition to giving PEV customers the opportunity to reduce their transportation fueling costs, the VGI rate will also promote the efficient integration of PEV charging with the grid, decreasing the need for investing in additional system capacity and power plants, to the benefit of all ratepayers. This structure can provide a framework for consideration for greater integration incentives through retail rates.

4.c Recommendations for New Services, Tariff Structures or Incentives for DER That Could Be Implemented as Part of the Above Referenced Demonstration Programs

In looking at future services, tariff structures or incentives for DERs that can help to enable the goals set forth in the DRP, an area for future study would be the right incentive/pricing structure for battery storage on the customer side of the meter, in particular for residential customers, to encourage greater integration. One model would be a direct incentive to the customer to allow the utility to control the timing of charging and discharging of the battery. Another option would be to provide price signals that create the incentive to charge/discharge at specific times, along the lines of VGI. The question would be what rate differentials would be needed to solicit the same or comparable behavior that could be achieved under a more monitor-and-control structure.

Section 5 – Safety

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 or modify existing standards in order to accommodate high levels of DER. For the purposes of these DRPs, the utilities shall include the following in their filings.

5.a Catalog Potential Reliability and Safety Standards that DERs Must Meet and Process to Facilitate Compliance

SDG&E is committed to providing a safe and reliable electric service. To ensure the safety of the public and its employees, SDG&E has over a century of electric system knowledge that it has codified into design and construction standards. DER installations must meet, at a minimum, the existing level of reliability and safety standards required and covered by the SDG&E overhead and underground electric construction standards manuals, electric standard practices, service planning manuals, and design manuals. Standards are available through the SDG&E internal website. Customer information is available through the SDG&E external site specific to governing rules and requirements in addition to SDG&E related interconnection (handbook) requirements. These standards are based on G.O.95, G.O.128, Cal-OSHA requirements, and the requirements of other governing agencies. The development and implementation of these standards is intended to ensure the high degree of system reliability and safety. New standards are regularly developed and existing standards are revised to facilitate the installation and safe operation of new distribution and communication technologies on the SDG&E electric distribution system and inform the operating practices for existing equipment. The proliferation of additional DER installations throughout the distribution networks only further increases requirements to ensure that safety and reliability are not compromised and that all associated equipment can be operated in a safe and coordinated manner.

The list in appendix II is extracted from SDG&E's current standards and provides examples of requirements that must be met to ensure the safe and reliable operation of distributed generation devices on SDG&E's overhead and underground distribution grid. These standards are required based on CPUC G.O.s 95 and 128 in addition to Cal-OSHA. The standards and requirements highlighted in this section provide required oversight to the construction, operation, maintenance, and reliability of these facilities by qualified personnel. Consideration must be given to ensure further network additions meet these requirements, which also include trained first-responder availability so network reliability and safety is not compromised.

For an example of SDG&E's Safety and Design Standards, please see Appendix II.

It is SDG&E's policy to implement safety practices that comply with local, state, and federal electric safety codes to ensure system reliability and a safe environment for utility electrical workers, community emergency responders, and the public. SDG&E offers informational resources to increase customer awareness of electrical safety and electrical systems to comply with governing codes and safety requirements. The expansion of DERs and at customer sites will require improved power monitoring and control technologies, communication devices, and electric circuit protection and relay coordination. Additional advanced equipment and resources are needed on both utility and DER assets to integrate advanced SCADA technologies into the existing power grid. SCADA-related communication upgrades required to accommodate additional DER equipment on distribution circuits should also be accounted for and compatibility ensured. In-depth performance monitoring and control are needed to ensure system reliability and safety improvements do not suffer as a result of expanded DER adoption.

5.b Describe How DERs and Grid Modernization Could Support Higher Levels of System Reliability and Safety

Electric reliability is presently measured with use of standardized industry indices and reported to the CPUC as required per reliability reporting requirements. SDG&E utilizes such standard power industry service indicators to assess its electric distribution system reliability performance and to identify appropriate remediation actions to address reliability issues. These indicators consist of outage-based calculations that are based on outage event factors, as prescribed by the Institute of Electrical and Electronic Engineering (IEEE). Indices provide important information on the relative extent of comparative events to assess system reliability and customer service based on both the frequency and duration of momentary and sustained service interruptions. Momentary interruptions are defined as unplanned events that result in a customer receiving no electrical service (e.g., zero voltage) for a period less than five minutes. As a greater number of DERs are installed and operated on the SDG&E power grid, detailed analysis of circuit and equipment performance and power flow would be needed to optimize the operational interaction of such new technologies on an advanced utility grid before, during, and after the outage event. This increase in DERs will also have a significant impact on planned and forced outages from the standpoint that many additional operational steps will be required to ensure public and employee safety and system reliability. The results of this analysis may indicate the need and location for installing additional sectionalizing and control equipment.

SAIDI is one of the most common measurements of system performance for sustained service interruption. SAIDI measures the total outage duration for the average customer during a given period. A detailed power flow analysis in response to an outage would be needed to determine whether reduced outage time is attributed to an advanced SCADA utility grid or the response of DERs interconnecting to and operating within the distribution network. SDG&E has an established plan to identify and replace applicable aging equipment with advanced SCADA-based equipment that is compatible with SDG&E's wireless and fiber-optic communication network. This plan, which expands the automatic switching, system protection, and advanced Smart Grid operating techniques available to SDG&E's distribution operators, may need to be expanded to include the installation of additional advanced SCADA-based equipment as the level of DER penetration increases.

As SDG&E installs greater numbers of advanced SCADA and communication devices, its operational database and ability to improve reliability is enhanced. DERs would also be expected to operate with compatible controls, communication, and protection devices. Efficient deployment of new DER devices within a utility network of advanced SCADA technologies offers opportunities for synchronization to maximize customer benefits and system performance.

The communication and coordination of increasing SCADA devices also requires tight regulatory controls over information and physical security to ensure continued system safety and reliability and avert potential new threats that are likely to be introduced. Increased staffing of trained personnel will also impact groups such as first responders, system operators, field maintenance employees, and security-related staff for increasing policy and monitoring requirements.

An example of grid modernization that supports a higher level of system reliability is SDG&E's field operations of its Borrego Springs microgrid project. This project integrates the use of 26 MW of renewable energy from the nearby Borrego Solar Facility with an advanced SCADA utility microgrid that consists of large battery storage, local power generation, automated switching, and multiple residential rooftop solar systems. The project is partially funded with grants from the CEC and the DOE. A distribution operating procedure is needed for safe and reliable control and operation of distributed energy resources. In general, a separate operating procedure is needed for each circuit that includes all equipment and operating factors.

Field performance demonstrated the ability of an advanced integrated microgrid to sustain the delivery of renewable electric power to 2,800 metered customers in the desert community of Borrego Springs. The utility microgrid, under the control of SDG&E's grid operations personnel, operated in parallel with the utility source and was then transferred into "islanding" mode without any loss of service. The large battery storage system minimized power fluctuations and allowed for a smooth integration of renewable resources into the microgrid. The integration of large and small distributed resources, battery storage, advanced SCADA controls, and wireless/fiber-optic communication facilities enabled a successful transition through operating modes while providing power to critical load centers such as community cool zones, gas stations, and grocery stores.

The integration of DERs with an advanced utility grid offers opportunities to improve system reliability and public safety. Consistent equipment standards, compatible specifications, periodic inspection, and performance verification would facilitate the integration of diverse devices on the advanced utility power grid. Improved power flow analysis, equipment control enhancements, and communication network advances would enhance the integration of new technologies and advanced power grid devices and improve customer service and reliability.

Additional system protection, controls, standards, and training would be needed to achieve identified and desired benefits.

SDG&E requires an approved distribution operating plan for certain circuits where DER devices are installed. These plans provide detailed operating information of the circuit to ensure reliable service and safe operating conditions. The plan sets forth operating procedures between the circuit and distribution grid, jurisdictional boundaries, equipment connectivity, ratings and specifications, communication devices and specifications, operating modes, scheduling procedures, contact information, switching procedures, site map, GIS circuit map, and descriptions of key equipment and equipment location. This plan is essential to community safety and safe operations during system emergencies.

The plan is based on SDG&E resource information, electric safety requirements, and experience and working relationships with local building officials, inspectors, government agencies, and professional associations. Additional requirements and equipment may be needed to minimize risk of DERs causing electrical back-feed on circuits that are de-energized or in "islanding" mode. Requirements may vary depending on technology type. Periodic routine standardized equipment inspection programs may be needed to ensure safe operations and identify any required maintenance. Customer privacy would be safeguarded and any issues addressed.

5.c Describe Major Considerations Involving DER Equipment on Distribution Grid that Could be Mitigated

Major considerations of DER are safety and reliability/stability issues due to increased two-way complex power flow, the proximity of low voltage, high voltage, and AC and DC sources. The increased use and deployment of DER on the SDG&E electric distribution system would require a significant expansion of current practices to ensure public and worker safety and system reliability. SDG&E presently utilizes equipment and operational safety standards to provide safe conditions in environments where complex multi-directional power flow and various voltage types exist.

Many of the same safety standards that are presently deployed on standard electrical equipment to safeguard community safety could be expanded to meet the demands of increased DER deployment on the electric distribution grid. Additional requirements include expanded electric regional system planning, project management, environmental project management, project data warehouse, expanded outage management and project scheduling functions, the submittal of proposed DER project site plans, approvals and specifications for review, pre-installation verification of proposed technologies, pre-construction verification of proposed communication operating devices, and long term maintenance specifications and plans.

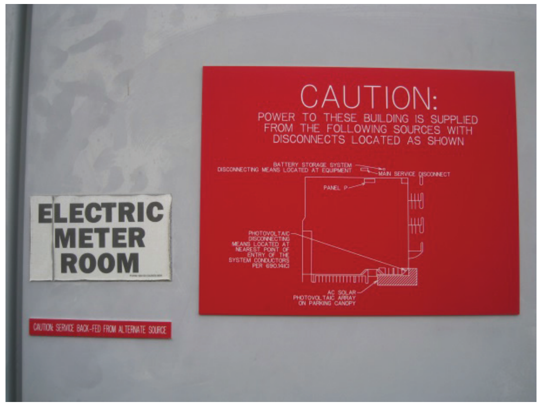
Rapidly increasing DER-related additions to distribution circuits will also have a significant impact on overhead standards and associated items, such as pole loading calculations and avian protection requirements. This could be a tremendous effort to track and monitor compliance to ensure the overhead facility design standards, safety, and environmental regulations are not violated. Underground facility impacts should also be considered with regards to impact on existing facilities and potential impact on additional structures being added to currently populated right-of-way and easement areas. Additionally, special protection schemes will have to be developed or modified to coordinate and/or mitigate system issues created from the additional resources impacting those distribution circuits.

Consideration is also critical to necessary additional expenses/accounting required to mitigate the impact of DER. One example would be that SCADA devices currently do not monitor the direction of current flow. SDG&E may also need sensors with more accuracy, as this functionality will become a higher priority as DER becomes more ubiquitous. Doing so, however, will require large investments to upgrade or replace existing monitoring equipment, switches, and sensors. Other examples would include the likely need for widespread utility owned energy storage and other devices to mitigate the impacts of DER and new communication infrastructure (may be SCADA expansion or a separate system) to retrieve data from the DER or other installed equipment.

Another consideration is the increase in personnel that will be required to monitor and act on the DER and/or its impact on the transmission and distribution systems. Staffing requirements for these positions include, but are not limited to, utility first responders and and non-utility first repsonders, such and firefighters and law enforcement.

Increased staffing of trained personnel will also impact groups such as system operators, field maintenance employees, and security-related staff by increasing policy and monitoring requirements.

Examples of typical safety practices such as safety warning signs, site placards showing equipment location, locked compartments, and equipment identification tags are shown below. Emergency contact information, manual equipment bypass and shutoff devices, and structural protective devices also may be needed to meet the needs of large scale DER deployment. For DER installations, it may not be evident that an electrical hazard is present, or what measures are necessary to make the situation safe. In most cases, first responders are not trained or equipped to deal with nascent DER technologies. For traditional electrical infrastructure, firefighters and law enforcement depend on the utility to isolate equipment and make a situation safe to work in. When responding to emergencies, it is imperative that first responders are given the proper information to make a decision whether to proceed or call trained electrical workers to address any safety hazards. Even with proper identification, the presence of a DER installation may delay the response of firefighting and law enforcement personnel due to unfamiliarity with the DER technology. If first responders believe that DERs may present a hazard, they may not enter a premise until utility or other qualified personnel arrive, putting victims of an emergency in further danger. Safety signage, placards, and equipment identification must be concise and absolutely clear in how to proceed safely. Additionally, an aggressive outreach and training program will be required to ensure that first responders stay up-to-date and comfortable with changes in DER technology.



5.d Describe Education and Outreach to Inform Local Permitting Authorities on Current Best Practice Safety Procedures for DER Installation

The SDG&E community outreach programs presently work with local Plan-Check and code enforcement departments, law enforcement agencies, fire departments, and other emergency first responders and life support agencies to improve electric safety awareness, communication, and operational coordination with SDG&E. SDG&E's current community awareness programs would be significantly increased to provide ongoing education and outreach to city planning and permit departments to keep them informed on DER deployment and SDG&E's electrical safety requirements. DER technologies would need to be included in these programs to promote safety and awareness of new technologies. DER additions would also require increased first responder educational awareness of additional electric hazards, which would need to be clearly spelled out through additional training and required signage. Ongoing improvements and awareness of best practices would continuously monitor changes in technology to stay abreast of change.

Additional community outreach to residential communities such as home owner associations, multi-family housing complexes, low-income housing areas, trailer parks, and individual home owners via town hall-type meetings would also be necessary to help increase community awareness of DER systems. Educational awareness of DER would include topics such as basic information on what DERs are, what DERs can and can't do, DER do's and don'ts, and what to do in an emergency.

Additional customer information to increase awareness of DERs in the community would also be necessary. Such information could be made available online or through public forums and could include DER simulations, frequently asked questions, interactive demonstrations, and other educational and awareness techniques. The following are examples of permitting authorities and safety practices followed with regards to existing DER-type installations that will need to be enforced and enhanced to meet the associated increasing scope and impacts.

- SDG&E's filed tariffs include but are not limited to:
  - Rule 21
    - Generation interconnection
    - Point of interconnection
  - Rule 16
    - Meter and service on property served
    - Generation systems spanning multiple properties (not permissible)
- Public Resources Code 25741
  - Renewable electrical generation facility
- Federal Energy Regulatory Commission (FERC)
- Line of demarcation (utility side to premises wiring)
- Public Utility Code, Section 8
- California State General Orders (G.O.)
- SDG&E's standards:
  - Underground (UG)
  - Overhead (OH)
  - Service (SS&G)
  - Design
  - Construction
  - Systems Protection and Coordination Engineering (SPACE)
- National Electric Code (NEC)
- Authority Having Jurisdictions (AHJ)

Section 6 –Barriers to Deployment

This section identifies barriers that must be overcome to successfully optimize the role of DERs in helping the state achieve its GHG reduction mandates.

Per the Guidance direction to the utilities to identify barriers to deployment of DERs, SDG&E has identified several barriers which may slow the adoption of DERs, and ultimately, the realization of state policy goals. While many of the barriers described below are cross-cutting in nature and affect multiple sectors, the barriers have been categorized to improve readability and accessibility of the information provided. The five categories include Regulatory, Third-Party, Cost, Technology, and Utility Operations. While not specifically categorized, the need to maintain safety concerns and protocols is both explicitly and implicitly embedded within many of these barriers.

Each specific barrier described under the respective category header contains an overview of the barrier, as well as a list of concerns and thoughts for future consideration and discussion.

Regulatory

The desired increased level of DER penetration cannot be achieved without commensurate changes taking place within the regulatory process. Without these changes, identifying locations to install and operate distributed energy resources cannot truly be optimized in a manner that balances the needs of all stakeholders.

Rates, Incentives, and Cost of Service-Based Rates

Provisions within existing tariffs and the current rate design framework create subsidies and programs whereby some customers are burdened with costs incurred for but not paid by other customers.

Concerns

- The interconnection and operation of DER might expand the unfair transfer of costs among customers
- Tariffs that incent the correct amount of DER to provide the required services in the identified optimal locations are mandatory

Considerations

- Rate reform is required to enable the distribution system to be accessible and used in a fair and equitable manner by both service providers and end-use customers
- Cross-subsidization should be minimized and avoided whenever practical
- Customers should pay for the services they receive and be compensated for the services they provide

Communications

The DRP process will require a much more holistic environment where planning information needs to be shared between the utility and DER developers. The exchange of information is expected to be bi-directional while maintaining the required levels of security and privacy.

Common Model of Information and Processes

SDG&E's distribution planning processes have historically been conducted internally utilizing the utility's standards, processes, and information. The expanded evaluation of DERs within the utility's distribution planning process will necessitate the need for expanded communications between the utility and DER developers.

Concerns

- Communication processes and protocols need to be created to accommodate the requirements of all stakeholders
- Developing the communication platforms will take time and funding
- The utility's planning cycle may differ from the DER developer's planning cycle, potentially leading to lost opportunities for all parties

Considerations

- Evaluate adapting existing processes to incorporate communications with DER developers
- The utility and DER developer should identify and communicate their minimum and maximum needs to aid in reaching a balanced solution
- Stakeholders should pursue establishing consistent timelines and deadlines regarding energy planning and procurement cycles

- Stakeholders should share commonalities in processes and approaches when practical

Grid Insight

Implementing the DRP process will require expending funds to achieve the goal of optimal siting of DER across SDG&E's service territory. Planning an efficient and realistic distribution system necessitates that the benefits associated with a DER include the value of the services provided by the DER, as well as the costs incurred to receive those services.

Voltage from AMI Meters

Expanding the data-gathering and transmitting capabilities of the existing AMI infrastructure will provide circuit voltage profiles in a detailed manner that support the ICA and LNBM analyses.

Concern

- The AMI meters installed by SDG&E have the ability to measure voltage and alarms for exceeding voltage thresholds. However, this capability was not implemented in the initial AMI deployment.
- Utility use of AMI meters to provide voltage monitoring and control has been met with legal challenges regarding patent infringement
- Retrieving voltage data from AMI meters will require a significant investment in software infrastructure

Considerations

- AMI meters should be configured to provide voltage and other data as part of the optimal location analysis

Data Availability

The DRP requires that significant levels of system and customer usage information are available to support the development of the plans on an ongoing basis. The access to this information is needed and desired by numerous stakeholders.

Concerns

- Publicly available data should be made available in a timely fashion to meet the needs of all DRP stakeholders

- Customer privacy and security issues are not standardized across stakeholders, nor are data sources and definitions
- Recorded data is often subjected to varying levels of quality control
- Some proprietary and/or confidential data is not available to the public

Considerations

- Policies, procedures, and protocols for sharing data among stakeholders need to be developed
- Data formats should be standardized to simplify access and usage
- Data should be aggregated to support the needs of planners but not violate privacy
- Data users must be accountable for security and privacy protection standards
- Publicly available data should be published and refreshed on a regular basis

Increased Operational Support Systems

As an increasing number of DERs connect to the distribution system, new technologies will be required to ensure they are operated efficiently and to manage the stability of the grid. The new monitoring and control systems will operate in real-time and may require transmittal of signals more frequently than those provided by the CAISO to manage the bulk power system.

Concerns

- Additional management of the distribution system will be required as the impact of additional DERs on the flow and quality of power increases
- Additional resources (staffing, software, and hardware) will be required to effectively manage the increased number of DERs

Considerations

- Issues and concerns caused by a DER should be mitigated by that DER
- New systems will be required to ensure that DER operates effectively and in concert with the distribution system

Utility Operations

The results of the DRP process will affect SDG&E operations across a variety of departments. While the DRP is specifically targeting the planning process, its impacts will go beyond planning and affect other areas as well.

Distribution System Operations

SDG&E's Distribution Operations personnel are responsible for managing the safe, reliable, and efficient operation of our distribution system. Incorporating significant additional levels of DERs into the distribution system would expand existing and create new roles and responsibilities for both field and office Operations personnel.

