BEFORE THE PUBLIC UTILITIES COMMISSION OF THE

STATE OF CALIFORNIA

Order Instituting Rulemaking Regarding Policies, Procedures and Rules for Development of Distribution Resources Plans Pursuant to Public Utilities Code Section 769.	Rulemaking 14-08-013 (Filed August 14, 2014)
And Related Matters.	Application 15-07-002 Application 15-07-003 Application 15-07-006

(NOT CONSOLIDATED)

In the Matter of the Application of PacifiCorp (U 901-E) Setting Forth its Distribution Resource Plan Pursuant to Public Utilities Code Section 769.	Application 15-07-005 (Filed July 1, 2015)
And Related Matters.	Application 15-07-007 Application 15-07-008

SOUTHERN CALIFORNIA EDISON COMPANY'S (U 338-E) IMPLEMENTATION PLANS FOR DEMONSTRATION PROJECTS A AND B

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Dated: June 16, 2016

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SOUTHERN CALIFORNIA EDISON COMPANY'S (U 338-E) IMPLEMENTATION PLANS FOR DEMONSTRATION PROJECTS A AND B

Pursuant to the May 2, 2016 *Assigned Commissioner's Ruling (1) Refining Integration Capacity and Locational Net Benefit Analysis Methodologies and Requirements; And (2) Authorizing Demonstration Projects A And B* ("ACR"),[1] Southern California Edison Company ("SCE") respectfully submits its (1) Demonstration Project A Implementation Plan and (2) Demonstration Project B Implementation Plan, attached as Appendices A and B, respectively.

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[1] R.14-08-013, 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, Appendix A at p. 20 ("Project [Implementation] Plan [for Demonstration Project A] filed within 45 days of the date of this ruling") & p. 37 ("Implementation Plan [for Demonstration Project B] filed within 45 days of this Ruling.").

I.

INTRODUCTION AND PROCEDURAL BACKGROUND REGARDING IMPLEMENTATION PLANS

On August 20, 2014, the California Public Utilities Commission ("Commission") initiated Rulemaking (R.)14-08-013 ("DRP OIR") to establish policies, procedures, and rules to guide California investor-owned utilities ("Utilities") in developing their Distribution Resource Plan (DRP) Proposals. The Utilities were required to file individual DRPs by July 1, 2015 in compliance with California Public Utilities Code Section 769. On February 6, 2015, the Commission issued an Assigned Commissioner's Ruling, setting forth detailed guidance ("Final Guidance") for Utilities to follow in their Section 769 compliance filing. The Final Guidance directed the Utilities, among other requirements, to: (a) develop a specification for a demonstration project (*i.e.*, "Demo A") where the Utilities' Commission-approved Integration Capacity Analysis ("ICA") methodology is applied to all line sections or nodes within a Distribution Planning Area ("DPA") and (b) develop a specification for a demonstration project (*i.e.*, "Demo B") where the Utilities' Commission-approved Locational Net Benefit Analysis ("LNBA") methodology is performed for one DPA. On July 1, 2015, SCE filed its DRP, which included proposals for Demo A and Demo B.

On November 10, 2015, Commission staff convened a workshop on ICA methodologies and associated Demo A proposals. Following the ICA workshop, the Utilities produced an ICA workshop report.

On January 8, 2016, the then-assigned Administrative Law Judge ("ALJ") issued a ruling inviting pre-workshop comments and alternatives to LNBA methodologies. Pre-LNBA workshop comments were filed and served on January 26, 2016. Commission staff convened a workshop on the LNBA methodology and associated Demo B proposals on February 1, 2016.

On February 18, 2016, the then-assigned ALJ issued a ruling inviting parties to offer comments on ICA methodologies, the ICA workshop report produced by the utilities, LNBA methodologies, the LNBA workshop, and Demos A and B. The parties were instructed to address specific questions relative to the ICA components and LNBA methodologies. The Utilities and other interested parties filed and served their responses on March 3, 2016.

