SDG&E' DISTRIBUTION RESOURCES PLAN

DEMONSTRATION B – LOCATIONAL NET BENEFIT ANALYSIS

Final Report

December 22, 2016

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1 Demo B Background and Objectives

On August 14, 2014, the California's Public Utilities Commission (CPUC or Commission) issued Rulemaking (R.) 14-08-013 which established guidelines, rules, and procedures to direct California's investor-owned electric utilities (Utilities or IOUs) to develop their Distribution Resources Plan (DRP). On February 6, 2015, the Commission issued a guidance ruling[1] for the IOUs in filing their DRPs. This guidance ruling included a requirement that an IOU propose a demonstration project (Demo B) that performs the Commission approved Locational Net Benefit Analysis (LNBA) methodology for one distribution planning area (DPA). The LNBA helps specify the benefits that distributed energy resources (DERs) can provide in a given location, meeting a specific distribution need. On July 1, 2015, the three IOUs filed DRPs in compliance with the Guidance Ruling. On February 1, 2016, a workshop on LNBA was held. The Commission subsequently issued an Assigned Commissioner's Ruling (ACR) on May 2, 2016 and a revised ACR on August 23, 2016. In relevant part, the ACR approved a demonstration LNBA methodology (LNBA methodology) framework, instructed the IOUs to apply the LNBA methodology to a DPA, and directed the IOUs to submit a final report for this Demo B by the end of 2016.[2] [3] The Commission anticipates issuing a Decision in Q1 2017 that will adopt an LNBA methodology for the IOUs to implement across their respective entire system.

The objectives of Demo B are to:

- Select a DPA that includes:
  - "one near-term and one longer-term distribution infrastructure project for possible deferral"[4] and;
  - "at least one voltage support/power quality- or reliability/resiliency-related deferral opportunity in addition to one or more capacity-related opportunities."[5]

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[1] Assigned Commissioner's Ruling on Guidance for Public Utilities Code Section 769 – Distribution Resource Planning, ("Final Guidance"), February 6, 2015.

[2] *Assigned Commissioner's Ruling: (1) Refining Integration Capacity and Locational Net Benefit Analysis Methodologies and Requirements; and (2) Authorizing Demonstration Projects A and B*, May 2, 2016, at pp. 25-34.

[3] *Assigned Commissioner's Ruling: (1) Refining Integration Capacity and Locational Net Benefit Analysis Methodologies and Requirements; and (2) Authorizing Demonstration Projects A and B*, August 23, 2016, at pp. A26-A38.

[4] *Assigned Commissioner's Ruling: (1) Refining Integration Capacity and Locational Net Benefit Analysis Methodologies and Requirements; and (2) Authorizing Demonstration Projects A and B*, August 23, 2016, at p. A25.

[5] *Assigned Commissioner's Ruling: (1) Refining Integration Capacity and Locational Net Benefit Analysis Methodologies and Requirements; and (2) Authorizing Demonstration Projects A and B*, August 23, 2016, at p. A25.

- Apply the approved LNBA methodology to identify potential distribution infrastructure projects for deferral, calculate LNBA results under two DER growth scenarios, and develop DER requirements necessary to defer the project.
- Display results in an online heat map as a layer along with the Integration Capacity Analysis (ICA) results.

This detailed final report describes how San Diego Gas & Electric (SDG&E) fulfilled the Commission's requirements for Demo B. Specifically, this report: (1) details methods used to calculate locational benefits in Demo B; (2) demonstrates how SDG&E determined locational variability of benefits within a selected DPA and discusses the results; (3) develops project requirements that must be met for DERs to defer projects; and (4) tests methods and applies lessons learned to future LNBA work. This report also details (see Appendix 3) the specific requirements defined in the ACR, mapping the location where each requirement is addressed in this report, the online heat map, or downloadable dataset.

The following chapters of this final report were written as a collaborative effort between SDG&E, Pacific Gas & Electric Company (PG&E), and Southern California Edison (SCE). These chapters include: Chapter 1 – Demo B Background and Objectives, Chapter 2 – Electric Services, Chapter 7 – Project Deferral Benefit Calculation. In addition, the three IOUs have engaged with Energy and Environmental Economics (E3) to develop an excel tool for estimating location-specific avoided costs of installing DERs; this LNBA tool is based on a specific approved LNBA methodology framework provided to the utilities by the May 5, 2016 ACR for Demo B. Appendix 2, which presents the proposed LNBA methodology, was written by E3.

Many of the approaches in the LNBA methodology described in this report were taken as a result of discussions in the LNBA Working Group, which was formed as a result of the May 5, 2016 ACR. In particular, the LNBA Working Group expressed strong support for using technology-agnostic approaches to evaluating location-specific benefits in Demo B. The methods and tools reflected in this report are therefore designed, to the maximum extent possible, to easily evaluate any DER or combination of DERs.

Demo B provides an initial demonstration of a number of new planning analyses. It is the IOUs' expectation that these methods will continue to evolve as more experience is gained. The results of this demonstration will help inform a Commission Decision to update the LNBA process for the first system-wide implementation. The IOUs expect that this initial LNBA public tool will provide useful information to DER developers in choosing where to site DER projects. The IOUs also expect that portions of the analyses developed in this demonstration will ultimately be incorporated into IOU annual planning processes. Specifically, the analysis of identifying which conventional distribution projects may be deferred by DER solutions is related to the Deferral Framework to be developed in Sub-track 3 of Track 3 of the DRP proceeding. The IOUs look forward to engaging with the Commission and Stakeholders to refine these tools and expand their usefulness. While the specific analyses described in this demonstration is only the first step and will not necessarily be incorporated into the annual

planning process, the IOUs believe this work will lay the foundation to critical transformation in the IOUs annual planning activities.

1.1 Definition of LNBA Components for Demo B

The ACR defined two methodologies – a primary analysis and a secondary analysis – by which IOUs could determine the benefits of DERs in each location within its selected DPA(s).[6] Given that the secondary analysis would require significant time to develop additional methodologies and the given time constraints for Demo B, as acknowledged in the ACR,[7] the IOUs decided to pursue the primary analysis (as defined in Table 2 of the ACR, reproduced in Table 1 below); however, the LNBA Tool is designed to easily incorporate many refinements, including some that are reflected in the secondary analysis.[8]

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6 *Assigned Commissioner's Ruling: (1) Refining Integration Capacity and Locational Net Benefit Analysis Methodologies and Requirements; and (2) Authorizing Demonstration Projects A and B*, August 23, 2016, at pp. A26-A27.

7 *Assigned Commissioner's Ruling: (1) Refining Integration Capacity and Locational Net Benefit Analysis Methodologies and Requirements; and (2) Authorizing Demonstration Projects A and B*, August 23, 2016, at p. A27.

8 *Assigned Commissioner's Ruling: (1) Refining Integration Capacity and Locational Net Benefit Analysis Methodologies and Requirements; and (2) Authorizing Demonstration Projects A and B*, August 23, 2016, at pp. A26-A38.

Table 1 Reproduction of Table 2 from ACR
Approved LNBA Methodology Requirements Matrix for Demo B

Components of avoided costs	Proposed LNBA in IOU Filings	Primary Analysis	Secondary Analysis
from DERAC	*from IOU applications*	*Required*	*Optional additional*
Avoided T&D	**Sub-Transmission / Substation / Feeder**	**As proposed but with modifications (1)**	**As proposed but with modifications (1)**
	Distribution Voltage / Power Quality	**As proposed but with modifications (1)**	**As proposed but with modifications (1)**
	Distribution Reliability / Resiliency	**As proposed but with modifications (1)**	**As proposed but with modifications (1)**
	Transmission	**As specified herein (2)**	**As specified herein (2)**
Avoided Generation Capacity	System and Local RA	Use DERAC values	Use DERAC values with location-specific line losses (3)
	Flexible RA	Use DERAC values with flexibility factor (4)	Use DERAC values with flexibility factor (4)
Avoided Energy	Use LMP prices to determine	Use DERAC values	As proposed but with modifications regarding use of LMP prices (5) and location-specific losses (3)
Avoided GHG	incorporated into avoided energy	Use DERAC values	As proposed
Avoided RPS	similar to DERAC	Use DERAC values	As proposed
Avoided Ancillary Services	similar to DERAC	Use DERAC values	As proposed
additional to the DERAC	Renewable Integration Costs	values or descriptions of these benefits (6)	values or descriptions of these benefits (6)
	Societal avoided costs	values or descriptions of these benefits (6)	values or descriptions of these benefits (6)
	Public safety costs	values or descriptions of these benefits (6)	values or descriptions of these benefits (6)

The benefits in the LNBA methodology include: avoided transmission and distribution (T&D) costs; avoided generation capacity costs; avoided energy costs; avoided greenhouse gas (GHG) costs; avoided renewable portfolio standard (RPS) costs, avoided ancillary services costs; renewable integration costs; and societal and public safety costs. The avoided T&D costs are further broken down into four categories: (1) sub-transmission, substation, and feeder; (2) distribution voltage or power quality; (3) distribution reliability or resiliency; and (4) transmission. Similarly, avoided generation capacity costs are further broken down into two categories: (1) system and local resource adequacy (RA); and flexible RA. The non-T&D components are sometimes referred to in this report generally as system-level avoided costs.

1.2 Definition of Net in Demo B

In a typical net benefit analysis, total net benefits represent the net present value of benefits minus the net present value of costs. However, because table 2 of the ACR[9] defines the LNBA for Demo B as the combined net present value of the components detailed in the paragraph above, the ACR does not include DER costs as specific components of Demo B. However, the value of each component can be either positive or negative. For example, an energy storage device that reduces feeder peak load may have a negative energy avoided cost if the feeder peak occurs when CAISO prices are lower than the prices during charging times.[10]

1.3 LNBA Tool Overview

To calculate the LNBA values, the IOUs engaged E3 to develop a public LNBA tool ("LNBA tool") for Demo B. This tool incorporates the primary analysis components as describe in Table 2 of the ACR[11] and is divided into two major parts. The first part, a project deferral benefit module, calculates the indicative value of deferring a specific capital project. The second part, a system-level avoided cost module, estimates the system-level avoided costs given a user-defined DER solution. The summation of results from both modules provides the estimated achievable avoidable cost for a given DER solution at a specific location. Users provide an hourly profile corresponding to the DER solution of interest. For any DER solution, expressed as an hourly DER profile, the LNBA tool provides two quantitative results corresponding to the two modules described above: (1) an indicative value of the T&D deferral if the solution meets the projects' need requirements; and (2) an estimate of the system-level avoided costs based primarily on E3's DERAC tool.

The project deferral benefit module allows users to input various capital project assumptions and calculate the benefit of deferring such projects. Users need to define various financial inputs, such as the cost of the capital project, discount rate, inflation rate, deferral duration, and revenue requirement multiplier. Similarly, users need to define various project requirements, such as the project driver, electrical characteristic duration, scale, and time of need, loss factors, etc.[12] For the purpose of Demo B, the IOUs will provide indicative inputs for project requirements for the projects identified as deferrable. The IOUs will also provide default

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[9] *Assigned Commissioner's Ruling: (1) Refining Integration Capacity and Locational Net Benefit Analysis Methodologies and Requirements; and (2) Authorizing Demonstration Projects A and B*, August 23, 2016, at pp. A27-A28.

[10] Locational Net Benefit Analysis Working Group presentation, July 26, 2016, at pp. 12-16.

[11] *Assigned Commissioner's Ruling: (1) Refining Integration Capacity and Locational Net Benefit Analysis Methodologies and Requirements; and (2) Authorizing Demonstration Projects A and B*, August 23, 2016, at pp. A27-A28.

[12] Locational Net Benefits Analysis Working Group presentation, November 16, 2016, at pp. 18-23.

values for certain financial variables. Further discussion of inputs and sources is provided in Chapter 7.

The system-level avoided cost module calculates the estimated value of system-level avoided costs. These costs are composed of avoided generation capacity costs, avoided energy costs, avoided GHG costs, avoided RPS costs, avoided ancillary services costs, and renewable integration costs that exist for delivery of energy at any point on the system. Avoided societal and public safety costs were not quantifiable and thus were not included in the LNBA Tool for Demo B; however, consistent with commission guidance,[13] a qualitative description of societal and public safety benefits is included here in section 2.1.6. Once a user inputs assumptions, such as an hourly generation profile and contracted life, the module calculates the value of each system-level avoided cost components. Since these costs are at the system level, the system-level avoided cost results will not vary within the DPA of Demo B.[14] The system level avoided cost components were derived directly from E3's DERAC[15] as outlined within the ACR.

1.4 Heat Map Overview

The heat map associated with Demo B provides a visual depiction of Demo B's deferrable project results calculated using the project deferral module of the LNBA tool. Since values calculated from the system-level avoided cost in Demo B are the same for all locations in the DPA, the heat map does not show these LNBA components. Results for the heat map are further separated by six layers consisting of three time periods—short, medium, and long term, as directed by the commission[16] – each depicted under two DER growth scenarios. There are two additional layers that map the two DER growth scenarios to the DPA.[17] The Demo B heat map is on the same platform as the ICA map, enabling users to access ICA and LNBA data through the same interface. A link to SDG&E's heat map with access instructions is provided in Appendix 1.

1.5 CPUC Requirements and Deliverables

The ACR details a number of requirements and deliverables to be met as part of Demo B. The final deliverables for Demo B include this final report, a heat map displaying LNBA results, and the LNBA tool. In order to ensure that the requirements of the ACR are met, The IOUs have provided a table (Appendix 3) that maps specific ACR requirements to its location in the three final deliverables.

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[13] 5/2 ACR, p. 27, "Societal Avoided costs…. Values or descriptions of these benefits."

[14] Locational Net Benefits Analysis Working Group presentation, November 16, 2016, at pp. 18-23.

[15] https://ethree.com/public_projects/cpuc4.php

[16] 5/2 ACR, p. 28, "….upgrade needs…should be in three categories that correspond to the near-term forecast (1.5-3 year), intermediate term (3-5-year) and long-term (5-10 year) or other time ranges, as appropriate."

[17] DRP Demo B – Mapping Requirements, September, 28, 2016, p. 2.

2 Electric Services

Sec. 4.4.1(A) of the ACR requires the IOUs to identify the full range of electric services that result in avoided costs for all locations within the DPAs selected for analysis. The values must include electrical services associated with distribution grid upgrades identified in: (i) the utility distribution planning process, (ii) circuit reliability improvement process, and (iii) maintenance process (*See* ACR at p. A29).

To accurately value DERs and their services, the IOUs must identify gaps in available services. The LNBA methodology proposed by the Commission requires the IOUs to consider the full range of electric services that DERs can provide; this includes electric services that are internal (utility owned) and external (third party providers) to the utility, both of which can potentially result in an "avoided cost".[18] To quantify the potential reduction in investment costs and to ensure sustainability and reliability of services, each service should also be compared to the conventional "wire-based" methods.

Generally speaking, the electric services should address the two key planning processes (planning for capacity and planning for reliability), as well as the need to ensure safe operation and timely maintenance of the system. That is, electric services are associated with three core functions:

- Utility distribution capacity planning processes,
- Circuit reliability/resiliency improvement processes, and
- Safety/maintenance processes.

In order to investigate the type and value of the services that can be provided by DERs, each service will be characterized from the following perspectives:

- How the service is provided today (*i.e.*, conventional method).
- How a DER can provide the service.

Several factors may limit the ability of DERs to provide reliable electric services. These factors need to be carefully addressed and evaluated during design and deployment stages, including:

- Impact on the conventional engineering practices, such as impact on the protection design; change in protection methodology due to fault current reduction; protection desensitization; significant change in the voltage level; contingency analysis, and forecast accuracy.
- Technology advancement and system requirements to realize the service and prevent any adverse impact on the grid

[18] *Assigned Commissioner's Ruling: (1) Refining Integration Capacity and Locational Net Benefit Analysis Methodologies and Requirements; and (2) Authorizing Demonstration Projects A and B*, August 23, 2016, at p. A29.

- Performance certainty (performance requirements, criteria and availability).
- Current regulatory barriers to the operation of DERs may not allow them to achieve full value (*e.g.*, for safety purposes, inverters are required to shut off in the event of grid outage, unless a site has back up generation that is isolated from the grid and that only provides energy to facilities that are isolated from the grid).
- Impact on distribution operations, switching analysis and temporary system reconfiguration.
- Standardization.

The following sections describe the electric services, grouped by the potential role of DERs to provide these services: Services DERs can provide, Services that DERs may be able to provide in the future, and services that DERs are not considered able to provide. For the purposes of Demo B, DERs were only assumed able to defer projects associated with the services described in section 2.1 (services that DERs can provide in Demo B).

2.1 Services that DERs Can Provide in Demo B

2.1.1 Transmission and Distribution Capacity Deferral

DERs may reduce the thermal loading on all components of the electrical grid (in a radial system, thermal loading is reduced between the DER's location and the location of the existing source(s) of generation, *e.g.,* the substation so long as the DER does not cause excessive reverse power flow). By reducing the load on the distribution system, a DER may alleviate the need to construct additional electrical infrastructure and allow existing equipment to supply more load. To accomplish this, a DER must deliver energy at the time of peak load, therein reducing the maximum electrical demand on existing system components. Because the cost for the grid's existing infrastructure has already been reflected in rate, the reduction in electrical demand facilitated by a DER does not necessarily result in value for utility customers/ratepayers. In order for a DER to have real value for customers, it must defer a future capital infrastructure investment(s); in this case, it must defer an infrastructure investment needed to increase thermal capacity. If the DER capacity enhancement fails to defer future infrastructure investment(s), there is simply no added value for ratepayers. However, when a DER does defer utility expenditures of some kind, the DER creates added value equal to the time value of money that the utility would have charged ratepayers for the original capital project. The T&D deferral module developed by E3 in conjunction with working group will serve as a calculator for these values. For a full explanation of the module please refer to section 9.1.

2.1.2 Voltage support

DERs can provide voltage support in areas within the distribution system where customers have low/high voltage conditions outside of Rule 2 limits. Voltage support services are substation and/or feeder level dynamic voltage management services that are capable of dynamically correcting voltage conditions outside acceptable limits in coordination with utility voltage/reactive power control systems. Though these services can be provided by an individual

resource and/or aggregated resources, DERs in Demo B are limited to providing services linked to an individual resource.

Typically, the utilities mitigate local low voltage issues by installing equipment that is capable of injecting or consuming reactive power[19] (*e.g.*, capacitor banks/DVCs); equipment that can regulate or boosting voltage(*e.g.*, load tap changers (LTCs),[20] voltage regulators, and booster transformers), or by changing the tap setting on distribution transformers.[21] DERs can provide ratepayer benefit if they are able to defer or eliminate a capital infrastructure investment required for voltage control.

DERs may potentially provide voltage support for the grid in two different ways. First, if the unit operates within the requirements defined in Rule 21 for smart inverters, it can contribute to local voltage control via the injection or absorption of reactive power typically via power electronics in the DER's DC to AC inverter. This feature could be used to both increase and decrease voltage. Second, DERs could reduce the net load on the circuit and therein decrease the voltage drop[22] experienced across a distribution feeder.

The value of the voltage support service is directly determined by the deferral value of a planned voltage support project. As with deferred capacity projects, the deferral value is driven by the time value of money realized by deferring an investment. In the absence of planned investment, there are no avoided costs, and thus no value to a DER for providing a voltage service. More specifically, as long as voltage remains within the Rule 2 limits there is no need for voltage support and therefore no value in providing additional voltage support equipment.

In Demo B, voltage support project deferral requirements are expressed in terms of load reduction rather than reactive power injection or absorption. This ensures that non-inverter-based DER technologies such as energy efficiency are able to be evaluated as DER solutions to deferrable voltage support projects.

2.1.3 Reliability - Back-tie

The back-tie service creates value by deferring an upgrade to a back-tie source. A back tie source is used to improve restoration of service in abnormal grid conditions: In order to

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[19] Reactive Power – Power required to serve inductive loads like that of motors that is derived from current and voltage becoming out of phase when electrical energy is converted into magnetic energy.

[20] Load tap changers are extra windings on a substation transformer that can be added or subtracted under load to change a transformers winding ratio to either increase or decrease voltage as needed.

[21] Many local distribution transformers (transformers that step down voltage from the distribution primary level to the secondary service level) have several taps on them that can be manually changed when de-energized to change the winding ratio of the transformer in order to decrease or increase voltage as necessary.

[22] Voltage drop occurs in all electrical networks where the voltage lowers as you get further away from the source. It is directly proportional to the impedance along that same path.

ensure reliable service within a distribution system, it is desirable to have a back-up tie installed such that it can be used to transfer the load from the faulted feeder to an adjacent feeder with available capacity. However, the capacity of a tie switch may be limited and may not be sufficient to accommodate the additional power required by the customers on the faulted feeder. One traditional method to resolve the limited capacity is to employ higher rated infrastructure (*e.g.,* higher rated back-tie switches and larger size electrical equipment). DERs can provide ratepayer benefit if they are able to defer or eliminate a future capital infrastructure investment required to increase back-tie capacity.

The DER alternative would include installing DERs downstream of the tie switch, therein reducing the load transferred in the event that the transfer switch is closed. The load reduction would be such that an existing (lesser rated) tie switch would be able to supply the required amount of load. Similar to the other T&D deferral services, the value of this service would be equal to the time value of money that would have been spent on a project to improve the rating of the tie switch to achieve an equal transfer capability with the DERs installed.

2.1.4 Resiliency via Microgrid

In order to provide electric services reliably, an alternate power source can be used in case distribution outages occur. As referenced in the previous section, utilities usually design their distribution systems such that all circuits have back-ties to adjacent circuits in order to provide another source. The redundancy in power sources allows system operators to "cutover" load in the event of a planned or unplanned outage.

An alternative to back-ties is a microgrid. A microgrid essentially provides the same service as a back-tie by enabling a portion of the distribution system to be isolated and powered by its own "internal" generation. During an outage, microgrids provide more reliability than back-ties, in that they do not leave customers vulnerable to larger system outages (*e.g.*, a substation or transmission line outage). However, because substation and transmission outages are rare, the minor increase in reliability brought about by microgrids generally does not justify their added cost. Because the cost for providing redundancy through a "wires" method becomes more expensive in rural areas, microgrids can be a particularly useful alternative to enhance reliability for critical loads that are geographically remote. DERs could potentially provide a local microgrid service, consisting of several DERs that feed customers until normal grid service is restored. In order to provide this service, the DERs in combination with a microgrid control system need to have "islanding and load following" capability. Depending on the ownership structure and customers' involvement, the safety, integrity and duration of the service become critical challenges that require in-depth investigation. For the DER solution to be counted on as a 100% available backup solution, the DER must be capable of black start[23] and fast recovery in order to assist with restoration processes.