Concerns

- The roles and responsibilities of operating and managing DERs will need to evolve as the services provided by DERs evolve
- The planning process will need to expand to account for the operation and services associated with various DER technology types

Considerations

- DER should not negatively impact the safe, efficient, and reliable operation of the distribution system
- A Distributed Energy Resource Management System (DERMS) is a requirement for future utility operations

Interactions between the Transmission and Distribution System

Electrical energy has historically flowed from the transmission system to the distribution system. As the penetration of DERs increases, the frequency and magnitude of reverse power flow into the transmission system from DERs will also increase. Additionally, qualifying DERs can currently be scheduled to serve a transmission market function without regard for distribution system considerations.

Concerns

- The operations of DERs and other equipment located on the distribution system can affect the operations of equipment located on the transmission system, and vice versa
- Some DER-provided services may become independent of the transmission or distribution system interconnection
- DERs interconnected at the distribution level and providing system and transmission-level services can negatively impact the distribution system

Considerations

- Impacts on the distribution system need to be adequately considered for all DERs, regardless of the services the DER provides
- Negative impacts caused by interconnecting a DER should be reflected in the benefit analysis for that DER and mitigated as required
- DERs should be operated primarily to provide the contracted services

Technology

The successful execution of the DRP process will depend on the development, implementation, and ongoing support of existing and new technology solutions to provide timely and accurate information to utilities, customers, and third-party DER developers. These solutions, largely within the realm of the information technology domain, must not only meet the new emerging demands of the initial DRP vision but also be able to adapt and grow to meet future needs. Maximizing the value from the numerous information systems is especially challenging because many of the solutions are only now being developed and will require time to mature. Communications among various systems may also be a challenge because standards for sharing and integration of data are not agreed upon nor are the systems designed to reflect a common industry vision.

Upgrade of Planning Tools

Today's generation of distribution planning tools were established to provide solutions for traditional uni-directional power flows and simple characterizations of load shapes. The planning environment envisioned by the DRP requires a new generation of tools to support bi-directional energy flows and a more probabilistic view of both load and supply.

Concerns

- Software tool are being upgraded but are not yet available to meet the DRP planning needs
- Integration of new software is time-consuming, costly, and is often ignored
- Software vendors often present unrealistic schedules and deliverables of their tools and trivialize the challenges encountered when integrating platforms into existing or new modeling and operating environments

Considerations

- Utilities need sufficient time and resources to incorporate the necessary tools within the evolving distribution planning processes

Section 7 – DRP Coordination with Utility General Rate Cases

One of the most critical components of the DRP process will be the interfacing of the DRP process with the utility's future General Rate Cases (GRC). This section will describe the specific actions or investments SDG&E may include in its next GRCs as a result of the DRP process.

As stated previously, SDG&E believes that the ideal way to achieve the policy goals that the commission envisions for this DRP is to incorporate the DRP activities into its yearly planning process. During this annual process, SDG&E identifies a system deficiency or system need, which is usually related to a capacity shortfall, and proposes solutions to resolve that need. The yearly planning cycle closely analyzes the next five years, and reviews years five through 10 to ensure a solution is in place before a need arises. This means, however, that this process is a living one, and each year the previous forecasts are validated, needs are re-verified and the proposed solutions are re-analyzed to make sure the solution is still necessary. The solutions that are identified in the annual DPP are then authorized through the appropriate GRC. As clearly recognized by the CPUC, seamless coordination between the DRP, the existing annual DPP, and the GRC is critical to a realistic path forward. To this end, SDG&E has identified three basic types of distribution system investments: cost-effective investments to accommodate higher DER penetration, traditional infrastructure investments that cannot be displaced by DERs, and traditional investments that can be deferred or replaced by appropriately specified DERs. A few examples of types of investments that are authorized through the GRC that cannot be replaced by DER are equipment replacements, maintenance, monitoring equipment, billing, metering, and customer service. As part of its yearly plan, SDG&E will identify the traditional investments that can be potentially deferred or replaced by appropriate DERs and will include those types of investments in future GRCs. The first two categories of investment identified above will follow the normal GRC process.

In addition, SDG&E has identified two ways in which it will incur costs associated with implementing the DRP that will need to be resolved in the next GRC:

a. Costs associated with developing, implementing, operating, and analyzing the demonstrations projects.

b. Costs associated with installing cost-effective monitoring and control equipment, as well as upgrading certain aspects of the distribution system to enable the integration of DERs.

To facilitate cost recovery for these DRP related costs, SDG&E recommends the establishment of Memorandum Accounts (MAs) to track costs and subsequently present for review and recovery to the Commission at a later time. SDG&E plans to include these DRP related costs as part of its revenue requirement request in the next GRC (estimated to be filed in 2017) and if approved, will no longer require MAs to record these costs from that implementation point forward.

Memorandum Accounts

SDG&E proposes to establish two MAs as a means to track expenses associated with designing, procuring, installing, operating and maintaining the demonstration projects and potential new investments in infrastructure and software that are necessary to create an electrical distribution grid that can fully incorporate DERs. The first MA will track incremental costs associated with demonstration projects proposed and approved in this Plan; the second MA will track incremental costs associated with system infrastructure upgrade projects yet to be determined.

The respective MAs will record the incremental operating and maintenance (O&M) costs incurred to implement the respective projects as well as the incremental capital-related costs (depreciation, tax and return) incurred when placing the respective projects into service.

ADVICE FILING

Upon Commission approval of this Application, SDG&E will file an Advice Letter to establish the MAs effective with the DRP approval date.

Potential DER-related investments

As penetration of DER increases, the complexity of planning, designing, and operating the grid also increases. Intelligence gets pushed to the edge of the grid and creates new operating dynamics that need to be addressed in order to continue to provide reliable electric service to customers.

In order to fulfill the CPUC's goal of creating a future electric distribution infrastructure and planning procedures with respect to incorporating DER into the planning and operations of SDG&E's electric distribution system, SDG&E has identified a number of opportunities to update its capabilities. These projects and initiatives will address some of the barriers to the DRP identified in Section 6, mitigate some the issues related to DER integration and facilitate development of the capability to optimize DER siting.

Below are examples of investments in transmission and distribution infrastructure that SDG&E believes will accelerate the transition to the DER ready distribution grid. Some investments would be expansions of existing programs or projects, while others would be completely new initiatives. The investments identified below include monitor-and-control as well as traditional infrastructure investments where appropriate.

Monitor and Control: SCADA Expansion

SDG&E's reliability and safety program goals are to maintain and/or improve reliability and safety in response to the challenges associated with renewable generation and PEVs. The utility will accomplish this goal by improving measurement, control, protection, data recording, and management and optimization capabilities. Initially, SDG&E will focus on increasing the measurement and recording capabilities across its grid, providing the basis for an increased understanding of grid performance and the data to perform detailed analysis on past events. In the future this will enable SDG&E to implement control and protection schemes that will improve the ability of the utility and the CAISO to anticipate problems and respond to them automatically and manually. The data will also allow for programs that will stabilize and optimize the grid, also improving its resilience.

Expansion of SCADA to expand remote operability and automated operation of distribution SCADA capable switches enables more circuit automation, increases reliability, and increases visibility of DER. This deployment is critical to allow higher penetration of DER. This will also continue SDG&E's goal of providing faster isolation of faulted electric distribution circuits and branches, resulting in faster load restoration and isolation of system disturbances.

As the penetration of distributed renewables increases on the distribution system, this SCADA expansion will allow SDG&E to re-configure circuits. By automatically re-configuring circuit the amount of DER and load can be balanced to better accommodate areas of high DER penetration.

Higher penetration of DER technologies create voltage regulation issue that require SCADA control of all capacitors on SDG&E's distribution system and is distinct from the SCADA expansion for switches discussed below. Benefits of SCADA for capacitors include: better voltage and VAr control, reduced maintenance, and better system diagnostics. When coupled with energy storage, dynamic line ratings, and phasor measurements, new control schemes can be implemented which will mitigate the impact of PV system output fluctuations on system voltage.

SDG&E has been using SCADA controlled devices in various types of equipment for many years. SCADA controlled capacitor banks will provide local and remote control, failure prediction and detection, reduced operating cost, and should enhance distribution system performance through improved voltage and reactive power control. As certain elements of the Smart Grid evolve, including less predictable DER, the ability to dynamically adjust reactive power flow will become more critical. Presently, SDG&E discovers capacitor issues during the annual capacitor survey or through customer voltage problems. SCADA controlled capacitors will provide SDG&E the ability to be proactive in capacitor maintenance, instead of reactive. Furthermore, SCADA control will provide a faster and more economical way to update the software, adjust control settings, and regulate the voltage of the distribution system.

Traditional: Phase Identification

Typical of many utilities, today SDG&E does not have information on the phase relationships of facilities beyond three-phase devices. Therefore, a significant portion of SDG&E's distribution system will be unavailable for optimal siting of DER. Accurate identification of phasing is necessary for planning and distribution operations of the post-DER distribution system. This should enable improved worker safety, more accurate fusing, improved system planning, and reduced system losses.

Correct identification of the phases of an electrical system is a critical element of the operation and management of a distribution system. Phasing information affects real-time and planned operations of the system. Capturing and maintaining phasing information will maximize the functionality of the new distribution management system and smart meters by creating accurate models to analyze the operation and events within the distribution system. Identifying the phase to which each transformer is connected allows for a more accurate model, provides a clear decision for adding new single phase loads to a circuit, and allows better phase balancing to occur.

From a safety perspective, it is important to identify the phase of each conductor on a three-phase feeder as well as the individual phases on single-phase branches. Having all phases identified gives the distribution operator and the troubleshooter better information about which lines may present a hazard during an outage situation, which is especially important when there are many potential electrical sources on a circuit, such as in a high penetration DER area.

Traditional: Conversion of 4 kV Substations to 12 kV

Converting legacy 4 kV substations to 12 kV substations mitigates voltage issues and increases the DER carrying capacity of circuits allowing higher penetrations of DER while alleviating safety, operation, and maintenance issues. Half of SDG&E's 4 kV substations are over 50 years old. As a result, replacement parts are no longer available and qualified crews and electricians who are familiar with their design and operation are in short supply, which creates safety as well as maintenance issues. From a reliability standpoint, high failure rates and the lack of replacement parts causes more frequent and unnecessary extended outages. Lastly, the maintenance cost associated with 4 kV substations is unusually high and continues to increase.

To increase DER integration capacity in these areas, SDG&E would invest in conversion of 4 kV circuits to 12 kV circuits and removal of de-energized distribution facilities. SDG&E's reliability assessment team has identified the condition of 36 4 kV substations remaining in the system. Together, they serve 90 4 kV circuits, 58,000 customers, and 100MW of load. Twenty-two substations are 40 years or older. Certain equipment inside the substations such as transformers and breakers are obsolete, and replacement parts are no longer available. This investment would increase DER integration capacity, rectify safety issues associated with the operation of those substations, and improve reliability to the customers currently on 4 kV circuits.

Monitor and Control: Phasor Measurement Unit (PMU)

Implementation of PMUs on the electric distribution system allows for improved transient control, fault detection/isolation, and the ability of the system to accommodate higher penetration levels of DER. Installation of PMUs on the electric distribution system are expected to improve reliability by employing high speed, time synchronized measurement devices. These devices will be utilized in conjunction with energy storage devices to create a control system which can mitigate the impact of intermittent renewables. Phasor measurement technologies are a leading example of a new generation of advanced grid monitoring technologies that rely on high speed, time-synchronized, digital measurements.

Phasor measurement technologies will help mitigate the intermittency issues associated with distributed renewables by employing high-speed, time-synchronized measurement devices installed in substations and at key points on the distribution system. Using time stamped, digitized waveform measurements, SDG&E can analyze the output of PV systems, identify changes in PV output and enable the dispatch of energy storage devices to counteract the effects of the PV output fluctuation.

Phasor measurement technologies are also needed for understanding potential problems; therefore, they are a key component of a stable, self-healing grid. As the penetration of DERs increases, there will be increased voltage and phase-angle fluctuations at various points on the system. PMU data can equip system operators with better real-time information about actual operating margins so that they can better understand and manage the risk of operating closer to the operating limits.

To achieve this goal, SDG&E would install PMU equipment on circuits with a high penetration of PV. The equipment will be installed at points on the circuit where there is significant aggregation of PV systems. Additionally, a Phasor Data Collector (PDC) will be installed at each substation. An assessment tool will be developed to provide the ability to record, archive, analyze, and display phasor data. The interconnection and link of PMUs into a network will bring time-synchronized data to a central location to create a wide-area view of the grid, and enable a smooth transition to the DER-ready grid.

Monitor and Control: Data Analytics

As the number of endpoint devices and the data they produce increases, it is necessary to provide an infrastructure to house the vast amounts of new data generated and make it available for analysis on a near-real-time basis. New analytics tools will be deployed and specifically tailored to the business domains to uncover a greater understanding of this new data in areas such as: predictive asset maintenance, weather adjusted demand forecasting, situational analysis, system optimization, voltage regulation schemes, and customer usage analytics. Underlying foundational capabilities include ensuring that internal company data is consistently used and aligned with external Smart Grid industry standards.

As SDG&E broadens it collection of data, new storage systems are likely to be needed. As a result, the utility expects to field big data storage systems that can effectively ingest and process large volumes of potentially incommensurate data at substantially lower cost than existing database systems. The selection of this system or systems is tied directly to the needs of the DRP locational analysis incorporating load, existing infrastructure/assets, cost, policy, and environmental considerations.

Section 8 – DRP Coordination with Utility and CEC Load Forecasting

One of the expected outcomes of the DRP process is greater granularity and accuracy in Utility forecasting of DERs' impact on load. This improved and more granular load forecasting will most likely be able to provide input to the IEPR forecast. With this in mind, each utility should describe how the results of the DRP will influence their own internal load forecasting, the CEC's IEPR load forecast and by extension the Commission's LTPP and the CAISO's TPP.

SDG&E employs a top-down approach for developing an electricity demand forecast. County-wide economic and demographic drivers and regional weather data are used to produce a system level forecast of energy and peak demand. Attention is paid to DERs at the service territory level but, initially, not at or below the substation level. SDG&E's forecast is used internally and also provided to the CEC for consideration as they work to prepare a demand forecast for use in the biennial IEPR.

SDG&E also prepares a distribution substation-level electric load forecast in parallel with the system-level demand forecast, using the system-level demand forecast as a control. The system-level forecast is provided to system resource planners to aid in preparation of resource plans for the CPUC's LTPP proceeding and the CAISO's TPP. The substation-level electric load forecast is used by distribution system planners in their DPP to aid in the preparation of plans for enhancing and expanding the company's electric distribution system.

This new DRP process adds another level of detailed planning to both the system-level and substation-level load forecasting processes. Forecasters who prepare the system-level demand forecast will be required to pay even more attention to DER growth forecasts and to develop a way in which the DER impact can easily be segregated from the system-level forecast and provided to system resource planners (for inclusion in their LTPP and TPP planning activities) and to the distribution planners (to be de-aggregated across the substations and distribution circuits and used in their analyses).

Each of the above planning groups will review and analyze the impacts of the forecasted DER capacity within their respective forums (e.g., LTPP, TPP, DPP) and modify the forecasted values as necessary based upon information, criteria, or planning decisions made within their respective groups. The planners then provide the revised DER capacity values to the system-level forecasters for consideration in the following forecast cycle. For example, the distribution planners will modify the “input” DER forecast they receive based upon the results of the ICA and the LNBM.

Because of the cyclical exchange of DER forecast data on a system level vs. a transmission level vs. distribution level, SDG&E believes that the system-level DER growth scenario analyses should become a deliverable of the IEPR stakeholder initiative. The level of stakeholder participation and transparency available during the state-level IEPR process will help ensure that the initial DER growth scenarios developed for inclusion in the various forecasting and planning functions are consistent with regard to assumptions and estimates and are as detailed as possible.

Section 9 – Phasing of Next Steps

As discussed already, the DRPs are likely only to be effective if they serve as the starting point in an ongoing effort to integrate DERs into distribution planning, operations, and investment. With this in mind, the DRP process should be a living one, where the Commission, the utilities and stakeholders engage continuously to refine the activities and goals that are central to the DRPs themselves.

9.a Rolling Updates to DRPs

Unlike the utility's distribution planning cycle, which identifies specific projects required to address the future needs of the distribution grid, the DRP, as per the DRP Guidance, does not result in specific applications for DERs. Rather, two main deliverables of this initial DRP Filing are proposed analysis methodologies, which will provide results that will be used by DER developers (ICA) and the utility (LNBM) to facilitate DER integration. SDG&E proposes that incorporating these analysis methodologies into the annual DPP is the most effective approach. Much of what is included in this DRP filing is one-time in nature, and is not repeatable in updated filings. SDG&E proposes only to file updated DRPs if necessary on a biennial cycle. Items that might be updated include revisions to methodologies or consideration of emerging DER technologies that were not contemplated in this initial DRP.

As previously mentioned, SDG&E intends to identify three types of DER-related investments in its annual DPP: cost-effective investments to accommodate higher DER penetration, traditional infrastructure investments that cannot be displaced by DERs, and traditional investments that can be deferred or replaced by appropriately specified DERs.

SDG&E acknowledges the value of reviewing the status of DRP-related activities on an ongoing basis. However, because many of the deliverables included in this DRP filing can be considered "once and done," e.g., requesting approval for proposed analyses methodologies, identifying safety concerns, identifying barriers, identifying next steps, etc.; and because SDG&E believes that many of the actionable deliverables should be incorporated into existing processes; e.g., analyses incorporated into DPP and DER growth scenarios incorporated into IEPR, SDG&E proposes that a biennial DRP status report will be more effective than a biennial DRP Filing as a means of providing the status of DER development.

To achieve a more transparent stakeholder process, SDG&E believes that the establishment of a group akin to the Procurement Review Group (PRG) would be a valuable tool in the distribution planning process. This group could help inform the project selection process, and evaluate the merits of capacity driven DER investments. This group should be composed of the utilities and third party evaluators that do not have a financial interest in the results of the process.

9.b Phased Approach to DRP Filings

Phase 1 (2016 – 2017)

- Utilities will develop/acquire tools and models to evaluate the capacity of the distribution system to support DER under the current load forecasting scenarios.

SDG&E proposes the CPUC adopt this scope of Phase 1. As mentioned throughout this DRP, SDG&E is in the process of upgrading its tools and power flow models to a more dynamic platform where DER can be analyzed and incorporated into the distribution system.

- Deliverables of this phase include making GIS maps and power flow models of the entire distribution system to the substation [and feeder] level available to third parties in a standard format that is tool independent.
  - In order to support third party participation in determination of optimal locations, there should be the necessary policy support for third party access to maps and models.

SDG&E proposes the CPUC adopts this scope of Phase 1 with the following amendments. The Guidance describes data sharing by the utilities that the Commission envisions occurring during Phase 1 of DRP implementation, including power flow models, LNBM models, and values. SDG&E recommends that it will make available results from its ICA, in GIS maps and tabular form. These results will help to inform DER developers where there is existing capacity in interconnect DER. While SDG&E supports a more transparent planning process, the utility also believes that the release of comprehensive modeling data is inappropriate, and may lead to a confusing and antagonistic planning process. Even with power flow data and models, much of the results depend upon load forecast models and other engineering decisions that may be different among each of the stakeholders. Since SDG&E (and the other utilities) are charged with operating and maintaining a safe and reliable distribution system, it is more appropriate that the *need* determination for system upgrades remain with the utility. *How* that system need is met can be a function of market participation, including the application of a DER solution. A high level of DER penetration can be accomplished without inviting stakeholders that each have a vested interest to get into a tug of war over the need for individual projects. The more important focus for distribution planning should be providing safe, reliable, and cost-effective electric service to all ratepayers.

- Include planning and design of communications infrastructure to support interconnection of DER for monitoring and control.

SDG&E proposes the CPUC adopt this scope of Phase 1. To achieve reliable, cost-effective integration of DER, SDG&E believes that the tools and methodologies developed in Phase 1 will better inform and further improve the utilities' distribution planning process. As part of Phase 1, SDG&E will develop a plan to increase control and monitoring of its distribution circuits to increase DER integration. Today utilities deploy control and monitoring equipment to serve customer demand, and deal with the complex nature of a dynamic, load-serving distribution system. The distribution system will become even more complex as the penetration of DERs becomes such that two-way flows are commonplace. While increased DER penetration may drive the need for more and better control and monitoring equipment, the implementation of any new communications infrastructure needs to leverage existing systems where feasible, and provide prudent investment for the benefit of all ratepayers, not just DER projects.