On May 2, 2016, the Assigned Commissioner issued the ACR, approving ICA and LNBA methodologies and requirements on an interim basis for use in Demos A and B. The ACR also directed the Utilities to prepare implementation plans for their respective Demos A and B consistent with a series of prescriptive requirements for these demonstration projects that were outlined in Appendix A to the ACR.

SCE's implementation plan for Demo A is attached as Appendix A. SCE's implementation plan for Demo B is attached as Appendix B.

II.

CONCLUSION

SCE respectfully submits these implementation plans pursuant to the requirements of the ACR.

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Appendix A

Demonstration Project A Implementation Plan

Appendix A:

Demonstration A Implementation Plan

Southern California Edison

Table of Contents

1 Summary

On August 14, 2014, the California's Public Utility Commission ("Commission") issued Rulemaking (R.) 14-08-013 which established guidelines, rules, and procedures to direct California investor-owned electric utilities ("Utilities") to develop their Distribution Resources Plan ("DRP"). On February 6, 2015, the Commission issued Final Guidance[1] for the public utilities in filing their DRP. This guidance included a requirement for an IOU to develop a specification for a demonstration project ("Demo A") that performed the Commission approved Integration Capacity Analysis ("ICA") methodology to all line sections or nodes within a Distribution Planning Area ("DPA").

On May 2, 2016, the Commission issued an Assigned Commissioner's Ruling (ACR)[2] (1) Refining Integration Capacity and Locational Net Benefit Analysis Methodologies and Requirements; and (2) Authorizing Demonstration Projects A And B. Pursuant to this ACR, Southern California Edison ("SCE") submits this implementation plan for Demonstration Project A ("Demo A"). In this implementation plan, SCE describes how it addresses the nine components and meets the nine functional requirements described in ACR and has organized the content in two chapters:

- Chapter 2 describes the scope of the Demo A including two DER scenarios to be studied (functional requirement nine) and the selection of two DPAs.
- Chapter 3 presents the detailed implementation plan including details to meet the requirements set forth in the ACR.

The Appendix to this implementation plan summarizes how all the Commission requirements are addressed.

SCE's project team will also coordinate with the ICA Working Group as directed to ensure Demo A objectives are being met and adjusted as needed based on the ICA Working Group discussions and recommendations.

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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 ("ACR"), May 2, 2016.

2 Demo A Project Scope

2.1 DER Scenarios

The Final Guidance and ACR requires Demo A to demonstrate dynamic ICA using two DER scenarios:

1) The DER capacity does not cause power to flow beyond the substation busbar, and
2) The DERs technical maximum capacity is considered irrespective of power flow toward the transmission system (T&D interface).[3]

SCE will conduct each scenario in two different DPAs.

2.2 DPA Selections

Per the ACR, Demo A selects two DPAs that represent the range of physical and electrical conditions within SCE's distribution system.[4] Further, Demo A performs the complete ICA methodology down to the line section or node for all feeders within the selected DPAs.

The two DPAs that SCE selected are the Johanna and Rector DPAs. Figure 1 illustrates the DPAs' geographic locations. The Johanna DPA is a dense urban area, while Rector DPA is a typical rural service area. As shown in Table 1, the DPA selections cover a broad range of physical and electrical characteristics encountered in SCE's distribution system. The Johanna DPA is located in Orange County and is part of the Preferred Resource Pilot (PRP) project. The Rector DPA is located in Central Valley and is made up of residential, commercial, and agricultural load impacted by recent drought conditions. The Rector DPA service area is more than six times the size of the Johanna DPA, but has only about twice the customers and approximately 50% more of projected load. The Johanna DPA serves a mixture of residential, commercial, and light Industrial loads.

[3] Rulemaking 14-08-013, DRP Final Guidance p.6; ACR, Appendix A, at p. 4.
[4] The requirement expanded from only one DPA required in the Final Guidance.