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[23] Black start is a common industry reference to be able to reenergize the grid from a black out condition. For microgrids, it is a specific reference to the microgrid's DER being able to energize the microgrid in complete separation from the rest of the distribution grid.

2.1.5 Avoided Energy Losses

The reasons for energy losses on the grid are multifactorial, the most important of which are impedance and current. Impedance is largely determined by the design of distribution equipment, such as conductor and cable sizing/materials, transformer loss ratings, operating temperature, and distance from source of generation. Moreover, energy losses on equipment increase to the square of the amount of current flowing through the equipment. The current flowing on equipment is largely determined by the configuration of load, voltage level of equipment, and the power factor of the load. Historically, power factor is optimized by the utility via fixed and switched capacitor banks in the distribution system or at large customer facilities (behind-the-meter, customer-owned).

DERs can reduce energy losses by both reducing impedance and reducing loading on equipment by serving load locally and improving the distribution system's power factor. The value of reduced energy losses will be realized by the ratebase customer through avoided energy costs. The calculation for the value of avoided costs will be calculated buy inputting a loss reduction factor that will serve to increase the energy a DER is credited with offsetting. DER located uniformly throughout a system will generally serve to reduce energy losses; since part of the load is supplied locally by DER units, the magnitude of power flow and currents along distribution lines and transformers will be reduced. DERs can also potentially decrease losses by providing/injecting reactive power close to where it is needed which will also decrease current along the conventional electrical path and again result in reduced losses. As long as DER energy delivery/reduction is highly coincident and in proximity to customer loads, a DER may be able provide services that reduce energy losses. The benefits/impacts of a particular DER will differ as a function of the point of interconnection location. Ideally, in addition to being optimally located, an inverter-based DER would be capable of operating at non-unity power factor (*e.g.*, injecting reactive power) when needed to optimize power factor as previously described in order to maximize reduction in losses. It must also be noted however, that high penetration levels of DER can also cause reverse power flows with magnitudes greater than the pre-DER forward power flow, potentially increasing energy losses. This type of scenario can be avoided with proper engineering oversight.

2.2 Services that DERs May be able to Provide in the Future

For the purposes of Demo B the only services that DERs can provide are described in section 2.1. This section addresses the services that DERs have the potential to provide, but are not assumed to provide in Demo B. Limitations on DERs' ability to provide these services may be based on insufficient information (*e.g.,* equipment life extension), insufficient control infrastructure (*e.g.,* VVO), or lagging regulatory processes (*e.g.,* frequency regulation).

2.2.1 Conservation Voltage Reduction (CVR) and Volt/VAR Optimization (VVO)

The IOUs were directed to "include opportunities for conservation voltage reduction and volt/VAR optimization."[24] CVR refers to the ability of devices, including certain DERs, to maintain voltage levels at the lower-end of the range of acceptable voltage levels. Doing so can reduce the electrical consumption of certain customer end use devices without a noticeable change in performance. CVR is often a byproduct of Volt/VAR Optimization – a general term for more precisely monitoring and controlling line voltages and power factor. Because CVR reduces customer consumption it can be viewed very similarly to energy efficiency initiatives.

As described in section 2.1.2, a typical distribution circuit's voltage is controlled by distribution facilities at the substation or on distribution lines such as substation load tap changers, line voltage regulators, voltage boosters and capacitors. As a standard practice, the IOUs currently set these devices to deliver as low a voltage to the customer service panels within the acceptable range as possible in order to achieve CVR.[25]

Additional CVR-based energy consumption reduction beyond that achieved by standard practice may be achieved by more sophisticated voltage controls, such as those that enable VVO. The problem with crediting DERs for avoided costs through CVR, however, is twofold. First, quantifying the potential savings on any particular circuit requires thorough knowledge of how voltage level effects consumption which is highly dependent on a variety of factors specific to that circuit and the customer end use devices that are on that circuit. Second, to achieve CVR, DERs must be working in concert and be coordinated with utility devices; so CVR is a service that DERs individually cannot effectively provide. In addition to this, the avoided costs are mainly on the customer end and are not incremental investments. The two benefits would include the minor reduction in capacity constraints and the small reduction in losses due to less demand, which to accurately calculate would require rigorous dynamic powerflow studies.

For Demo B, CVR benefits associated with a DER can be incorporated in the DER load reduction assumptions used to develop the Hourly DER Profile input (see Chapter 7). One simple method to estimate CVR energy savings is to use the CVR factor, which is the ratio of percent energy savings to percent voltage reduction: [percent energy savings] = [CVR Factor] x [percent voltage reduction].

The percent voltage reduction is largely a function of the starting voltage and circuit configuration. In Demo B, the IOUs have not done the engineering analysis and field research to estimate these quantities; however, a benchmarking exercise summarized in PG&E's 2017 GRC

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[24] 5/2 ACR, p. 30.

[25] For example, PG&E's Rule 2, section 2.1 states "…for the purposes of energy conservation, distribution line voltage will be regulated to the extent practicable to maintain service voltage… on residential and commercial circuits between 114 V and 120 V." Available at: http://www.pge.com/tariffs/pdf/ER2.pdf

found that prior studies indicate a range of 0.76 to 4.0 for average voltage reduction percent and a range of 0.06 to 2.7 for the CVR factor.[26]

2.2.2 Equipment Life Extension

DERs may extend the lifespan of distribution equipment. Specifically, the reduction in thermal stress facilitated by DERs may extend the life of electrical insulation (*e.g.*, cable jacketing or transformer oil/paper winding insulation), which in turn may lead to longer electrical equipment lifetimes.

However, the correlation between thermal stress and insulation lifespan are currently poorly characterized, making it difficult to accurately quantify the potential role of DERs in extending equipment life. Furthermore, at present, most electrical equipment is replaced for reasons unrelated to insulation or conductor failure, *e.g.*, service upgrades, corrosion, damage, bad connections, and new protection schemes. The majority of equipment replacement needs are identified in the utility's corrective maintenance program, only a small percentage of which are related to loading. Because most equipment replacement is unrelated to insulation/conductor failure, potential savings in the realm of equipment life extension are relatively small compared to the more tangible benefits of DERs.

Also, load-increasing DERs and generating DERs at very high penetration may negatively impact equipment life by increasing net loading (through backflow, increasing equipment operations, or by creating larger thermal stresses through more rapid load changes). Highly variable generation and load can increase the operation of line regulators, capacitors and load tap changers, potentially resulting in reduced equipment life. To credit DERs with avoided cost related to equipment life extension, further study to fully understand the correlations between loading and equipment life is needed. The utilities see such inquiry as an opportunity in the long term refinement.

2.2.3 Security Risk Mitigation

Having DERs supplying critical loads reduces the reliance on the central grid; if operated correctly, DERs may be able to create a more robust grid. Being able to avoid low probability, high impact events may mitigate some of the potential losses and serve to reduce security risks associated with larger assets. The reduced security risks would be a significant societal benefit created by the aggregation of mass deployment of DER.[27] However, to date, there are no known efforts to objectively quantify the decreased security risks or societal gains associated with DERs supplying critical loads (as opposed to a conventional central power plant).

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[26] *See* PG&E 2017 GRC Phase I Work papers Table 13-22.

[27] Evaluation Framework and Tools for Distributed Energy Resources, February 2003.

2.2.4 System Support Services

System support services, also known as Ancillary Services, include frequency regulation, spinning reserve, and non-spinning reserve. The California Independent System Operator (CAISO) currently has programs that allow aggregated DER or large DER to participate in its existing market of these system support services. Moreover, the CAISO is currently looking at modifications to its tariffs to better accommodate DER in the future.

Frequency regulation

Frequency regulation (Reg.) is the provision of short term energy used by the CAISO to manage Area Control Error (ACE). CAISO procures Reg. UP and Reg. DOWN as separate products in Day Ahead (DA) and Hour Ahead (HA) markets, instructing qualified/awarded generators on a 4 second basis to provide Reg. UP or Reg. DOWN services. Payments are made per the DA and HA cleared prices. Actual net energy delivered over the hour is settled at the balancing energy price, as determined by the Real Time (RT) Market price. There is also a Pay for Performance tariff that rewards generators for accuracy in response - this tends to favor faster resources, such as fast energy storage devices. Where Reg. UP provision is constrained locally, a resource may apply for self-provision service, meaning the resource can provide its share of frequency regulation requirements locally and avoid the regulation market. Frequency regulation service is part of maintaining the reserve generation capacity for the system.

The "frequency-Watt" function is a feature that can be offered by the new generation of inverter-based DERs (smart inverters) to provide fast frequency regulation in milliseconds. The "frequency-watt" mode enables the smart inverter to mitigate frequency deviations by injecting/absorbing active power. This mode can be used either in emergency situations (when a large frequency deviation causes system instability) or in normal situations (to smooth out minor frequency deviations).[28]

Spinning Reserve

Spinning Reserve is the on-line reserve generation capacity synchronized to the grid system, ready to meet electric demand within 10 minutes of a dispatch instruction by the ISO. Spinning Reserve is needed to maintain system stability during emergency operating conditions and unforeseen variations in load.

Some DER technology types will be able to provide spinning reserve and some will actually serve to increase spinning reserve requirements. Various energy storage technologies and demand response are likely to be able to provide this service, while most renewable DERs can adversely impact the system's spinning reserve requirement. For instance, energy storage system increases the available reserves on the system without decreasing conventional generators' efficiency. By setting a minimum discharge level, the distributed energy storage can

[28] DER: Advanced Power System Management Functions and Information Exchanges for Inverter-based DER Devices, Modelled in IEC 61850-90-7.

always provide some energy as spinning reserve. On the other hand, penetration of PVs can increase the spinning reserve requirements of the system in three scenarios: (i) when there is a rapid frequency drop (*e.g.,* due to a generator outage) and the spinning reserve is required, the PV will likely trip off due to the prevailing frequency ride through setting schemes on most inverters. Therefore, the frequency drop is exacerbated and the need for reserve is increased; (ii) when there is a transient drop (*e.g.,* caused by cloud passing), the PV output drops rapidly- up to a50% drop in 30 seconds. If there are a lot of PV installed within a small area, that affects the spinning reserve requirements; and (iii) when there is a load shedding action to be performed, the net load drop can be less than what may have been designed, reducing the effectiveness of load shedding schemes. Like the frequency regulation market, the spinning reserve market is already well established for larger generators, and the IOUs will rely on the CAISO to further develop the market for DERs that can eventually be included in the LNBA.

Non-spinning Reserve

Non-Spinning Reserve is off-line generation capacity that can be ramped to a designated generation capacity value and synchronized to the grid within 10 minutes of a dispatch instruction by the CAISO. Moreover, it is capable of maintaining that output for at least two hours. Non-Spinning Reserve is needed to maintain system stability during emergency conditions. The barriers to including non-spinning reserve in the LNBA are the same as the frequency response and spinning reserve services.

As these services are paid for in existing CAISO markets, the value is accounted for like all the other system level avoided costs in other markets segments (energy, emissions, etc.). However, for Demo B purposes, the system support services market for DERs is not well established enough to have a clear understanding of how the IOUs can assess a DER's ability to provide these services. Once more market history is established through the CAISO, the utilities will have more data to assess if/how certain DER technologies can actually deliver these services and determine the market costs for these services. Because the CAISO will be the main solicitor for these services, the IOUs will rely on the CAISO to define how DERs will deliver such services. Once DERs begin to successfully capture revenue streams from the support services markets, the IOUs will begin to include the additional system level avoided costs in the LNBA for DERs. Although the ancillary services (AS) market for DERs is not yet developed, the utilities current approach to account for DERs providing these services is to include Frequency Regulation, Spinning Reserve and Non Spinning Reserve in LNBA as defined for Demo B. Per commission guidance, the IOUs adopted the E3 DERAC estimates of avoided AS.[29]

2.2.5 Power Quality

Electric service is expected to be provided within power quality planning limits defined by utility guidelines and applicable industry standards, addressing the following aspects: Total Harmonic Distortion (THD), voltage sags/swells, fast transients, voltage unbalance and flicker.

[29] 5/2 ACR, p. 27, "Avoided Ancillary Services…Use DERAC values."

As such, mitigating any of these power quality issues is a part of normal utility distribution operations in electrical grid maintenance. In exceptional cases, customers may also request certain additional power quality services from the utility to assist in customer side power quality issues as well. These services can be provided through overall circuit level enhancement or managed locally (*e.g.,* by installing filters or relocating capacitor banks). It is important to note that providing quality power is a service distinct from the voltage support service described in section 2.1, which only addresses sustained high/low voltage issues caused by distribution configuration or loading/generation. Common power quality issues are listed below to indicate services that DERs may be able to provide.

Total Harmonic Distortion

Some DERs may lower system impedance, and a lower impedance of the combined system with respect to harmonics results in lower voltage distortion and THD from the nonlinear loads. This benefit is likely as long as the DER is not a significant source of harmonics.

Voltage sag

If the DER is installed near the end user's equipment, it can help mitigate voltage sag experienced from in rush currents. This would be considered a service of value as long as the voltage drops attributed to in rush currents drive customer voltage below the lower limit of ANSI C84.1 Range A. Conversely, DERs could extenuate the need for this service (if the DER trips offline during voltage sags, driving voltage even lower than the pre-DER conditions).[30]

Voltage swell

DERs may be able to absorb load and thus limit voltage swell to within suitable ranges. The presence of DERs, however, can also lead to additional temporary overvoltage (voltage swells). The following table describes the scenarios DER can affect negatively on voltage swells.

Table 2: Impact of DER on voltage swells

Power Quality Issue	Description of PQ Issue and Likely Positive or Negative Impacts of DER	Power Conversion Systems
Voltage Swell	**Negative -** Certain transformer connections for DER can cause voltage swells on healthy phases during line-to-ground faults during islanding.	wye/ungrounded wye, delta/wye, delta/delta, wye/wye with an ungrounded generator
Voltage Swell	**Negative -** Voltage swells and ferro-resonant over-voltages can occur due to resonance between the DER impedance and distribution capacitors during islanding.	All
Voltage Swell	**Negative -** Out-of-phase reclosing between the utility system and an islanded DER may cause transient over voltages.	All

[30] Grid Reliability and Power Quality Impacts of Distributed Resources, EPRI Technical Update, W. Steely, March 2003.

Voltage Unbalance

Presence of DERs can either aggravate or improve the voltage unbalances. Table 3 summarizes different scenarios which DER can impact the voltage unbalances.

Table3: Impact of DER on Voltage Unbalance

Power Quality Issue	Description of PQ Issue and Likely Positive or Negative Impacts of DER	Power Conversion Systems
Voltage Unbalance	**Negative -** Existing feeder voltage unbalance can cause machine connected DER to trip on current unbalance or cause rotor heating due to high negative-sequence currents.	Synchronous Generator or Induction Generator
Current Unbalance	**Negative -** Depending on the winding arrangement of the DER interconnection transformer, feeder current unbalance will be reflected in the interconnection transformer causing overload and possibly damage if the transformer is not protected.	grounded-wye/delta and grounded-wye/grounded-wye transformer (with the generator grounded)
Current Unbalance	**Positive -** In cases where DER feeds a constant power into utility distribution feeders, the lower phase voltage will see a relatively higher current and consequently a tendency to raise the voltage.	Synchronous generator or Self-commutated Inverter

Voltage flicker

Some DERs may be able to provide a voltage smoothing function to reduce voltage flicker experienced by customers. Many DERs, however, can cause more voltage flickers to occur. Voltage fluctuations can cause flickers visible to human eyes. This results in lamps changing their light intensity or flickering. Stopping or starting a DER can lead to sudden voltage fluctuations which in turn could lead to more adverse voltage conditions. Table 4 has describes the ways DER affect negatively on voltage flicker.

Table 4: Impact of DER on Voltage Flicker

Power Quality Issue	Description of PQ Issue and Likely Positive or Negative Impacts of DER	Energy Source/Prime Mover
Flicker	**Negative -** Low RPM, low number of cylinder machines applications or misfiring engines can cause voltage fluctuation.	Reciprocating Engine
Flicker	**Negative -** Cloud caused irradiance changes could produce flicker.	Photovoltaic
Flicker	**Negative -** Fluctuations in the wind speed, pitching/yaw errors in blades, wind shear, and tower shading can produce flicker.	Wind Turbine/Generator

Regardless of DER capability, as long as the existing power quality is at service levels within required ranges, there is no need for power quality services and DERs will provide no benefit. If there is a need, a DER that can offset that need would be valued for the avoided cost achieved through deferral of the conventional project that would have met the power quality need. Therefore, the value of these services will be accounted for in the deferral module. However, as detailed above, DERs may have both negative and positive implications on common power quality issues. Additional analyses are needed to clarify the net benefits of DER on power quality. For these reasons power quality services are not currently estimated or otherwise included in Demo B LNBA values.

2.2.6 Societal Benefits

Societal benefits are broadly defined as any benefits (or costs), including those related to public safety, that are linked to the deployment of DERs, which are external to the IOUs' revenue requirements. Many environmental impacts associated with energy production have been internalized in the IOU revenue requirements through policy mechanisms such as the RPS and multi-sector GHG Cap and Trade system. Many public safety impacts associated with energy production have been internalized in the IOU revenue requirement through other regulatory mechanisms, such as mandatory inspection and maintenance programs. There are several regulatory activities focused on societal benefits currently under-way: Energy Division is currently developing a proposal to address how societal benefits may be included in DER cost effectiveness analysis[31] in the IDER proceeding; the commission is leading an Integrated Resource Plan proceeding, a long-term electric resource planning proceeding initiated by SB350 (2015) which incorporates statewide GHG emission reduction goals and also includes cost of air

[31] Materials from a 9/22/2016 workshop on this topic are available online at: http://www.cpuc.ca.gov/General.aspx?id=10745.

pollutants or GHG emissions local to disadvantaged communities, per statute. These activities necessarily overlap and require close coordination; however, it is expected that information regarding specific types of societal benefits and quantification approaches will be determined in one or both of these proceedings. Such information could be used to inform future definitions or quantification of societal benefits in LNBA. For Demo B, no societal or public safety components were quantified. Long term improvements to the LNBA methodology and tool may quantify societal and/or public safety components.

2.3 Services that DERs Cannot Provide

This section highlights distribution services that are considered non-deferrable for Demo B.

2.3.1 Repair or Replacement

Utility equipment is generally repaired or replaced to address service upgrades, corrosion, external damage, and/or new protection schemes. For example, equipment and structures need to be replaced after being damaged by car contact, vegetation intrusion, or simply degradation over time.

2.3.2 Reliability (Non-Capacity Related)

Section 2.1 detailed reliability improvements that DERs can provide. However, the utility's costs for other activities and projects to improve reliability, e.g., non-capacity related projects such as: installing new sectionalizing equipment, sensors, fault detection, and emergency preparation/response initiatives, cannot be provided by DERs. Many of these costs will exist regardless of DERs being installed on a distribution system.

2.3.3 Operations and Maintenance

Maintenance is required to continue the safe and correct operation of equipment. Certain costs to operate and maintain the electrical grid will exist regardless of DERs being installed on a distribution system. There is no mechanism for DERs to defer the need to perform the majority of maintenance activities on existing equipment.

2.3.4 Emergency Preparation and Outage Response Services

The utility's ability to restore service after outages is not improved by DERs, with the exception of back-tie enhancement through load reduction. Beyond the ability to positively impact some restoration scenario through back-ties DERs do not offset services that require proactive equipment installation in preparation for an emergency, the replacement of damaged equipment during/after an emergency, or response strategies to dispatch service personnel more efficiently. Generally there are no similarities between services utilities provide in emergency scenarios to services offered by DER. Furthermore, emergency services typically need to be implemented in a very short time frame, and simply cannot be met through DER solicitation efforts. As such, costs associated with improving emergency response are not avoidable by installing DERs.

2.3.5 New Business/Work at the Request of Others

These projects entail the installation of necessary infrastructure to serve new customers. If there is a lack of existing infrastructure, new customers cannot consume or produce energy. DERs do not mitigate the need to connect new customers to the grid.

3 SDG&E Selected Planning Area (Northeast)

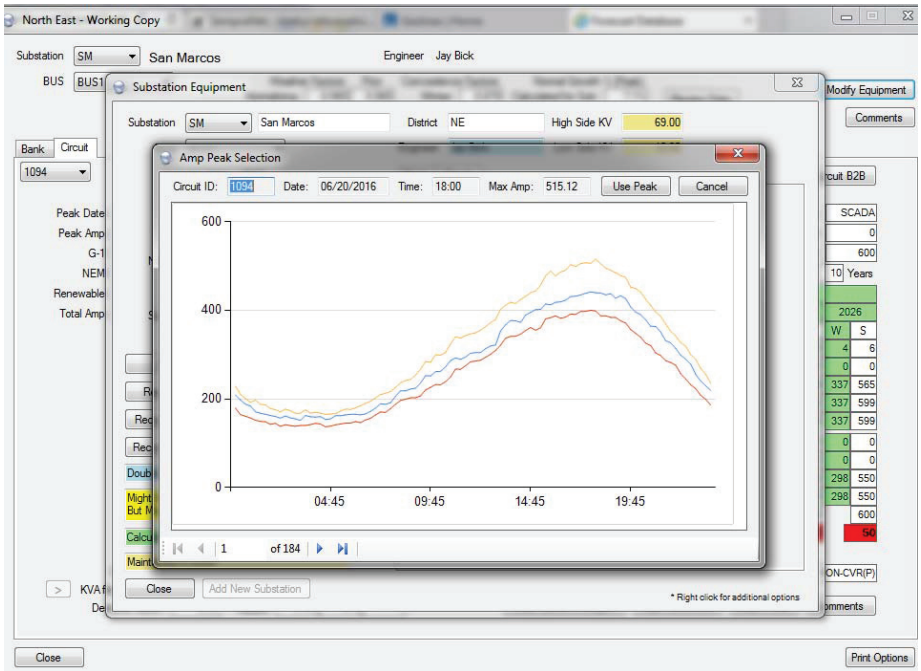
For the purposes of Demo B, SDG&E decided to evaluate its Northeast planning district. The region was chosen for multiple reasons, the most important of which was having a variety of planned distribution projects. The Northeast district also has one of SDG&E's most diverse terrains and economic regions in that it contains urban industrial, residential suburban, and rural commercial/residential distribution electrical infrastructure/loads with a combination of low and high load growth areas. The region's diversity and variety of projects led SDG&E to believe it would be the ideal portion of its service territory to explore the possibility of capital infrastructure project deferral through the deployment of DERs. The following are some quick statistics on the Northeast planning district.