SDG&E anticipates the need to install additional data gathering and operational equipment resulting from this DRP filing. Below is a listing of potential projects to support interconnection of DER. SDG&E will identify the appropriate type and location for this equipment and request approval from the CPUC to either open a memo account to track the associated costs, or in a future GRC.

Data Analytics: AMI as Sensors

SDG&E has deployed 1.4 million electric meters as part of its AMI system. The original deployment was focused on creating a wireless system that recorded hourly and 15-minute consumption data for residential and commercial/industrial customers respectively.

The electronic meters that SDG&E deployed have significant capabilities. In addition to billing, the utility is currently utilizing the AMI data for statistical sampling for operations support, transformer loading dashboards, transformer load profiles, and improved planning. As PV systems penetration level increases, SDG&E has begun to investigate the meter's voltage monitoring capabilities for use as a widespread, ubiquitous sensor for voltage. A small pilot program with 25,000 meters has begun and the voltage data is now being ported from the AMI collection engine into a data historian for analysis. As SDG&E begins to analyze the data, the results demonstrate the potential for a comprehensive program to improve planning and operations that are essential for future DRP optimized location goals.

Monitor and Control: DERMS

DERMS is an advanced software application that will optimize resource utilization in response to system operational events, and environmental and equipment conditions (collectively reliability events). DERMS is expected to have a forecast planning horizon of 24-48 hours for developing optimal resource allocation within its planning horizon. DERMS includes several different, but integrated, software components that incorporate advanced optimization algorithms to dispatch demand and supply side resources. For example, DERMS could dispatch or send signals to a Demand Response Management System (DRMS) to communicate with Home Area Network (HAN) devices initiating customer energy battery storage units or reducing plug-in EV charging and activating other controls of distributed demand and supply resources.

DERMS will be integrated with DRMS, OMS/DMS, weather systems, ISO systems, and third party aggregators and operators. Specifically, DERMS is expected to identify location specific demand and supply resources and transmit corresponding control signals to balance local and global system energy demand and supply. DERMS will also support utility operational controls via an interface into the OMS/DMS that will facilitate situational awareness of the grid as distributed dynamic resources become more prevalent. In addition, DERMS will communicate with company and third party systems and services (e.g., virtual load groups, demand response aggregators) to optimize both company operated and third-party operated resources and demand.

Phase 2a (2018 – 2019)

- Employ the methodologies and tools defined in Phase 1 to determine impacts on the distribution system at the substation or feeder level.
    - The models will provide information that can be used to identify both optimal locations and combinations of DERs that can provide services in those locations.

SDG&E proposes the CPUC adopt this scope of Phase 2a.

- As possible given funding constraints, utilities will continue to deploy sensors and communications infrastructure designed in Phase 1 to continue collecting and analyzing data.
    - Simulation of DER portfolios using models developed in Phase 1 should be completed using data acquired via monitoring and communications systems to determine impacts on the distribution system.

SDG&E proposes the CPUC adopt this scope of Phase 2a.

- The output of this phase will be "Distributed Energy Resource Development Zones" (could be Distribution Planning Areas) that can be associated with locational values.

- [Additional] DER portfolios would be defined within these zones using the process of value optimization.
  - The value optimization methodology will specify tools and processes to compare DERs as an alternative to traditional distribution infrastructure investments, including both operations and economic factors.

SDG&E proposes the CPUC adopts this scope of Phase 2a with the following amendments. The role of the utilities should be in increasing integration of DERs and identifying and increasing available capacity of the grid. Establishing DER development zones may result in oversaturation of DER in certain areas of the distribution system while leaving other areas underserved. Additionally, where an IOU may identify a development zone may not prove profitable to DER business models. Therefore, the utilities should identify where there is a capacity or voltage need on the distribution system, and the market response will determine the extent that DERs can solve the identified need. SDG&E believes that this market response could be in the form of solicitations and offers in response to specific needs identified on the distribution system. One potential option is the utility issuing solicitations as needed to resolve grid issues and then evaluating the offers received.

SDG&E could adapt its current Least-Cost Best-Fit (LCBF) methodology, as described in its LTPP, to use in the evaluation of DER resources. The LCBF includes quantitative and qualitative evaluations that apply consistent criteria to candidate products to determine which best match SDG&E's portfolio requirements. The net market value (NMV) components include any quantifiable benefit compared to market forward curves, price forecasts, and avoided costs. It includes any fixed and variable costs and benefits related to capacity, energy, ancillary services, renewable energy credits (RECs), and emissions compliance. The resulting NMVs could be used to rank DER project offers economically against competing DER solutions as well as traditional infrastructure solutions. The qualitative evaluation furthers the NMV ranking by listing all identifiable non-quantifiable aspects of each offered project. These may include things like developer experience, technology risk, other environmental concerns (e.g., water usage), project viability, developer Disadvantaged Business Enterprise status, etc. The qualitative factors are used along with the NMV ranking to determine the best solution based on cost and overall portfolio fit (LCBF).

- Utilities will specify tools and processes to compare DERs as alternative providers of distribution reliability functions, including voltage regulation, etc.

SDG&E proposes the CPUC adopts this scope of Phase 2a with the following amendments. As previously discussed in the Optimal Locational Benefits analysis section, SDG&E identified several possible ways DERs will be used as alternatives to traditional reliability and voltage regulating equipment. It is not appropriate, however, to give DERs credit or compensation for reliability services that they do not or cannot provide. Reliability metrics, such as System Average Interruption Duration Index (SAIDI) and System Average Interruption Frequency Index (SAIFI), are heavily influenced by the ability for utilities to respond quickly, either by SCADA operation, which minimizes the impacted area within minutes, or for SAIFI, by anticipatory replacement of underground cable and installation of sectionalizing. Currently, DERs cannot change these metrics as the DERs are removed from service following an outage. In the future, there might be a combination of DERs with capabilities that can allow the DER to stay online during an outage, and with the appropriate utility control and monitoring, could potentially affect SAIDI and SAIFI.

With respect to distribution-circuit-voltage control, SDG&E believes that all resources connecting to the grid should be required to operate within a minimum-power-factor range and to maintain voltage within a range specified by the utility. These are standard requirements for generators seeking interconnection through the CAISO's generator-interconnection queue. Generators participating in the CAISO's wholesale markets, whether connected at the distribution level or the transmission level, do not receive compensation for producing or absorbing reactive power within the mandated power factor range. SDG&E recommends that the Commission adopt, as quickly as possible, the smart inverter requirements to facilitate management of distribution-level voltage and power quality, thereby enhancing DER deployment at the lowest overall cost to consumers. Smart inverters will mitigate some of the challenges of DERs, therefore allowing more to connect.[25]

- Utilities will specify processes for utilizing the above tools, including incorporating stakeholder input and feedback into analytical methods.

SDG&E proposes the CPUC adopts this scope of Phase 2a. The utility fully supports incorporating stakeholder input and as mentioned previously, encourages the CPUC to form a stakeholder group similar to the PRG to add transparency, and allow the state agencies and appropriate stakeholders to provide input to the DPP.

Phase 2b (Ongoing, 2018 and Beyond)

- This phase will entail stakeholder-driven development of DER procurement policy and mechanisms for the IOUs. Procurement policy will be competitively neutral and will accommodate development of non-utility owned distribution systems such as islandable microgrids and parallel direct current and thermal distribution systems.

SDG&E proposes the CPUC adopts this scope of Phase 2b. The utility agrees with the staff's identified need for stakeholder-driven development of DER procurement policies and mechanisms for the IOUs. Only via a competitively neutral evaluation process will SDG&E's rate payers be assured that rates will reflect selection of the most cost-effective project providing the required services. Incorporating non-utility owned DER onto the IOU-operated distribution system creates many questions regarding solicitation, contracting, performance criteria and

[25] PG&E, SCE and SDG&E filed a joint motion regarding the implementation of Smart Inverters on July 18, 2014, pursuant to Assigned Commissioner's Amended Scoping Memo and Ruling Requiring the IOUs to File Proposed Revised Electric Tariff Rule 21, dated May 13, 2014 in Rulemaking (R.) 11-09- 011.

penalties, and payment and cost recovery that need to be identified and resolved prior to the first DRP based DER project becoming operational.

DERs have the potential to substitute for utility owned distribution capacity upgrades where they provide equivalent services with higher net value. Net value (essentially, the difference between total costs and benefits) estimates and calculations for DERs will require availability assurances, additional standards for interconnection, adoption of transmission system approaches, and the development of new methods to quantify and account for the locational value of DERs.

As SDG&E's DPP evolves to incorporate elements of the DRP, it is envisioned that SDG&E will initiate solicitations – such as requests for offers, or request for proposals – to procure DER to address a subset of capacity-related issues on the distribution system. In these solicitations, SDG&E will identify a specific distribution system need in a specific location. SDG&E will propose what it believes to be its best solution (whether DER or traditional), which will provide a benchmark for third party proposals. SDG&E will then choose the solution that best meets the capacity need in the most cost-effective manner, regardless of provider. As with current procurement practices, the selected solution will balance resource capabilities and be evaluated in a manner that identifies the optimal solution while maintaining low costs to ratepayers. In addition, DER solutions will need to meet SDG&E's commercial viability standards to ensure that customer investments are adequately protected. SDG&E believes these solicitations will provide the primary, if not sole, vehicle to compensate DER providers for providing specified distribution capacity related services to the utility.

Other factors, such as performance assurances and interconnection issues, will also factor into the evaluation process. For example, for non-utility owned DER, a third party must also provide a guarantee that assures the resource addresses the distribution system need that necessitated the upgrade. There are several ways of achieving that assurance, including contractual and technical means. In one scenario, SDG&E would control and manage the DER, allowing it to be operated consistent with the distribution system need. Second, the DER provider may choose to pair its resource with a load shedding scheme to ensure that utility customers will not experience operational issues – such as an overload – should the DER resource fail to perform as required. Another, less preferred option may be a purely contractual arrangement, whereby the DER agrees to pay significant penalties to SDG&E should it not meet its performance obligations. In most cases, utility monitoring and control of DERs provides a higher level of assurance, and will therefore have a higher associated value to ratepayers than simple contractual penalties.

While SDG&E will include estimates of all relevant value streams in its selection process, the utility will not compensate resources for providing services it does not require. For example, a DER resource may, through adherence to strict interconnection and deliverability requirements, be eligible to provide capacity that would satisfy a load serving entity's system, local or flexible RA requirements. If SDG&E is short RA capacity in the foreseeable future, this capability might have a certain value that will be considered in the bid evaluation process. On the other hand, if SDG&E is long RA capacity in the foreseeable future, the DER's capability to provide RA, while valuable in the abstract, has no incremental value to the utility's customers. Because SDG&E does not need RA services, the ability to provide those services will not and should not be factored in the DER provider's favor in the evaluation process. In these circumstances, the DER will be responsible for pursuing RA market opportunities independent of compensation that SDG&E will provide under its conceptual solicitation mechanism.

In the evolution of its rules for the interconnection of DERs (Rule 21), SDG&E recommends that the Commission approve eligibility criteria for DER that are compatible with the CAISO's approach to not compensate resources for providing voltage within predefined power factor ranges. This recommendation is consistent with the IOUs' joint motion regarding the implementation of Smart Inverters. Smart Inverters can provide local voltage control capability for DERs that would otherwise lack such capability. Future changes may include updates to standards for operating constraints such as power factor set points, which in turn would determine whether a DER would be compensated (via contract or tariff) for operating outside of a prescribed range. As the Rule 21 proceeding is well underway at the Commission, specifics regarding changes to interconnection standards should be addressed in that forum.

- This phase will encompass development of Distribution System Markets that can support grid service transactions.

SDG&E proposes the CPUC adopts this scope of Phase 2b with the following amendments. Regarding DER procurement, SDG&E believes that DER can be incentivized to connect in appropriate areas via the three Ps: Price, Program, or Procurement. Each of these three tools can be an effective method of soliciting DER participation in areas that can benefit from increased integration of DER. With these procedures in place, the need for a "distribution market" can be largely eliminated, and DERs that wish to participate in market actions can bid into the appropriate CAISO markets.

- This phase will include the IOUs, on an ongoing basis, updating the distribution system status in terms of DER deployment and associated system impacts.

SDG&E proposes the CPUC adopts this scope of Phase 2b with the following amendments. SDG&E intends to update its DPP to include DER status updates, forecasting, and procedures for DER procurement, but believes that DRP processes should be folded into existing processes as much as possible to avoid duplicating efforts. SDG&E believes that revised forecasts reflecting different DER growth scenarios should be included in the CEC's IEPR process (reference write-up on Section 7), and not be part of any subsequent DRP filings. DER status updates and new procedures can be incorporated into SDG&E's annual DPP, and impacts to DER integration will be shown in SDG&E's updated ICA results.

- Implement a stakeholder-driven process to develop an analytical plan for how these deployment scenarios would impact distribution planning and identify gaps that exist in current plans to support achieving each of the scenarios.

SDG&E proposes the CPUC adopts this scope of Phase 2b.

- The DRPs will specify a plan for developing a rolling five-year DER forecast to be included in distribution infrastructure planning, including how the forecast will influence distribution expenditures.

SDG&E proposes the CPUC adopts this scope of Phase 2b with the following amendments. SDG&E recommends that to the extent possible the DRP should be incorporated into SDG&E's existing DPP which identifies distribution expenditures which are authorized through the GRC.

APPENDIX I: INITIAL AND 10-YEAR FORECAST VALUES FOR THE INTEGRATED CAPACITY ANALYSIS

a. Initial Values for the Integrated Capacity Analysis

These are the initial values for the ICA, using SDG&E's methology and up to date Synergi Models. Reverse flow is not allowed in these results.

Circuit	Max GEN IC in KW	# of Zones	KW Zone 1	PF Zone 1	KW Zone 2	PF Zone 2	KW Zone 3	PF Zone 3
71	500	2	500	100	500	100		
72	1000	2	1000	100	1000	100		
73	500	1	500	100				
74	1500	2	1500	100	1500	-80		
83	1000	2	1000	100	1000	100		
84	2000	2	2000	100	2000	100		
86	1500	3	1500	100	1500	100	1500	100
87	2000	1	2000	100				
88	2000	3	2000	100	2000	100	2000	100
90	3000	3	3000	100	2500	100	3000	100
91	2500	3	2500	100	2500	100	2500	100
92	2500	3	2500	100	2500	100	2500	100
95	1500	2	1500	100	1500	100		
140	3500	3	3500	100	3500	100	3500	100
156	1500	2	1500	100	1500	100		
158	2500	2	2500	100	2000	100		
159	3500	2	3500	100	3500	100		
160	1500	3	1500	100	1500	100	1500	100
161	3000	3	3000	100	3000	100	3000	100
162	2000	3	2000	100	1500	100	2000	100
163	3000	3	3000	100	3000	100	3000	100
164	1000	1	1000	100				
165	2500	3	2500	100	2500	100	2500	-80
166	3000	2	3000	100	3000	100		
205	3500	3	3500	100	3500	100	2000	-80
206	1500	3	1500	100	1500	100	1500	100
207	3500	3	3500	100	2500	100	3500	100
208	2000	1	2000	100				
209	3000	3	3000	100	3000	100	3000	100
223	1500	3	1500	100	1500	100	500	-80
225	1000	1	0	100				
226	500	2	500	100	500	100		
227	1000	1	1000	100				

Circuit	Max GEN IC in KW	# of Zones	KW Zone 1	PF Zone 1	KW Zone 2	PF Zone 2	KW Zone 3	PF Zone 3
228	2500	2	2500	100	2500	100		
229	1500	2	1500	100	1500	100		
242	2500	3	2500	100	2500	100	2500	100
244	1500	3	1500	100	1500	100	1500	100
245	1000	3	1000	100	1000	100	1000	100
246	1500	3	1500	100	1500	100	1500	100
274	3500	2	3500	100	2500	-80		
275	2500	3	2500	100	2500	100	2500	100
276	3000	3	3000	100	3000	100	2000	-80
277	2500	3	2500	100	2500	100	2500	-80
278	2000	2	2000	100	2000	100		
279	1500	2	1500	100	1500	100		
280	1000	3	1000	100	1000	100	1000	100
281	500	3	500	100	500	100	500	100
282	2000	2	2000	100	2000	100		
283	2500	3	2500	100	2500	-80	1500	100
308	1500	3	1500	100	1500	100	1500	100
309	1000	2	1000	100	1000	100		
351	500	3	500	100	500	100	500	100
355	500	3	500	100	500	100	500	100
356	500	3	500	100	500	100	500	100
357	500	3	500	100	500	100	500	100
358	2500	3	2500	100	2500	100	2500	100
361	2500	2	2500	100	2500	100		
362	1500	2	1500	100	1500	100		
363	500	2	500	100	500	100		
364	3000	2	3000	100	3000	-80		
365	3500	3	3500	100	3500	100	3500	100
368	3500	2	3500	100	3500	100		
383	1000	2	1000	100	1000	100		
384	1000	2	1000	100	1000	100		
385	3000	2	3000	100	3000	100		
390	500	3	500	100	500	100	500	100
391	1000	1	1000	100				
392	1000	2	1000	100	1000	100		
393	1500	2	1500	100	1500	100		
394	2000	2	2000	100	2000	100		
396	1000	3	1000	100	1000	100	1000	100
397	1500	2	1500	100	1500	100		
399	1000	2	1000	100	1000	100		
400	500	2	500	100	500	100		
404	2000	2	2000	100	2000	100		

Circuit	Max Gen IC in KW	# of Zones	KW Zone 1	PF Zone 1	KW Zone 2	PF Zone 2	KW Zone 3	PF Zone 3
409	2000	3	2000	100	2000	100	2000	100
412	1000	2	1000	100	1000	100		
413	1000	2	1000	100	1000	100		
414	1500	2	1500	100	1500	100		
416	2000	2	2000	100	2000	100		
417	1000	3	1000	100	1000	100	1000	100
418	2000	3	2000	100	2000	100	2000	100
432	1000	2	1000	100	1000	100		
433	1500	2	1500	100	1500	100		
434	2000	2	2000	100	2000	100		
435	1500	1	1500	100				
436	1000	2	1000	100	1000	100		
437	500	2	500	100	500	100		
438	2000	2	2000	100	2000	100		
439	1000	2	1000	100	1000	100		
506	2500	3	2500	100	2500	100	2500	100
507	2000	2	2000	100	2000	100		
508	2000	2	2000	100	2000	100		
509	3000	3	3000	100	3000	100	3000	100
513	2000	2	2000	100	2000	100		
514	1000	2	1000	100	1000	100		
515	2000	2	2000	100	2000	100		
516	2000	2	2000	100	2000	100		
517	500	2	500	100	500	100		
518	1000	2	1000	100	1000	100		
519	2000	2	2000	100	2000	100		
521	1000	1	500	-80				
522	2000	3	2000	100	2000	100	2000	100
532	2500	2	2500	100	2500	100		
533	2000	2	2000	100	2000	100		
534	2000	3	2000	100	2000	-80	2000	-80
535	1000	2	1000	100	1000	100		
547	2500	2	2500	100	2500	100		
548	1500	2	1500	100	1500	100		
549	1500	2	1500	100	1500	100		
550	1000	2	1000	100	1000	100		
551	1500	2	1500	100	1500	100		
552	500	2	500	100	500	100		
553	1500	3	1500	100	1500	100	1500	100
554	1500	1	1500	100				