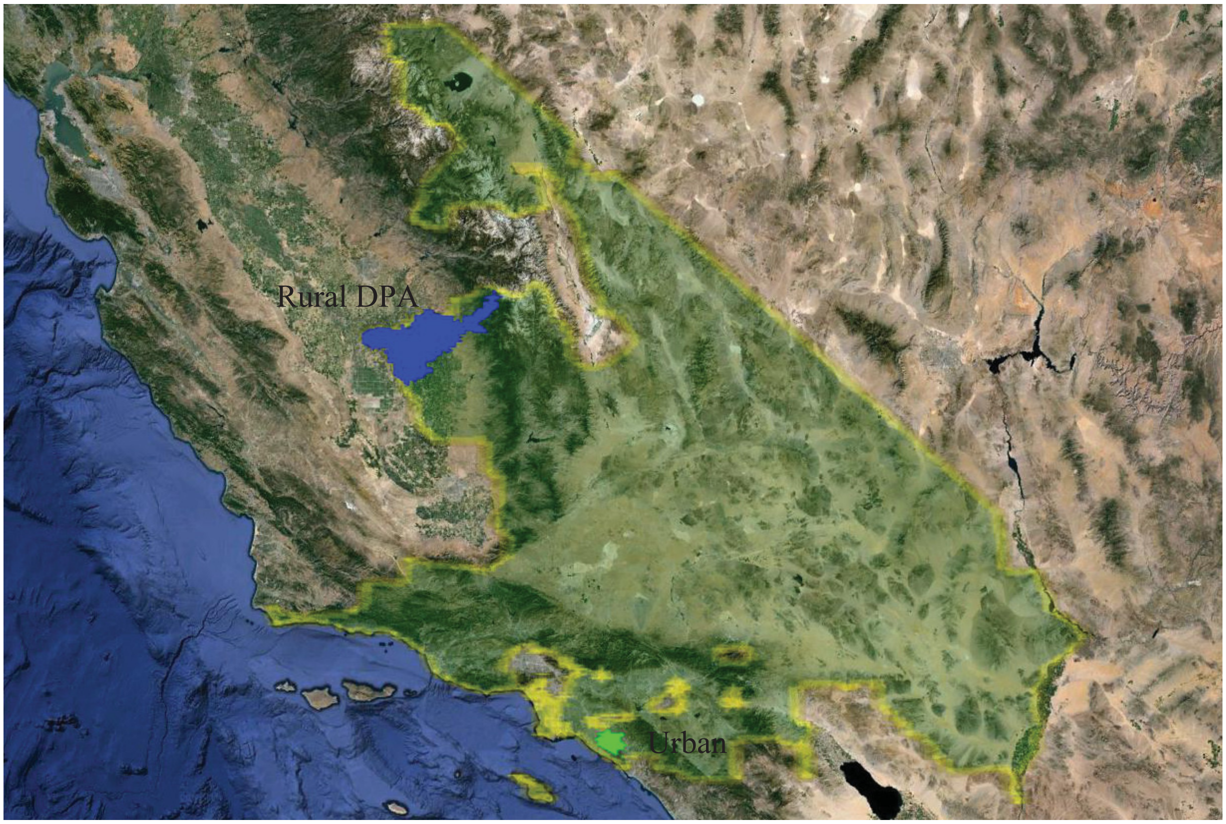

Figure 1 DPA Selections

Table 1 DPA Characteristics Overview

	Johanna DPA	Rector DPA
Substations	Johanna 66/12, Camden 66/12, and Fairview 66/12	Goshen 66/12, Hanford 66/12, Mascot 66/12, Octol 66/12, and Tulare 66/12
Area	Orange County	Central Valley
Service Area Size	18 mi^2	120 mi^2
No. Feeders	31	49
No. Customers	25,100	49,700
2016 Projected Load	217 MVA	314 MVA
No. Service transformers	2,375	9,617
Load types	Mixture of residential, commercial, and light Industrial loads	Mixture of residential and commercial, with significant agricultural loads
Special Notes:	Within PRP region	Load growth driven by drought conditions