- 23 Distribution Substations
- 1,390 MW of Distribution Capacity
- 197,949 Residential Meters, 30,102 Commercial Meters, 106 Industrial Meters
- Service territory includes the City of San Marcos, Escondido, Poway, Vista, Ramona, Valley Center, Rancho Bernardo, Bonsall, and Fallbrook

3.1 Planning Inputs: Load

To begin Demo B for the Northeast territory, SDG&E was required to carry out the first step of the normal planning process which was to develop the 2016 load forecast for distribution circuits and the substations. Historically, every year SDG&E has constructed the peak load forecast for each circuit/substation by looking at the load data for every hour of the previous year via an automated tool to determine when the peak day occurred.

Figure 1: SDG&E's Existing in House Forecasting Tool



The user/planner than verifies that the peak data selected by the tool occurred under normal system configuration in order to validate the peak measurement. Once the peak day is determined, the peak value is then weather normalized based on historical weather data and then modified to reflect a 1 in 10 year hot weather condition via weather factors provided from SDG&E' meteorology department.

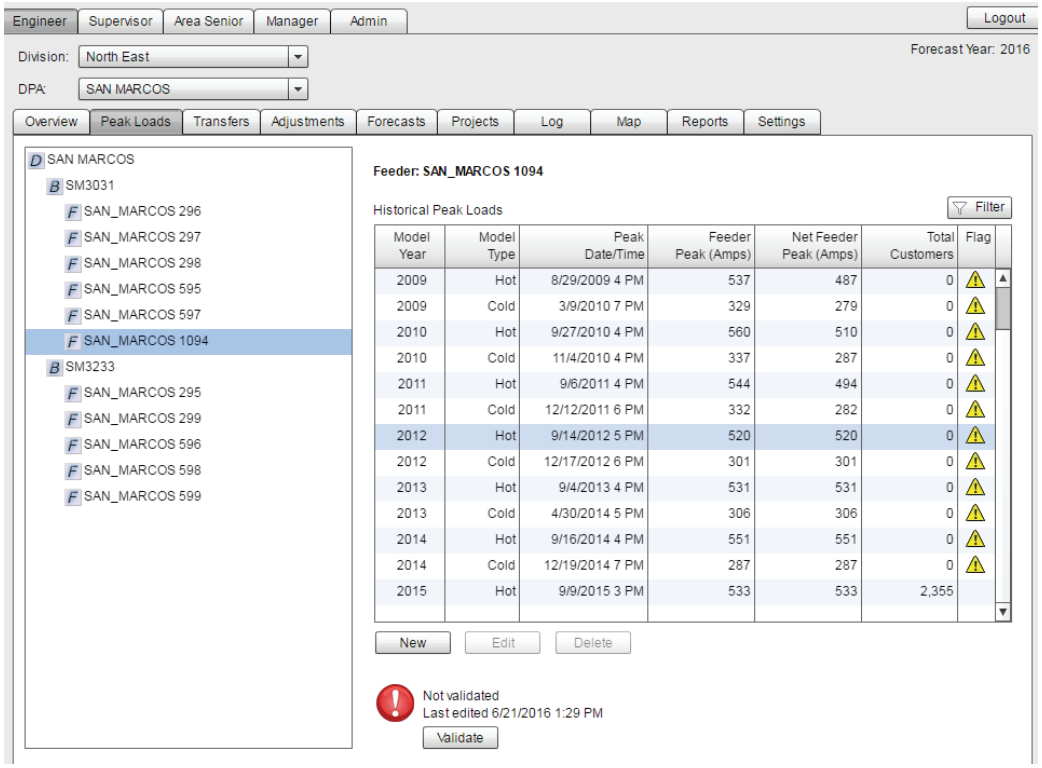
Figure 2: Example of Weather Adjustment Factor Inputs

Weather Factors		Prior
Normalizing:	0.980	0.980
Adversing:	1.060	1.060

Forecasted large individual loads and cutovers are also added or subtracted to forecast the next 10-years' 1 in 10 potential peaks.

This past year however, as outlined in its 2015 DRP Application, SDG&E performed this process for the first time in parallel with Integral Analytics LoadSEER software (LoadSEER) to enhance the accuracy and reliability of SDG&Es distribution forecast. LoadSEER requires the input of the past 10 years' worth of load peaks, transfers, spot load additions, as well as weather data. LoadSEER is able to automate the input of raw load data via a tool called Supervisory Control and Data Acquisition (SCADA) scrubber. Like that of the existing SDG&E forecasting tool, the data still requires review to make sure no false peaks are being recorded from temporary cutovers or other anomalies.

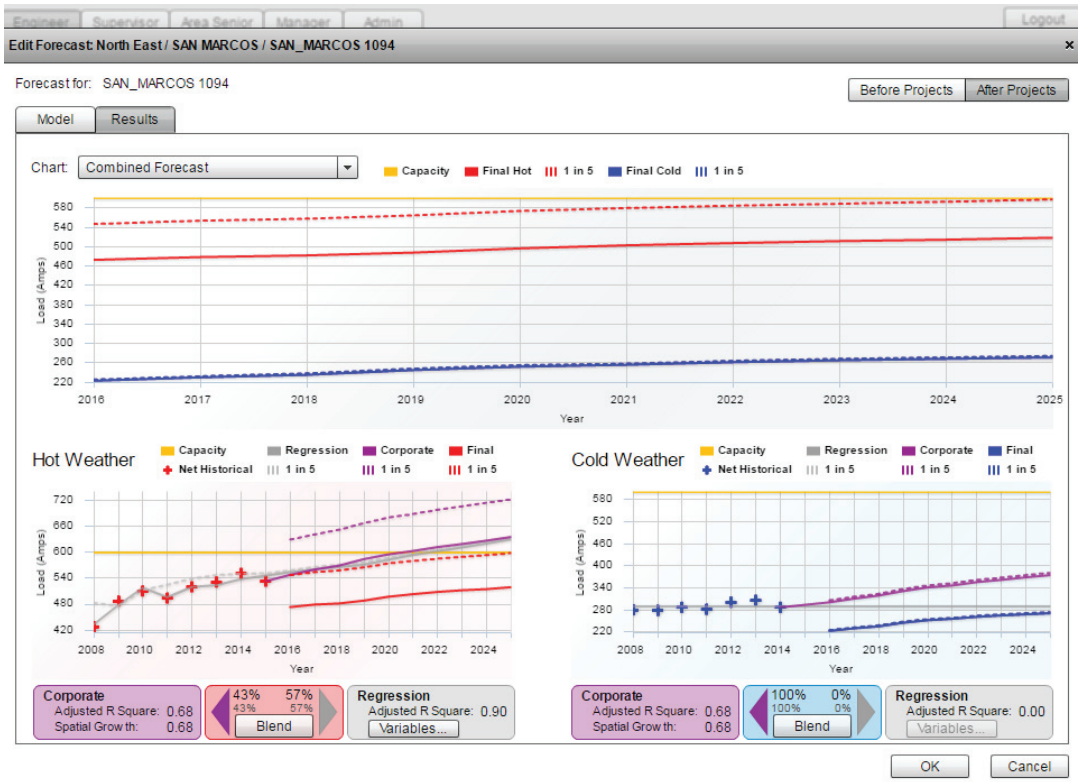
Figure 3: Example of Inputted Peak data Within LoadSEER



Model Year	Model Type	Peak Date/Time	Feeder Peak (Amps)	Net Feeder Peak (Amps)	Total Customers	Flag
2009	Hot	8/29/2009 4 PM	537	487	0	
2009	Cold	3/9/2010 7 PM	329	279	0	
2010	Hot	9/27/2010 4 PM	560	510	0	
2010	Cold	11/4/2010 4 PM	337	287	0	
2011	Hot	9/6/2011 4 PM	544	494	0	
2011	Cold	12/12/2011 6 PM	332	282	0	
2012	Hot	9/14/2012 5 PM	520	520	0	
2012	Cold	12/17/2012 6 PM	301	301	0	
2013	Hot	9/4/2013 4 PM	531	531	0	
2013	Cold	4/30/2014 5 PM	306	306	0	
2014	Hot	9/16/2014 4 PM	551	551	0	
2014	Cold	12/19/2014 7 PM	287	287	0	
2015	Hot	9/9/2015 3 PM	533	533	2,355	

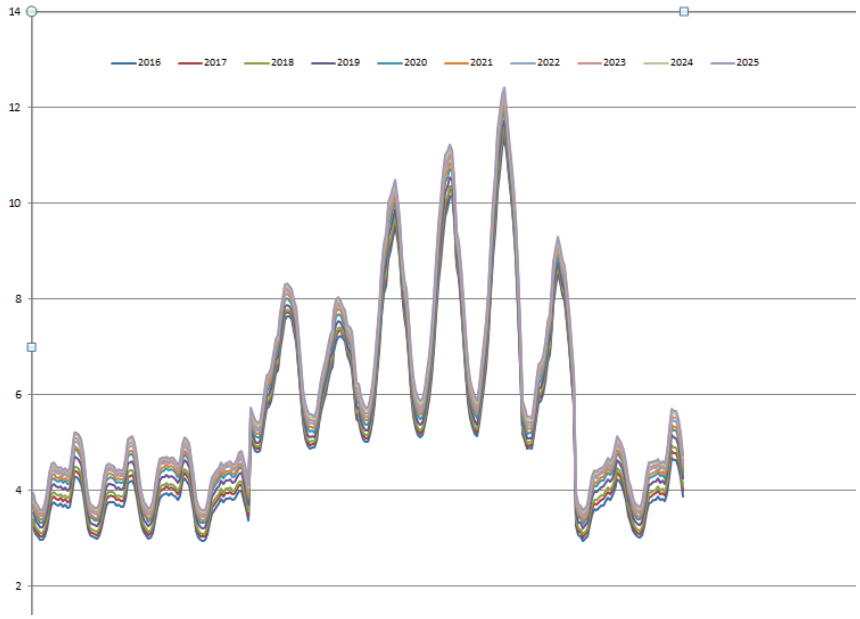
LoadSEER then uses the raw data and interpolates a summer and winter peak weekday/weekend load forecast based on the historical data, geospatial data, and economic variables distinct to a circuit's or substation's region. The economic variables associated with each distribution load forecast are only used if they are deemed to have both relevance and a high correlation. LoadSEER identifies variables with high degrees of historical correlation to the raw data, but ultimately the user will determine which of the identified variables are relevant to the region and will be used. The growth forecast is otherwise mainly tied to the system wide forecast. Depending on the degree of correlation, the user can blend the weighting of the system wide forecast or the economic variable based regression forecast.

Figure 4: Example of Load Forecasts Created by LoadSEER



SDG&E chose LoadSEER as new planning tool because of its more comprehensive inclusion of data relevant to load forecasts, but also because LoadSEER is able to generate a forecasted 24 hour dynamic forecasted load curve (load curve) instead of a single static peak that SDG&E was previously using. The 24 hour curves that are generated are able to take into account new load curves that have variable output throughout a 24 hour period (*e.g.*, solar PV, or electric vehicles). The 24 hour load curves are required in order to perform both demo A's ICA, by running powerflow for every hour of a day, and for demo B's LNBA, by being able to forecast both the magnitude and the duration of forecasted overloads on distribution elements throughout SDG&E's system. This data is critical to understanding the exact services that DERs will need to be able to provide in order to defer capital upgrades. An example of this load curve (24 hour x 12 month) is shown below.

Figure 5: Example of LoadSEER's 24 Hour Dynamic 12 Month Forecast

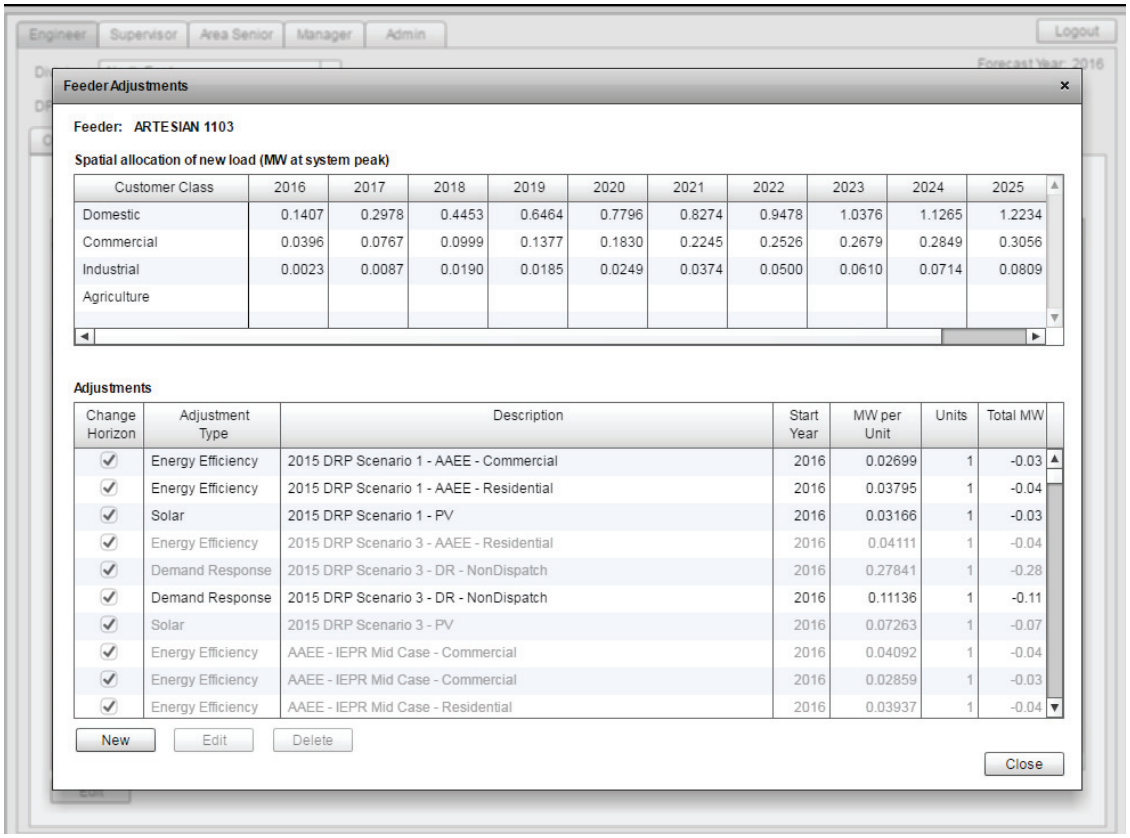


The load curve provides the planner an understanding of when (day and month) and for how long (which hours) a circuit's performance may be exceeding certain threshold limitations. The planners will use this information to identify the types of services that could be provided by a DER to mitigate forecasted overloads for particular distribution equipment.

3.2 Planning Inputs: DER Forecasts

Another benefit to developing the load curves is that SDG&E planners are able to account for the hourly impacts of specific DER technology types being deployed on a circuit or substation overtime. This added capability enables a more comprehensive ability to assess the impact of future DER growth scenarios. An example would be to calculate the hourly impact of deploying 100 kW of PV solar panels vs. 200 kW. As outlined in the ACR, SDG&E included the IEPR baseline DER growth scenario in the construction of its load curves as well as the Integrated Energy Policy Report (IEPR) High DER Growth forecast in its alternative DER forecast scenario. SDG&E accomplished this in LoadSEER by allocating the system wide IEPR DER forecast by technology type relative to customer types in each distribution asset's adjustment folder.

Figure 6: Example of an Adjustment Portfolio for a Feeder within LoadSEER



Feeder Adjustments

Feeder: ARTESIAN 1103

Spatial allocation of new load (MW at system peak)

Customer Class	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Domestic	0.1407	0.2978	0.4453	0.6464	0.7796	0.8274	0.9478	1.0376	1.1265	1.2234
Commercial	0.0396	0.0767	0.0999	0.1377	0.1830	0.2245	0.2526	0.2679	0.2849	0.3056
Industrial	0.0023	0.0087	0.0190	0.0185	0.0249	0.0374	0.0500	0.0610	0.0714	0.0809
Agriculture										

Adjustments

Change Horizon	Adjustment Type	Description	Start Year	MW per Unit	Units	Total MW
✓	Energy Efficiency	2015 DRP Scenario 1 - AAEE - Commercial	2016	0.02699	1	-0.03
✓	Energy Efficiency	2015 DRP Scenario 1 - AAEE - Residential	2016	0.03795	1	-0.04
✓	Solar	2015 DRP Scenario 1 - PV	2016	0.03166	1	-0.03
✓	Energy Efficiency	2015 DRP Scenario 3 - AAEE - Residential	2016	0.04111	1	-0.04
✓	Demand Response	2015 DRP Scenario 3 - DR - NonDispatch	2016	0.27841	1	-0.28
✓	Demand Response	2015 DRP Scenario 3 - DR - NonDispatch	2016	0.11136	1	-0.11
✓	Solar	2015 DRP Scenario 3 - PV	2016	0.07263	1	-0.07
✓	Energy Efficiency	AAEE - IEPR Mid Case - Commercial	2016	0.04092	1	-0.04
✓	Energy Efficiency	AAEE - IEPR Mid Case - Commercial	2016	0.02859	1	-0.03
✓	Energy Efficiency	AAEE - IEPR Mid Case - Residential	2016	0.03937	1	-0.04

New Edit Delete Close

Depending on the DER technology type, SDG&E allocated DER based on the % of system total of a certain customer type (commercial/residential/industrial) on a circuit or substation or by % of load coincident to system peak. SDG&E understands this is a relatively rudimentary allocation methodology and is supportive of considering the development of a more sophisticated allocation methodology as a potential long term refinement.

4 Description of Deferrable Upgrade Projects by Planning Area

The first part in identifying the Demo B projects was to make sure all the projects met the deferability criteria in order to capture T&D deferral value in addition to system level values. Ideally, capital projects used for the demo B evaluation would have high dollar values and be driven by relatively small demand for both capacity and duration of energy to optimize the T&D deferral values provided by any DER relative to their cost, i.e., result in a high $/kw deferral value. As discussed in the LNBA working group, SDG&E is providing the following indicative range for project costs which will also be included in the LNBA Heat Maps. The estimate of the project cost was completed using SDG&E's internal cost estimating practices.

$ = no deferral value (still has other LNBA components, e.g., energy)
$$ = deferral value between 0 and 100 $/kW
$$$ = deferral value between 100 and 5000 $/kW
$$$$ = deferral value greater than 500 $/kW

SDG&E identified the following distribution capital projects and their associated project costs that fit these parameters in the Northeast planning district. The projects details are as follows:

4.1 Project 1: Offload San Marcos Circuit 596/597 through Circuit 296 Extension

SDG&E Budget Number: 97248

Indicative Project Cost: $$$

Project Area: Northeast District

Unique Identifier: DPSS Number: 652039-010 Work Order Number: 2560390

4.1.1 Project Drivers: Capacity

SDG&E has received several large interconnection/load addition requests from the Cal State San Marcos Campus and surrounding developments in the city of San Marcos. The total load growth during the next 10 years for the area is expected to create around 5-6 MW maximum coincident demand once all existing planned load additions are fully built and operational, with the possibility of an additional 2 or more MWs in subsequent years from future tentative projects. The two existing circuits feeding the area are already highly loaded and have experience loads exceeding 90% of their rated thermal capacity on several occasions.

To accommodate the new growth, SDG&E has planned a project that entails extending an existing lightly loaded circuit (296) to the load addition area. This will allow some existing load to be transferred to this lightly loaded circuit and for some of the forecasted new load to also be supplied by this extended circuit. Circuit 296 will have approximately 6 MW of existing thermal capacity that can be used to feed the new load. The project mainly consists of constructing a new 4000 ft. section of a 600 Amp rated cable to be buried under a new road that is being designed and built by the city in conjunction with the development in the area. Because the road is going to be built new, SDG&E has the opportunity to install the underground conduit infrastructure without the need to repave the road, work at night, or have traffic control. The new feeder will connect to circuit 596 via several new tie-switches. Once load is transferred from circuit 596 to circuit 296, the next phase of this project, the transferring of load from circuit 597 to circuit 596, will take place to lessen the load on circuit 597. This involves closing an existing tie-switch and installing a new tie-switch. .