Circuit	Max Gen IC in KW	# of Zones	KW Zone 1	PF Zone 1	KW Zone 2	PF Zone 2	KW Zone 3	PF Zone 3
590	1500	2	1500	100	1500	100		
591	1500	3	1500	100	1500	100	1500	100
592	1000	2	1000	100	1000	100		
593	1000	2	1000	100	1000	100		
723	3000	2	3000	100	3000	100		
726	3500	2	3500	100	3500	100		
727	500	1	500	100				
729	1500	2	1500	100	1500	100		
730	2500	3	2500	100	2500	100	2500	-80
731	2000	3	2000	100	2000	100	2000	100
732	2000	3	2000	100	2000	100	2000	100
733	3000	3	3000	100	2500	100	3000	100
750	500	2	500	100	500	100		
751	2000	2	2000	100	2000	100		
752	3000	2	3000	100	3000	100		
754	2000	2	2000	100	2000	100		
755	2500	2	2500	100	2500	100		
759	1000	2	1000	100	1000	100		
760	500	1	500	100				
761	2000	3	2000	100	2000	100	2000	100
762	1500	2	1500	100	1500	100		
763	1000	1	1000	100				
772	1500	1	1500	100				
773	2000	3	2000	100	2000	100	2000	100
774	2000	1	2000	100				
775	1500	2	1500	100	1500	100		
777	500	2	500	100	500	100		
821	500	2	500	100	500	100		
830	3500	2	3500	100	3500	100		
834	1000	2	1000	100	1000	100		
850	1000	1	1000	100				
851	2000	2	2000	100	2000	-80		
852	2500	2	2500	100	2500	-80		
853	1500	2	1500	100	1500	100		
854	2000	2	2000	100	2000	-80		
856	1500	2	1500	100	1500	100		
857	2000	2	2000	100	2000	100		
858	1500	3	1500	100	1500	100	1500	100
920	1000	2	1000	100	1000	100		
921	2000	2	2000	100	2000	100		

Circuit	Max Gen IC in KW	# of Zones	KW Zone 1	PF Zone 1	KW Zone 2	PF Zone 2	KW Zone 3	PF Zone 3
922	2000	2	2000	100	2000	100		
923	1500	2	1500	100	1500	100		
925	1500	1	1500	100				
926	1000	1	1000	100				
927	1500	2	1500	100	1500	100		
940	500	2	500	100	500	100		
941	2500	2	2500	100	2500	100		
942	3500	2	3500	100	3500	100		
944	1000	2	1000	100	1000	100		
946	1500	2	1500	100	1500	100		
948	1000	3	1000	100	1000	-80	1000	-80
949	1500	2	1500	100	1500	100		
1006	500	2	500	100	500	100		
1007	1500	2	1500	100	1500	100		
1048	1500	1	1500	100				
1100	1500	2	1500	100	1500	100		
1101	500	3	500	100	500	100	500	100
1103	1000	2	1000	100	1000	100		
1105	1000	3	1000	100	1000	100	1000	100
1116	3000	2	3000	100	3000	100		
1117	2500	3	2500	100	2500	100	2500	100
1119	3000	2	3000	100	3000	100		
1138	500	3	500	100	500	100	500	100
1139	500	2	500	100	500	100		
1160	1000	2	1000	100	1000	100		
1221	2000	2	2000	100	2000	100		
1224	1500	2	1500	100	1500	100		
1266	1000	2	1000	100	1000	100		
1286	2000	2	500	100	500	100		
1287	2000	1	1500	100				
1297	1000	2	1000	100	1000	100		
1458	1000	3	1000	100	1000	100	1000	100

b. 10-Year Forcast Values for the Integrated Capacity Analysis

These are the 10-year forecast values for the ICA, performed by Integral Analytics using older Synergi models. Reverse flow limits are ignored in these results. These values will change significantly over time, as each circuit is treated separately, and effects to circuits at the same substation and the transmission system are ignored.

Circuit	Max GEN IC in KW	# of Zones	KW Zone 1	PF Zone 1	KW Zone 2	PF Zone 2	KW Zone 3	PF Zone 3
34	9800	1	9800	100				
35	5600	2	5600	100	5600	100		
36	5600	1	5600	100				
37	7000	1	7000	100				
38	7000	3	7000	100	2900	100	2900	100
39	7000	1	7000	100				
40	8400	2	8400	100	4300	100		
41	9800	3	9800	100	4300	100	2900	100
42	7000	3	7000	100	4300	100	2900	100
43	7000	3	7000	100	4300	100	4300	100
44	7000	3	7000	100	4300	100	100	100
45	5600	3	5600	100	2900	100	9800	100
46	9800	1	9800	100				
47	1500	1	1500	100				
48	1500	1	1500	100				
49	9800	1	9800	100				
50	5600	2	5600	100	4300	100		
51	4300	2	4300	100	2900	100		
52	4300	3	4300	100	2900	100	9800	100
53	9800	1	9800	100				
54	4300	2	4300	100	2900	100		
55	7000	2	7000	100	2900	100		
56	7000	2	7000	100	5600	100		
57	9800	3	9800	100	5600	100	4300	100
58	5600	3	5600	100	2900	100	2900	100
59	1500	3	1500	100	1500	100	100	100

Circuit	Max GEN IC in KW	# of Zones	KW Zone 1	PF Zone 1	KW Zone 2	PF Zone 2	KW Zone 3	PF Zone 3
60	8400	3	8400	100	4300	100	1500	100
61	2900	3	2900	100	2900	100	1500	100
62	2900	3	2900	100	1500	100	100	100
63	4300	3	4300	100	2900	100	1500	100
64	1500	2	1500	100	1500	100		
65	4300	3	4300	100	2900	100	2900	100
66	4300	3	4300	100	2900	100	1500	100
67	2900	2	2900	100	100	100		
68	2900	3	2900	100	2900	100	1500	100
69	2900	3	2900	100	2900	100	1500	100
70	1500	2	1500	100	1500	100		
71	7000	2	7000	100	4300	100		
72	4300	2	4300	100	4300	100		
73	100	1	100	100				
74	7000	2	7000	100	2900	100		
75	1500	3	1500	100	100	100	100	100
76	5600	2	5600	100	5600	100		
77	5600	2	5600	100	2900	100		
78	2900	3	2900	100	1500	100	1500	100
79	100	2	100	100	100	100		
80	7000	3	7000	100	4300	100	1500	100
81	5600	2	5600	100	2900	100		
83	8400	3	8400	100	4300	100	4300	100
84	9800	2	9800	100	8400	100		
85	9800	3	9800	100	5600	100	4300	100
86	8400	2	8400	100	4300	100		
87	5600	2	5600	100	5600	100		
88	9800	3	9800	100	8400	100	4300	100
89	8400	1	8400	100				
90	7000	3	7000	100	4300	100	4300	100
91	100	3	100	100	100	100	100	100
92	100	3	100	100	100	100	100	100
93	100	3	100	100	100	100	100	100
94	9800	3	9800	100	7000	100	2900	100
95	100	2	100	100	100	100		
96	100	3	100	100	100	100	100	100
98	9800	1	9800	100				
99	9800	1	9800	100				
100	5600	2	5600	100	4300	100		
102	8400	1	8400	100				

Circuit	Max GEN IC in KW	# of Zones	KW Zone 1	PF Zone 1	KW Zone 2	PF Zone 2	KW Zone 3	PF Zone 3
103	5600	2	5600	100	2900	100		
104	5600	2	5600	100	100	100		
105	4300	2	4300	100	4300	100		
106	9800	1	9800	100				
107	4300	1	4300	100				
108	8400	1	8400	100				
109	9800	1	9800	100				
110	9800	1	9800	100				
111	4300	2	4300	100	4300	100		
112	9800	1	9800	100				
113	4300	2	4300	100	4300	100		
114	2900	3	2900	100	2900	100	1500	100
115	9800	1	9800	100				
116	1500	3	1500	100	1500	100	1500	100
117	7000	1	7000	100				
118	8400	1	8400	100				
119	9800	1	9800	100				
120	1500	2	1500	100	1500	100		
121	9800	1	9800	100				
122	7000	2	7000	100	100	100		
123	2900	2	2900	100	2900	100		
124	9800	2	9800	100	4300	100		
125	9800	1	9800	100				
126	9800	1	9800	100				
127	9800	1	9800	100				
128	8400	1	8400	100				
129	2900	2	2900	100	2900	100		
130	2900	3	2900	100	1500	100	1500	100
131	4300	2	4300	100	4300	100		
132	2900	1	2900	100				
133	1500	2	1500	100	1500	100		
134	7000	1	7000	100				
135	7000	1	7000	100				
136	8400	2	8400	100	4300	100		
137	5600	2	5600	100	5600	100		
138	9800	2	9800	100	4300	100		
139	9800	2	9800	100	5600	100		
140	8400	3	8400	100	5600	100	5600	100
141	4300	1	4300	100				
142	4300	3	4300	100	2900	100	1500	100

Circuit	Max GEN IC in KW	# of Zones	KW Zone 1	PF Zone 1	KW Zone 2	PF Zone 2	KW Zone 3	PF Zone 3
143	9800	3	9800	100	5600	100	5600	100
144	9800	3	9800	100	5600	100	4300	100
145	8400	2	8400	100	5600	100		
146	7000	2	7000	100	5600	100		
147	7000	2	7000	100	4300	100		
149	7000	2	7000	100	5600	100		
150	2900	2	2900	100	2900	100		
151	1500	2	1500	100	1500	100		
152	1500	3	1500	100	1500	100	1500	100
153	2900	3	2900	100	1500	100	100	100
154	2900	3	2900	100	1500	100	1500	100
155	7000	3	7000	100	4300	100	1500	100
156	5600	2	5600	100	2900	100		
157	1500	3	1500	100	100	100	100	100
158	4300	2	4300	100	2900	100		
159	4300	3	4300	100	2900	100	2900	100
160	5600	2	5600	100	2900	100		
161	8400	3	8400	100	5600	100	4300	100
162	7000	3	7000	100	4300	100	4300	100
163	8400	3	8400	100	5600	100	2900	100
164	7000	3	7000	100	2900	100	2900	100
165	8400	3	8400	100	4300	100	2900	100
166	9800	3	9800	100	4300	100	2900	100
167	9800	3	9800	100	7000	100	4300	100
168	9800	3	9800	100	4300	100	2900	100
169	5600	2	5600	100	4300	100		
170	1500	3	1500	100	2900	100	1500	100
171	5600	3	5600	100	5600	100	1500	100
172	100	1	100	100				
175	1500	1	1500	100				
176	1500	2	1500	100	2900	100		
177	7000	3	7000	100	4300	100	1500	100
178	7000	3	7000	100	4300	100	2900	100
179	2900	1	2900	100				
180	5600	2	5600	100	4300	100		
181	8400	2	8400	100	7000	100		
182	9800	3	9800	100	4300	100	1500	100
183	9800	3	9800	100	7000	100	2900	100
184	5600	2	5600	100	5600	100		
185	7000	3	7000	100	4300	100	2900	100

Circuit	Max GEN IC in KW	# of Zones	KW Zone 1	PF Zone 1	KW Zone 2	PF Zone 2	KW Zone 3	PF Zone 3
186	7000	3	7000	100	4300	100	2900	100
187	5600	2	5600	100	4300	100		
188	8400	3	8400	100	4300	100	2900	100
189	7000	2	7000	100	4300	100		
190	8400	3	8400	100	5600	100	2900	100
191	2900	2	2900	100	2900	100		
192	9800	3	9800	100	8400	100	5600	100
193	9800	1	9800	100				
194	4300	3	4300	100	2900	100	1500	100
195	1500	2	1500	100	1500	100		
196	4300	2	4300	100	2900	100		
197	2900	3	2900	100	1500	100	1500	100
198	7000	3	7000	100	2900	100	2900	100
199	5600	2	5600	100	5600	100		
200	100	3	100	100	100	100	100	100
202	4300	3	4300	100	4300	100	1500	100
203	100	3	100	100	100	100	100	100
204	1500	1	1500	100				
205	4300	3	4300	100	4300	100	1500	100
206	2900	3	2900	100	2900	100	1500	100
207	4300	3	4300	100	4300	100	2900	100
208	2900	1	2900	100				
209	5600	3	5600	100	4300	100	1500	100
210	1500	2	1500	100	1500	100		
211	1500	2	1500	100	100	100		
212	100	3	100	100	100	100	100	100
213	7000	2	7000	100	4300	100		
214	1500	2	1500	100	100	100		
215	1500	3	1500	100	1500	100	1500	100
216	2900	2	2900	100	1500	100		
217	1500	1	1500	100				
220	100	2	100	100	100	100		
221	100	3	100	100	9800	100	9800	100
222	100	3	100	100	1500	100	100	100
223	7000	3	7000	100	2900	100	1500	100
224	5600	1	5600	100				
225	9800	1	9800	100				
226	5600	1	5600	100				
227	5600	2	5600	100	5600	100		
228	7000	2	7000	100	5600	100		

Circuit	Max GEN IC in KW	# of Zones	KW Zone 1	PF Zone 1	KW Zone 2	PF Zone 2	KW Zone 3	PF Zone 3
229	4300	1	4300	100				
230	4300	3	4300	100	2900	100	1500	100
231	1500	3	1500	100	2900	100	1500	100
232	1500	3	1500	100	1500	100	1500	100
233	1500	1	1500	100				
234	1500	3	1500	100	1500	100	1500	100
235	9800	3	9800	100	7000	100	4300	100
236	8400	3	8400	100	5600	100	1500	100
237	1500	2	1500	100	1500	100		
239	4300	3	4300	100	2900	100	1500	100
240	2900	3	2900	100	5600	100	1500	100
241	7000	3	7000	100	5600	100	2900	100
242	7000	3	7000	100	100	100	4300	100
243	4300	3	4300	100	1500	100	1500	100
244	8400	3	8400	100	5600	100	4300	100
245	5600	2	5600	100	2900	100		
246	7000	3	7000	100	5600	100	1500	100
247	5600	3	5600	100	4300	100	1500	100
248	4300	3	4300	100	4300	100	4300	100
249	7000	3	7000	100	4300	100	1500	100
250	19600	2	19600	100	3000	100		
251	3000	1	3000	100				
252	16800	3	16800	100	8600	100	3000	100
253	19600	1	19600	100				
254	16800	1	16800	100				
255	7000	3	7000	100	4300	100	2900	100
256	7000	2	7000	100	5600	100		
257	9800	2	9800	100	5600	100		
258	9800	1	9800	100				
260	100	2	100	100	1500	100		
261	7000	1	7000	100				
262	8400	2	8400	100	4300	100		
263	8400	1	8400	100				
264	9800	1	9800	100				
265	9800	1	9800	100				
266	9800	2	9800	100	7000	100		
267	9800	1	9800	100				
268	5600	2	5600	100	5600	100		
269	4300	1	4300	100				
270	5600	2	5600	100	4300	100		

Circuit	Max GEN IC in KW	# of Zones	KW Zone 1	PF Zone 1	KW Zone 2	PF Zone 2	KW Zone 3	PF Zone 3
271	8400	1	8400	100				
272	5600	2	5600	100	5600	100		
273	5600	2	5600	100	4300	100		
274	5600	2	5600	100	2900	100		
275	8400	3	8400	100	4300	100	2900	100
276	7000	3	7000	100	4300	100	2900	100
277	7000	3	7000	100	4300	100	1500	100
278	4300	3	4300	100	2900	100	100	100
279	4300	2	4300	100	2900	100		
280	8400	3	8400	100	7000	100	1500	100
281	5600	3	5600	100	4300	100	100	100
282	9800	2	9800	100	5600	100		
283	4300	3	4300	100	4300	100	1500	100
284	5600	2	5600	100	2900	100		
286	9800	3	9800	100	2900	100	2900	100
287	7000	3	7000	100	4300	100	2900	100
288	8400	3	8400	100	5600	100	2900	100
289	7000	3	7000	100	4300	100	2900	100
290	100	2	100	100	100	100		
291	100	2	100	100	100	100		
292	100	1	100	100				
293	100	2	100	100	100	100		
294	100	2	100	100	100	100		
295	5600	2	5600	100	4300	100		
296	2900	2	2900	100	1500	100		
297	100	3	100	100	1500	100	1500	100
298	7000	2	7000	100	4300	100		
299	5600	3	5600	100	4300	100	2900	100
300	4300	3	4300	100	2900	100	1500	100
302	9800	1	9800	100				
303	8400	3	8400	100	5600	100	4300	100
304	5600	2	5600	100	2900	100		
305	2900	3	2900	100	1500	100	1500	100
306	7000	3	7000	100	2900	100	2900	100
307	4300	3	4300	100	2900	100	1500	100
308	8400	2	8400	100	4300	100		
309	5600	2	5600	100	4300	100		
310	5600	3	5600	100	4300	100	2900	100
311	5600	3	5600	100	2900	100	2900	100
312	4300	2	4300	100	2900	100		

Circuit	Max GEN IC in KW	# of Zones	KW Zone 1	PF Zone 1	KW Zone 2	PF Zone 2	KW Zone 3	PF Zone 3
313	7000	3	7000	100	2900	100	2900	100
314	5600	3	5600	100	2900	100	2900	100
315	5600	3	5600	100	4300	100	2900	100
319	9800	1	9800	100				
320	4300	2	4300	100	2900	100		
321	5600	3	5600	100	4300	100	2900	100
322	7000	3	7000	100	2900	100	2900	100
323	9800	3	9800	100	5600	100	1500	100
324	7000	2	7000	100	4300	100		
325	5600	3	5600	100	4300	100	1500	100
326	8400	3	8400	100	5600	100	100	100
329	100	3	100	100	100	100	100	100
330	100	3	100	100	100	100	100	100
331	100	3	100	100	100	100	100	100
334	100	3	100	100	100	100	100	100
335	9800	1	9800	100				
338	8400	1	8400	100				
339	7000	3	7000	100	4300	100	1500	100
340	4300	3	4300	100	2900	100	100	100
341	4300	3	4300	100	2900	100	1500	100
342	5600	2	5600	100	100	100		
343	7000	2	7000	100	7000	100		
344	9800	2	9800	100	9800	100		
346	2900	1	2900	100				
350	1500	1	1500	100				
351	2900	3	2900	100	2900	100	1500	100
352	100	2	100	100	100	100		
353	2900	3	2900	100	1500	100	1500	100
354	1500	1	1500	100				
355	2900	3	2900	100	1500	100	1500	100
356	5600	3	5600	100	2900	100	1500	100
357	5600	3	5600	100	4300	100	2900	100
358	8400	3	8400	100	7000	100	2900	100
361	7000	2	7000	100	5600	100		
362	7000	2	7000	100	4300	100		
363	5600	1	5600	100				
364	8400	3	8400	100	4300	100	4300	100
365	7000	2	7000	100	4300	100		
366	5600	2	5600	100	4300	100		
367	8400	1	8400	100				
368	7000	2	7000	100	100	100		
369	8400	1	8400	100				
370	9800	1	8400	100	100	100		
372	100	1	100	100				
373	100	1	100	100				

Circuit	Max GEN IC in KW	# of Zones	KW Zone 1	PF Zone 1	KW Zone 2	PF Zone 2	KW Zone 3	PF Zone 3
374	2900	2	2900	100	2900	100		
375	100	1	100	100				
376	8400	3	8400	100	5600	100	4300	100
377	100	3	100	100	100	100	100	100
378	100	1	100	100				
380	9800	3	9800	100	7000	100	2900	100
381	8400	3	8400	100	5600	100	2900	100
382	5600	1	5600	100				
383	5600	2	5600	100	4300	100		
384	5600	2	5600	100	4300	100		
385	9800	2	9800	100	7000	100		
386	9800	3	9800	100	7000	100	1500	100
387	7000	3	7000	100	2900	100	2900	100
390	9800	3	9800	100	5600	100	4300	100
391	5600	2	5600	100	5600	100		
392	9800	3	9800	100	8400	100	5600	100
393	8400	3	8400	100	4300	100	100	100
394	8400	2	8400	100	4300	100		
395	5600	2	5600	100	1500	100		
396	7000	3	7000	100	4300	100	2900	100
397	7000	2	7000	100	4300	100		
399	5600	2	5600	100	2900	100		
400	4300	2	4300	100	2900	100		
401	9800	2	9800	100	5600	100		
402	7000	2	7000	100	4300	100		
403	9800	3	9800	100	7000	100	4300	100
404	8400	2	8400	100	5600	100		
405	5600	2	5600	100	5600	100		
406	5600	2	5600	100	4300	100		
407	9800	1	9800	100				
409	9800	3	9800	100	7000	100	4300	100
410	9800	3	9800	100	5600	100	4300	100
411	5600	3	5600	100	7000	100	1500	100
412	8400	3	8400	100	4300	100	2900	100
413	5600	1	5600	100				
414	5600	3	5600	100	2900	100	2900	100
415	9800	3	9800	100	8400	100	2900	100
416	8400	2	8400	100	5600	100		
417	9800	3	9800	100	5600	100	4300	100
418	8400	3	8400	100	4300	100	1500	100
423	5600	1	5600	100				
424	7000	1	7000	100				
425	5600	1	5600	100				
426	5600	3	5600	100	4300	100	100	100
427	8400	1	8400	100				