3 Demo A Implementation Plan Requirements

Appendix A of the ACR states that the Demo A Implementation Plan shall include:

- Documentation of specific and unique project learning objectives, including how the results are used to inform ICA development and improvement;
- A detailed description of the revised ICA methodology that conforms to the guidance in Section 1.3 and Section 1.4 of the ACR, including a process flow chart;
- A description of the load forecasting or load characterization methodology or tool used to prepare the ICA;
- Schedule/Gantt chart of the ICA development process for each utility, showing 1) any external (vendor or contract) work required to support it, and 2) additional project details and milestones including, deliverables, issues to be tested, and tool configurations to be tested;
- Any additional resources required to implement Demo A not described in the Applications;
- A plan for monitoring and reporting intermediate results and a schedule for reporting out including a Working Group report out at least two times over the course of Demo A with an intermediate report and a final report;
- Electronic files available to the CPUC Energy Division and ORA to view and validate inputs, models, limit criteria, and results; and subject to appropriate confidentiality rules, other parties may also request copies;
- Any additional information necessary to determine the probability of accurate results and the need for further qualification testing for the wider use of the ICA methodology and to provide the ultimate evaluation of ex-post accuracy; and
- ORA's proposed twelve criteria or metrics of success to evaluate IOU ICA tools, methodologies and results are adopted and should be used as guiding principles for evaluating ICA.[5]

SCE's implementation plan addresses these requirements as described in the following sections.

3.1 Demo A Project Learning Objectives

The primary objective of Demo A is inform future ICA development as well as how ICA should be incorporated into the Rule 21 interconnection process. Specifically, SCE will explore the following learning objectives:

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5 ACR, at pp. 17-18.

- **Reverse Flow at T&D Interface:** Assess DER hosting capacity with and without limiting reverse power beyond substation busbar.
- **Diverse Locations:** Evaluate two DPAs covering a broad range of physical and electrical characteristics encountered in SCE distribution systems.
- **Granularity:** Assess the level of granularity necessary and meaningful for the ICA.
- **Power System Criteria:** Refine and develop consistent power system limitation criteria and study their impacts.
- **DER Portfolios and New Technology:** Investigate methods for evaluating DER portfolios, CAISO dispatch, and Smart Inverters.
- **Consistent Maps and Outputs:** Ensure consistent and readable maps to the public with similar data and visual aspects.
- **Computational Efficiency:** Evaluate methods for faster and more accurate update process that works for SCE's entire service territory.
- **Comparative Analysis:** Develop benchmark for consistency and validation across techniques and Utilities.
- **Locational Load Shapes:** Utilize Smart Meters for localized load shapes.
- **Future Roadmap:** Determine roadmap and timelines for future ICA development and improvement based on demonstration learnings.

3.2 Revised ICA Methodology

Consistent with ALJ Mason's June 10, 2016 email ruling, SCE will perform and test both the streamlined hosting capacity analysis method (streamlined method) identified as the Baseline ICA Methodology in the ACR and the iterative power flow based hosting capacity analysis method (iterative method). Both methods will be conducted based on the following four steps. A comparative assessment of the two methods will be performed to identify a best single ICA method or a combination of both methods, which is described in section 3.8.

3.2.1 ICA PROCESS

SCE's ICA methodology contains the four general steps as described below. Figure 2 captures a simplified version of SCE's ICA process.