4.1.2 Circuit Data

Circuit 597: 21,350 connected kVA
Residential Meters: 2659 42% of peak load
Commercial Meters: 223 9% of peak load
Industrial Meters: 2 49% of peak load
Circuit peak 7:10 P.M.
Existing DER: 1,767 Solar PV, 9.2 kW ES, 1,180 kW fuel cell
SDG&E Weather Zone: North Coast Inland Valleys

Table 5: Maximum Forecasted Overloads by Year (MWs): Circuit 597 with IPER Trajectory DER Growth

Month -Hour	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
9-20	0.908	1.243	1.532	1.899	2.360	2.770	3.113	3.433	3.764	4.104

Circuit 596: 32,158 connected kVA
Residential Meters: 1,661 30% of peak load
Commercial Meters: 435 59% of peak load
Industrial Meters: 1 11% of peak load
Circuit Peak: 4:40 P.M.
Existing DER: 573.3 kW Solar PV, 4.6 kW ES, 4.0 kW Wind
SDG&E Weather Zone: North Coast Inland Valleys

Table 6: Maximum Forecasted Overloads by Year (MWs): Circuit 596 with IPER Trajectory DER Growth

Month -Hour	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
9-14	0	0.947	1.140	1.290	1.668	2.028	2.250	2.427	2.800	2.953

Figure 7: Required Electrical Characteristics to Mitigate Forecasted Overloads on Circuit 597

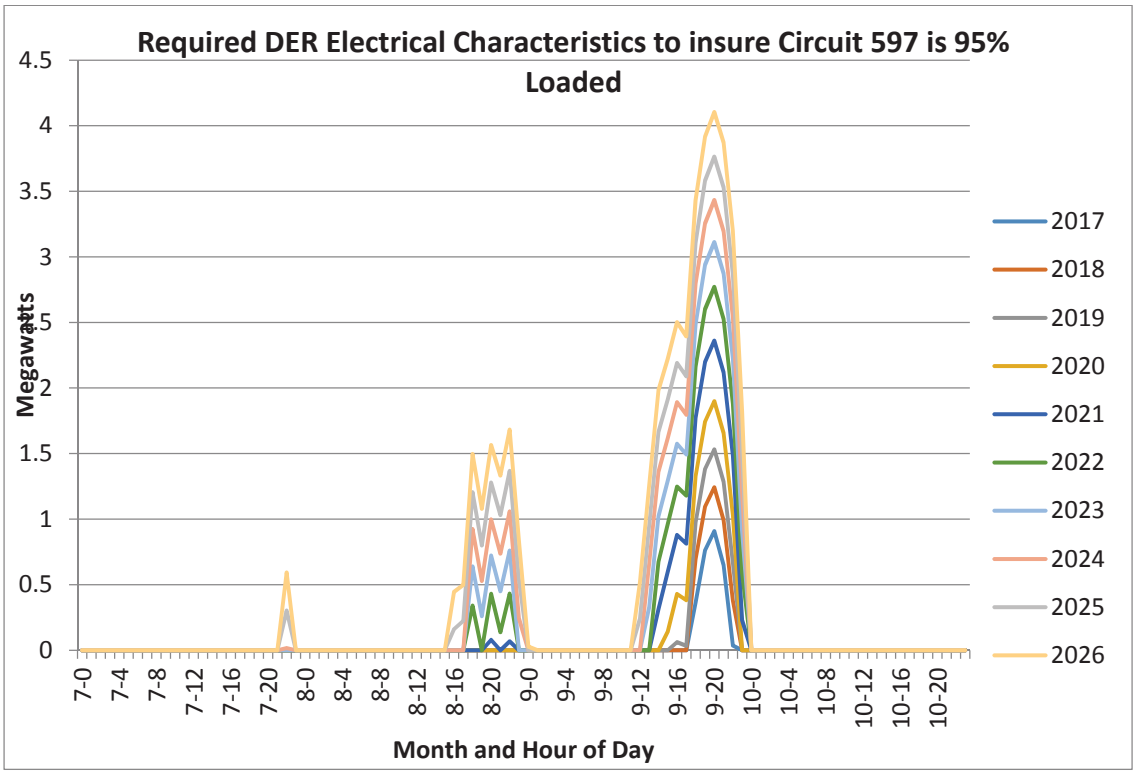
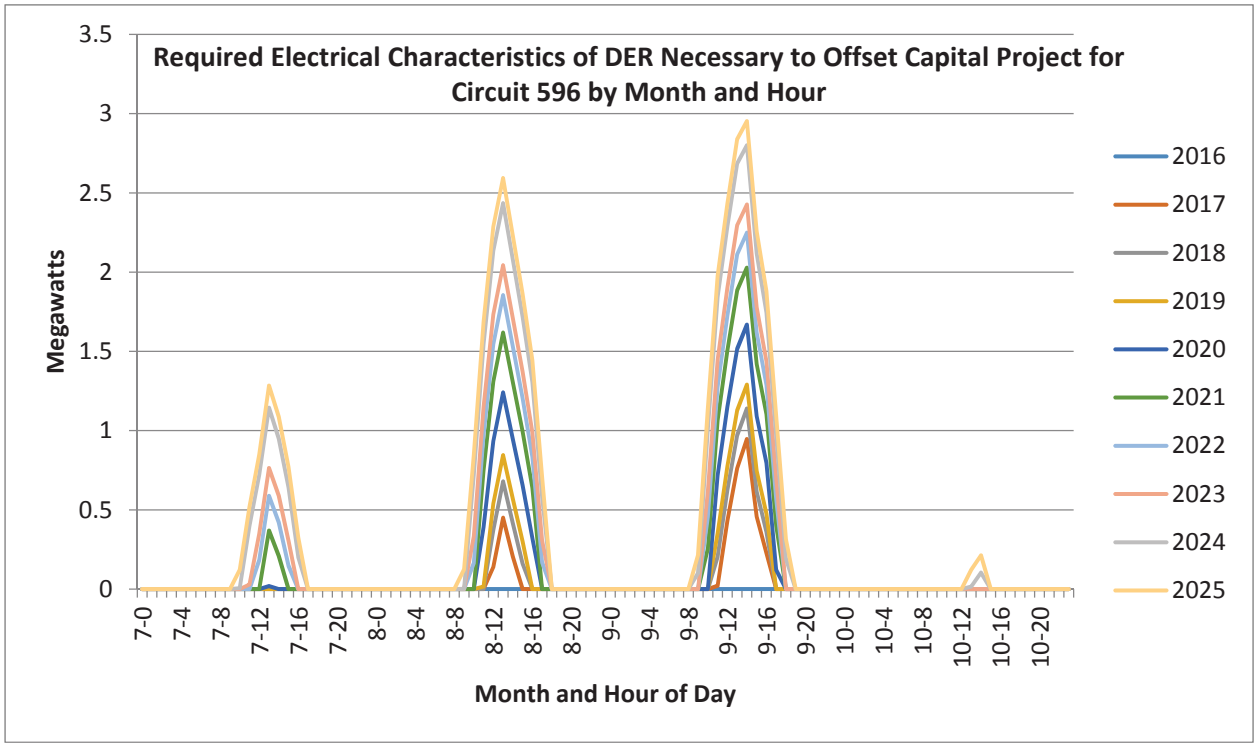


Figure 8: Required Electrical Characteristics to Mitigate Forecasted Overloads on Circuit 596



Capital project in service date: 6/1/2018

4.1.3 296 Circuit Extension - High Growth DER Scenario

The overload values above are derived from load forecasts for circuits 596 & 597 if DER growth was in line with the IEPR trajectory growth forecast. When load forecasting with the DRP Application's high growth DER scenario, results have correspondingly smaller overload magnitudes. The reduction in overload magnitudes, however, does not result in the change of timing/need for this particular project. The alternative scenario magnitude of overloads driving these projects will be made available on SDG&E's heat map in the High DER Growth layers. Furthermore, the electrical characteristics required for each project that are included in this document are subject to change as the circuit forecasts will be rerun/revised for 2017 to include 2016 circuit peaks and new load additions.

4.2 Project 2: Circuit 522 1/0 Cu Section Re-Conductor

SDG&E Budget Number: 97248

Indicative Project Cost: $$$

Project Area: Northeast District

Unique Identifier: DPSS Number: 159861-010 Work Order Number: 2953970

4.2.1 Project Drivers: Capacity

This project is to re-conductor 15 spans of circuit 522 that is currently 1/0 CU B strand (rated at 310 Amps, i.e., ~6MW thermal rating) to 636 ACSR (12MW thermal rating). Currently, under adverse conditions, it is possible for this portion of the circuit to overload. The re-conductor will eliminate the possibility of thermal failure as well as improve the back-tie capacity to neighboring circuits. Because the forecasted overload is relatively small and there is not much forecasted new load growth, a relatively small amount of DER capacity may defer the need for this project for a longer time.

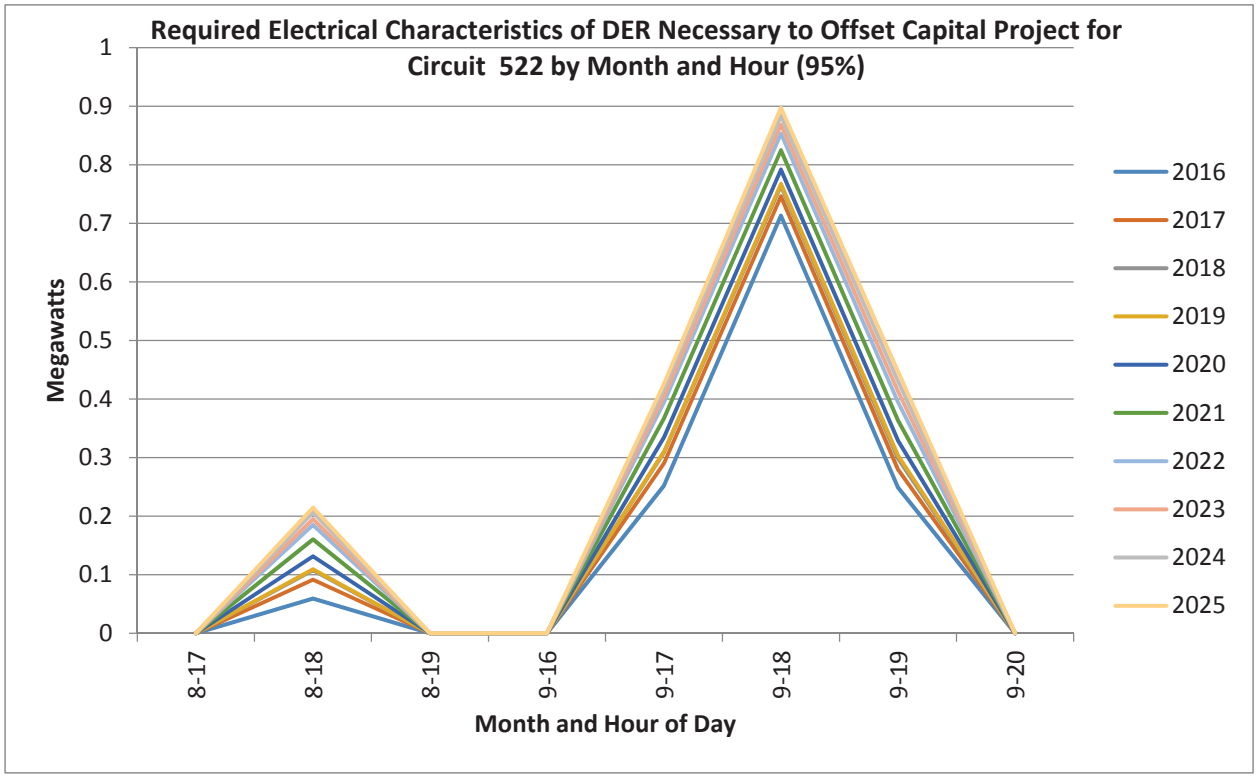
4.2.2 522 Circuit Data

Circuit 522: 21,732 k VA
Residential Meters: 2,103 71% of peak load
Commercial Meters: 118 29% of peak load
Industrial Meters: 0 0% of peak load
Existing DER: 1,716.9 kW Solar PV, 4.6 kW ES, 3.2 kW Wind
SDG&E Weather Zone: North Coast Inland Valleys

Table 7: Maximum Forecasted Overloads (MWs): Circuit 522 with IPER Trajectory DER Growth

Name	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
522	0.713	0.746	0.764	0.768	0.792	0.825	0.853	0.869	0.884	0.897

Figure 9: Required Electrical Characteristics to Mitigate Forecasted Overloads on Circuit 522



Capital project in service date 6/1/2018

4.2.3 4.2.3 Circuit 522 Reconductor - High Growth DER Scenario

Similar to Project 1, the load forecast that includes the DRP Application's High Growth DER scenario results in correspondingly smaller overload magnitudes, but the overall reduction in overload magnitudes does not result in changing the timing/need for this project. The alternative scenario magnitude of overloads driving this project will be made available on SDG&Es heat map in the High DER Growth layers. Again, these forecasts are subject to change as they will be rerun/revised for the 2017 forecast year to include 2016 peak data and new load additions.

4.3 Project 3: Circuit 182 12kV 200A Voltage Regulator

SDG&E Budget Number: 97248

Indicative Project Cost: $$

Project Area: Northeast District

Unique Identifier: DPSS Number: 652041-010 Work Order Number: 2560410

4.3.1 Project Drivers: Low end of line voltage (110V)

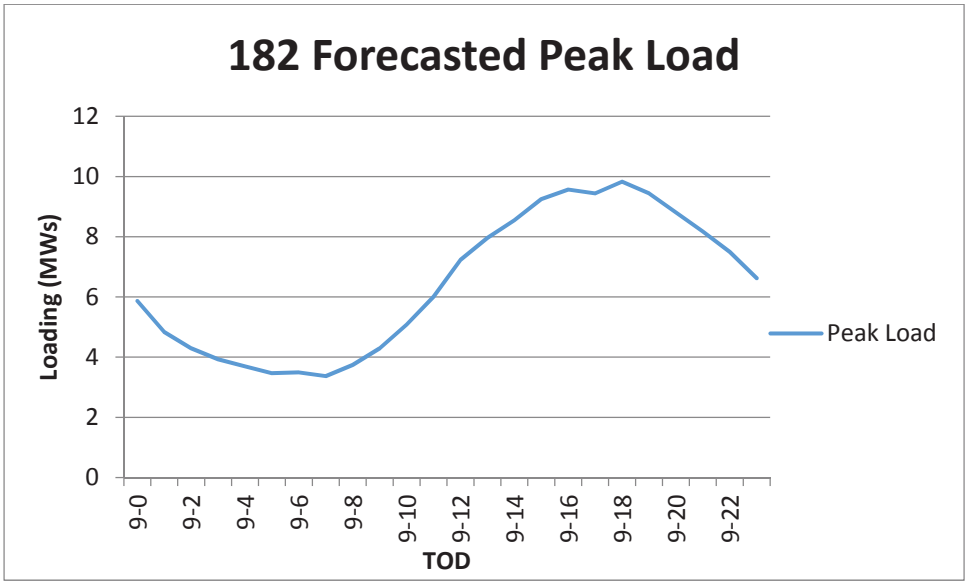
This project is to insure that a service area, including several hundred individual residences, is not delivered voltage at a level that is outside the Rule 2 required bandwidth of

114-126 volts. When circuit 182 is highly loaded, a portion of the circuit experiences enough of a voltage drop that service to some customers is outside of the acceptable voltage range. This situation is primarily due to the load being a long distance from the supplying substation. This problem may be addressed by DER in multiple ways, which includes being located within the area experiencing low voltage, located upstream of that area, or inverter aggregation. The services required of a DER to address the needs may depend upon the location of the DER on this circuit, with one option being to provide services during the peak hours within the low voltage area. The 2016 adverse peak load forecast is shown below for reference.

4.3.2 Circuit Data

Circuit 182: 25,335 k VA
Residential Meters: 1,973 58% of peak load
Commercial Meters: 262 31% of peak load
Industrial Meters: 2 11% of peak load
Existing DER: 2,208.1 kW Solar PV, 34.6 kW ES
SDG&E Weather Zone: North Coast Inland Valleys

Figure 10: Required Electrical Characteristics to Mitigate Forecasted Overloads on Circuit 522



4.3.3 182 Voltage Regulator - High Growth DER Scenario

Altering the load forecast to include the DRP Application's High Growth DER scenario does not result in changing the timing/need for this project. The low voltage conditions of the particular load pocket on circuit 182 will exist regardless of either scenario of natural DER growth. Any DER installed on this circuit, especially in the low voltage load pocket, will assist in voltage support, but the quantities needed are such that it will require a utility initiative. Again, the high DER growth forecast for this circuit will be included on the high growth scenario layers of SDG&E's heat map.

4.4 Demo B Project 3 (Capacity): New San Marcos 12 kV Circuit (Incremental Regional Capacity)

SDG&E Budget Number: 97248

Indicative Project Cost: $$

Project Area: Northeast District

Unique Identifier: DPSS Number: 651633-010 Work Order Number: 2544860

4.4.1 Project Drivers: Medium term need of capacity on circuits 298, 295, and long term needs on circuits 596, 597, and 299

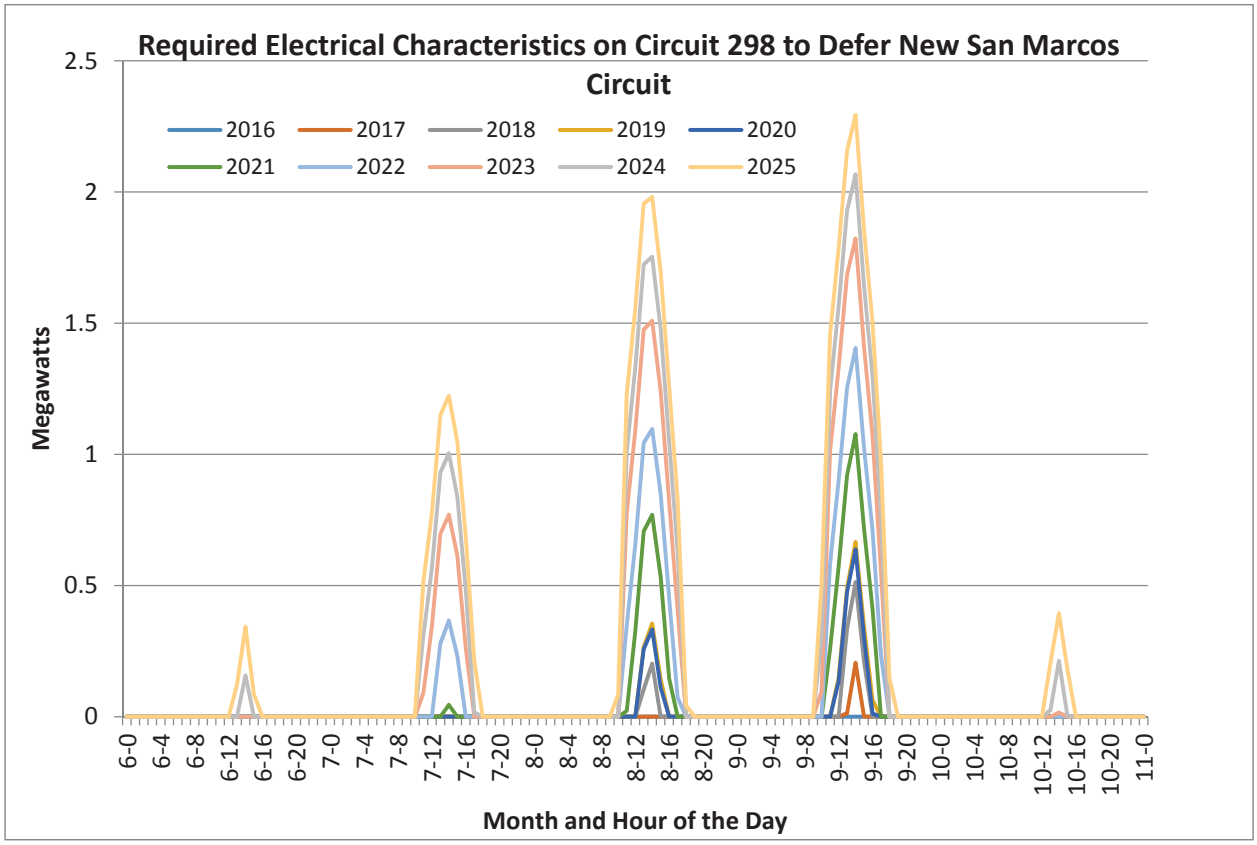
This project is partially related to project 1 in that it will ultimately be needed if the load continues to grow as planned into the 2020 horizon on circuits 299, 596 and 597. In addition to resolving the longer term issues with circuits 299, 596 and 597, this new circuit will resolve issues on two other highly loaded circuits 298 and 295. All of these circuits are fed from the San Marcos substation. The project will enable load from each of these circuits to be transferred to a new feeder that is to be located in a corridor shared by all of these circuits. Loads on existing circuits would be lessened by either direct transfer to the new feeder, or by transferring load to a circuit that has had its load reduced due to a transfer to the new feeder. In order to defer the need for this project, DERs would need to mitigate thermal overloads on all of these circuits. The most near term overloads, however, are forecasted on circuit 298 and 299, so partial deferral could be achieved by deploying DER on these circuits and meeting their needs first.

Circuit 298: 42,314 k VA
Residential Meters: 1,228 15% of peak load
Commercial Meters: 934 75% of peak load
Industrial Meters: 2 10% of peak load
Existing DER: 1,716.9 kW Solar PV, 4.6 kW ES, 3.2 kW Wind
SDG&E Weather Zone North Coast Inland Valleys

Table 8: Maximum Forecasted Overloads (MWs): Circuit 298 with IPER Trajectory DER Growth

Circuit	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
298	0.00	0.21	0.51	0.67	0.64	1.08	1.41	1.82	2.07	2.29

Figure 11: Required Electrical Characteristics to Mitigate Forecasted Overloads on Circuit 298

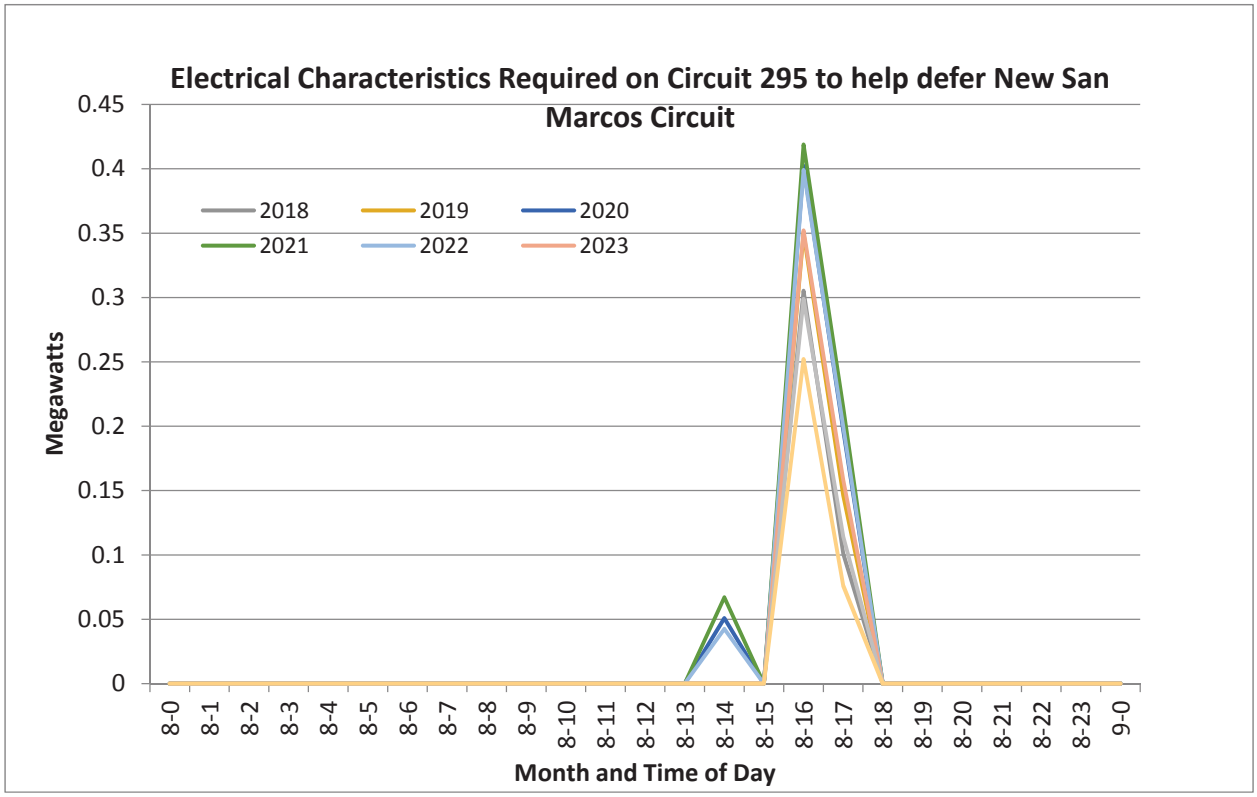


Circuit 295: 13,340 k VA
Residential Meters: 1,889 45% of peak load
Commercial Meters: 205 10% of peak load
Industrial Meters: 1 45% of peak load
SDG&E Weather Zone North Coast Inland Valleys

Table 9: Maximum Forecasted Overloads (MWs): Circuit 295 with IPER Trajectory DER Growth

Circuit	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
295	0.00	0.00	0.31	0.35	0.40	0.42	0.40	0.35	0.30	0.25

Figure 12: Required Electrical Characteristics to Mitigate Forecasted Overloads on Circuit 295



Both Circuit 596 and 597 forecasted overloads are included earlier in this document (see section 4.1) so their data is excluded here.