Circuit	Max GEN IC in KW	# of Zones	KW Zone 1	PF Zone 1	KW Zone 2	PF Zone 2	KW Zone 3	PF Zone 3
428	8400	1	8400	100				
429	8400	1	8400	100				
430	8400	2	8400	100	7000	100		
431	5600	2	5600	100	4300	100		
432	4300	2	4300	100	4300	100		
433	5600	2	5600	100	5600	100		
434	7000	2	7000	100	5600	100		
435	4300	2	4300	100	4300	100		
436	8400	2	8400	100	5600	100		
437	4300	2	4300	100	4300	100		
438	7000	2	7000	100	5600	100		
439	7000	2	7000	100	5600	100		
440	100	2	100	100	100	100		
441	1500	2	1500	100	100	100		
442	9800	2	9800	100	1500	100		
443	100	3	100	100	100	100	100	100
444	1500	3	1500	100	3000	100	1500	100
445	200	1	200	100				
448	100	2	100	100	100	100		
449	5600	2	5600	100	100	100		
450	8400	3	8400	100	4300	100	2900	100
451	5600	2	5600	100	5600	100		
452	9800	3	9800	100	8400	100	2900	100
453	9800	3	9800	100	5600	100	1500	100
457	8400	1	8400	100				
458	7000	2	7000	100	4300	100		
460	100	3	100	100	100	100	100	100
461	100	3	100	100	100	100	100	100
462	100	3	100	100	100	100	100	100
463	100	3	100	100	100	100	100	100
464	4300	2	4300	100	4300	100		
465	7000	1	7000	100				
467	9800	1	9800	100				
468	7000	1	7000	100				
469	5600	1	5600	100				
470	1500	2	1500	100	1500	100		
471	5600	2	5600	100	2900	100		
472	1500	2	1500	100	1500	100		
473	8400	3	8400	100	2900	100	2900	100
474	4300	3	4300	100	2900	100	1500	100
475	5600	2	5600	100	4300	100		
476	8400	3	8400	100	5600	100	2900	100
477	7000	1	7000	100				
480	5600	3	5600	100	2900	100	2900	100
481	4300	2	4300	100	4300	100		

Circuit	Max GEN IC in KW	# of Zones	KW Zone 1	PF Zone 1	KW Zone 2	PF Zone 2	KW Zone 3	PF Zone 3
482	8400	2	8400	100	5600	100		
483	7000	2	7000	100	5600	100		
486	7000	3	7000	100	5600	100	2900	100
487	9800	1	9800	100				
488	5600	2	5600	100	5600	100		
489	7000	2	7000	100	4300	100		
490	4300	1	4300	100				
491	4300	2	4300	100	2900	100		
492	8400	3	8400	100	4300	100	2900	100
493	8400	2	8400	100	1500	100		
494	9800	1	9800	100				
496	7000	1	7000	100				
497	5600	3	5600	100	4300	100	2900	100
498	4300	1	4300	100				
499	100	1	100	100				
500	4300	3	4300	100	2900	100	2900	100
501	4300	2	4300	100	1500	100		
502	2900	3	2900	100	1500	100	1500	100
503	9800	1	9800	100				
504	2900	3	2900	100	2900	100	1500	100
505	1500	3	1500	100	1500	100	1500	100
506	2900	3	2900	100	1500	100	1500	100
507	4300	2	4300	100	2900	100		
508	1500	2	1500	100	1500	100		
509	1500	3	1500	100	1500	100	1500	100
510	1500	3	1500	100	1500	100	9800	100
511	100	2	100	100	100	100		
512	1500	2	1500	100	1500	100		
513	7000	2	7000	100	5600	100		
514	8400	3	8400	100	5600	100	2900	100
515	7000	2	7000	100	4300	100		
516	7000	1	7000	100				
517	5600	2	5600	100	2900	100		
518	8400	2	8400	100	5600	100		
519	7000	2	7000	100	4300	100		
520	1500	1	1500	100				
521	100	1	100	100				
522	1500	3	1500	100	1500	100	1500	100
523	1500	2	1500	100	1500	100		
524	100	2	100	100	100	100		
525	100	2	100	100	100	100		
528	9800	1	9800	100				
529	4300	2	4300	100	2900	100		
531	9800	3	9800	100	8400	100	4300	100
532	5600	3	5600	100	2900	100	100	100

Circuit	Max GEN IC in KW	# of Zones	KW Zone 1	PF Zone 1	KW Zone 2	PF Zone 2	KW Zone 3	PF Zone 3
533	100	3	100	100	100	100	100	100
534	100	2	100	100	100	100		
535	100	1	100	100				
536	100	3	100	100	100	100	100	100
537	100	1	100	100				
538	100	1	100	100				
539	100	2	100	100	100	100		
540	100	1	100	100				
541	100	1	100	100				
542	100	3	100	100	100	100	100	100
543	100	1	100	100				
544	100	1	100	100				
545	5600	2	5600	100	4300	100		
546	5600	2	5600	100	2900	100		
547	8400	2	8400	100	5600	100		
548	5600	2	5600	100	4300	100		
549	9800	2	9800	100	5600	100		
550	9800	3	9800	100	5600	100	4300	100
551	5600	2	5600	100	4300	100		
552	5600	2	5600	100	5600	100		
553	7000	3	7000	100	4300	100	4300	100
554	7000	1	7000	100				
555	9800	2	9800	100	8400	100		
556	7000	3	7000	100	4300	100	2900	100
557	8400	2	8400	100	5600	100		
558	4300	2	4300	100	2900	100		
559	5600	1	5600	100				
560	5600	1	5600	100				
561	7000	2	7000	100	4300	100		
562	8400	3	8400	100	4300	100	4300	100
563	8400	2	8400	100	5600	100		
564	5600	2	5600	100	4300	100		
565	8400	1	8400	100				
566	4300	2	4300	100	4300	100		
567	7000	2	7000	100	4300	100		
570	4300	2	4300	100	4300	100		
571	5600	2	5600	100	4300	100		
572	7000	2	7000	100	1500	100		
574	100	1	100	100				
575	100	1	100	100				
576	100	3	100	100	100	100	100	100
577	100	1	100	100				
578	4300	2	4300	100	2900	100		
579	7000	2	7000	100	4300	100		
580	5600	2	5600	100	4300	100		

Circuit	Max GEN IC in KW	# of Zones	KW Zone 1	PF Zone 1	KW Zone 2	PF Zone 2	KW Zone 3	PF Zone 3
581	5600	2	5600	100	5600	100		
582	4300	2	4300	100	2900	100		
583	1500	1	1500	100				
584	5600	2	5600	100	2900	100		
585	7000	2	7000	100	7000	100		
586	2900	3	2900	100	1500	100	1500	100
587	5600	2	5600	100	4300	100		
588	4300	2	4300	100	2900	100		
589	5600	2	5600	100	2900	100		
590	5600	2	5600	100	2900	100		
591	9800	3	9800	100	5600	100	4300	100
592	5600	2	5600	100	2900	100		
593	5600	2	5600	100	4300	100		
594	9800	3	9800	100	4300	100	2900	100
595	7000	2	7000	100	5600	100		
596	7000	3	7000	100	5600	100	4300	100
597	8400	3	8400	100	4300	100	1500	100
598	5600	2	5600	100	4300	100		
599	5600	3	5600	100	4300	100	1500	100
700	7000	2	7000	100	4300	100		
701	5600	3	5600	100	4300	100	100	100
702	5600	3	5600	100	7000	100	1500	100
703	8400	2	8400	100	4300	100		
704	5600	2	5600	100	2900	100		
706	8400	3	8400	100	5600	100	4300	100
707	5600	1	5600	100				
708	4300	2	4300	100	2900	100		
710	19600	1	19600	100				
711	11200	1	11200	100				
712	8600	2	8600	100	8600	100		
713	14000	1	14000	100				
714	16800	2	16800	100	14000	100		
715	16800	3	16800	100	8600	100	8600	100
716	16800	1	16800	100				
718	5600	3	5600	100	5600	100	4300	100
719	9800	3	9800	100	5600	100	4300	100
723	8400	2	8400	100	4300	100		
726	5600	2	5600	100	5600	100		
727	5600	1	5600	100				
728	9800	3	9800	100	7000	100	5600	100
729	7000	2	7000	100	4300	100		
730	8400	3	8400	100	5600	100	2900	100
731	8400	3	8400	100	4300	100	2900	100
732	9800	3	9800	100	7000	100	5600	100
733	9800	3	9800	100	5600	100	5600	100

Circuit	Max GEN IC in KW	# of Zones	KW Zone 1	PF Zone 1	KW Zone 2	PF Zone 2	KW Zone 3	PF Zone 3
735	5600	2	5600	100	2900	100		
736	9800	1	9800	100				
737	9800	1	9800	100				
738	9800	3	9800	100	5600	100	4300	100
739	9800	1	9800	100				
740	9800	3	9800	100	5600	100	4300	100
741	8400	2	8400	100	4300	100		
742	7000	1	7000	100				
743	8400	1	8400	100				
744	9800	1	9800	100				
745	8400	1	8400	100				
746	5600	1	5600	100				
747	8400	1	8400	100				
748	9800	2	9800	100	5600	100		
749	7000	1	7000	100				
750	1500	2	1500	100	1500	100		
751	4300	2	4300	100	2900	100		
752	4300	3	4300	100	2900	100	2900	100
753	100	2	100	100	100	100		
754	5600	2	5600	100	4300	100		
755	1500	2	1500	100	1500	100		
756	5600	1	5600	100				
757	4300	2	4300	100	4300	100		
759	5600	3	5600	100	2900	100	2900	100
760	9800	1	9800	100				
761	9800	2	9800	100	7000	100		
762	5600	1	5600	100				
763	5600	1	5600	100				
765	7000	2	7000	100	4300	100		
766	4300	1	4300	100				
768	5600	2	5600	100	4300	100		
770	9800	3	9800	100	5600	100	5600	100
771	9800	3	9800	100	8400	100	8400	100
772	7000	1	7000	100				
773	7000	3	7000	100	7000	100	100	100
774	7000	1	7000	100				
775	5600	1	5600	100				
776	4300	2	4300	100	2900	100		
777	7000	1	7000	100				
779	5600	2	5600	100	4300	100		
780	8400	3	8400	100	4300	100	100	100
781	8400	3	8400	100	2900	100	2900	100
782	5600	2	5600	100	5600	100		
783	9800	3	9800	100	7000	100	4300	100
785	7000	1	7000	100				

Circuit	Max GEN IC in KW	# of Zones	KW Zone 1	PF Zone 1	KW Zone 2	PF Zone 2	KW Zone 3	PF Zone 3
786	9800	1	9800	100				
788	4300	3	4300	100	2900	100	1500	100
789	4300	3	4300	100	2900	100	1500	100
790	5600	2	5600	100	2900	100		
791	5600	3	5600	100	2900	100	2900	100
792	4300	3	4300	100	2900	100	1500	100
793	2900	3	2900	100	1500	100	1500	100
794	4300	3	4300	100	2900	100	1500	100
795	4300	3	4300	100	2900	100	100	100
796	4300	3	4300	100	1500	100	2900	100
797	4300	3	4300	100	2900	100	2900	100
798	1500	2	1500	100	1500	100		
799	5600	3	5600	100	4300	100	2900	100
821	1500	2	1500	100	1500	100		
830	7000	2	7000	100	5600	100		
831	7000	2	7000	100	5600	100		
832	8400	2	8400	100	5600	100		
833	5600	2	5600	100	4300	100		
834	7000	3	7000	100	4300	100	2900	100
835	5600	3	5600	100	4300	100	2900	100
836	4300	2	4300	100	4300	100		
846	8400	1	8400	100				
847	8400	1	8400	100				
850	5600	2	5600	100	4300	100		
851	7000	2	7000	100	5600	100		
852	5600	2	5600	100	4300	100		
853	5600	1	5600	100				
854	8400	3	8400	100	4300	100	4300	100
855	8400	3	8400	100	5600	100	4300	100
856	5600	2	5600	100	2900	100		
857	9800	2	9800	100	4300	100		
858	4300	3	4300	100	2900	100	2900	100
859	8400	3	8400	100	5600	100	1500	100
900	7000	3	7000	100	4300	100	2900	100
901	8400	3	8400	100	5600	100	4300	100
902	9800	3	9800	100	5600	100	2900	100
903	5600	2	5600	100	4300	100		
904	8400	3	8400	100	4300	100	4300	100
905	9800	3	9800	100	5600	100	1500	100
907	100	3	100	100	1500	100	100	100
908	4300	3	4300	100	2900	100	1500	100
909	2900	3	2900	100	2900	100	2900	100
910	5600	2	5600	100	2900	100		
911	5600	2	5600	100	4300	100		
912	5600	2	5600	100	2900	100		

Circuit	Max GEN IC in KW	# of Zones	KW Zone 1	PF Zone 1	KW Zone 2	PF Zone 2	KW Zone 3	PF Zone 3
913	5600	2	5600	100	2900	100		
915	2900	2	2900	100	1500	100		
916	7000	2	7000	100	4300	100		
920	4300	3	4300	100	4300	100	2900	100
921	7000	2	7000	100	4300	100		
922	8400	2	8400	100	4300	100		
923	9800	1	9800	100				
924	8400	1	8400	100				
925	8400	1	8400	100				
926	7000	1	7000	100				
927	7000	2	7000	100	4300	100		
930	8400	1	8400	100				
931	8400	2	8400	100	4300	100		
932	7000	2	7000	100	5600	100		
933	5600	2	5600	100	4300	100		
934	4300	2	4300	100	2900	100		
935	9800	1	9800	100				
936	8400	2	8400	100	4300	100		
937	7000	2	7000	100	5600	100		
940	5600	2	5600	100	4300	100		
941	8400	3	8400	100	4300	100	2900	100
942	7000	2	7000	100	4300	100		
943	9800	3	9800	100	7000	100	5600	100
944	4300	1	4300	100				
945	7000	2	7000	100	5600	100		
946	8400	2	8400	100	5600	100		
947	9800	1	9800	100				
948	4300	3	4300	100	1500	100	1500	100
949	5600	3	5600	100	2900	100	2900	100
950	5600	1	5600	100				
951	8400	1	8400	100				
952	5600	2	5600	100	4300	100		
953	7000	2	7000	100	5600	100		
954	8400	1	8400	100				
955	7000	1	7000	100				
956	5600	1	5600	100				
957	7000	1	7000	100				
958	9800	1	9800	100				
959	8400	1	8400	100				
960	7000	2	7000	100	4300	100		
961	7000	1	7000	100				
962	7000	1	7000	100				
963	8400	2	8400	100	2900	100		
966	9800	1	9800	100				
967	4300	1	4300	100				

Circuit	Max GEN IC in KW	# of Zones	KW Zone 1	PF Zone 1	KW Zone 2	PF Zone 2	KW Zone 3	PF Zone 3
968	9800	3	9800	100	7000	100	5600	100
969	9800	1	9800	100				
970	9800	3	9800	100	5600	100	2900	100
971	1500	2	1500	100	1500	100		
972	1500	1	1500	100				
973	1500	1	1500	100				
974	1500	1	1500	100				
975	8400	3	8400	100	4300	100	2900	100
980	7000	2	7000	100	4300	100		
981	5600	3	5600	100	4300	100	4300	100
982	4300	3	4300	100	4300	100	2900	100
983	4300	3	4300	100	2900	100	1500	100
984	1500	1	1500	100				
985	7000	3	7000	100	4300	100	4300	100
986	2900	2	2900	100	2900	100		
987	7000	3	7000	100	5600	100	4300	100
988	2900	1	2900	100				
989	5600	2	5600	100	2900	100		
990	9800	2	9800	100	4300	100		
991	4300	2	4300	100	4300	100		
992	5600	2	5600	100	4300	100		
993	7000	3	7000	100	4300	100	4300	100
994	7000	1	7000	100				
995	7000	2	7000	100	5600	100		
1001	4300	3	4300	100	1500	100	100	100
1006	7000	3	7000	100	4300	100	2900	100
1007	8400	2	8400	100	4300	100		
1010	9800	1	9800	100				
1021	7000	3	7000	100	5600	100	5600	100
1022	2900	3	2900	100	2900	100	2900	100
1025	100	1	100	100				
1026	100	1	100	100				
1030	1500	2	1500	100	1500	100		
1039	7000	3	7000	100	2900	100	2900	100
1048	9800	1	9800	100				
1049	8400	2	8400	100	4300	100		
1060	7000	1	7000	100				
1070	2900	2	2900	100	1500	100		
1071	4300	3	4300	100	2900	100	2900	100
1072	1500	2	1500	100	1500	100		
1073	5600	3	5600	100	2900	100	100	100
1076	5600	3	5600	100	2900	100	2900	100
1077	9800	2	9800	100	7000	100		
1078	9800	1	9800	100				
1079	7000	3	7000	100	1500	100	1500	100

Circuit	Max GEN IC in KW	# of Zones	KW Zone 1	PF Zone 1	KW Zone 2	PF Zone 2	KW Zone 3	PF Zone 3
1081	2900	3	2900	100	4300	100	2900	100
1082	8400	1	8400	100				
1085	1500	2	1500	100	1500	100		
1094	8400	3	8400	100	5600	100	2900	100
1100	7000	2	7000	100	5600	100		
1101	7000	3	7000	100	5600	100	2900	100
1102	9800	3	9800	100	7000	100	7000	100
1103	8400	3	8400	100	4300	100	2900	100
1104	4300	2	4300	100	2900	100		
1105	7000	3	7000	100	4300	100	2900	100
1116	2900	3	2900	100	1500	100	1500	100
1117	5600	3	5600	100	4300	100	2900	100
1118	7000	3	7000	100	4300	100	2900	100
1119	5600	3	5600	100	2900	100	2900	100
1138	8400	3	8400	100	5600	100	2900	100
1139	7000	2	7000	100	4300	100		
1140	5600	1	5600	100				
1152	7000	1	7000	100				
1153	9800	1	9800	100				
1160	100	1	100	100				
1166	1500	3	1500	100	100	100	100	100
1173	5600	2	5600	100	4300	100		
1174	9800	1	9800	100				
1180	1500	2	1500	100	1500	100		
1201	100	3	100	100	100	100	100	100
1215	5600	2	5600	100	1500	100		
1219	1500	1	1500	100				
1221	7000	2	7000	100	5600	100		
1222	8400	3	8400	100	4300	100	4300	100
1223	5600	2	5600	100	5600	100		
1224	5600	2	5600	100	2900	100		
1225	8400	2	8400	100	7000	100		
1233	1500	3	1500	100	1500	100	1500	100
1234	1500	3	1500	100	1500	100	1500	100
1235	1500	3	1500	100	100	100	100	100
1242	9800	3	9800	100	100	100	4300	100
1243	100	3	100	100	100	100	100	100
1250	1500	3	1500	100	100	100	1500	100
1251	2900	1	2900	100				
1252	2900	1	2900	100				
1256	2900	1	2900	100				
1257	1500	1	1500	100				
1258	2900	1	2900	100				
1260	7000	2	7000	100	4300	100		
1266	5600	2	5600	100	4300	100		

Circuit	Max GEN IC in KW	# of Zones	KW Zone 1	PF Zone 1	KW Zone 2	PF Zone 2	KW Zone 3	PF Zone 3
1269	2900	1	2900	100				
1286	7000	2	7000	100	100	100		
1287	5600	1	5600	100				
1297	4300	2	4300	100	2900	100		
1299	100	3	100	100	100	100	100	100
1434	7000	3	7000	100	5600	100	2900	100
1435	4300	2	4300	100	2900	100		
1436	4300	2	4300	100	4300	100		
1437	9800	1	9800	100				
1438	4300	3	4300	100	5600	100	100	100
1442	9800	1	9800	100				
1444	7000	1	7000	100				
1458	5600	3	5600	100	4300	100	4300	100

APPENDIX II: SAMPLE LISTING OF CONSTRUCTION, OPERATION, AND RELIABILITY STANDARDS

As the influx of distributed energy resources connecting to and / or providing services to and through the electric grid continues to grow, adherence to all applicable construction, operation, maintenance, and reliability standards will remain a paramount focus to ensure a continued safe environment for the public and utility employees, as well as a continued reliable and efficient operation of the grid. The following list is a sample of the numerous standards that may apply to a DER connecting to SDG&E's distribution system. This non-exclusive list includes excerpts from SDG&E's Overhead Practices Standards Series 100 – 1700, Underground Practices Standards Series 3100 – 4800, and Service Standards and Guides Series 100 - 1200.