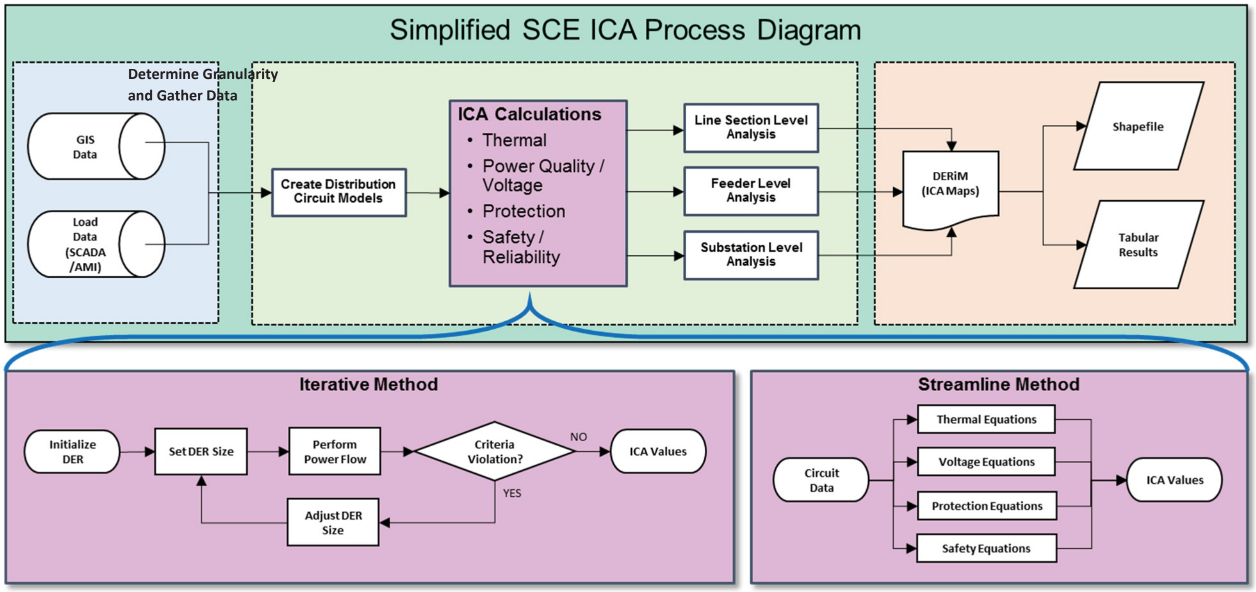

Figure 2 ICA Methodology Process Diagram

1) Determine granularity and gather data

SCE's hosting capacity analysis will be performed within the selected DPAs down to all the nodes of each primary line section including three-phase and single-phase sections of individual distribution feeders. Compared to studying just a set of specific nodes, this level of increased granularity may require a higher level of computing resources. SCE believes, however, this level of granularity is appropriate to meet the objective of facilitating the interconnection process.

Geographic Information System (GIS) data and load/generation profiles are extracted and provided to the analysis. GIS data is used to build distribution system models. Load and generation profiles define various scenarios the grid may experience and are derived from SCE's load forecasting analysis tool.

2) Create Distribution Circuit Models

Distribution circuit models represent the distribution system's electrical connectivity, and voltage and protective device settings. These models ensure system behaviors under different DER scenarios can be simulated via power flow analyses. SCE develops distribution circuit and substation models in CYMDIST and validates the parameters to ensure the models reflect actual field conditions.

Demo A will utilize the latest circuit configuration based on the GIS asset information. SCE is seeking to implement the capability to automate the update of circuit configuration whenever there is a change to the GIS map. This will ensure that future ICA studies will be based on most up-to-date circuit configurations.

3) Perform ICA Calculations

SCE applies four categories of power system limitation criteria to the ICA. Table 2 summarizes the set of power system criteria that are incorporated in the Demo A. As SCE will work with the ICA Working Group to develop limit criteria that are consistent across the Utilities and comply with SCE's system design, this list may change depending on the Working Group's requests and recommendations.