4.4.2 New San Marcos 12kV Circuit - High Growth DER Scenario

Altering the load forecast to include the DRP Application's high growth DER scenario does in fact alter the requirements of this particular project. Under the high DER growth scenario, the issues on circuit 596, 597 and 299 are all substantially reduced/eliminated. However, the forecasts for circuits 295 and 298 still justify the need for the new circuit in the medium term. In any DER growth scenario, this new circuit project will greatly increase the capacity to the San Marcos region and increase operational flexibility/reliability. When accounting for the reliability improvement, it is clear substantial amounts of DER would need to be deployed to fully offset all the services a new feeder would provide to the San Marcos region. Again, the high DER growth forecast for this circuit will be included on the high growth scenario layers of SDG&E's heat map.

4.5 Project Information Template for the downloadable Demo B dataset.

The following data will be provided by the IOUs via the downloadable Demo B dataset, which will be linked to each one of the projects identified in the each of the IOUs respective heat

maps. The template below reflects the data that the IOUs are planning to provide, and is subject to change in the future.

PROJECT IDENTIFICATION:

Project Name:

Project Area: [for PG&E, Division and planning area names]

Program / Project Type: [*e.g.,* Capacity Program / Distribution Capacity Deferral]

Budget Code: [OPTIONAL *e.g.,* PG&E MAT Code 06E]

Unique Identifier: [OPTIONAL *e.g.,* order number, etc. etc.]

PROJECT DRIVERS:

Associated Existing Equipment and Location:

Key Driver of Need: [*e.g.,* Ag pumping due to shifts in crops or drought, or specific load additions on a certain expected date]

Known Forecast Uncertainties: [*e.g.,* quality of historical data]

Observed Issues: [*e.g.,* customer voltage complaints?]

Expected Magnitude of Need: [2016: ##MW/XX%; 2017…]

Expected Timing of Need: [season or Month(s) and time-of-day]

Load Reduction Requirement Development Notes: [*e.g.,* load reduction profile is based on raw 8760 SCADA data at feeder head from 2015, or *e.g.,* load reduction profile is based on 95%ile weekday load profile from AMI data].

DER Growth Forecast Sensitivity:

DRP Very High DER Scenario Magnitude of Need: [Are timing/magnitude of project drivers impacted?]

Other DER Scenario Magnitude of Need: [OPTIONAL: Are timing/magnitude of project drivers impacted?]

CONVENTIONAL UPGRADE DESCRIPTION:

New/Upgraded Equipment and Location:

Associated Load Transfers: [*e.g.,* from an overloaded facility to a new facility].

Expected Equipment In-Service Date:

Expected Funds Commitment Date: [If different from above. Technically, the financial benefit starts on the funds commitment date, while the in-service date sets the needed timing for DER implementation].

5 Distribution Operation and Maintenance Upgrades identified in Northeast DPA

Each of SDG&E's six planning areas, including the Northeast district, has large volumes of various ongoing maintenance activities. Currently, most distribution system components are maintained based on SDG&E's Corrective Maintenance Program (CMP), which consists of inspections followed by repair if needed. Within this maintenance program, DER provided services have almost no value added because the majority of these activities/jobs are not deferrable by DERs. SDG&E does recognize, however, if the maintenance requirements could be changed to allow for a fully preventive and condition-based maintenance program, there could be some opportunities for DERs to reduce maintenance cost. This is due to DER services being able to improve electrical loading of various power system components (electrical loading refers to stresses such as continuous loading, temporary overloading, and exposure to short circuit fault current) through congestion management. This would require new data/information to be obtained and carefully analyzed through intelligent diagnostic and monitoring schemes, and this would come at some cost to customers. Furthermore, new data analytic tools with proper tracking of maintenance schedules and databases of system events will play an important role, and these too would also come at some cost. Regardless, if the utilities could move to more of a conditioned based monitoring maintenance system, there may be some moderate value in DERs providing services that enable the utility to avoid some maintenance costs.

5.1 SDG&E Corrective Maintenance Program

The following section elaborates on the specific work activities that occur as part of the SDG&E corrective maintenance program, and why DERs services are not considered viable in deferring these activities. Per CPUC requirements, every electric utility is required to have a maintenance program whereby every structure/ asset is inspected within a time cycle specific to each asset to insure public safety. The specific inspection requirements for this program are outlined in the CPUC's General Order 165 (GO 165). If a problem is found during the inspection phase, qualified electrical workers are required to take corrective actions (repair) within a specified time frame following the inspection to mitigate the issue. Furthermore, additional maintenance is also performed beyond the requirements of the CPUC to insure assets are functioning properly and that they will last throughout their expected lifetimes. The regular inspections typically generate thousands of job orders each year in each of SDG&Es districts. The job orders can vary from a job as simple as placing a sticker on energized equipment to properly mark hazards, to as large as replacing structures adjacent to freeway crossings because of wooden pole rot. GO 165 has established minimum inspection cycles and record keeping requirements for distribution equipment. In general, utilities must patrol their systems once a year in urban areas and once every two years in rural areas. Furthermore, depending on the type of equipment, detailed inspections of the distribution equipment are required every 3-5 years during which the condition of inspected equipment, issues found, and a scheduled date for

corrective action must be recorded. SDG&E's CMP program has defined eight different inspection categories as follows:[32]

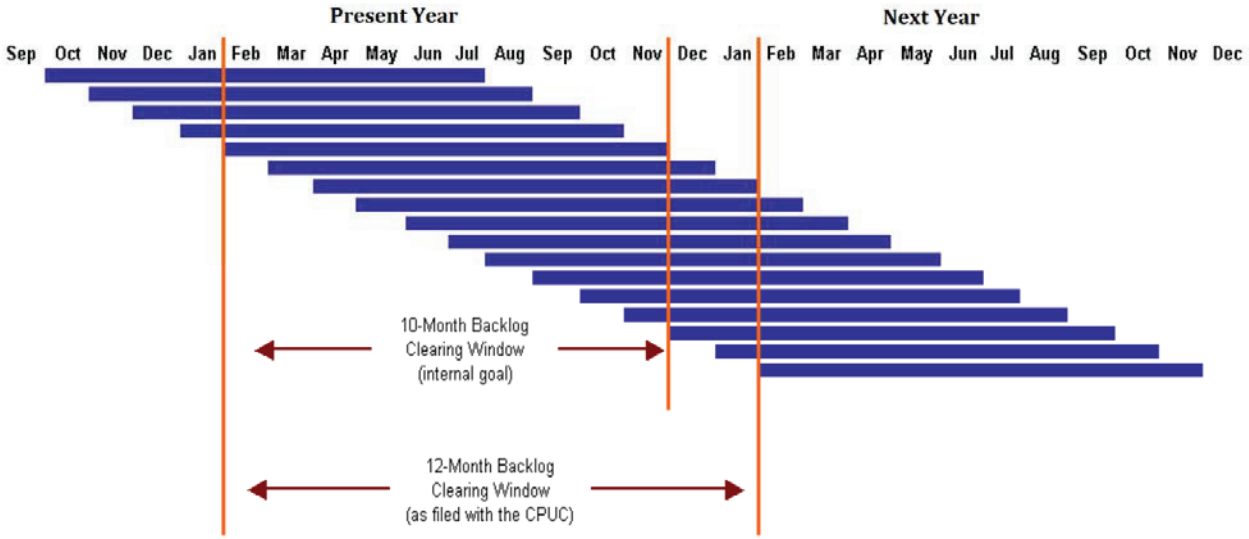
1. Overhead Visual Inspections
2. Underground Above Ground Dead-front Internal and External Inspections
3. Underground Above Ground Live-front Internal and External Inspections
4. Underground Subsurface Internal Inspections
5. Underground Oil and Gas Switch Inspections
6. Intrusive Wood Pole Inspections
7. Urban Patrol
8. Rural Patrol

SDG&E has set two internal goals related to its CMP program, namely inspection goals and follow-up repair goals. These goals are outlined as follows:

1. Inspection Goal: The SDG&E inspection goal is to complete inspections by October 31 of each year. This goal is established by monitoring the number of facilities in each community in each cycle, and dividing that number by the cycle length. Then, reports are generated which indicate what facilities have been inspected in the previous cycle for a corresponding year.
2. Follow-up Repair Goal (Backlog Goal): Although GO 165 requires all issues to be corrected within 12 months of the inspection date, SDG&E goal is to correct all issues within 10 months from the inspection date (or to prioritize the repair accordingly to identify critical conditions) in order to prevent exceeding the GO 165 deadline. To achieve this goal, a 10-month cumulative backlog is monitored by SDG&E. The graph below shows the follow-up repair backlog requirements of the SDG&E.

[32] For detailed description of the inspection cycles, refer to the SDG&E CMP Program Manual.

Figure 13: The 10-month clearing window for follow-up repair goal (note that any issue with an inspection date prior to the beginning of the bar must be cleared by the date by the end of the bar).



5.2 Operation & Maintenance Projects

As discussed above, SDG&E is required to keep a record of inspected equipment, found infractions, and scheduled dates for follow-up repairs. This record keeping is particularly important to achieve backlog goals. When reviewing the SDG&E CMP backlog records, it can be observed that detailed information is recorded for the inspected assets that require follow-up repair. Some of the recorded items include: equipment type and ID, notification type and date, request and reference date, follow-up due date, functional and physical locations, community affected, inspection code, inspector ID, and descriptions of the infraction and its severity. As an example, the following table shows a summary of the backlog CMP list in the Northeast region for Year 2016. Identified infractions resulting from the inspections shall be resolved within a 10-month period from the latest inspection date.

Table 10: SDG&E CMP Work Activities

Event Code & Type	Number of Events
I236 Damaged/Missing High Volt Sign - 1-	295
I230 Damaged Ground Molding	289
I234 Damaged/Missing High Volt Signs - 2	168
I246 SDGE/Cust Pole or Stub Pole Dmged/B	127
I048 Substructure Lid Damage	117
I019 SDGE/Veg Caused Cannot Open/Inspect	83
I038 Internal Corrosion Replace (Severe)	77
I239 Idle Equipment	69
I238 Abandoned Facilities (Pole/Conducto	53
I016 External Corrosion Replace (Severe)	52
I241 Damaged Cross-Arm	42
I332 Veg in Guy - Heavy Strain or Abrasi	39
I682 Restoration Recommended, C-Truss	30
I327 Vegetation Climbing Space Obstructi	27
I063 Oil Leak from Bushing/Case/Duct/Cab	21
I481 Pole Replacement from POIN	21
I218 Private Prop Caused Pole Inaccessib	19
I291 Private Prop Caused Cannot Open/Ins	18
I298 Other - Infraction - No Applicable	17
I254 SDG&E Insufficient Clearance	17
I058 Other - Infraction/No Code -Repair	17
I274 Guy Grounded	16
I219 SDGE / Veg Caused Pole Inaccessible	14
I207 SDGE Leaning Pole or Potential Over	13
I276 Slack Anchor Guy	11
I323 Veg in Service - Guard	11
I206 Damaged / Missing Pole Hardware	11
I330 Vegetation Working Space Obstructio	10
I201 Pole Steps Lower than 10ft	9
I681 Restoration Rejected, Replace	9
I026 Ground Rods or Studs Missing	9
I277 Damaged / Missing Guying	8
I283 Damaged/Missing/Incorrect Sta. Pole	8
I321 Veg in Secondary (SSC/Aerial Cable)	8
I148 Top Section Damage	8
I209 Foreign Attachment / Unauthorized E	7
I246 SDGE POLE/STUB DAMAGED	14
I055 Poss. Wire Entry to Energ/Exposed P	7
I241 C/O Damaged Xarms	7
I263 Private Property Hazardous Conditio	6
I096 Conduit Damaged	6
I098 Conduit not Strapped Down	6
I282 Bolt Covers Missing	6
I290 Private Prop Working Space Obstruct	6
I012 Temp Rise - (per ESP 120)	6
I020 Unsecured - Bolts/Latch/Lock Missin	5
INCP Inspection Incomplete	5

Out of 1,904 reported infractions, 13 events were associated with switches and 218 events were associated with distribution service transformers. However, the majority of events are related to internal or external corrosion, as well as vegetation management. Less than 0.03% of the maintenance events have temperature rise related root-causes; and these are mainly due to an increase in the ambient temperature.

According to GO 165, all infractions observed during the inspection phase shall be resolved within 12 months of the inspection date. It is worth noting that follow-up repair crews are located in construction and operating centers within the planning area (districts) they are inspecting (Northeast inspections and maintenance are performed by Northeast electric crews).

6 Distribution Reliability Upgrades Identified in the Northeast DPA

6.1 Circuit Reliability Improvement Process

Reliability metrics, such as System Average Interruption Duration Index (SAIDI) and System Average Interruption Frequency Index (SAIFI), are heavily influenced by the utility's ability to respond quickly, either remotely by SCADA operation, which minimizes the impacted area within minutes, or by anticipatory replacement of underground cable and installation of sectionalizing. Currently, DERs cannot improve these metrics because DERs that interconnect to the grid, per safety codes, are removed from the distribution grid upon sensing an outage. Additionally, utilities are best positioned to identify equipment that has high failure rates (such as certain vintages of underground cable) and then replace this equipment ahead of time to reduce the frequency of unplanned or forced outages. Some examples of traditional "wires" equipment that currently support providing these types of services include, but are not limited to:, circuit breakers and relays, reclosers, switches, sectionalizers, fault interrupters, SCADA, and Fault Location, Isolation and Service Restoration (FLISR).

Similar to the maintenance activities, the reliability work being performed in each of SDG&Es districts is not considered as deferrable by DERs. As described earlier in section 2.1.4, DERs may provide incremental reliability services not being offered by the utilities by either be built as part of a microgrid or enhancing back-ties; but at this time, SDG&E has not identified a need for any such projects in the Northeast DPA. The majority of SDG&Es capital reliability projects consist of vintage cable replacement (typically unjacketed), replacement of Do Not Operate Energized (DOE) switches, and the installation of SCADA switches to enable further customer segmentation/enhanced fault isolation as well as faster outage recovery. All of these capital improvements simply cannot be replaced by DER contributions unless the DER is serving customers in complete isolation to the grid.

6.2 Historical Causes of Outages

Table 11 below provides the top contributing categories identified in the root-cause analyses of outages based on historical reliability data for the last 5 years. As can be observed, the largest contributing factors to outages are associated with cable / equipment failures (50% of cases), and/or external factors such as vehicles, animals or external objects (20%) that have hit the lines or poles and caused breaking/disturbing of the supply path. The reasons for the

remaining 30% of the unplanned outages cover variety of causes with very low individual contributing percentages such as faulty operation of protection systems, lightning and wind due to storms, etc. Therefore, there are very few root-causes of outages that can be associated with power quality, equipment overloading, or circuit design that could be mitigated by DER contribution.

Table 11: SDG&E Historical Causes of outages (Past 5 Years)

Equipment Failure/Faulted	% of events	External Impact	% of events
Faulted cable	19.8	Vehicle contact	11.1
Connector/jumper/splice/elbow/rack	16.2	Foreign object in distribution line	5.3
Switch faulted/mechanical	2.6	Bird contact	2.1
Insulator/pin failure/wire floating	0.9	Animal contact	1.9
Conductor failure/wire down	1.8		
Crossarm failure	1		
Lightning Arrester/Transformer failure	4.5		
Cutout failure	1.5		
Capacitor failure	1.6		
Total	49.9	Total	20.4

Another observation from reliability data is that only about 4% of outages were caused by issues associated with transmission systems or at the substation level that would have affected large areas and significant numbers of customers. Most reliability related events have occurred locally and have impacted small numbers of customers in local areas. For this reason, the SDG&E system wide indices highlighting the number of interruptions, such as SAIFI, have been very low, around 0.52 average interruptions per customer. This observation suggests that, excluding exceptional circuit level or substation level outage cases, unless a reliability service is offered locally and close to specific end-use customers, the system wide benefits will be immaterial.

6.3 Operations Based Reliability Improvement

In addition to the above mentioned capital improvements projects, SDG&E also enhances reliability by improving operations practices. Such activities include the deployment of more fault indicators to enable the more rapid location of a fault, phase identification to expedite the identification of a fault, adding Infrared guns on electric crews trucks to scan for hot spots which can lead to potential failure, and many other initiatives that either result in better preventative maintenance or faster restoration in the event of an outage. The money spent to improve and maintain quality operations practices is not avoidable via any services that DER may be able to provide.

6.4 Potential Distribution Reliability Improvement Projects in Northeast DPA

Table 12: Tentative SDG&E Cable Replacement Jobs in Northeast

DPSS #	W.O. #	Project Name
252196-010	2959240	C189:ERI 2012 BRANCH CABLE REPLACEMENT
353437-010	2382650	C293:ERI 2013 BRANCH CABLE REPL, PART 1
555064-010	2474470	C450: 2015 BRANCH CABLE REPLACEMENT
551914-010	2444640	C453:2015 PBR PROACTV CBL RPL 2OF4
551920-010	2444650	C453:2015 PBR PROACTV CBL RPL 3OF4
551920-020	2444651	C453:2014 PBR PROACT Cbl Rep - OH
252211-010	2959310	C502:ERI 2012 BRNCH & FEEDER CBL RPL
255286-010	2962780	C751:2013 ERI BRNCH CBL RPL D3367869764
161797-010	2956300	C855:2012 ERI BR CBL REP D3512970503,
161798-010	2956310	C855:2012 ERI BRANCH CABLE REPL D145597
161799-010	2956320	C855:2012 ERI BRNC CBL REP D3512670499
352611-010	2979390	C922: 2013 ERI BRANCH CABLE REPLACE PH 1
352611-020	2452640	C922: 2013 ERI BRANCH CABLE REPLACE PH 2
353437-010	2382650	C293:ERI 2013 BRANCH CABLE REPL, PART 1
650696-010	2496990	C855: 2015 Branch Cable Replace.
650696-010	2496990	C855: 2015 BRANCH CABLE REPLACEMENT
055963-020	2937951	C350:ERI 2010 FEEDER CBL REPL
651764-010	2550090	C453: 2016 Branch Cable Replacement
TBD	TBD	C451: 2016 Branch Reconductor
TBD	TBD	C188: 2016 ERI Branch Cable Replacement
TBD	TBD	2016: C281 ERI Branch Cable Replacement
TBD	TBD	C539: 2016 ERI Branch Cable Replacement

Table 13: Tentative SDG&E SCADA Switch Projects in Northeast

DPSS #	W.O. #	Project Name
156579-010	2950370	C1094: 2011 SGDP SCADA EXP
156579-030	2950372	C1094:2011 SGDP SCADA EXP - OH WORK
156579-020	2950371	C1094:KEARNY SCADA WORK
551920-020	2444651	C453:2015 PBR PROACTV CBL RPL 3OF4-OH
252693-020	2959851	C488: KEARNY SCADA WORK (OH)
252693-010	2959850	C488:ERI 2012 SCADA INITIATIVE-SECTIONAL
257061-010	2964230	C543,BE: INSTALL PME3 SWITCH
951060-010	2918690	C543: 2009 SGDP SCADA EXP Bernardo
352609-010	2979370	C576:2013 ERI SCADA INIT- SECTIONALIZING
457756-010	2390000	C595: 2014 SCADA INITIATIVE
355766-010	2303070	C597:ERI 2013 SCADA INIT-SECTIONALIZING

258128-020	2965211	C910: KEARNY SCADA WORK (UG)
258128-010	2965210	C910:2012 SCADA INITIATIVE & DOE SWI REP
551794-010	2443450	CSL1 PBR Fuse Replacement
555603-010	2479240	CRB1:2016 PBR WORST CIRC SAIFI CUTOVER
555603-020	2479242	CRB1:2016 PBR WORST CIRC (OH RETAG)
555603-030	2479243	CRB1:2016 PBR-INST GANG SWI/POLE CHG OUT
457752-010	2384710	C970: 2014 SCADA INITIATIVE
457752-020	2384711	C970: KEARNY SCADA WORK
457750-010	2384520	C299: ERI 2013 SCADA INITIATIVE-UG
457754-010	2389920	C599: 2013 ERI SCADA INITIATIVE-UG
355753-010	2302840	C539:ERI 2014 SCADA INIT-SECTIONALIZING
355838-010	2303250	C516: 2011 SGDP SCADA EXPANSION
353436-010	2382640	C177:2013 ERI SCADA INIT SECTIONALIZING
457750-020	2384521	C299: ERI 2013 SCADA INITIATIVE-OH
457754-020	2389921	C599: 2013 ERI SCADA INITIATIVE-OH
060756-020	2942701	C909,VC:2010 ERI SECT- INSTALL GANG SWI

Table 14: Tentative SDG&E DOE Switch Projects in Northeast

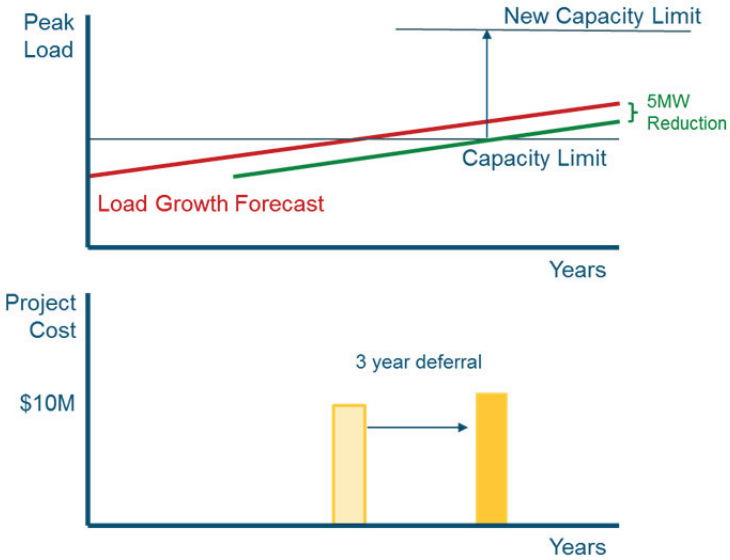
DPSS #	W.O. #	Project Name
552807-010	2456970	C925: 2015 REPLACE DOE SWI
552810-010	2457060	C513: 2015 REPLACE DOE SWI
552811-010	2457170	C294: 2015 REPLACE DOE SWI
862685-010	2915170	C935:DOE SWITCH REPL
651135-010	2510240	C500: Replace DOE Switch
651547-010	2530730	C475: DOE SWITCH REPLACEMENT
651546-010	2530650	C456: DOE SWITCH REPLACEMENT
059528-010	2941430	C284: DOE SWITCH REPLACEMENT
651723-010	2542540	C932: 2016 DOE SWITCH REPL
651724-010	2542770	C915: 2016 DOE SWITCH REPL
651725-010	2543010	C922: 2016 DOE SWI REPL
651726-010	2543300	C913:REPL 4WAY SWI W/4WAY SCADA
651727-010	2544300	C913: INSTALL A PME-11

7 Project Deferral Benefit Calculation

7.1 LNBA Tool Deferral Benefit Calculation

In Demo B, DERs are considered able to defer distribution upgrades by reducing load such that they mitigate the problem that is the driving the need for a distribution upgrade. The diagram below provides an example of the simple case of a forecasted overload on a distribution facility which would typically require a distribution capacity upgrade.