While some of these standards may sound like minor requirements, the safety implications of a lineman opening or closing an incorrectly labeled switch or insufficient clearances being established between electrical equipment can lead to catastrophic results.

OVERHEAD PRACTICES: STANDARD SERIES 100 - 1700

- Pedestrian Path of Travel and Accessibility
  - Provides guidelines for accommodating the needs of all pedestrians, including those with mobility, visual, or hearing disabilities, at work sites that encroach upon a sidewalk, walkway, or crosswalk.
- Overhead Distribution Switch Numbering
  - Explains the method of overhead distribution switch numbering.
- Overhead High Voltage Sign Installation Requirements
  - Explains and illustrates the installation requirements of high voltage signs, for wood, concrete, fiberglass, and steel for new construction and maintenance.
- SCADA Site Identification Decal
  - Requirements showing the decal used to identify all SCADA sites.
- Pole Marking
  - Shows and describes pole marking methods. All poles (new or replacement) shall be tagged with a pole/equipment number, including other applicable tags such as circuit number, transformer size, fuse size, etc.
- Communication Infrastructure Provider Identification
  - Provides ownership identification tag requirements for communication attachments to SDG&E owned poles.
- G.O. 95 Pole Construction and Ground Clearances
  - Shows the vertical clearances between open wire conductors and cable as required by the G.O. 95. Typical drilling and gaining dimensions are included.
- G.O.95 Requirements

- Provides references in determining minimum requirements of G.O. 95. In some cases, SDG&E standard practices are more restrictive and shall be used.

- High Voltage Clearances for Non-Utility Workers and Equipment
  - These clearances apply to all persons who are not qualified electrical workers authorized by SDG&E to work on SDG&E owned high voltage (600v-50kv) conductors.
- G.O. 95 Structure and Service Drop Attachment Clearances
  - Describes minimum clearances of wires from illuminated and non-illuminated signs.
  - Shows minimum clearance and separation requirements of energized overhead conductors from containers of flammable or explosive mixtures.
  - Shows minimum clearances of supply service drops over thoroughfares, from buildings, at points of attachments to buildings, and the method of attachment.
- Climbing and Working Space -- Clearances
  - Shows and explains climbing space for horizontal insulator construction.
  - Shows climbing space for buck arm construction.
  - Shows the climbing spaces as they relate to dead ending in vertical configuration - 750v and above.
  - Shows the climbing spaces for different aerial cable construction and applies to new or existing 0-750 volt aerial cable construction.
  - Shows the climbing spaces for different secondary rack construction and applies to the rework and rearrangement of existing low voltage rack construction.
  - Shows climbing space on poles with transformers or similar apparatus using 0-750v aerial cable.
- Clearance of Supply Service Drops
  - Clearance of supply service drops from other supply conductors and open wire communications
- Transformer Station Clearances
  - Shows clearance requirements between communications and equipment for transformer installations.
- Magnetic Field Reduction Policy
  - Provides reference to the CPUC Orders that establish EMF policy
- Primary Neutral Conductor Sizes
  - Describes primary neutral conductor sizes as it applies to copper and aluminum conductors for various sizes in the overhead system.

<u>POLES, ARMS AND HARDWARE</u>

- Loading Districts
  - Describes loading districts which affect construction of overhead facilities according to elevation or other conditions.
- Sample wind and vertical loading calculations
  - This standard describes pole class selection due to wind loading of conductors.
  - Describes pole class selection due to wind loading of equipment.
  - Describes the method to determine vertical pole loading.
- Installation of Permanent Steps
  - Shows the installation of pole steps in accordance with SDG&E requirements.
- Sag and Tension Requirements
  - Lists requirements for sag and tension specifications and methodology.
- Pole bracing

- Shows methods of pole bracing used on installations where poles are subjected to sinking and leaning.

GROUNDING, BONDING

- Grounding General Information
    - Shows grounding details for wood and steel poles.
- Bonding General Information
    - Shows methods of bonding and application.

TRANSFORMERS, BOOSTER

- Transformer Application
    - A guide for selecting transformer(s). By prefix. For replacement of existing units in field. And determining those that are obsolete.
- Secondary Transformer Installation
    - Shows the installation of a single-phase, 240/120 volt, secondary transformer for raising or lowering secondary voltage.
- 7.2 Or 12kv Single Phase Installation
    - Shows the method of installing a 7.2 and 12 kv single-phase transformer.
- 7.2 Or 12kv Three Phase Installation, Single Phase Transformer
    - Shows the installation of 7.2 and 12kv, three-phase transformers.
- Grounding Bank Installation
    - Shows the installation of a 12kv grounding bank with cluster mounting bracket.

SECTIONALIZING, ARRESTORS

- Secondary Current-Limiting Fuses
    - Describes the use of secondary current limiting fuses.
- Primary Current-Limiting Fuse Installation
    - Shows current limiting fuses used for cable pole construction.
- Fuses Used In Overhead Construction
    - Shows various types of fuses used on the overhead distribution system.
- Overhead Expulsion Fuse Marking
    - Shows decals to be installed on overhead expulsion fuse holder to identify amperage of fuse element.
- Cutout Assembly
    - Shows the fuse to be used on the 4kv and 12kv electric system in the fire threat zone.
- Electronic Sectionalizer
    - Shows various electronic sectionalizers and their general application.
- In-Line Hook-stick Switch Installation
    - Shows the installation of primary in-line hook-stick disconnects, dead-end clamp connected. This is a preferred method for existing pin and insulator construction. These switches can be installed on #4-4/0 copper and #4-636 aluminum conductor.
- Single Phase Hook-stick Switch Installations
    - Shows various methods of installing cross-arm mounted disconnect switches, 12kv and below.
- Three Phase Gang Operated Switch Installations
    - Shows a horizontal break gang operated pole top switch for circuit ties or sectionalizing purposes.

- Sectionalizing Cutouts Installation, Tangent Position
  - Shows the installation of cutouts used to sectionalize circuits on tangent position,
- Sectionalizing Cutouts Installation, Buck Corner Position
  - Shows the installation of cutouts used to sectionalize circuits on tangent position,
- Cross-arm Mounted Parallel Fuse And Hook-stick Switch Installation
  - Shows the installation method for a fuse and switch in parallel to be used with #336.4 ACSR or #4/0 copper and larger conductors.
- Cross-arm Mounted Parallel Fuse And Solid Blade Cutout Installation
  - Shows the installation method for a fused and solid blade cutout in parallel to be used with #3/d ACSR or #1/d copper and smaller conductors.
- Application Of Surge –Lightning- Arresters
  - Describes the purpose and use of surge arresters on the distribution system.
- Lightning Arrester Installation On 4kv Circuits
  - Shows methods of installing lightning arresters on 4kv circuits.
- Nova Switch And SCADA Form 6 Controller With Hook-stick By-Pass Switches
  - Shows the installation method of a nova switch for use as a service restorer, line switch or a tie switch.
- Overhead Fault Indicator Installation And Operation
  - Shows and describes the installation of overhead fault indicators with ratings of 800 and 1000 amps on 3/0, 4/0, 336 and 636 conductors.
- Overhead Auto-ranging Fault Indicator Installation And Operation
  - Shows and describes the installation of overhead auto-ranging fault indicators, both illuminated and wireless.

LIGHTING

  - G.O. 95 minimum clearances

WILDLIFE PROTECTION

- Avian Protection - General
  - References the designated avian protection critical areas and those standards and publications which provide guidance for the application of avian safe construction.
- Avian Mortality Reporting Requirements And Procedures
  - Outlines the requirement and procedure for reporting all avian mortalities.
- Pin And Insulator Cover-Up Devices For Avian Protection
  - Illustrates the installation of avian protection cover-up devices for pin and insulator construction.
- Transformer Cover-Up Devices For Avian Protection
  - Illustrates the installation of avian protection cover-up devices for both single phase and three phase transformer construction in avian protection critical areas and for all new transformer installations.
- Lightning Arrester & Cutout Cover-Up Devices For Avian Protection
  - Illustrates the installation of avian protection cover-up devices for both lightning arresters and cutouts. All lightning arresters require cover-up
- Cross-arm Construction - 3 & 4-Wire Tangent Avian Safe Construction
  - Illustrates phase conductor positions for new single circuit, tangent, three and four wire construction in an avian protection area.

- Cross-arm Construction - 3 Wire Dead-end Avian Safe Construction
  - Illustrates phase conductor positions for new single circuit, dead-end, three wire construction in an avian protection area.
- Cross-arm Construction - 4-Wire Dead-end Avian Safe Construction
  - Illustrates phase conductor positions for new single circuit, dead-end, four wire cross-arm construction in an avian protection area.
- Cross-arm Construction - 4 Wire-Line & Buck Avian Safe Construction
  - This standard illustrates phase conductor positions for new single circuit, dead-end, four wire and buck arm construction in an avian protection area.
- Modified Construction For Existing Poles Avian Safe Construction
  - Illustrates the application of covered jumper wire for existing poles in three- or four-wire construction, specifically in avian protection areas. The standard applies to poles where only a single circuit exists, with dead-ends. This construction is only to be used on existing wood poles that do not meet the clearance requirement for underarm construction, but do meet the pole loading calculation. It also applies where installation of a taller pole is not practical.
- Cross-arm Construction - 4-Wire Tangent Two Levels - Avian Safe Construction
  - Illustrates phase conductor positions for new single circuit, tangent, four wire construction in an avian protection area.
- Pole Top Nest Platform Construction
  - Illustrates the various methods of installing a pole top nest platform.

<u>UNDERGROUND PRACTICES: STANDARD SERIES 3100-4800</u>

- Distribution Switch Numbering (UG 3104)
  - Provides guidelines each switch identified by a unique number that indicates the circuit(s) on which it operates.
- Distribution Structure Numbering
  - Provides guidelines each structure identified by a unique number, including provisions for different applications such as customer generation, etc.
- Electric Conduit Field Mapping
  - Shows field mapping requirements of electric conduit for the purposes of creating an accurate as-built.

<u>IDENTIFICATION</u>

- Cable Identification
  - Identifies cables in accordance with CPUC G.O. 128 and SDG&E safety requirements to ensure uniform coding of primary cable for personnel safety and identification.
- Communication Conduit Identification
  - Shows the method of identifying ownership of communication conduit installed by SDG&E.
- Structure Equipment Identification
  - Shows structure/equipment identification number in accordance with CPUC G.O. 128 and SDG&E requirements. Installations of tags are required and illustrated.
- Fire Pump Warning Labels
  - Shows the label to be installed on all transformers which serve fire pumps located in buildings or structures.
- Primary Metering Station Identification

- Shows the installation and identification of circuit numbers, circuit voltage, and structure/equipment identification numbers for primary metering equipment, both SDG&E and customer-owned.

- Transformer Station Identification
  - Shows the installation and identification of circuit numbers, structure/equipment identification numbers, fuse sizes, switch numbers, and the location of the fault indicators.
- Subsurface/Surface Operable & Pad-Mounted Switch Identification
  - Shows the installation and identification of circuit numbers, structure/equipment identification numbers, fuse sizes, switch numbers, and the location of the fault indicators.
- Identification Decals
  - Shows the labels to be installed on all equipment/structures.
- Pad-Mounted Equipment – High Voltage Decal
  - Shows the tags used to identify the presence of high voltage inside pad-mounted equipment.
- Customer Generator Identification – Warning Tag
  - This standard shows the tags used to identify pad-mounted equipment that is interconnected to a customer generator.
- SCADA Site Identification Decal
  - This standard shows the tags used to identify all SCADA sites/equipment.
- Buried Fiber Optic Cable Warning Decal
  - This standard shows the buried fiber optic cable warning decal to be attached to all riser conduits containing fiber optic cables.
- Pad-Mounted Equipment – Working Space Tags
  - This standard shows the tags used to define the safe working space around pad-mounted equipment.

SUBSTRUCTURES, CONDUITS

- Concrete Products - Manholes, Handholes, Covers And Enclosures
  - Lists the concrete products used in subsurface installations.
- FALSE CURB
  - Provides information pertaining to false curbs.
- Installation Of Substructures On Sloping Grades
  - Shows the installation and material required to set substructures on sloping grades.
- Manholes
  - Shows the installation and material requirements for a manhole.
- Street Resurfacing
  - Shows resurfacing of an existing street after the installation or raising of a substructure.
- Joint Trench Typical Location For Underground Conversions
  - Shows typical joint trench location for underground conversions.
- Imported Or Native Backfill
  - Shows typical placement of base, shading, and imported or native backfill material.
- Trench Paralleling Foundations
  - Shows a typical service trench excavation paralleling a residential building.
- Underground Distribution - Trenches And Utility Positioning
  - Shows typical placement of utilities within trenches for distribution and service in dedicated r/w (street) and private property, and provides the minimum depth and clearance that must be maintained between various utilities occupying the same trench.

- Conduit Sizing For Underground Cables
  - Lists the minimum conduit size required for the installation of primary and secondary cables.
- Conduit And Conduit Fittings
  - Shows the conduit and fittings used to construct underground conduit systems.
- Conduit Installations Practices
  - Shows practices which are essential for proper installation of a conduit system.
- Conduit Spacer Data
  - Shows conduit spacers for multi-duct installation.
- Conduit, Encased Multi-Conduit Installation
  - Shows cement and slurry mixture. Also shown are concrete slurry encased conduit installations.
- Conduit Stub Marker And Tracer Wire Locating System
  - Shows the installation and material required for installing the conduit stub marker and ball marker locating system used to locate and show the depth of primary, secondary and service conduit stubs.
- Conduit Installation In Bridges
  - Explains the process required to install electric conduit in new and existing bridges.
- Conduit Substructure Adaptors
  - Shows the accessories and procedures that enable 1 inch conduit to be installed into 5 inch substructure duct terminators.
- Conduit Splicing Installation For Cable-In-Conduit -Pid & Sida
  - Shows the installation and material requirements for splicing or repairing cable-in-conduit conduit or flexible conduit.
- Soil Gas Mitigation
  - Used when constructing underground electric distribution facilities in areas where it has been determined high concentrations of soil gas are present.

<u>PADS, RETAINING WALLS, CLEARANCES</u>

- Pad-Mounted Equipment Wire Entry Prevention
  - Shows sealant used to fill gaps between concrete pads and pad-mounted equipment to prevent a person from passing a wire or other conducting material from the outside into a compartment with exposed live parts after the equipment is closed and locked.
- Single-Phase Transformer/Utility Equipment Pad
  - Shows the pad and installation requirements for the allowable conduit combinations and configurations for a single-phase transformer, three-phase fuse cabinet, single-phase fuse cabinet and single-phase cable terminator.
- Pme 9, 10 & 11 Pad
  - Shows the box pad w/temporary cover and conduit placement for the pad-mounted pme 9, 10, 11 air break and 2 sided 4-way trayer switches.
- Transformer Sound Enclosure
  - Shows the dimensional criteria for installation of pad-mounted transformer sound enclosures. Enclosures are to be used when transformers noise is to be reduced.
- Equipment Barrier Protection And Clearance
  - Illustrates barrier post usage when needed to protect SDG&E facilities from passenger vehicles, trucks, fork lifts, trailers or other heavy mobile items.
- Clearance Requirements For Pad-Mounted And Subsurface Equipment From Above Ground Objects

- Shows the minimum retaining wall and operating clearances required for pads and subsurface structures.

- Minimum Operating Clearance Requirements For Pad-Mounted Equipment
  - Shows the minimum operating clearances required for pad mounted equipment.
- Clearances Between SDG&E Facilities And Other Above Ground Objects
  - Illustrates the required clearances from above ground objects and minimum hot stick clearance.

SECONDARY/SERVICES

- Secondary Test Procedure
  - Used when connecting secondary conductors to an energized source.
- Residential Riser And Conduit
  - Shows 2 inch conduit termination at the customer's conduit riser.
- Underground Electrical Service Lateral – Customer Installed Conduit, Residential Or Commercial
  - Shows customer installed conduit for a residential or commercial service lateral.
- Sealing Service Lateral Conduit, Instructions
  - Shows the installation and material requirements for sealing service lateral conduits (per G.O. 128 - Rule 31.6)
- Elevation Of Customer Facilities Preventing Water Entry
  - Covers the elevation of customer primary and secondary service laterals when they are lower than that of the SDG&E facility that serves them and preventing water entry.

GROUNDING

- Grounding Hardware
  - Covers the hardware used in grounding pad mounted and sub-surface equipment and facilities.
- Trench Ground Wire
  - Shows the (preferred i) trench ground wire installation used to provide grounding. This method shall be used when the same party is responsible for the conduit and pad installation and when a system neutral from a substation or grounding bank is present.
- Equipment Grounding Installation
  - Shows equipment grounding installation used to provide equipment grounding. This method shall be used when different parties are responsible for conduit and pad installations.

TELECOMMUNICATIONS, SCADA

- Telecommunications Splicing Pedestal
  - Shows equipment and installation for SDG&E telecommunications.
- Telecommunications Conduit Riser & Trench
  - Shows equipment and installation for SDG&E telecommunications involving conduit riser & trench.
- Telecommunications Fiber Optic Riser Pole
  - Shows the method used attach multiple 1-1/4 inch PVC conduits to rise poles.
- Telecommunications 4-Way Conduit, Bends, Sweeps And Inner Duct
  - Shows typical SCADA installations in transformer vaults.

VAULT STANDARDS

- Extensive specifications pertaining to the installation of SDG&E distribution facilities in a customer-owned vault. The information provides requirements to be followed for the construction of the vault and installation of electrical equipment per SDG&E standards.
- This installation must comply with all applicable rules of the Electrical Safety Orders of the Division of Industrial Safety, Department of Industrial Relations, State of California, National Electric Code, CA Code of Regulations Title 8, CPUC G.O. 128, and other governing codes and ordinances.

SERVICE STANDARDS AND GUIDES: SERIES 100-1200

CUSTOMER GENERATION (800)

- Distributed Generation
- Regulations For Connection Of Customer-Owned Sources
- Data Required For Design
- Net Generator Output Metering
- Inspection Requirements
- Accessibility
- Disconnection Devices
- Billing And Purchase Of Energy Metering
- Regulations For Connection Of Customer-Owned Sources

APPENDIX III: DER GROWTH SCENARIOS

APPENDIX III.a - SCENARIO 1

SCENARIO 1:

2014 Update IEPR (Updates Adopted Final 2013 IEPR Mid Case Demand Forecast with 2014 actual peaks and updated economic demographics) with Mid Case AAEE from Adopted Final IEPR. Values are in MW

Year	Total End Use Load From Mid Case 2014 Update IEPR (1)	Remove EV Charging	Add Back DR	Adjusted End Use Load	Distribution Losses (5.3%)	Substation Load	Mid Case AAEE From Adopted Final 2013 IEPR	Distribution Losses (5.3%)	Substation AAEE	Final Adjusted Substation Load 1-in-2	1-in-10 Weather Adjustment Factor	Final Adjusted Substation Load 1-in-10
2015	4,605	2	39	4,642	246	4,888	48	3	50	4,837	1.115	5,393
2016	4,667	4	40	4,703	249	4,952	103	5	109	4,843	1.115	5,400
2017	4,740	6	40	4,775	253	5,028	154	8	162	4,866	1.115	5,425
2018	4,811	7	41	4,845	257	5,102	203	11	213	4,888	1.115	5,450
2019	4,878	9	42	4,911	260	5,171	252	13	265	4,906	1.115	5,470
2020	4,938	11	42	4,968	263	5,232	296	16	312	4,920	1.115	5,486
2021	4,995	14	43	5,024	266	5,290	345	18	363	4,927	1.115	5,494
2022	5,054	16	43	5,082	269	5,351	397	21	418	4,933	1.115	5,500
2023	5,110	19	44	5,135	272	5,407	454	24	478	4,929	1.115	5,496
2024	5,168	21	44	5,190	275	5,465	511	27	538	4,927	1.115	5,494
2025	5,225	24	44	5,245	278	5,523	568	30	598	4,925	1.115	5,491

Footnote (1): Because this spreadsheet begins with end-use demand values, PV and non-PV Cogen do not need to be added back in.