Table 2 Power System Criteria and Sub-criteria

Limitation Categories	Power System Criteria Description
Thermal Criteria	• Substation Transformer • Circuit Breaker • Primary Conductor • Main Line Devices • Tap Line Device
Power Quality / Voltage Criteria	• Transient Voltage • Steady State Voltage
Protection Criteria	• Line Equipment Interrupter Capability • Protective Relay Reduction of Reach
Safety / Reliability Criteria	• Operational Flexibility

SCE will perform both the iterative method and the streamlined method to test the system performance against the limitation criteria described above to identify the ICA as described below:

- **Iterative Method**: Detailed time-series power flow and short circuit duty studies are run in Cyme CYMDIST to identify the maximum DER hosting capacity that does not violate any power system limitation criteria. This analysis is performed iteratively at all circuit nodes, and will be run under multiple scenarios (*e.g.*, time, DER portfolios) using Cyme Python scripting.
- **Streamlined Method**: A power flow study is completed on a circuit to establish the baseline parameters of the system. Results from this power flow study (impedance values, voltage, current, etc.) are fed into a spreadsheet/database and run through specific equations that calculate the hosting capacity limitations at each node. The results can then be compared to the defined DER scenarios.

For both methods, the DER capacity limits are determined based on individual power system criteria with the final ICA results dependent on the most limiting power system criterion.

4) Publish ICA results

The ICA results will be made publicly available using the Renewable Auction Mechanism (RAM) Program Map within SCE's Distributed Energy Resource Interconnection Map (DERiM)[6]. Figure 3 shows an example of the DERiM display.

Figure 3 DERiM Display Example

DERiM is an interactive smart map developed based on ESRI's ArcGIS online platform that aims to connect developers with the SCE system data needed to enable strategic DER siting. Users can click on a feeder segment displayed on the map or use the advanced search functionality to obtain the ICA results. These results include detailed information on the DER type, frequency, timing (diurnal and seasonal) and duration of the thermal, voltage, or system protection constraints that limit hosting capacity on each feeder segment. Additional information such as feeder loading and voltage, customer type breakdown, and existing DER capacity will also published when allowed by data sharing limitations. ICA results may also be downloaded in machine readable format.

3.2.2 ICA MODIFICATIONS

The ACR directs SCE modify its ICA methodology with nine technical requirements mapping to the Final Guidance. SCE's plan to meet these requirements is described in the following sections. The modifications requested in the Appendix A of the ACR will be applied to both the streamlined and the iterative methods.

[6] Users can access DERiM and its associated User Guide at the following location: http://on.sce.com/gridinterconnections.

1) Quantify the Capability of the Distribution System to Host DER

a) Devices that contribute to reactive power on the circuit (e.g. capacitors, etc.) and their effect on the power flow analysis shall be included in the power flow model.

SCE develops distribution circuit and substation power flow models in CYMDSIT with careful validation using available information from different data sources. The power flow model includes cable and conductor, line devices such as capacitor bank, switches, automatic reclosers, and voltage regulators, loads, generators, and substation devices including transformers and breakers. The parameters of capacitor banks include but not limited to size, voltage, and control settings are validated so that their effect on the power flow will be properly reflected in the analysis.

b) Power flow analysis shall be calculated across multiple feeders, whenever feasible for more accurate ICA values. All feeders that are electrically connected within a substation shall be included in this analysis.

During the power flow analysis for a given feeder, all of the neighboring feeders that are supplied by the same substation transformer, that is those electrically connected within a substation, are included in the simulation. These neighboring circuits are simulated at their projected loading with existing DERs connected, which helps to ensure that the ICA results for the individual feeders reflect the maximum possible integration capacity values.

When all the electronically connected feeders within the substation are interconnecting a high level of DERs, there may be upstream impacts on the substation or even sub-transmissions system. If the power flow analysis shows no violation of any applicable power system criteria, then it is likely that the substation can accommodate the DERs without system upgrades. If any of the criteria is violated, the study then will iteratively adjust the DER size by an equal percentage until the maximum DER capacity limit that the substation can host without system upgrade is identified. If the aggregated DER is approaching the substation level DER capacity limit, some circuits may not be able to host DERs at the full amount of their identified ICA values, otherwise issues may arise on the substation and require upgrade.

c) The ICA shall be modified to reflect DERs that reduce or modify forecast loads.