Figure 14: Visualization of Project Deferral



The upper chart depicts a DER's ability to delay, for three years, a forecasted overload by reducing peak load by 5 MW. The lower chart depicts the effect of this delay on the timing and quantity of capital investment for the distribution capacity upgrade project which mitigates the overload. Note that the project cost is nominally larger after the three year deferral due to inflation of material and labor.

The ratepayer benefit of a deferral is primarily a result of the cost to capitalize such an investment: the present value of raising capital in year 4 instead of year 1. The quantity of this benefit is calculated in Demo B using the Real Economic Carrying Charge (RECC) method, per commission direction.[33] In this method, a RECC factor is multiplied by the original upgrade project capital cost to yield the benefit of a one year deferral. This factor, expressed below, is a function of the utility's cost of capital and the life of the capital asset as well as inflation.

RECC factor:[34]

$$\text{RECC} = \frac{(r-i)}{(1+r)}\left(\frac{(1+r)^N}{(1+r)^N-(1+i)^N}\right) .$$

i=inflation, r=discount rate, N = life of the capital asset

The RECC factor multiplied by the original capital investment does not fully capture all of the ratepayer savings from a deferral. This is because the actual amount recovered from

[33] 5/2 ACR, p. 30, "Compute a total avoided cost…Use the Real Economic Carrying Charge method."

[34] This is calculated in the LNBA Tool, Project Inputs & Avoided Costs tab, Row 117.

ratepayers for the original capital investment is always greater than the project cost. The revenue requirement, or RRQ, effectively charged to ratepayers includes various other costs such as taxes, franchise fees, utility authorized rate of return, and overheads. These general cost factors are captured in a RRQ Multiplier, which is applied to the result of (the capital investment x the RECC factor). The RRQ Multiplier may vary for different projects, for example, where different types of equipment are treated differently in tax accounting.

Finally, ratepayers also see a benefit associated with reduced annual O&M activities required of a new distribution facility. This O&M expense is a direct pass thru to customers, and therefore it is not multiplied by the RECC factor or the RRQ Multiplier. Since O&M costs are incurred in the year they are performed, lifetime O&M is also subject to inflation. The complete expression of ratepayer benefit associated with a one-year deferral is thus

Deferral Benefit = [original project cost] x [RECC Factor] x [RRQ Multiplier] + [levelized annual O&M]

For a multiple-year deferral, the yearly deferral value beyond the first year is simply discounted to a present value using a discount factor derived from the same discount and inflation rates used in the RECC factor.[35]

7.2 Inputs and Outputs

This section provides an overview of the primary LNBA Tool inputs, outputs and settings related to the deferral benefit calculation. Additional description of these inputs, outputs and settings as well as others are provided in Appendix 2 "LNBA Guide" file. Major inputs related to the deferrable project are summarized below. These are categorized as either Universal Inputs analysis or Project Specific Inputs.

[35] This total deferral benefit is calculated in the LNBA Tool, Project Inputs & Avoided Costs tab, Rows 152-161.

7.2.1 Universal Inputs

Table 15: Universal Inputs into the LNBA Project Deferral Value Calculator

Name	Location in LNBA Tool	Description	Source
Discount Rate	Project Inputs & Avoided Costs; C5	Used for various financial calculations.	These are set to the IOUs' commission-approved Weighted Average Cost of Capital (WACC).[36]
RRQ Multiplier	Settings; C13:E28	Converts capital cost to revenue requirement.	These are calculated using historical averages for similar projects with similar assets
Equipment Inflation Rate	Settings; F13H28	These are set at a standard 2%	Standard Assumption
O&M Inflation Rate	Settings; I13:K28	These are set at a standard 2%	Standard Assumption
Book Life	Settings; L13:L28	Used to calculate RECC.	These are obtained from FERC Accounting Standards (Deprecation life cycles) for each asset type
O&M Factor	Settings, M13:O28	Used to determine annual O&M savings for associated with a deferral. These are annual O&M for a type of equipment as a percent of its capital cost.	These are derived from the SDG&E approved rule 2 tariffs for alternate service (what we would charge customers to account for O&M)

[36] CPUC Decision D.12-12-034 set the currently applicable WACCs for each IOU.

7.2.2 Project-Specific Inputs

Table 16: Project Specific Inputs into the LNBA Project Deferral Value Calculator

Name	Location in LNBA Tool	Description	**Source**
Project Identifiers	Project Inputs & Avoided Costs; Rows 18 and 19	Used to identify each project.	N/A
Equipment Type	Project Inputs & Avoided Costs; Row 20	Used to select RRQ Multiplier, Book Life, and O&M Factor for a project	N/A
Project Cost	Project Inputs & Avoided Costs; Row 27	Used to calculate deferral benefit. The tool evaluates low (x0.7) and high (x1.5) sensitivities, reflecting uncertainty in the cost estimate. These are derived from cost estimating standards.[37]	Per 5/2 ACR, each IOU used "existing approaches for estimating costs of required projects."
Cumulative MW Reduction Needed	Project Inputs & Avoided Costs; Rows 33-47	Used to define amount of load reduction needed to achieve deferral.	LoadSEER 10 year 12/24 dynamic forecast reporting tool less the existing capacity
Project Install/Commitment Year	Project Inputs & Avoided Costs; Row 30	Compared with DER Install Year to check whether a project can be deferred by a DER; also used to evaluate duration of a deferral.	Derived based on projected overloads.
Project Flow Factors	Project Inputs & Avoided Costs; Table at C53	Used to identify upstream projects and the extent to which they're impacted by load reduction at downstream project locations	Percent of MWh provided by downstream project relative to the upstream projects needs
Loss Factors	Project Inputs & Avoided Costs;	Used to translate Hourly DER Profile to an actual	SDG&E specific system average loss

[37] Specifically, the low and high sensitivities reflect a Class 4 estimate as described in the American Association of Cost Estimating recommended practice 17R-97, available at: http://www.aacei.org/toc/toc_17R-97.pdf.

	Table at C67	impact on loading at the location of the problem that causes a deferrable project to exist.	factors for T&D calculated in 2016 LTPP Scenario Tool
Load Profile/Need Profile	AreaPeaks; tables at rows 16-8775	Used to define profile of required DER load reduction to achieve deferral.	Equal to the Cumulative MW reduction Needed Calculated with LoadSEER forecasts minus the existing capacity.
Threshold	AreaPeaks; Row 13	Defines the threshold above which an overload is assumed to occur in the Load Profile/Need Profile.	The Rated Capacity of the equipment projected to overload

7.2.3 DER Inputs

Major inputs related to the deferrable project are summarized below. These are the primary inputs that DER providers or stakeholders would use to evaluate various DER alternatives.

Table 17: DER Inputs into the LNBA Project Deferral Value Calculator

Name	Location in LNBA Tool	Description	Source
DER Location	DER Dashboard, F4	Used to identify the primary deferrable project which the DER is downstream from.	User Input
DER Useful Life	DER Dashboard, F6	Used to calculate lifecycle avoided costs.	User Input
DER Install Year	DER Dashboard, F7	Used to determine which projects are deferrable and for various avoided cost analyses.	User Input
Defer T&D to this year	DER Dashboard, F8	Used to identify the DER load reduction requirement associated with the deferrable projects upstream of DER Location. If set to 2025, for example, the tool checks whether the Hourly DER Profile is sufficient to mitigate the problem causing upstream deferrable projects to exist in 2024 and prior years.	User Input
DER Type	DER Dashboard, K3	Used to determine renewable integration costs.	User Input

Hourly DER Profile	DER Dashboard, F57:F8816	Hourly load increase/decrease associated with a DER solution. Should be constructed using 2015 calendar and a 1:10 weather year.	User Input
Dependability in local Area	DER Dashboard, F5	Use this to easily scale the DER profile up or down.	User Input

7.2.4 Tool Settings

In addition to inputs, the LNBA Tool has a variety of settings that will determine how certain calculations are made. Major settings and default values are described below

Table 18: LNBA Project Deferral Value Calculator Tool Settings

Name	Location in LNBA Tool	Description	Default
T&D Value Basis	DER Dashboard, E13	"Allocation-based Average vs "Requirement-Based Threshold", "Allocation based average" assigns value even if the peak reduction is insufficient for deferral"	Requirement-based threshold
Case to use for allocated hourly costs	Project Inputs and Avoided Costs, C8	Select whether to use the base cost or the high or low sensitivities.	Base
Include or Exclude Deferral Value	DER Dashboard, I24:I33	Manually include or exclude T&D deferral value associated with deferrable projects upstream of DER Location. Default: Include	Include
Include Component	DER Dashboard, D41:D49	Manually include or exclude LNBA components in LNBA results.	Include

7.2.5 Outputs

The primary LNBA Tool output is lifecycle DER avoided cost, which is provided in total as well as broken down by component in the table in the DER Dashboard tab at cell I50. This includes the T&D deferral benefit component, which is provided explicitly at cell M45.

7.3 Calculating Transmission Benefits

The tool is capable of evaluating a transmission project deferral opportunity in the same way that distribution projects are evaluated in Demo B. The same inputs are required, primarily the timing and cost of a deferrable project and the DER load reduction profile required to achieve

that deferral. The May 2, ACR specifically directs the utilities to evaluate the transmission component of LNBA by quantifying the co-benefit value of ensuring that preferred resources relied upon to meet planning requirements in the California ISO's approved 2015-2016 Transmission Plan[38] materialize as assumed. However, Section 7.3 of the 2015-2016 Transmission Plan does not provide sufficient information to do this analysis. Specifically, it does not identify projects which would be required in the absence of those preferred resources or the associated project costs. It also does not provide information needed to develop DER load reduction requirements. In lieu of analyzing specific transmission deferral benefits, the LNBA Tool includes a generic system-wide transmission benefit input for users to define.[39] Note that this input is per kW of the DER type that is being analyzed (e.g., per kW of PV). The default transmission value is set to zero, consistent with the default value found in the Public Tool developed in the NEM Successor Tariff Proceeding (R.14-07-002).

SDG&E recognizes the potential for DER to defer certain transmission projects, and as explained above, the LNBA tool does allow for a specific transmission project deferral calculation given a specifically identified transmission project. Unlike the sensitivity study in section 7.3 of the California ISO's 2015-2016 Transmission Plan, which lacks specific system needs and specific project details, section 7.2 of the California ISO's Annual Transmission Plan does identify and approve specific transmission projects and is currently the best source of information to determine which, if any, transmission projects could be deferred by DER. For purpose of Demo B, SDG&E reviewed the following approved CAISO transmission projects located in Northeast and was unable to identify a DER transmission project deferral.

Pending Projects Located In Northeast District		
Project Title	**ISD**	**Driver**
Upgrade TL633 Bernardo - Rancho Carmel	Mar-18	The higher line rating is required to mitigate P1-P7 NERC violations identified in the Artesian East 230kV study. This project is due to the Artesian Expansion project.
TL13820 Reconductor Sycamore Canyon - Chicarita	Dec-18	The contingency loss of Encina Bank 60 & 61 combined with the loss of Carlsbad Repower generation on the 138kV system will overload TL13820.
2nd San Marcos - Escondido 69kV Line	Mar-20	NERC P0 violations were identified on TL684 (ES-SM) when both Escondido peakers were dispatched and there was high flows on P44 and high imports through Imperial Valley. NERC P1 violations are also identified with the loss of TL684.

[38] Available on the CAISO Website at: http://www.caiso.com/Documents/Board-Approved2015-2016TransmissionPlan.pdf.

[39] Located in the LNBA Tool's DER Dashboard tab at cell K6.

2nd Poway - Pomerado 69kV Line	Jun-20	NERC P1 violations were identified on TL6913 (POM-PO) for the N-1 of TL23051.

SDG&E recommends the IOUs and stakeholders continue to participate in the future California ISO's Annual Transmission Planning Processes to identify and determine specific projects that can be potentially deferred by DER. This will allow the LNBA working groups to refine this initial approach, enabling a more detailed treatment of transmission benefits similar to the detailed analysis of distribution benefits in Demo B.

7.4 System Level LNBA Components

As indicated in the LNBA overview, the system-level avoided cost module calculates the values of DER services that are consistent regardless of a DERs location in a distribution system. These values are commonly associated with conventional generators mainly derived from the energy marketplace. These components include avoided energy, avoided generation capacity, avoided GHG, avoided RPS, avoided ancillary services, and the renewable integration cost adder.

7.4.1 Sources

The commission approved E3 avoided cost calculator version 1.0[40] [41] and a revised distributed energy resources avoided cost model ("DERAC"), were used to derive avoided energy, system avoided generation capacity, avoided GHG, avoided RPS, and avoided ancillary services. For each component sourced from the avoided cost calculator, an hourly profile is provided for 31 years (2016-2047) in the 'SystemAC' tab of the LNBA tool. The source for the renewable integration cost adder is the interim value adopted in 2014 from D.14-11-042[42].

7.4.2 User Inputs in 'DER Dashboard' Tab of LNBA Tool

In order for the system-level avoided cost module to properly calculate the value of the components, the user needs to provide basic DER information, value for benefits that the DER can obtain, and a DER hourly profile. A user will be required to input these pieces of information in the 'DER Dashboard' tab of the LNBA tool. These inputs will need to be defined in three sections of the 'DER Dashboard' tab: 'DER Settings and Full Local T&D Avoided Cost', 'DER Avoided Costs', 'DER Hourly Shape and Calculations'.

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[40] Avoided Cost Calculator v1.

[41] The use of the avoided cost calculator as the source for avoided energy, system capacity, GHG, RPS, and ancillary services costs provides an estimation of those components based on publicly available data.

[42] *Decision Conditionally Accepting 2014 Renewables Portfolio Standard Procurement Plans and an Off-Year Supplement to 2013 Integrated Resource Plan*, November, 24, 2014, pp. 61-63.

7.4.3 'DER Settings and Full Local T&D Avoided Cost' Section

In the 'DER Settings and Full Local T&D Avoided Cost' section (Row 1) of the 'DER Dashboard' tab, the user will need to select the DER location and DER type. In addition, the user will need to define the dependability in the local area, DER useful life, DER install year, last year of deferral, transmission avoided cost, and local RA multiplier. *See* Figure 15 for an example the 'DER Settings and Full Local T&D Avoided Cost' section.

Figure 15: 'DER Settings and Full Local T&D Avoided Cost' section

DER Settings and Full Local T&D Avoided Cost — Version 2.10

DER Location and Annual Inputs						
DER Location	Circuit 1107		DER Type	WIND		
Dependability in local area (eg.g: 90%)	90%		Integration cost adder ($/MWh)	$ 4.00		
DER Useful Life (yrs)	20		Transmission Avoided Cost ($/kW of DER)	$0.00	(Default = 0)	
DER install year	2017	InstallYr	Generation Capacity LCR Multiplier	1.5	(Default = 1.0)	
Defer T&D to this year (Max 2026)	2026					

7.4.4 'DER Impact on Local T&D' Section

In the 'DER Impact on Local T&D' section (Row 11), the user selects the T&D value basis and the components to include in the calculation. Under the dropdown menu of the T&D value basis, there are two options: requirement-based threshold and allocation based average. By selecting the requirement-based threshold option, the DER hourly profile must be able to meet the project need in order to obtain the T&D benefit. By selecting the allocation based average option, the DER hourly profile does not need to meet the project need in order to obtain some T&D benefit. In short, the T&D value basis dropdown allows the user to select whether or not the DER solution receives partial T&D value when that solution does not meet the project needs.

7.4.5 'DER Avoided Costs' Section

The 'DER Avoided Cost' section (Row 37) contains two areas. In the 'Include Component?' area, the user can select whether or not the DER solution will receive the benefit of each component. Under the 'Lifecycle Value from DER by Component ($)' area, the 'DER Avoided Costs' section provides outputs of total value ($) of the DER solution by component for the contracted life. Figure 16 shows an example of the 'DER Avoided Costs' section.

Figure 16: 'DER Avoided Costs' Section

DER Avoided Costs

Include Component?	
Energy	TRUE
Gen Capacity	TRUE
Ancillary Services	TRUE
CO2	TRUE
RPS	TRUE
Flex RA	TRUE
Integration Cost	TRUE
System Trans	TRUE
T&D	TRUE

Lifecycle Value from DER by Component ($)	Circuit 1107	All Affected Areas
Energy	$1,982,819	$1,982,819
Gen Capacity	$555,478	$555,478
Ancillary Services	$18,393	$18,393
CO2	$797,824	$797,824
RPS	$808,743	$808,743
Flex RA	-$306,118	-$306,118
Integration Cost	-$221,372	-$221,372
System Transmission	$0	$0
Local T&D	**$0**	**$1,956,858**
Total Avoided Cost ($)	**$3,635,767**	**$5,592,625**

7.4.6 DER Hourly Shape and Calculations Section

In the 'DER Hourly Shape and Calculations' section (Row 52), the user will need to input a DER hourly output for the entire year (8760 hours). The hourly shape is entered in the yellow highlighted cells (*See* Figure 17). In the 'Hourly lifecycle unit avoided costs (hourly $/kW)' area, this area provides the hourly net present value by component for the contracted life of the DER solution. This output with the hourly DER solution provides the information needed to calculate the total value by component in the 'DER Avoided Costs' section.