TSV 6/14/2015

Installed Capacity

Year	PV: Residential	PV: Non-residential	Fuel Cell CHP	Fuel Cell Electric	Gas Recip. Engine	Gas Turbine	Micro Turbine	Total Non PV	Total: PV	Total: Non PV
2015	145	130	7	14	32	140	1	195	275	195
2016	172	141	9	14	34	140	2	199	313	199
2017	173	150	9	14	36	140	3	202	323	202
2018	174	160	10	14	39	140	3	206	334	206
2019	176	171	10	14	41	140	4	209	346	209
2020	192	182	10	14	44	140	5	213	374	213
2021	218	194	11	14	47	140	6	217	411	217
2022	250	205	11	14	49	140	7	220	455	220
2023	288	216	11	14	52	140	7	224	504	224
2024	329	227	11	14	55	140	8	227	556	227
2025	371	238	11	14	57	140	9	230	609	230

Contribution to System at Time of System Peak

Year	PV - Residential	PV: Non-residential	Fuel Cell CHP	Fuel Cell Electric	Gas Recip. Engine	Gas Turbine	Micro Turbine	Total Non PV	Total: PV	Total: Non PV	Demand Response: Year	Demand Response: Non Dispatchable	Demand Response: Dispatchable	Demand Response: Total DR	EV: Remove EV Charging
2015	71	62	4	7	15	90	1	117	132	117	2015	39	39	78	2
2016	83	67	5	8	17	90	2	122	149	122	2016	40	40	80	4
2017	82	71	6	8	19	90	2	125	153	125	2017	40	40	80	6
2018	82	75	7	8	22	90	3	129	157	129	2018	41	40	81	7
2019	82	80	7	8	24	90	4	133	162	133	2019	42	39	81	9
2020	90	85	7	8	27	90	5	137	175	137	2020	42	40	82	11
2021	102	90	7	8	30	90	5	140	192	140	2021	43	39	82	14
2022	117	96	7	8	32	90	6	144	213	144	2022	43	40	83	16
2023	135	101	7	8	35	90	7	147	236	147	2023	44	40	84	19
2024	155	106	7	8	37	90	8	150	260	150	2024	44	40	84	21
2025	175	110	7	8	40	90	8	153	285	153	2025	44	40	84	24

TSV 5/4/2015

Description:
Step 2 of tab "Substation Load" removed EV, PV, and Non-PV DER impacts from the system level forecast. This tab, DER By Techonology, reflects the system level DER impact values used in this scenario.

This spreadsheet contains two sections, separated by by a heavy blue line. The upper portion of the spreadheet provides the installed capacity data associated with the PV and Non-PV in the lower portion of this spreadsheet.
o The values in the lower portion of the spreadsheet represent the forecasted impact, in MW, of PV, Non-PV, DR, and EV DERs on SDG&E's system level peak demand.

Because scenario 1 is the base scenario, no modifications were made to the values in the IEPR forecasts; therefore SDG&E's replacement impact values are the same values as those removed.

SDG&E's Distribution System Planners disaggregate these system level impact values down to the substation and distribution circuit level.

	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P
8	**Additional Achievable Energy Efficiency Savings For SDG&E Service Territory**															
9	**CED 2013 Final Forecast, Mid Savings Scenario, Revised April 2014**															
10	Sector	Savings Category	Type	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	
11	Residential	Total	Peak (MW, Customer Side)	0	3	22	46	67	94	117	141	163	185	206	229	
12	Commercial	Total	Peak (MW, Customer Side)	6	9	37	68	97	118	143	163	190	219	253	287	
13	Industrial-Manufacturing	Total	Peak (MW, Customer Side)	0	0	1	2	2	3	3	4	5	5	6	7	
14	Agricultural	Total	Peak (MW, Customer Side)	0	0	0	0	0	0	0	1	1	1	1	1	
15	All Sectors	Total		6	13	60	116	167	215	265	309	358	410	466	524	
16																
17	**Customer Side AAEE adjusted to change base yr to 2015 and add impact for 2025**															
18	Sector	Savings Category	Type	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
19	Residential	Total	Peak (MW, Customer Side)			19	43	64	91	114	138	160	182	203	226	251
20	Commercial	Total	Peak (MW, Customer Side)			28	59	88	109	134	154	180	209	244	278	309
21	Industrial-Manufacturing	Total	Peak (MW, Customer Side)			1	1	2	3	3	4	4	5	6	6	7
22	Agricultural	Total	Peak (MW, Customer Side)			0	0	0	0	0	1	1	1	1	1	1
23	All Sectors	Total				48	103	154	203	252	296	345	397	454	511	568
24																
25	**Distribution System Losses 5.3%**															
26	Sector	Savings Category	Type			2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
27	Residential	Total	Peak (MW, Customer Side)			1	2	3	5	6	7	8	10	11	12	13
28	Commercial	Total	Peak (MW, Customer Side)			1	3	5	6	7	8	10	11	13	15	16
29	Industrial-Manufacturing	Total	Peak (MW, Customer Side)			0	0	0	0	0	0	0	0	0	0	0
30	Agricultural	Total	Peak (MW, Customer Side)			0	0	0	0	0	0	0	0	0	0	0
31	All Sectors	Total			Total	3	5	8	11	13	16	18	21	24	27	30
32					Rounded	3	5	8	11	13	16	18	21	24	27	30
33																
34	**AAEE with distribution System Losses**															
35	Sector	Savings Category	Type			2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
36	Residential	Total	Peak (MW, Customer Side)			20	45	67	96	121	145	168	192	214	238	265
37	Commercial	Total	Peak (MW, Customer Side)			29	62	93	115	141	162	190	220	257	292	325
38	Industrial-Manufacturing	Total	Peak (MW, Customer Side)			1	1	2	3	3	4	5	5	6	6	7
39	Agricultural	Total	Peak (MW, Customer Side)			0	0	0	0	0	1	1	1	1	1	1
40	All Sectors	Total			Total	50	109	162	213	265	312	363	418	478	538	598
41	TSV 5/4/2015															

The spreadsheet, tab "AAEE workpaper - page 1", contains the AAEE impact calculations. Adjustments are made, consistent with those made by the CEC to develop the 2014 IEPR Update Forecast, to move the starting point from 2013 to 2015. Another adjustment was made to extend these impacts one year to 2025.

Step 1.
Begin with customer-side AAEE from the 2013 IEPR demand forecast (Col A-O, Rows 10-15).

Step 2.
The year-to-year impacts are cumulative. To reset the starting point to 2015 subtract the cumulative value as of 2014 from each of the cumulative value in step 1, starting with 2015 and going through 2024 (Col F-O, Rows 27-30).

Step 3.
Extend the 2024 value to 2025 by increasing the impact by the difference between 2023 and 2024 values. Do this to the total value for all sectors and then distribute it proportionally across each sector (Col p, Rows 19-23).

Step 4.
Compute distribution losses for each impact value (ColF-P, Rows 27-31).

Step 5.
Combine all values in rows 19-23 with corresponding values in rows 27-31 to arrive at AAEE with distribution losses included (Col F-P, Rows 36-40).

The values in these tables represent the results of SDG&E allocating the DER Growth Scenario Peak Demand Impact Values (MW), by technology type, across the distribuition circuits. The system level impacts were allocated evenly across all circuits, with a factor for coastal vs. inland used for AAEE and DR and a factor regarding existing cogen used for cogen.

o PV: System values spread evenly across SDG&E's distribution system.
o PEV: System values spread evenly across SDG&E's distribution system.
o ES: System values spread evenly across SDG&E's distribution system.
o Cogen: System values spread evenly across the distribution circuits with existing cogen.
o AAEE: 20% of system value assigned evenly to coastal distribution circuits and 80% assigned evenly to inland distribution circuits.
o DR: Assigned evenly to coastal distribution circuits

Scenario 1: Base DER Growth Per Circuit (MW)								
Year	PEV	Non-Disp.	Dispatched	Cogen	PV	AAEE Coastal	AAEE Inland	ES
2015	0.0025	0.12	0.12	4.50	0.16	0.03	0.08	0.00
2016	0.0050	0.12	0.12	4.69	0.18	0.06	0.17	0.00
2017	0.0074	0.12	0.12	4.81	0.19	0.09	0.26	0.00
2018	0.0087	0.12	0.12	4.96	0.19	0.12	0.34	0.00
2019	0.0112	0.13	0.12	5.12	0.20	0.15	0.43	0.00
2020	0.0136	0.13	0.12	5.27	0.22	0.18	0.50	0.00
2021	0.0173	0.13	0.12	5.38	0.24	0.21	0.58	0.00
2022	0.0198	0.13	0.12	5.54	0.26	0.24	0.67	0.00
2023	0.0235	0.13	0.12	5.65	0.29	0.27	0.77	0.00
2024	0.0260	0.13	0.12	5.77	0.32	0.31	0.86	0.00
2025	0.0297	0.13	0.12	5.88	0.35	0.34	0.96	0.00

APPENDIX III.b - SCENARIO 2

Scenario No. 2: 2014 Update IEPR (Updates Adopted Final 2013 IEPR High Case Demand Forecast with 2014 actual Peaks and fresh Econ Demos) with Mid AAEE from Adopeted Final IEPR. Values in MW

Year	Total End Use Load From High Case 2014 Update IEPR (1)	Remove High Case EV Charging	Add Back High Case DR	Adjusted End Use Load	Distribution Losses	Substation Load	Mid Case AAEE From Adopted Final 2013 IEPR, Same as used for 2014 LTPP High Growth Case	Nondispatchable DR from SDGE 2015 IEPR Demand Forecast	Dispatchable DR from SDGE 2015 IEPR Demand Forecast	Distribution Losses	Substation AAEE-DR	Final Adjusted Substation Load 1-in-2
2015	4,623	3	39	4,659	247	4,906	48	28	51	7	133	4,772
2016	4,716	6	40	4,750	252	5,002	103	49	52	11	215	4,787
2017	4,815	9	40	4,847	257	5,104	154	50	52	14	270	4,833
2018	4,907	12	41	4,936	262	5,198	203	52	52	16	323	4,875
2019	4,995	15	42	5,021	266	5,287	252	52	52	19	375	4,912
2020	5,080	18	42	5,104	270	5,374	296	53	52	21	422	4,952
2021	5,158	22	43	5,179	274	5,453	345	53	52	24	474	4,979
2022	5,234	25	43	5,253	278	5,531	397	53	52	27	529	5,002
2023	5,305	28	44	5,322	282	5,604	454	54	52	30	590	5,014
2024	5,379	30	44	5,392	286	5,678	511	54	52	33	650	5,028
2025	5,452	33	44	5,462	289	5,752	568	55	52	36	711	5,041

Footnote (1): Because this spreadsheet begins with end-use peak demand, PV and Non-PV Cogen do not need to be added back in.

TSV 6/14/2015

Step 1.
Initial total end use load is from the CEC's 2014 Upate IEPR Forecast-High Demand Case. See Cloumn C .

Step 2.
Remove DER impact included in this forecast by subtracting out or adding back-in where appropriate:
o Subtract out EV Charging (Col D)
o Add back DR impacts (Col E)
The result is an adjusted system level end use load (Col H)

Step 3.
Compute distribution losses on adjusted end use load (col I)
Add the losses to the adjusted end use load to arrive at substation load at the system level. (Col J)

Step 4.
Copy the AAEE impacts from column G of the spreadsheet behind tab "AAEE Breakout" and paste them here (Col L).
Enter Nondispatchable and dispatchable DR in Clolumns M and N. The source of these values is SDG&E's 2015 IEPR Demand Forecast, filed with the CEC on April 24, 2015.
Compute distribution losses on these AAEE and DR impacts (Col O)
Add the AAEE impacts, DR impacts and Losses to arrive at substation AAEE-DR at the system level (Col P)

Step 5.
Subtract Substation AAEE-DR (Col P) from Substation Load (Col J) to arrive at Final Adjusted Substation Load (Col R). This substation load is at the system level. An SDG&E Distribution System Planner will now distribute these system level load values to substaions and below.

Scenario No. 2: 2014 Update IEPR (Updates Adopted Final 2013 IEPR High Case Demand Forecast with 2014 actual peaks and fresh econ Demos) with Mid AAEE from Adopeted Final IEPR. Values in MW

	R	S	T	U	V	W	X	Y	Z	AA	AH	AI
3			Additional DER Adjustemnts to be Distributed Throughout the Distribution System									
4				DERs From the SDGE 2015 IEPR Demand Forecast (Filed with CEC on 4/24/15)								
5	Final Adjusted Substation Load 1-in-2		Year	EV Charging at Time of Coincident Peak	PV Private Supply at Time of Coincident Peak	PV Private Supply Installed Capacity	Non PV Private Supply at Time of Coincident Peak	Non PV Private Supply Installed Capacity	Storage From CPUC Decision 13-10-040 on Storage Procurement Distribution System Support)		1-in-10 Weather Adjustment Factor	Final Adjusted Substation Load 1-in-10
6	4,772		2015	6	161	438	101	160			1.115	5,321
7	4,787		2016	7	200	531	102	161			1.115	5,338
8	4,833		2017	9	232	607	103	162			1.115	5,389
9	4,875		2018	11	262	680	104	164	5		1.115	5,436
10	4,912		2019	13	289	749	104	165	8		1.115	5,477
11	4,952		2020	14	316	815	105	167	12		1.115	5,522
12	4,979		2021	14	341	877	106	168	18		1.115	5,552
13	5,002		2022	15	365	938	107	169	24		1.115	5,577
14	5,014		2023	15	388	996	108	171	33		1.115	5,591
15	5,028		2024	15	411	1,054	109	172	44		1.115	5,606
16	5,041		2025	15	434	1,111	110	174	44		1.115	5,621

Step 6.
The calculations on Tab: Substation Load - page 1 reflect removing the PEV, DR, PV, and Non-PV DER system-level impacts values from the IEPR forecast.
This section of the spreadsheet reflects incorporating replacement DERs impact values from SDG&E's 2015 IEPR Forecast for EV, PV and Non-PV DERs.
Also, a ES was added as a new DER technology type. The ES values were sourced from the Storage DER is CPUC Decision 13-10-040 on Storage Procurement Distribution System Support (Col U-Z)

Step 7.
SDG&E's Distribution System Planners disaggregate the resulting new system level impact values down to the substations and distribution circuit level.

	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P
8	**Additional Achievable Energy Efficiency Savings For SDG&E Service Territory**															
9	**CED 2013 Final Forecast, Mid Savings Scenario, Revised April 2014**															
10	Sector	Savings Category	Type	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	
11	Residential	Total	Peak (MW, Customer Side)	0.0	2.9	22.3	46.0	67.0	93.9	117.4	140.5	162.7	185.0	206.3	229.1	
12	Commercial	Total	Peak (MW, Customer Side)	6.1	9.4	37.1	68.3	97.4	118.1	143.2	163.3	189.6	218.6	253.3	287.0	
13	Industrial-Manufacturing	Total	Peak (MW, Customer Side)	0.2	0.4	1.0	1.6	2.2	2.9	3.5	4.1	4.7	5.3	5.9	6.5	
14	Agricultural	Total	Peak (MW, Customer Side)	0.0	0.0	0.1	0.2	0.3	0.4	0.5	0.6	0.7	0.7	0.8	0.9	
15	All Sectors	Total		6.3	12.7	60.5	116.1	166.9	215.3	264.6	308.5	357.7	409.7	466.4	523.6	
16																
17	**Customer Side AAEE adjusted to change base yr to 2015 and add impact for 2025**															
18	Sector	Savings Category	Type	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
19	Residential	Total	Peak (MW, Customer Side)			19	43	64	91	114	138	160	182	203	226	251
20	Commercial	Total	Peak (MW, Customer Side)			28	59	88	109	134	154	180	209	244	278	309
21	Industrial-Manufacturing	Total	Peak (MW, Customer Side)			1	1	2	3	3	4	4	5	6	6	7
22	Agricultural	Total	Peak (MW, Customer Side)			0	0	0	0	0	1	1	1	1	1	1
23	All Sectors	Total				48	103	154	203	252	296	345	397	454	511	568
24																
25	**Distribution System Losses 5.3%**															
26	Sector	Savings Category	Type			2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
27	Residential	Total	Peak (MW, Customer Side)			1.0	2.3	3.4	4.8	6.1	7.3	8.5	9.7	10.8	12.0	13.3
28	Commercial	Total	Peak (MW, Customer Side)			1.5	3.1	4.7	5.8	7.1	8.2	9.6	11.1	12.9	14.7	16.4
29	Industrial-Manufacturing	Total	Peak (MW, Customer Side)			0.0	0.1	0.1	0.1	0.2	0.2	0.2	0.3	0.3	0.3	0.4
30	Agricultural	Total	Peak (MW, Customer Side)			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1
31	All Sectors	Total			Total	2.5	5.5	8.2	10.7	13.3	15.7	18.3	21.0	24.0	27.1	30.1
32					Rounded	3	5	8	11	13	16	18	21	24	27	30
33																
34	**AAEE with distribution System Losses**															
35	Sector	Savings Category	Type			2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
36	Residential	Total	Peak (MW, Customer Side)			20	45	67	96	121	145	168	192	214	238	265
37	Commercial	Total	Peak (MW, Customer Side)			29	62	93	115	141	162	190	220	257	292	325
38	Industrial-Manufacturing	Total	Peak (MW, Customer Side)			1	1	2	3	3	4	5	5	6	6	7
39	Agricultural	Total	Peak (MW, Customer Side)			0	0	0	0	0	1	1	1	1	1	1
40	All Sectors	Total			Total	50	109	162	213	265	312	363	418	478	538	598
41																
42	TSV 5/4/2015															

The spreadsheet, tab "AAEE workpaper - page 1", contains the AAEE impact calculations. Adjustments are made, consistent with those made by the CEC to develop the 2014 IEPR Update Forecast, to move the starting point from 2013 to 2015. Another adjustment was made to extend these impacts one year to 2025.

Step 1.
Begin with customer-side AAEE from the 2013 IEPR demand forecast (Col A-O, Rows 10-15).

Step 2.
These impacts are cumulative, from year to year. To reset the starting point to 2015 subtract the cumulative value as of 2014 from ecah of the culuative value in step1, starting with 2015 and going through 2024 (Col F-O, Rows 27-30).

Step 3.
Extend the 2024 value to 2025 by increasing the impact by the difference between 2023 and 2024 values. Do this to the total value for all sectors and then distribut it proportionally across ecah sector (Col p, Rows 19-23).

Step 4.
Compute distribution losses for each impact value (ColF-P, Rows 27-31).

Step 5.
Combine all values in rows 19-23 with corresponding values in rows 27-31 to arrive at AAEE with distribution losses included (Col F-P, Rows 36-40).