DERs such as energy efficiency and some types of demand response can lead to a reduction in the forecasted loads and are applied to the load profile, according to the corresponding DER growth scenario. The modified load profiles will be applied in both the streamlined and the iterative methods.

d) Disclose any unique assumptions utilized to customize the power flow model of each IOU and all other calculation that could impact the ICA values.

SCE is and will continue to work closely with the ICA Working Group and other Utilities to ensure a consistent ICA method for comparable results. If any unique assumptions are needed due to SCE system-specific conditions, these assumptions will be communicated.

2) Common Methodology across All Utilities

a) *The "baseline" methodology with modifications described in this ruling will be used as a provisional common ICA methodology used by all Utilities in the Demonstration A Projects.*

Per ALJ Mason's June 10, 2016 email ruling, SCE will perform both the streamlined method (the "baseline" methodology) and the iterative method. The streamlined method adopts the modified baseline methodology described in the ACR. SCE will work with the Working Group to finalize the details of the ICA methodology including but not limited to protection limitation criteria and DER portfolios.

SCE will perform a comparative assessment for all circuits within the two selected DPAs to evaluate the accuracy, consistency, computing resource requirements between the two methods. To ensure consistency and help determine the most appropriate of the ICA methodologies across Utilities, SCE will perform the ICA on common reference feeders that can be compared with other Utilities' results on the same feeders.

3) Different Types of DER

a) *The methodology shall evaluate the capacity of the system to host DERs using a set of 'typical' DER operational profiles.*

SCE will utilize historical data and industry research to develop typical operational profiles for different DER types including but not limited to:

- Uniform Generation
- Photovoltaic (PV)
- PV with Tracker
- PV with Storage
- Uniform load
- Electric Vehicle (EV) – Residential EV rate
- EV – Workplace
- EV – Residential TOU rate
- Storage – Peak Shaving

Demo A will conduct the streamlined and iterative methods to evaluate the system capacity to host these different DER types based on their corresponding typical operational profiles.

b) *ICA shall quantify hosting capacity for portfolios of resource types.*

Based on the typical operational profiles of different DER types, SCE will develop representative DER portfolios including but not limited to:

- Solar
- Solar and stationary storage

- Solar, stationary storage, and load control
- Solar, stationary storage, load control, and EV

SCE will also work with the ICA Working Group to develop methods for evaluation of hosting capacity for the following resource types:

- DER portfolios responding to CAISO dispatch
- Facilities using smart inverters

Demo A will conduct both the streamlined and the iterative methods to quantify the system capacity to host different portfolios of DER types.

c) *Utilities shall propose a method for evaluating DER portfolio operational profiles that minimize computation time while accomplishing the goal of evaluating the hosting capacity for various DER portfolios system-wide.*

SCE will examine the circuit and load characteristics of the selected DPAs as well as the historical and outlook of DER penetration in these areas to identify the most likely DER portfolios for each DPA (e.g., a mix of storage, PV, and demand response). This most likely DER mixture will be used as the baseline portfolio to calculate the ICA.

d) *The ICA Working Group shall identify additional DER portfolio combinations.*

SCE will work with the ICA Working Group to identify additional DER portfolio combinations that represent the likely patterns of DER adoption and develop methods for evaluation of their hosting capacity in the system.

4) Granularity of ICA in Distribution System

a) *Locational granularity of ICA is defined as line section or node level on the primary distribution system.*

SCE will evaluate the hosting capacity for different DER types and portfolios at all the nodes of each primary line section of individual distribution feeders within the selected DPAs using both the streamlined and iterative methods.