Figure 17: 'DER Hourly Shape and Calculations' Example

52 DER Hourly Shape and Calculations

53

54	User Input for DER Hourly Shape				Hourly lifecycle unit avoided costs (hourly $/kW). Adjusted for exclusions and losses, but not for dependability or generation multiplier							
55	PST				Lifecycle	Lifecycle	Lifecycle	Lifecycle	Lifecycle	Lifecycle	Local T&D for	Local T&D for All Included
56	Hour Starting	Month	Hour	DER at meter (kW)	Energy	Gen Cpcty	AS	CO2	RPS	Flex RA	Circuit 1107	Affected Areas
57	1/1/15 12:00 AM	1	0	0.00	$0.58	$0.00	$0.01	$0.18	$0.17	$0.00	$0.00	$0.01
58	1/1/15 1:00 AM	1	1	0.00	$0.54	$0.00	$0.00	$0.17	$0.17	$0.00	$0.00	$0.01
59	1/1/15 2:00 AM	1	2	0.00	$0.53	$0.00	$0.00	$0.17	$0.17	$0.00	$0.00	$0.01
60	1/1/15 3:00 AM	1	3	0.00	$0.52	$0.00	$0.00	$0.17	$0.17	$0.00	$0.00	$0.01
61	1/1/15 4:00 AM	1	4	0.00	$0.54	$0.00	$0.00	$0.17	$0.17	$0.00	$0.00	$0.01
62	1/1/15 5:00 AM	1	5	0.00	$0.59	$0.00	$0.01	$0.18	$0.17	$0.00	$0.00	$0.01
63	1/1/15 6:00 AM	1	6	0.00	$0.54	$0.00	$0.00	$0.17	$0.17	$0.00	$0.00	$0.01
64	1/1/15 7:00 AM	1	7	0.00	$0.53	$0.00	$0.00	$0.17	$0.17	$0.00	$0.00	$0.01
65	1/1/15 8:00 AM	1	8	105.30	$0.52	$0.00	$0.00	$0.17	$0.17	$0.00	$0.00	$0.01
66	1/1/15 9:00 AM	1	9	720.21	$0.48	$0.00	$0.00	$0.17	$0.17	$0.00	$0.00	$0.01
67	1/1/15 10:00 AM	1	10	154.16	$0.45	$0.00	$0.00	$0.17	$0.17	$0.00	$0.00	$0.01
68	1/1/15 11:00 AM	1	11	293.76	$0.43	$0.00	$0.00	$0.17	$0.17	$0.00	$0.00	$0.01
69	1/1/15 12:00 PM	1	12	315.30	$0.41	$0.00	$0.00	$0.17	$0.17	$0.00	$0.00	$0.01
70	1/1/15 1:00 PM	1	13	175.15	$0.37	$0.00	$0.00	$0.17	$0.17	$0.00	$0.00	$0.01
71	1/1/15 2:00 PM	1	14	940.02	$0.40	$0.00	$0.00	$0.17	$0.17	$0.00	$0.00	$0.02
72	1/1/15 3:00 PM	1	15	727.53	$0.47	$0.00	$0.00	$0.17	$0.17	$0.00	$0.00	$0.02
73	1/1/15 4:00 PM	1	16	174.38	$0.70	$0.00	$0.01	$0.21	$0.17	$0.00	$0.00	$0.02
74	1/1/15 5:00 PM	1	17	0.00	$0.87	$0.00	$0.01	$0.26	$0.17	$0.00	$0.00	$0.01
75	1/1/15 6:00 PM	1	18	0.00	$0.89	$0.00	$0.01	$0.27	$0.17	$0.00	$0.00	$0.01
76	1/1/15 7:00 PM	1	19	0.00	$0.80	$0.00	$0.01	$0.24	$0.17	$0.00	$0.00	$0.01
77	1/1/15 8:00 PM	1	20	0.00	$0.81	$0.00	$0.01	$0.25	$0.17	$0.00	$0.00	$0.01
78	1/1/15 9:00 PM	1	21	0.00	$0.71	$0.00	$0.01	$0.21	$0.17	$0.00	$0.00	$0.01
79	1/1/15 10:00 PM	1	22	0.00	$0.66	$0.00	$0.01	$0.20	$0.17	$0.00	$0.00	$0.01
80	1/1/15 11:00 PM	1	23	0.00	$0.58	$0.00	$0.01	$0.18	$0.17	$0.00	$0.00	$0.01

Overview | DER Dashboard | Project Inputs & Avoided Costs | AreaPeaks | ReMapping | SystemAC | Flex RA | Settings | ...

7.5 System Level calculation of Avoided Energy Costs

The avoided cost of energy is defined as the total net present value of energy that does not need to be procured at the system level due to the generation or savings of the DER solution. Of note, there are line losses as energy is delivered from the system level to the distribution level. Thus, one megawatt-hour (MWh) of energy at the distribution level would offset a higher amount (*e.g.,* 1.05 MWh) at the system level. In order to get the value of this offset energy, the time, length, and amount of the energy of the DER solution needs to be known. For example, if the DER solution provides one MWh of energy on January 1st, 2016 at 8 AM for one hour, the corresponding energy price for that time is $27.59/MWh. Assuming that the line loss factor is 1.05, the value of this avoided energy is:

$$1\ MWh * 1.05 * \$27.59/MWh = \$28.97$$

7.6 Avoided Generation Capacity Costs

The avoided cost of generation capacity is subdivided into three different types: system, local, and flexible capacity.

7.6.1 Avoided System Generation Capacity

Avoided system generation capacity cost is defined as the total net present value of generation capacity that does not need to be procured at the system level, due to the reduction of needed capacity generated by the DER solution. Similar to system energy, there are losses associated with providing generation capacity down to the distribution level. Thus, one megawatt (MW) of generation capacity at the distribution level would offset a higher amount of generation capacity (*e.g.,* 1.07) at the system level. In order to calculate the value of the system generation capacity, the time, length, and amount of the capacity of the DER solution need to be known. For example, if the DER solution provides one MW of capacity on June 30th, 2016 at 3 PM for one hour, the corresponding system capacity for that time is $0.0277/MWh, assuming a loss factor of 1.07, the value of this avoided system capacity is:

$$1\ MW * 1\ h * 1.07 * \$0.0277/MWh = \$0.03$$

7.6.2 Avoided Local Generation Capacity

For local generation capacity, the IOUs were directed to use DERAC values;[43] however, DERAC does not include local generation capacity prices needed to evaluate benefits associated with avoided local RA purchases. The LNBA Tool includes a generic "Generation Capacity LCR Multiplier" so that a user can apply a local capacity premium to the DERAC system generation capacity prices included in the LNBA Tool as appropriate.[44] This value is defaulted to 1.

7.6.3 Avoided Flexible Generation Capacity

The avoided cost for flexible capacity is defined as the value of flexible capacity that does not need to be procured from the offsetting flexible capacity provided by the DER solution. In the LNBA tool, the value of flexible capacity was assumed to be $20 / kW-yr in 2016. For future years, the $20 / kW-yr value was escalated by 5% each year. To calculate the value of the avoided flexible capacity for a specific DER solution, the DER solution hourly profile is assessed for a three hour ramp.

7.7 Avoided GHG, RPS, and Ancillary Service Costs

Avoided GHG, RPS, and ancillary services costs are defined as the total net present values of each component that does not need to be procured at the system level (due to the DER providing the corresponding offset to each component). For example, if a DER solution can offset the need to procure a certain amount of RPS energy; the tool will calculate the value of the avoided RPS energy. Parallel to calculations of avoided energy and system capacity costs, the values of avoided GHG, RPS, and ancillary services are calculated by: summing the net present

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[43] 5/2 ACR, table 2, Approved LNBA Methodology Requirements Matrix for Demonstration Project B at p. 25, "Avoided Generation Capacity, System and Local RA, Use DERAC values."

[44] Located in the LNBA Tool DER Dashboard tab at cell K7.

values (using the hourly DER values) and multiplying the corresponding hourly value for each component on a per MWh basis.

7.8 LNBA Renewable Integration Cost

The renewable integration cost is dependent on the solution technology. For solar sources, the renewable integration cost is $3 / MWh. For wind sources, the renewable integration cost is $4 / MWh. All other technologies are $0 / MWh. To calculate total renewable integration cost, the appropriate DER technology is selected. The $ / MWh cost is subsequently multiplied by the total energy produced by the DER solution for its contracted life.

7.9 System Level Avoided Costs Calculator Example

The IOU's thought that it may be useful to include an example calculation from the system level avoided cost calculator to display how the utilities can value the various system level avoided costs a specific DER resource may be able to provide. The chosen example DER is a 100kW nameplate generator operating continuously for a 10 year period, and considered a 100% renewable resource able to be credited for contributing to system RA. If a DER was able to achieve these characteristics, the utilities would include the following values in their net benefit analysis of deploying that particular DER.

Lifecycle Value from DER by Component ($)	
Energy	$250,874
Gen Capacity	$105,663
Ancillary Services	$2,232
CO2	$84,511
RPS	$107,105
Flex RA	$0
Integration Cost	$0
System Transmission	$0
Total System Level Avoided Cost	$550,384

Because the results of this type of analysis may be considered of significant value, and because the current methodology focuses on a DER technology neutral analysis, a future refinement to the LNBA tool that may provide more accurate results could be to include an analysis to calculate the system level benefits of specific DER technologies. Accurate forecasting of a DER's generation output or reduction to load will help all stakeholders succeed in identifying and implementing cost effective DER solutions. The development of accurate DER output forecasting tools can be considered another potential long term refinement.

8 Conclusion

SDG&E would like to thank the members of the Demo B working group and the CPUC Energy Division for the guidance provided during the development of the LNBA methodology. In addition, SDG&E would like to thank More Than Smart for their leadership and facilitation of the Demo B working group. SDG&E believes that the LNBA methodology developed and its application to a DPA meet the requirements outlined in the Assigned Commissioner's Ruling

(ACR) issued May 2, 2016 and the revised ACR issued August 23, 2016. As the IOUs and stakeholders move forward in refining the locational net benefit analysis for DERs as a part of the ongoing Distribution Resources Plan proceeding, it is important to ask ourselves what we envision as the end use of all the tools we have developed in Demo B. SDG&E believes that by providing these tools to the public, we are providing the necessary transparency to allow DER developers to properly assess the benefits that DER can provide as well as where DER can provide locational benefits. However, SDG&E would like to remind stakeholders that the tools' utility provided inputs (e.g., cost of capital, revenue requirement factors, energy pricing forecasts, project cost estimates etc.) will need to remain confidential to avoid the unnecessary disclosure of information that can lead to a market advantage. SDG&E looks forward to the continued development of long term refinements of the LNBA methodology as identified in the ACR and ensuring that SDG&E continues to provide reliable, safe and cost-effective service to our customers.

Appendix 1: Heat Map

http://www.sdge.com/generation-interconnections/interconnection-information-and-map

Appendix 2: E3 LNBA Tool Documentation

LNBA Tool User Guide

Version 2.11, December 6, 2016

Table of Contents

This document is a quick user guide for the LNBA tool that calculates locational avoided costs for utility local T&D projects, as well as avoided cost benefits for a load reduction shape. The document is organized into three sections

1. Guide for DER stakeholders (DER users)
2. Additional info for utility staff (that populate the project cost-related inputs)
3. Methodology overview

The LNBA Tool is an excel spreadsheet that makes minimal use of VBA functions in order to maintain transparency and understandability. There is one VBA function that is used for interpolation of some inputs, and for that reason, VBA macros should be enabled when using this tool.

The overall structure of the tool is summarized below.

1. Tool Structure Overview

Tab	Function	Description
DER Dashboard	Interface tab for DER bidders	Determines the total avoided cost benefits of DER by location. Requires the user to select an area, and input an 8760 hours stream of DER load reductions (DER Output) in kW. The DER output should match the weather and chronology (weekdays/weekends) of the T&D information. The dates of the T&D info and the weather data can be found on the Remapping tab.
Project Inputs & Avoided Costs	Utility inputs and calculation of local T&D deferral avoided costs	***Utility Inputs:*** Project information such as cost and need for up to ten projects as well as generic utility discount rate and default inflation rate information. Also allows the utility to define the links between areas to allow for quantification of the benefits in the DER installation area, as well as other affected T&D areas. ***Results:*** Base low and high case avoided costs by project and aggregated for all projects affected by DER installed in the area.
AreaPeaks	Utility inputs to define the peak need and timing	Utility inputs of area loads (and peak threshold) or hourly area needs.
Remapping	Align system avoided costs with weather and chronology of the local T&D deferral avoided costs	Utility Inputs tab. Weather information by area is input in order to allow the system avoided costs to be remapped to more closely map the chronology (weekends) and temperature characteristics of the T&D information.

Tab	Function	Description
SystemAC	Repository for CPUC system avoided costs	Hourly system avoided costs. Values are from the 2016 Interim Update CPUC Avoided Costs.
FlexRA	Inputs and calculation of avoided costs for ramping	Flexible Resource Adequacy Costs and timing of ramping need period.
Settings	Various	Contains lists for dropdown boxes and utility-specific information that need only be updated on an annual basis. Data includes equipment revenue requirement multipliers and O&M costs as a percentage of direct costs. No project-specific inputs.

The next section describes the inputs on the DER Dashboard with which a DER stakeholder would interact.

2. Guide for DER Users.

DER users will enter their project information in the DER Dashboard tab of the tool. The user inputs are listed below. Yellow cells in the tool indicate user data inputs, orange cells indicate drop-down selections.

DER User Inputs

Item	Location	Note/Comment
DER Location	F4	Select the utility project area from the dropdown list. This should reflect the planned physical location of the DER installation. If there is more than one area that applies to the location, select the most geographically specific choice. For example, if the DER is being installed at UCLA, and the area choices included Westwood and Los Angeles County, one should select Westwood.
Dependability in Local Area	F5	Factor used to de-rate the local DER capacity reduction amount. 100% indicates that DER load reductions can be relied upon as dependable. A value of, say 90%, indicates a 10% reduction to the DER impact of local capacity. This factor is not applied to system benefits.
DER Useful Life	F20	Number of years the DER is expected to persist. This is used to calculate lifecycle system benefits for the DER
DER install year	F21	Year (e.g.,: 2017) that the DER would be operational and able to reduce the area peak. If the DER would be operational after the seasonal peak for the project area, enter the install year as the following year.
Defer T&D to this year	F22	DER will likely only be able to defer the local T&D investment for fewer years than the DER expected useful life. Enter the

Item	Location	Note/Comment
		number of years of project need that the DER could avoid and thereby allow deferral of the T&D project. The later the year, potentially the larger the deferral benefit, but also the higher the peak reduction need. The user can derive deferral years by entering DER profile and checking against the required electrical characteristics for each year, and can check the deferral values incrementally for each year following the DER install year.
DER Type	K3	Indicate if the DER is a solar or wind project. This information is used to assign integration costs to the solar and wind DER based on lifecycle MWh production.
DER at Meter	F57:F8816	DER output or load reduction at the customer meter or installation site. Data is in kW and does not reflect upstream losses. If the DER is weather sensitive, interacts with usage schedules that vary between weekdays and weekends/holidays, or is dispatchable, the user should take care that the values correspond to the year chronology and weather being used by the utility for defining the peak needs of each area. That information can be found in the Remapping tab columns H through M.

DER and Project Output

Item	Location	Note / Comment
T&D Value Basis	E13	Allows T&D value to be calculated in two ways. Requirement-based threshold or Allocation-based threshold differences are described in the methodology section
DER Peak Reductions		
kW Needed	D22:D33	Maximum deficiency for each project from the DER Install Yr. up to but not including the 'Defer T&D to this year" input.
Need after Dependable DER	E22:E33	Maximum area need in the same year used for the "kW Needed" after subtracting dependable DER load reductions.
Dependable DER Reduction	F22:F33	kW Needed less "Need after Dependable DER"
Potential Deferral Value ($)	H22:H33	Maximum value if all applicable projects can be deferred by the DER up to the "Defer T&D to this year"
Inclusion choice	I22:I33	Setting to "exclude" will set the deferral value for the T&D project to zero.
Attributed Deferral Value	J22:J33	Total deferral value, based on the selection of T&D Value Basis (Cell E13) and the inclusion choices.
Avoided Costs		
Inclusion Choice	D41:D49	Setting to FALSE will zero out the component in the table to the right

Item	Location	Note / Comment
Lifecycle values - system	H41:I48	Lifecycle costs and benefits provided by the DER.
DER kW output statistics		
DER Max Output (kW)	N20	Maximum of the hourly DER kW entered by the user in cells F57:F8816
Minimum	M23:N23	Minimum DER output during the peak hours. (Note that we use the term "DER output" in this section, but this could also apply to DER load reductions). If there is more than one project affected by the DER, there may be more peak hours in the "All Affected Areas" case, than the "Project Area" case. This will happen if the other affected areas have peak timings that differ from the project area. In that situation, the minimum could be lower for the "All Affected Areas" case.
Percentiles	M24:N26	X% indicates DER output is BELOW this value during X% of the peak hours.
Simple Average	M27:N27	Average DER output during the peak hours. Note that this is not the same as the average DER output over the year.
PCAF Wtd Average	M28:N28	Sum product of the DER hourly output and the hourly local T&D costs divided by the sum of the hourly local T&D costs.
HeatMaps		
Heatmap cost selection	S2:AQ15	The user can display a heatmap for either the individual project area costs, or the total costs for all affected areas. The costs shown are totals by month and hour for local T&D only, and do not include system components. The heatmap is useful for illustrating the timing of the peak reduction need.
DER Output	S19:AQ32	Heat map of the DER output or load reduction average kW by month and hour

The next section defines additional data fields that the utilities will need to populate.

3. Additional Data Inputs

This section summarizes the data that utilities would need to update for their projects. The information is organized by spreadsheet tab.

Utility Inputs

Item	Location	Note / Comment
DER Dashboard		
Transmission Avoided Cost	K6	Total lifecycle system transmission avoided cost savings per kW of DER output or reduction. Note that this is NOT per kW of demand change at the transmission system level, so losses should be accounted for in the entered value. Default is zero.
Generation	K7	The system avoided costs are from the CPUC 2016 Update.

Item	Location	Note / Comment
Capacity LCR Multiple		If the generation capacity costs in the update differ over the expected lifecycle of the DER, a value other than 1.0 can be entered to scale up or down the attributed generation capacity value. A value of 1.5 would increase the CPUC avoided generation capacity cost by 50%. Default is 1.0.
T&D Value Basis	E13	Utilities have the choice in how to value peak reductions. "Requirement-based threshold" assigns value for the project area only if peak reduction is sufficient for deferral. For other affected areas, value is based on the percentage of the kW need that is met by the DER. The user can "exclude" other affected projects to force the attributed value to zero. "Allocation-based average" is based on expected reductions and is not limited to discrete integer years of deferral. "Allocation-based average" calculates value using peak capacity allocation factors (see below for a description of PCAFs).
Include or Exclude Deferral Value	I24:I33	The utility can choose to exclude other affected areas from the valuation by selecting the "Exclude" option.
Include Component	D41:D49	Utilities can choose to exclude system avoided cost components by selecting the FALSE option.
Project Inputs & Avoided Costs		
First load forecast year	C4	This sets the first year of hourly peak/need information for all project areas.
Discount Rate	C5	Utility WACC, nominal. The revenue requirement multiplier, equipment inflation rates, O&M inflation rates, and O&M factors may vary by discount rate, so this input may also affect the values that are used for those items.
Generic Default Inflation Rate	C6	Used as the default for equipment and O&M annual inflation in the Settings tab.
Case to use	C8	The LNBA tool allows for three sets of cost estimates to be entered into the model. This dropdown indicates which set should be used for the reported results on the DER Dashboard tab.
Project information		
Location identifier	Row 18	User Text
Location mapping	Row 19	User Text
Equipment Type	Row 20	Revenue requirement multipliers, equipment inflation rates, O&M inflation rates, O&M costs, and project lifetimes are stored in the LNGA tool according to Equipment Types. This selection indicates which set of values are used.
Capital Cost ($000)	Row 27	Project capital cost. This value will be increased by the revenue requirement multipliers to convert the values to revenue requirement levels.
Cost Yr. Basis	Row 29	Indicates which year dollars are used for the Capital Cost

Item	Location	Note / Comment
		inputs. The Capital Costs are inflation adjusted as needed based on this Cost Yr. entry.
Project install/commitment year	Row 30	Used to determine ability of DER to defer the project. Projects with install/commitment years before the DER Install Yr. are excluded from the valuation.
Project Flow Factors	E49:X10	For each DER installation location (Column C), the utility should enter each other project that can be affected by DER installed at that location. Along with the identification, a flow factor should be entered to indicate how the DER would affect each project. The default flow factor is 100%, indicating a 1kW reduction in net demand in the installation area would translate to a 1kW reduction in the other affected area. A value of 50% indicates that the other affected area would only see half of the kW impact of the installation area.
Loss Factors	E64:X72	In this section, the utility enters the loss factors from the DER installation to the constrained utility equipment for the DER installation area and any other affected projects.
Area Peaks		
Starting date and time	B16	Enter the timestamp for the start of the hourly information. The utility can enter ten years of hourly data for each project to reflect are growth and usage changes, but all of the input data for all projects should match the weather and chronology indicated by this timestamp. For example, if the first 24 hours are for a Wednesday in the first year, all years should start with on a Wednesday. Furthermore if a heat storm occurred on August 20th – 23rd in the first year, the loads for all other years should also reflect a heat storm on August 20th – 23rd.
Area Peak / Need (kW)	Rows 16:8775	Enter the project area kW demand or kW need for each hour.
Threshold	Row 13	If an area has kW demand entered, a threshold can be input in this row to define the peak hours. Peak hours will consist of all hours with demand above the threshold. If a value of zero is input as the threshold, all hourly inputs above zero will define the peak period.
SystemAC		
		This tab contains the CPUC 2016 Update hourly avoided costs. (based on 2015 conditions and chronology) This will not need revision for Demo B, but could be updated in the future as needed for new system avoided costs.
Flex RA		
Integration Cost Adder ($/MWh)	D3:D5	The entered values are from D.14-11-042. This should not need revision for Demo B.
Month	D7	Month when the maximum need for ramp occurred in 2015. Used to define the hours of need for ramping. The choice of

Item	Location	Note / Comment
		ramp year should match the year used for the system avoided costs
Day	D8	Day of the month when the maximum need for ramp occurred in 2015.
End of hour interval before ramp starts	D9	Defines when maximum need for ramp occurred in 2015.
Flex RA Value ($/kW-yr)	Row 12	Annual flexible resource adequacy value in $/kW-yr.
Remapping		
Season definitions	D4:D15	Enter a value from 1 to 4 for each month to define up to four seasons. Days will be binned according to these seasons, and days will not be allowed to cross seasons in the remapping process.
Metric to Use	H4	Select whether to use the Min/Max metric or the 3-day weighted average metric for the remapping rankings.
3-Day temp metric settings	H8:H10	If you are using the 3-day metric, enter the weight you would like to assign to each day's average temperature.
Remap system costs?	H12	Set to FALSE to keep system avoided costs in original 2015 order. Default is TRUE.
Settings		
Discount Rates	C7:E7	Note that these are NOT used for discounting in the LNBA Tool. The tool allows multipliers and escalation rates to be linked to discount rates. These three cells define the three sets of multipliers and escalation rates. The discount rates should be entered in ascending order from left to right, to be compatible with the interpolation routines used in the tool.
Revenue Requirement Multiplier	C13:E28	Used to scale project costs to revenue requirement levels. Enter multipliers corresponding to the three discount rate sets. If the active discount rate entered in the Project Inputs & Avoided Costs tab does not match one of the discount rate sets, the tool will interpolate if the active discount rate is between two sets, or use the lowest or highest set values. The tool will not extrapolate values.
Inflation Rates	F13:K28	The inflation rates are set to the default generic inflation rate entered in the Project Inputs & Avoided Costs tab, but can be manually overwritten.
Book Life	L13:L28	The book life of the equipment type. This is used by the RECC formula to determine the annual deferral value for the equipment.
O&M Factor	M13:O28	Multiplied by the project cost (before revenue requirement multiplier) to define the annual incremental O&M cost for the project.
Default Loss	C30	This value is used to avoid division by zero errors if a loss

Item	Location	Note / Comment
Factor		factor for a project has been not been entered.
Default Flow Factor	C31	This value is used to avoid division by zero errors if a flow factor for a project has not been entered.
Dashboard Selection, etc.	Column S	Used for dropdown choices in the tool. Do not edit.