The values in these tables represent the results of SDG&E allocating the DER Growth Scenario Peak Demand Impact Values (MW), by technology type, across the distribution circuits. The system level impacts were allocated evenly across all circuits, with a factor for coastal vs. inland used for AAEE and DR and a factor regarding existing cogen used for cogen.

o PV: System values spread evenly across SDG&E's distribution system.
o PEV: System values spread evenly across SDG&E's distribution system.
o ES: System values spread evenly across SDG&E's distribution system.
o Cogen: System values spread evenly across the distribution circuits with existing cogen.
o AAEE: 20% of system value assigned evenly to coastal distribution circuits and 80% assigned evenly to inland distribution circuits.
o DR: Assigned evenly to coastal distribution circuits

Scenario 2: High DER Growth Per Circuit (MW)

Year	PEV	Non-Disp.	Dispatched	Cogen	PV	AAEE Coastal	AAEE Inland	ES
2015	0.0074	0.08	0.15	3.85	0.20	0.03	0.08	0.00
2016	0.0087	0.15	0.16	3.92	0.25	0.06	0.17	0.00
2017	0.0112	0.15	0.16	3.96	0.29	0.09	0.26	0.00
2018	0.0136	0.16	0.16	4.00	0.32	0.12	0.34	0.01
2019	0.0161	0.16	0.16	4.00	0.36	0.15	0.43	0.01
2020	0.0173	0.16	0.16	4.04	0.39	0.18	0.50	0.01
2021	0.0173	0.16	0.16	4.08	0.42	0.21	0.58	0.02
2022	0.0186	0.16	0.16	4.12	0.45	0.24	0.67	0.03
2023	0.0186	0.16	0.16	4.15	0.48	0.27	0.77	0.04
2024	0.0186	0.16	0.16	4.19	0.51	0.31	0.86	0.05
2025	0.0186	0.16	0.16	4.23	0.54	0.34	0.96	0.05

	B	C	D	E	H	I	J	K	L	M	N	O	P	Q	R
2	**Scenario No. 3: 2014 Update IEPR Mid Demand Forecast with High AAEE from Adopted Final IEPR. Values in MW**														
3	**Computation of DR for 5% of peak DR goal**														
4															
5	Year	Total End Use Load From Mid Case 2014 Update IEPR	Remove EV Charging	Add Back DR	Adjusted End Use Load	Distribution Losses (5.3%)	Substation Load		**High Case** AAEE From Adopted Final 2013 IEPR	Nondispatchable DR as 5% of Adjusted Peak Demand	Dispatchable DR as 5% of Adjusted Peak Demand	Distribution Losses (5.3%)	Substation AAEE and DR		Final Adjusted Substation Load 1-in-2
31	2015	4,605	2	39	4,642	246	4,888		58	114	114	15	302		4,586
32	2016	4,667	4	40	4,703	249	4,952		133	113	113	19	378		4,574
33	2017	4,740	6	40	4,775	253	5,028		212	112	112	23	459		4,569
34	2018	4,811	7	41	4,845	257	5,102		291	111	111	27	540		4,561
35	2019	4,878	9	42	4,911	260	5,171		373	110	110	31	624		4,547
36	2020	4,938	11	42	4,968	263	5,232		449	108	108	35	702		4,530
37	2021	4,995	14	43	5,024	266	5,290		536	107	107	40	789		4,501
38	2022	5,054	16	43	5,082	269	5,351		627	105	105	44	882		4,469
39	2023	5,110	19	44	5,135	272	5,407		727	103	103	49	983		4,424
40	2024	5,168	21	44	5,190	275	5,465		829	101	101	55	1,086		4,380
41	2025	5,225	24	44	5,245	278	5,523		886	100	100	58	1,144		4,379
42															
43	TSV 5/19/2015														

	R	U	V	W	X	Y	Z	AA	AB	AI	AJ	AK
3			Additional DER Adjustemnts to be Distributed Throughout the Distribution System									
4				DERs From the SDGE 2015 IEPR Demand Forecast (Filed with CEC on 4/24/15)								
5	Final Adjusted Substation Load 1-in-2		Year	EV Charging at Time of Coincident Peak (Same as Scenario 2)	PV Private Supply at Time of Coincident Peak (Same as Scenario 2)	PV Private Supply Installed Capacity (Same as Scenario 2)	Non PV Private Supply at Time of Coincident Peak (Same as Scenario 2)	Non PV Private Supply Installed Capacity (Same as Scenario 2)	Storage From CPUC Decision 13-10-040 on Storage Procurement Distribution System Support (Same as Scenario 2)		1-in-10 Weather Adjustment Factor	Final Adjusted Substation Load 1-in-10
31	4,586		2015	6	161	438	101	160			1.115	5,113
32	4,574		2016	7	200	531	102	161			1.115	5,100
33	4,569		2017	9	232	607	103	162			1.115	5,094
34	4,561		2018	11	262	680	104	164	5		1.115	5,086
35	4,547		2019	13	289	749	104	165	8		1.115	5,070
36	4,530		2020	14	316	815	105	167	12		1.115	5,051
37	4,501		2021	14	341	877	106	168	18		1.115	5,019
38	4,469		2022	15	365	938	107	169	24		1.115	4,983
39	4,424		2023	15	388	996	108	171	33		1.115	4,933
40	4,380		2024	15	411	1,054	109	172	44		1.115	4,883
41	4,379		2025	15	434	1,111	110	174	44		1.115	4,882

	AJ	AK	AL	AM	AN	AO	AP	AQ	AR	AS	AT	AU	AV	AW	AX
5	1-in-10 Weather Adjustment Factor	Final Adjusted Substation Load 1-in-10		Year	Total DERs New EV PV and Storage	DER Losses (5.3%)	DERs with Dist Losses	New AAEE expressed as a negative	Distribution Losses for new AAEE Expressed as a negative	Total New AAEE with losses	Adjusted Substation Load 1-n-2 with New AAEE New DERs and W/O DR	DR goal = 5% of Adj Peak Load without 5.3% Dist. Losses	NonDispatchable without Distribution Losses	Dispatchable without Distribution Losses	Total Adjusted 1-n-2 Substation Load with New AAEE New DERs and New 5% DR
31	1.115	5,113		2015	-257	-14	-270	-58	-3	-61	4,570	228	114	114	4,316
32	1.115	5,100		2016	-295	-16	-310	-133	-7	-140	4,517	226	113	113	4,264
33	1.115	5,094		2017	-326	-17	-344	-212	-11	-223	4,479	224	112	112	4,225
34	1.115	5,086		2018	-360	-19	-379	-291	-15	-307	4,435	222	111	111	4,183
35	1.115	5,070		2019	-389	-21	-410	-373	-20	-393	4,389	219	110	110	4,138
36	1.115	5,051		2020	-419	-22	-441	-449	-24	-473	4,340	217	108	108	4,089
37	1.115	5,019		2021	-451	-24	-474	-536	-28	-564	4,276	214	107	107	4,027
38	1.115	4,983		2022	-481	-26	-507	-627	-33	-660	4,209	210	105	105	3,962
39	1.115	4,933		2023	-515	-27	-542	-727	-39	-765	4,127	206	103	103	3,883
40	1.115	4,883		2024	-550	-29	-579	-829	-44	-873	4,043	202	101	101	3,801
41	1.115	4,882		2025	-573	-30	-603	-886	-47	-933	4,018	201	100	100	3,776

	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P
7	**Additional Achievable Energy Efficiency Savings For SDG&E Service Territory**															
8	**CED 2013 Final Forecast, High Savings Scenario, Revised April 2014**															
9	Sector	Savings Category	Type	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	
10	Residential	Total	Peak (MW, Customer Side)	0.0	3.0	25.5	52.1	76.3	106.7	133.5	159.9	187.6	217.9	247.6	277.1	
11	Commercial	Total	Peak (MW, Customer Side)	6.3	10.4	45.1	92.8	146.5	193.8	248.0	296.7	354.3	414.5	483.5	555.1	
12	Industrial-Manufacturing	Total	Peak (MW, Customer Side)	0.2	0.4	1.1	1.9	2.8	3.8	4.8	5.8	6.6	7.5	8.4	9.2	
13	Agricultural	Total	Peak (MW, Customer Side)	0.0	0.0	0.1	0.2	0.3	0.5	0.6	0.7	0.8	0.9	1.1	1.2	
14	All Sectors	Total		6.5	13.8	71.8	147.0	225.9	304.8	386.9	463.1	549.4	640.9	740.5	842.6	
15																
16	**Customer Side AAEE adjusted to change base yr to 2015 and add impact for 2025**															
17	Sector	Savings Category	Type	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
18	Residential	Total	Peak (MW, Customer Side)			23	49	73	104	130	157	185	215	245	274	293
19	Commercial	Total	Peak (MW, Customer Side)			35	82	136	183	238	286	344	404	473	545	582
20	Industrial-Manufacturing	Total	Peak (MW, Customer Side)			1	1	2	3	4	5	6	7	8	9	9
21	Agricultural	Total	Peak (MW, Customer Side)			0	0	0	0	1	1	1	1	1	1	1
22	All Sectors	Total				58	133	212	291	373	449	536	627	727	829	886
23																
24	**Distribution System Losses 5.3%**															
25	Sector	Savings Category	Type			2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
26	Residential	Total	Peak (MW, Customer Side)			1.2	2.6	3.9	5.5	6.9	8.3	9.8	11.4	13.0	14.5	15.5
27	Commercial	Total	Peak (MW, Customer Side)			1.8	4.4	7.2	9.7	12.6	15.2	18.2	21.4	25.1	28.9	30.9
28	Industrial-Manufacturing	Total	Peak (MW, Customer Side)			0.0	0.1	0.1	0.2	0.2	0.3	0.3	0.4	0.4	0.5	0.5
29	Agricultural	Total	Peak (MW, Customer Side)			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.1
30	All Sectors	Total			Total	3.1	7.1	11.2	15.4	19.8	23.8	28.4	33.2	38.5	43.9	46.9
31					Rounded	3	7	11	15	20	24	28	33	39	44	47
32																
33	**AAEE with distribution System Losses**															
34	Sector	Savings Category	Type			2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
35	Residential	Total	Peak (MW, Customer Side)			24	52	77	109	137	165	194	226	258	289	309
36	Commercial	Total	Peak (MW, Customer Side)			37	87	143	193	250	301	362	426	498	574	613
37	Industrial-Manufacturing	Total	Peak (MW, Customer Side)			1	2	3	4	5	6	7	8	8	9	10
38	Agricultural	Total	Peak (MW, Customer Side)			0	0	0	0	1	1	1	1	1	1	1
39	All Sectors	Total			Total	61	140	223	307	393	473	564	660	765	873	933
40																
41	TSV 5/4/2015															

Description of values and equations contained on Tabs: Substation Load pages 1, 2, 3.

Step 1.

Start with the total end use load from the CEC's 2014 Upate IEPR Forecast-Mid Demand Case. See Column C .

Step 2.

Remove DER impact included in this forecast by subtracting out or adding back in where appropriate:

o Subtract out EV Charging (Col D)
o Add back DR impacts (Col E)
o Add back Non-PV private supply (aka, co-gen) (Col F)
o Add back PV private supply (Col G)

The result is an adjusted system level end use load (Col H)

Step 3.

Compute distribution losses on adjusted end use load (Col I)

Add the losses to the adjusted end use load to arrive at substation load at the system level. (Col J)

Step 4.

Copy the AAEE impacts from row 22 of the spreadsheet behind tab "AAEE Workpaper" and paste them here (Col L).

Enter nondispatchable and dispatchable DR in Clolumns M and N. The source of these values is SDG&E's 2015 IEPR Demand Forecast, filed with the CEC on April 24, 2015.

Compute distribution losses on these AAEE and DR impacts (Col O)

Add the AAEE impacts, DR impacts and losses to arrive at substation AAEE-DR at the system level (Col P)

Step 5.

Subtract Substation AAEE-DR (Col P) from Substation Load (Col J) to arrive at Final Adjusted Substation Load (Col R). This substation load is at the system level. An SDG&E Distribution System Planner will now distribute these system level load values to substaions and below.

Step 6.

Step 2 above removed EV, DR, PV, and Non-PV DER impacts form the system level forecast. This section of the spreadsheet presents new DERs from SDG&E's 2015 IEPR Forecast for EV, PV and Non-PV DERs. Also, A new DER for Storage was added. The source of the Storage DER is CPUC Decision 13-10-040 on Storage Procurement Distribution System Support (Col U-Z)

Step 7.

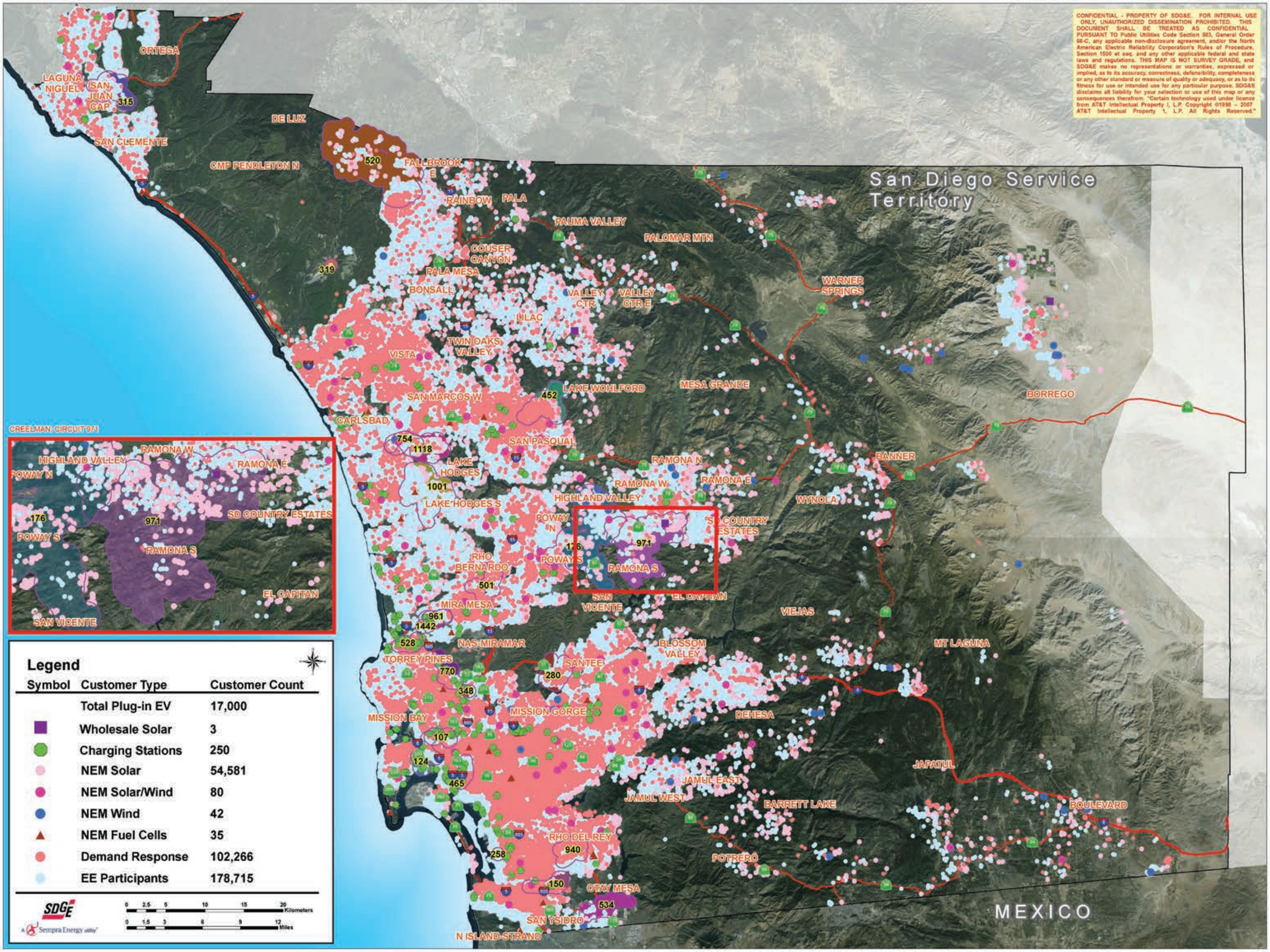
SDG&E's Distribution System Planners disaggregate the resulting new system level impact values down to the substation and distribution circuit level.

The values in these tables represent the results of SDG&E allocating the DER Growth Scenario Peak Demand Impact Values (MW), by technology type, across the distribuition circuits. The system level impacts were allocated evenly across all circuits, with a factor for coastal vs. inland used for AAEE and DR and a factor regarding existing cogen used for cogen.

o PV: System values spread evenly across SDG&E's distribution system.
o PEV: System values spread evenly across SDG&E's distribution system.
o ES: System values spread evenly across SDG&E's distribution system.
o Cogen: System values spread evenly across the distribution circuits with existing cogen.
o AAEE: 20% of system value assigned evenly to coastal distribution circuits and 80% assigned evenly to inland distribution circuits.
o DR: Assigned evenly to coastal distribution circuits

Scenario 3: Very High DER Growth Per Circuit (MW)								
Year	PEV	Non-Disp. DR	Dispatched DR	Cogen	PV	AAEE Coastal	AAEE Inland	ES
2015	0.0074	0.34	0.34	3.85	0.20	0.03	0.10	0.00
2016	0.0087	0.34	0.34	3.92	0.25	0.08	0.22	0.00
2017	0.0112	0.34	0.34	3.96	0.29	0.13	0.36	0.00
2018	0.0136	0.33	0.33	4.00	0.32	0.17	0.49	0.01
2019	0.0161	0.33	0.33	4.00	0.36	0.22	0.63	0.01
2020	0.0173	0.32	0.32	4.04	0.39	0.27	0.76	0.01
2021	0.0173	0.32	0.32	4.08	0.42	0.32	0.91	0.02
2022	0.0186	0.31	0.31	4.12	0.45	0.38	1.06	0.03
2023	0.0186	0.31	0.31	4.15	0.48	0.44	1.23	0.04
2024	0.0186	0.30	0.30	4.19	0.51	0.50	1.40	0.05
2025	0.0186	0.30	0.30	4.23	0.54	0.53	1.50	0.05

ATTACHMENT 1: DER PENETRATION IN SDG&E SERVICE TERRITORY



BEFORE THE PUBLIC UTILITIES COMMISSION OF THE

STATE OF CALIFORNIA

Application of San Diego Gas & Electric Company (U 902 E) For Approval Of Distribution Resource Plan	))))	A.15-07-___

NOTICE OF AVAILABILITY OF APPLICATION OF SAN DIEGO GAS & ELECTRIC COMPANY (U 902 E) FOR APPROVAL OF DISTRIBUTION RESOURCES PLAN

Please take notice of the electronic filing, on July 1, 2015, of the **APPLICATION OF SAN DIEGO GAS & ELECTRIC COMPANY (U 902 E) FOR APPROVAL OF DISTRIBUTION RESOURCES PLAN**. Pursuant to Rule 1.9 of the Rules of Practice and Procedure of the California Public Utilities Commission, the Application was made available by 5:00 p.m. on July 1, 2015 on SDG&E's website at the following location:

http://www.sdge.com/proceedings

The complete application and supporting materials is more than six (6) megabytes in size. SDG&E will upon request provide a copy of the application or any part thereof. SDG&E has all of the forgoing material available on compact disc (CD-ROM), which SDG&E would prefer to provide in lieu of hard copies for ease of handling and to conserve resources. SDG&E will however mail hard copies of documents to parties who request them. Copies of the GRC application, testimony, and other exhibits may be obtained by contacting:

Billie Overturf
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8330 Century Park Court, CP31E
San Diego, CA 92123
Telephone: (858) 654-1779
Email: BOverturf@semprautilities.com

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE

STATE OF CALIFORNIA

Application of San Diego Gas & Electric Company (U 902 E) For Approval Of Distribution Resource Plan	))))	A.15-07-___

CERTIFICATE OF SERVICE

I hereby certify that pursuant to the California Public Utilities Commission's Rules of Practice and Procedure, I have this day served a true and correct copy of the attached **NOTICE OF AVAILABILITY OF APPLICATION OF SAN DIEGO GAS & ELECTRIC COMPANY (U 902 E) FOR APPROVAL OF DISTRIBUTION RESOURCES PLAN** to each party named in the official service list for R.14-08-013. Those parties without an email address were served by placing copies in properly addressed and sealed envelopes and depositing such envelopes in the United States Mail with first-class postage prepaid.

Two hardcopies were also sent via Federal Express to Assigned Administrative Law Judge David M. Gamson and Assigned Commissioner Michael Picker.

Executed this 1st day of July 2015, at San Diego, California.

/s/ Jenifer Nicola
Jenifer Nicola

CPUC Home

CALIFORNIA PUBLIC UTILITIES COMMISSION
Service Lists

PROCEEDING: R1408013 - CPUC - OIR REGARDING
FILER: CPUC
LIST NAME: LIST
LAST CHANGED: JUNE 30, 2015

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