4. Methodology

Deferral Value and Avoided Costs

Potential Deferral Value (DefValTotPot[p,a]) ($)

Potential deferral value is the present value (in the DER install year) of capital and O&M deferral savings over the period of the DER install year up to, but not including the "Defer T&D to this Year."

DefValTotPot[p,a] = DefValCap[p,a] + DefValOM[p,a]

Deferral value of capital project (DefValCal[p,a]) ($)

DefValCal[p,a] is the present value of capital deferral savings. The savings is for all projects (p) that are affected by DER installed in area (a).

$$DefValCal[p,a] = \sum_{all\ projects} [DefValCap[p]\ that\ can\ be\ deferred\ by\ DER\ in\ location\ "a"]$$

where

$$DefValCal[p] = \sum_{yr=1}^{DefInstallYr-InstallYr} \left[\frac{Inv[p] * RRMult * RECC * (1 + esc[Inv])^{\ yr-1}}{(1 + disc)^{yr-1}}\right]$$

where

Inv[p]	=	The capital investment adjusted to the nominal year dollars of the DER install yr (adjusted by equipment-specific inflation factors)
	=	TDCapital *(1+esc[Inv])^(InstallYr – TDCostYr)
Esc[Inv]	=	annual escalation rate for the investment equipment type
InstallYr	=	Year the DER is to be installed under the base plan

DefInstallYr	=	Year the project will be built after deferral (*Defer T&D to this year* input). For example, if the InstallYr is 2017, and the project will be deferred three years, the DefInstallYr is 2020
TDCostYr	=	The base year for the project cost estimate (nominal costs in this year's dollars)
RRMult	=	Revenue requirement multiplier that adjusts the engineering cost estimate for the capital project to total revenue requirement cost levels. The adjustment reflects cost increases from factors such as corporate taxes, return on and of investment, property taxes, general plant, and administrative costs.
RECC	=	Real economic carrying charge. RECC converts capital cost into an annual investment cost savings resulting from a discrete period of deferral. The formula is shown below where r is the nominal discount rate, i is inflation, and n is the lifetime of the capital project.

$$RECC = \frac{(r-i)}{(1+r)} \frac{(1+r)^n}{[(1+r)^n - (1+i)^n]}$$

Deferral value of avoided incremental O&M (DefValOM[p,a]) ($)

DefValOM[p,a]	=	Present value of the incremental O&M that would be avoided by project deferral. The O&M is for all projects (p) that are affected by DER in area (a). The O&M is escalated each year by the O&M inflation rate, and discounted to present value dollars using the utility discount rate.

$$DefValOM[p,a]) = \sum_{yr=1}^{DefinstallYr-InstallYr} Inv[p] * OMFctr[p] * \left(\frac{1+OMesc[inv]}{1+r}\right)^{yr-1}$$

Where

OMFctr[inv]	=	O&M Factor for the investment type
OMesc[inv]	=	O&M escalation rate for the investment type

Lifecycle value for system components (LifeCycleValue)

Present value benefits of the DER over its useful life. Energy, Gen Capacity, Ancillary Services, CO2, and RPS are based on the CPUC 2016 Avoided Cost Update hourly values, and use the formula below:

$$LifeCycleValue = \sum_{yr=installYr}^{installYr+EUL-1} \left[\frac{\sum_{hr=1}^{hr=8760} SystVal[c,yr,h\prime] * DERkW[h]}{(1+r)^{yr-1}} \right] + \text{IntegValue} + \text{TValue}$$

Where

SystVal[c,yr,h']	=	System avoided cost in $/kWh for component c, in year yr, and hour h'.
c	=	the avoided cost component. Energy, Gen Capacity, Ancillary Services, CO2, and RPS are from the CPUC avoided cost model. Avoided costs are at the secondary voltage level and already reflect losses.
SystVal[flex,yr,h']	=	System avoided cost for flexible capacity value
	=	FlexRACap[yr] *FlexRAAlloc[h']
FlexRACap[yr]	=	Flexible RA Capacity value in $/kW (utility input on Flex RA tab)
FlexRAAlloc[h']	=	Hourly allocation factor for ramping, remapped to match weather and chronology of Local T&D area peak loads and weather. The allocation factor assigns a value of 100% to Nov 16, 2015 hour ending at 6pm, and negative 100% to Nov 16, 2015 hour ending 3pm. The net effect is a Flex RA capacity benefit for reduced ramp (6pm demand being lower than 3pm demand.) Note that the day may be moved to align 2015 conditions with local T&D conditions (see description of h').
f	=	Nominal utility discount rate
h	=	hour
h'	=	hour index, remapped to align 2015 system weather and weekday/weekend chronology to better match the weather and chronology of the local T&D hourly area peak/need.
EUL	=	Expected useful life of the DER in years (user input)
IntegValue	=	Present value of annual DER kWh output multiplied by the integration cost in cell K4, divided by 1000 (as the integration cost is in $/MWh). Discounting is done at the utility nominal discount rate.
TValue	=	System transmission capacity value is the input from Cell K6 multiplied by the DER maximum output.

Calculation of Project Need and DER Peak Reduction

Need after Dependable DER (Need_after_DER[p])

The kW needed after subtracting dependable DER load reductions.

Need_after_DER[p] = Max(AreaLoad[p][y][h] – Threshold[p] – DERkW[h] *Dependability /LossFactor[p,a] *FlowFactor[p,a])

Where

p	=	project
a	=	area where DER is installed
p,a	=	project area p, when DER is installed in area a.
AreaLoad	=	hourly project area load, or deficiency amount.
Threshold	=	kW above which there is an area deficiency. This entry is dependent on how the AreaLoad in input. In many cases the AreaLoad is entered as hourly deficiencies, in which case the Threshold would be zero.
DERkW[h]	=	DER reduction or output in each hour h. The output is before T&D losses
LossFactor[p,a]	=	Ratio of (1) DER impact at project p to (2) DER output in area a.
FlowFactor[p,a]	=	Derating factor if 1kW of DER demand reduction in area a does not translate to 1kW of demand reduction for project p. Default is 100% (no deration). If a value other than 100% is used, care should be taken to not double count impact reductions in the LossFactor.
Dependability	=	Dependability of DER is typically a low impact issue when looking at system-wide DER implementation because of the large diversity offered by large numbers of installations. Expected DER output is generally sufficient for estimating system-wide impacts. However, at smaller local distribution areas, the installations of DER will be smaller in number and the "safety" of the joint output of large numbers of devices will diminish. Therefore, the dependability of DER is a more important factor for smaller local distribution areas. In addition, DER that are weather dependent (such as PV) will be subject to common "failure" modes as the weather could impact all units in an area simultaneously. Therefore, the dependability of weather sensitive DER (both future and existing) is important as the penetration of the DER in an area increases.

Dependable DER Reduction

Dependable_DER_Reduction = kW_Needed[p] – Need_after_DER[p]

Where

kW_Needed[p] = Max over deferral years (AreaLoad[p][y][h] – Threshold[p])

Attributed Deferral Value

Attributed value for requirement-based threshold

For the project where the DER is installed (row 22), the Attributed Deferral value equals the Potential Deferral value if the kW reduction is Sufficient for Deferral (Cell G22 = TRUE). Otherwise zero.

For other affected projects (rows 24 and below), the value is the Potential Deferral (Col H) value multiplied by the ratio of the Dependable DER Reduction (Col F) divided by the kW Needed (Col D). The ratio is limited to not exceed 100%, and any project can be manually excluded by entering 'Excluded" in column I.

Attributed value for allocation-based average (AllocVal[a])

Value is based on expected reductions and is not limited to discrete integer years of deferral.

The Attributed Deferral value is calculated using peak capacity allocation factors (PCAF)for each affected local T&D area.

$$AllocVal[a] = \sum_{h=1}^{8760} DERkW[h] * AllocTD[a][h]$$

Where

DERkW[h] = DER reduction or output in each hour h. The output is before T&D losses

$$AllocTD[a][h] = \sum_{all\ affected\ p} TDperkW[p] * LossFactor[p,a] * FlowFactor[p,a] * PCAF[p,yr,hr]$$

TDperkW[p] = DefValCap[p]/ Need[p][DeferedYr-1]

Need[p][DeferedYr-1] = Total peak reduction need (kW) for project p in the last year to be deferred.

LossFactor[p,a] = Ratio of (1) DER impact at project p to (2) DER output in area a.

FlowFactor[p,a] = Derating factor if 1kW of DER demand reduction in area a does not translate to 1kW of demand reduction for project p. Default is 100% (no deration). If a value other than 100% is used, care

should be taken to not double count impact reductions in the LossFactor.

PCAF	=	Peak capacity allocation factor to assign relative weights to each hour in the peak period. The sum of the PCAFs for any year sum to 1.0.

$$PCAF[p, yr. h] = \frac{Max(0, Load[\mathrm{p, yr, h}] - Thresh[\mathrm{p}])}{\sum_{hr=1}^{8760} Max(0, Load[p, yr, h] - Thresh[p])}$$

Load[p,yr,h]	=	Hourly load or need in the project area, in the year.
Thresh[p]	=	Threshold for defining the peak hours for the project area. If the Load represents need, then Thresh would be zero. Otherwise all hours with load above Thresh would be considered peak hours.

Hourly Local T&D Costs (HourlyTD[a][h], HourlyTDAll[a][h])

Deferral value allocated to hours of the year based on the hourly PCAFs. Shown in N57:O8816 of the DER Dashboard.

HourlyTD[a][h]	=	Hourly local T&D costs for the project area where DER would be installed
	=	DefValCap[a] * AllocTDl[a][h]
HourlyTDAll[a][h]	=	Hourly local T&D Costs for all projects affected by DER in area a, that have not been explicitly excluded.
	=	Sum of all DefValCap[p,a] * AllocTD[p][h]

Other

Remapping process (h')

We expect that local area peak or need hourly information may be based on a year that differs from the 2015 year used for the CPUC system avoided cost development. To accommodate differing base years, the LNBA tool remaps days to better align the system avoided costs and local T&D peak/need (DER shapes are assumed to match the local T&D peak/need year). To do this, the LNBA tool calculates a temperature metric to rank days within user specified seasons, and recognizing weekdays and weekend/holidays.

The system avoided cost information is based on 2015. For discussion purposes, assume the local T&D hourly area peak/load information is for 2013. The remapping process follows the following process

1. Calculate peak temperature metrics for each day based on daily temperature information (min temp, max temp, average temp). The metric can vary by utility, and is meant to reflect weather conditions that drive peak usage (e.g.,: heat storms, lack of evening cooling, etc). There are two temperature metric options in the tool

    a) The three day weighted average metric equals 60% of the current day average temperature plus 20% of the prior day average temperature plus 10% of the average temperature for two days prior.

    b) The Min and Max temperature metric equals (0.7 x max) + [(0.003 x min) x (max-1)] + [(0.002 x (min-1)) x (max-2)]
2. Define up to four seasons (assign months to seasons)
3. Classify each day in 2015 and 2013 to "bins" defined by weekdays/weekend-holiday/season.
4. Rank the 2015 and 2013 days in each bin in descending order of the temperature metric.
5. For each bin (workday/weekend-holiday, season), map the highest ranked temperature metric day for 2015 to the highest ranked temperature metric day for 2013. Map the second highest 2015 day to the second highest 2013 day, etc. If there are more 2015 days in the bin than 2013 days, the lowest ranked 2015 days would be discarded. If there are fewer 2015 days in the bin than 2013 days, the lowest ranked 2015 day would be replicated as needed.
6. Assemble a new 8760 of system avoided costs (2015 original basis) that now reflect a 2013 basis, using the day mapping from above, and calibrate the total over the year so that the sum of the remapped avoided costs match the original avoided costs.

For Flex RA, the sum of the absolute values is used for calibration because the simple summation totals zero. If the ramp day is discarded during the remapping process, errors will be returned. In that case, an alternate ramp day should be designated in the Flex RA tab.

Appendix 3:

ACR to Final Documents Table

Requirement	ACR Description	ACR	Document	Location in Document
DPA Selection/Projects for Deferral	In selecting which DPA to study, the IOUs were instructed to, at minimum, evaluate one near-term (0-3 year project lead time) and one longer-term (3 or more year lead time) distribution infrastructure project for possible deferral. This guidance ruling expands the scope of the Demo Project B to require demonstration of at least one voltage support/power quality- or reliability/resiliency-related deferral opportunity in addition to one or more capacity-related opportunities. Both types of opportunities may be located in the same DPA, but if the DPA selected by any IOU does not include noncapacity-related opportunities, the IOU must evaluate a noncapacity project in another DPA.	4.1; pg. A24	Final Report	Chapter 3
LNBA Methodology Requirements	The approach is to specify a primary analysis that the IOUs shall execute and a secondary analysis that the IOUs may execute in addition to the required analysis. Consistent with the Roadmap staff proposal, the primary analysis shall use DERAC values, if available, for system-level values. For the primary analysis, the IOUs are directed to develop certain system-level values that are not yet included in the DERAC (e.g., Flexible RA, renewables integration costs, etc.) to the extent feasible.	4.3; pg. A26-A28	Final Report; (See also LNBA Tool)	Chapter 7, Appendix 2, (LNBA Tool)
Table 2	Primary Analysis	4.3; pg. A27-A28	Final Report	Chapter 7, Appendix 2, (LNBA Tool)
LNBA Specific Requirements				
Project Identification	The IOUs shall identify the full range of electric services that result in avoided costs for all locations within the DPAs selected for analysis. The values shall include any and all electrical services associated with distribution grid upgrades identified in (i) the utility distribution planning process, (ii) circuit reliability improvement process and (iii) maintenance process.	4.4.1 (1)(A); pg. A29	Final Report	Chapter 2, Downloadable Dataset
List of Locations for Projects	Develop a list of locations where upgrade projects, circuit reliability, or maintenance projects may occur over each of the planning horizons to the extent possible	4.4.1 (1)(B)i; pg. A29	Final Report, Downloadable Dataset	Chapters 4, 5, 6, Downloadable Dataset
Cost of Projects	Use existing approaches for estimating costs of required projects identified	4.4.1 (1)(B)ii; pg. A29	Final Report, Downloadable Dataset	Chapter 4, Appendix 2, (LNBA Tool)
Time Horizon of System Upgrade Needs	System upgrade needs identified in the processes should be in three categories that correspond to the near term forecast (1.5 – 3 year), intermediate term (3-5 year) and long term (5-10 year) or other time ranges, as appropriate and that correspond to current utility forecasting practice. A fourth category may be created employing "ultra-long-term forecast" greater than 10 years to the extent that such a time frame is supported in existing tools.	4.4.1 (1)(B)iii; pg. A29	Final Report, Downloadable Dataset	Chapters 4, 5, 6
List of Electric Services from Projects	Prepare a location specific list of electric services associated with the planned distribution upgrades, and present these electric service needs in machine readable and map based formats.	4.4.1 (1)(B)iv; pg. A30	Downloadable Dataset	Chapter 4, Downloadable Dataset
DER capabilities to provide Electric Services	For all electrical services identified, identify DER capabilities that would provide the electrical service. As a starting point, consider all DER derived from	4.4.1 (1)(B)v; pg. A30	Final Report	Chapter 2, 4

	standard and 'smart' inverters and synchronous machines.			
Specifications of System Upgrade Needs	A description of the various needs underlying the distribution grid upgrades; Electrical parameters for each grid upgrade including total capacity increase, real and reactive power management and power quality requirements; An equipment list of components required to accomplish the capacity increase, maintenance action or reliability improvement; Project specifications for reliability, maintenance or capacity upgrade projects identified by the utilities shall include specifications of the following services as applicable: Voltage Control or Regulation, Reactive Supply, Frequency Regulation, Other Power Quality Services, Avoided Energy Losses, Equipment Life Extension, Improved SAIFI, SAIDI and MAIFI results	4.4.1 (1)(B)vi(a-d); pg. A30	Final Report, Downloadable Dataset	Chapters 4, 5, 6, Downloadable Dataset
Compute Avoided Cost	Compute a total avoided cost for each location within the DPA selected for analysis using the Real Economic Carrying Charge method to calculate the deferral value of these projects. Assign these costs to the four avoided cost categories in the DERAC calculator for this location. Use forecast horizons consistent with the time horizon above.	4.4.1 (1)(B)vii(a-c); pg. A31	Final Report; (See also LNBA Tool tab)	LNBA Tool
Distribution System Services - Conservation Voltage Reduction and Volt/VAR optimization	To the extent that DER can provide distribution system services, the location of such needs and the specifications for providing them should be indicated on the LNBA maps. This analysis shall include opportunities for conservation voltage reduction and volt/VAR optimization. Additional services may be identified by the Working Group.	4.4.1 (1)(C); pg. A31	Final Report	Section 2.2.1
Transmission CapEx	For avoided costs related to transmission capital and operating expenditures, the IOUs shall, to the extent possible, quantify the co-benefit value of ensuring (through targeted, distribution-level DER sourcing) that preferred resources relied upon to meet planning requirements in the California ISO's 2015-16 transmission plan, Section 7.3, materialize as assumed in those locations. The IOUs shall provide work papers with a clear description of the methods and data used. If the IOUs are unable to quantify this value, they should use the avoided transmission values in the Net Energy Metering (NEM) Public Tool developed in R. 14-07-002.44	4.4.1 (2) + (A); pg. A31-A32	Final Report; (See also LNBA Tool tab)	Section 7.3
Line Losses	For the secondary analysis, use the DERAC avoided capacity and energy values modified by avoided line losses may be based on the DER's specific location on a feeder and the time of day profile (not just an average distribution loss factor at the substation).45 The IOUs shall provide a clear description of the methods and data used.	4.4.1 (3); pg. A32	N/A	N/A, Demo B LNBA Methodology focuses on the Primary Analysis in Table 2 of the ACR only.
Fexible Generation	For the avoided cost of generation capacity for any DERs which provides flexible generation, the IOUs shall apply a method, such as the "F factor" which has been proposed for the Demand Response Cost-effectiveness Protocols.46 The IOUs shall provide work papers with a clear description of the methods and data used.	4.4.1 (4); pg. A32	Final Report	Section 7.6.3
Avoided Energy - LMPs	For the secondary analysis, the IOUs may also estimate the avoided cost of energy using locational marginal prices (LMPs) for a particular location, as per the method described in SCE's application. The IOUs shall provide work papers with a clear description of the methods and data used.	4.4.1 (5); pg. A32	N/A	N/A, Demo B LNBA Methodology focuses on the Primary Analysis in Table 2 of the ACR only.
Avoided Costs - Renewable Integration, Societal,	If values can be estimated or described related to the avoided costs of renewable integration, societal (e.g., environmental) impacts, or public safety impacts, the	4.4.1 (6); pg. A32-A33	Final Report; (See also LNBA Tool tab)	Section 2.2.6

and Public Safety	IOUs shall propose their methods for including these values or descriptions in the detailed implementation plans			
Methodology Description	The IOUs shall provide detailed descriptions of the method used, with a clear description of the modeling techniques or software used, as well as the sources and characteristics of the data used as inputs.	4.4.1 (7); pg. A33	Final Report	Appendix 2
Software and Data Access	The IOUs shall provide access to any software and data used to stakeholders, within the limits of the CPUC's confidentiality provisions.	4.4.1 (8); pg. A33	Final Report	LNBA Tool and Heat Maps will be publicly available
DER Load Shapes and Adjustment Factors	Both the primary and secondary analyses should use the load shapes or adjustment factors appropriate to each specific DER.	4.4.1 (8); pg. A33	Final Report	Appendix 2
Other Related LNBA Requirements				
Heat Map	The IOU's LNBA results shall be made available via heat map, as a layer along with the ICA data in the online ICA map. The electric services at the project locations shall be displayed in the same map format as the ICA, or another more suitable format as determined in consultation with the working group. Total avoided cost estimates and other data may also be required as determined in the data access portion of the proceeding.	4.4.2 (1); pg. A33	Final Report	Appendix 1
DER Growth Scenarios	The IOUs shall execute and present their LNBA results under two DER growth scenarios: (a) the IEPR trajectory case, as filed in their applications (except that PG&E shall conform its PV forecast to the IEPR base case trajectory); and (b) the very high DER growth scenario, as filed in their applications. The DER growth scenario used in the distribution planning process for each forecast range should be made available in a heat map form as a layer in conjunction with the ICA layers identified earlier.	4.4.2 (2) + (a); pg. A33	Final Report	Section 3.2
General Requirements				
Equipment Investment Deferral	The IOUs shall identify whether the following equipment investments can be deferred or avoided in these projects by DER: (a) voltage regulators, (b) load tap changers, (c) capacitors, (d) VAR compensators, (e) synchronous condensers, (f) automation of voltage regulation equipment, and (g) voltage instrumentation.	5.1 (C); pg. A34	Final Report, Downloadable Dataset	Chapter 2, 4, 5, 6
Implementation Plan	The IOUs shall submit detailed implementation plans for project execution, including metrics, schedule and reporting interval. To the extent practicable, the IOUs shall consult with the LNBA working group on the development of the plan. The plan shall be submitted to the CPUC within 45 days of this ruling. The implementation plan shall include: A detailed description of the revised LNBA methodology; A description of the load forecasting or load characterization methodology or tool used to prepare the LNBA; A schedule/Gantt chart of the LNBA development process for each utility, showing: Any external (vendor or contract) work required to support it; Additional project details and milestones including, deliverables, issues to be tested, and tool configurations to be tested; Any additional resources required to implement Project B not described in the Applications	5.1 (d) + (i-iii); pg. A34-A35	Implementation Plan - Done	See IOU's Implementation Plans
Reporting	A plan for monitoring and reporting intermediate results and a schedule for reporting out. At a minimum, the Working Group shall report out at least two times over the course of the Demo B project: 1) an intermediate report; and 2) the final report.	5.1 (d)(iv); pg. A35	Implementation Plan - Done	See IOU's Implementation Plans