5) Limitation Categories

a) *Include all the different types of defined power system criteria and subcriteria in the analysis.*

The current set of power system criteria incorporated in Demo A is summarized in Table 2. SCE will continue to work with the ICA Working Group and will incorporate any changes or updates to the criteria as appropriate.

b) *Protection Limits used in ICA – The Utilities shall agree upon on a common approach to representing protection limits in the ICA.*

Currently, different Utilities developed their own protection limitation criteria based on their own distribution protection design. SCE will work with the ICA Working Group and other Utilities to develop a common approach that can represent the protection limits in the ICA and also comply with SCE's own protection design.

c) *Utilities shall provide documentation to describe the ICA limit criteria and threshold values and how they are applied in the Demonstration A Projects, in an intermediate status report, due Q3 2016.*

SCE has developed an initial set of ICA limit criteria and threshold values based on its system design, and will continue to work with the ICA Working Group to finalize the limit criteria to ensure the consistency across Utilities. After the final set of ICA limit criteria are developed and the threshold values for individual limit criteria are determined, SCE will provide detailed descriptions of these limit criteria and threshold values as well as the applications of these limit criteria in the Demonstration Project A in the intermediate status report, due third quarter 2016.

d) *Utilities shall provide documentation to identify and explain the industry, state, and federal standards embedded within the ICA limitation criteria and threshold values, and include this in Final Report due early Q4 2016.*

SCE will develop its ICA limit criteria and threshold values based on sufficient engineering justifications and compliance with the SCE's system design as well as industry, state, and federal standards. These references for the limitation criteria and threshold values will be included in the final report, due fourth quarter 2016.

e) *Included with ICA results for each feeder provide feeder-level loading and voltage data, customer type breakdown, existing DER capacity (to the extent not already available).*

To the extent permitted by applicable confidentiality restrictions, SCE will make the feeder loading and voltage, customer type breakdown, and existing DER capacity publicly available, along with the ICA results, on the DERiM interactive map and in a downloadable format.

f) *Identify feeders where sharing the information in paragraph "e" violates any applicable data sharing limitations.*

SCE will identify the feeders where sharing information such as feeder loading and voltage, customer type breakdown, and existing DER capacity violates any applicable data sharing limitations. For these feeders, only the appropriate information will be shared.

g) *ICA results should include detailed information on the type, frequency, timing (diurnal and seasonal) and duration of the thermal, voltage, or system protection constraints that limit hosting capacity on each feeder segment.*

SCE plans to present the detailed ICA results on DERiM where users can click on a feeder displayed on the map or use search functionality to obtain the hosting capacities by each of the thermal, voltage, protection, and safety limitation as well as the final ICA values. In addition, SCE will present the ICA values by hour, which provides more information for customers to understand the frequency, timing, duration, and severity of the potential issues. This information can aid in designing DER portfolios to address the constraints.

6) Publish the Results via Online Maps

a) *All information made available in this phase of ICA development shall be made available via the existing ICA maps in a downloadable format.*

The ICA results and applicable data will be made publicly available using SCE DERiM and in a downloadable format.

SCE will work with the ICA Working Group to determine the format for the ICA maps and downloadable information (e.g., data attributes, color coding, mapping tools, etc.) so the stakeholders across the utilities' service territories can access consistent and useful information.

To the extent permitted by applicable confidentiality restrictions, relevant load and voltage profiles, reactive power requirements, or specific information related to potential system protection concerns will also be provided.

SCE will work with the ICA Working Group and other Utilities regarding new data types identified in the ICA Working Group for inclusion. Information presented in the maps and associated materials will be clearly explained using legends and notes. Any limitations or caveats will be provided.

b) *Existing RAM map information and ICA results shall be displayed on the same map. RAM information shall be the default information displayed on that map with ICA data available if the user specifies it.*

SCE will display the detailed ICA results on DERiM, where the existing RAM map information is displayed as the default information, but at different layers. The ICA results will be displayed based on the users' selection. Different levels of ICA results detail may be displayed depending on the granularity of the user request.

7) Time Series or Dynamic Models

a) *ICA shall utilize a dynamic or time series analysis method as specified in the Final Guidance.*

SCE will perform time series analysis (streamlined method) and automated power flow analyses (iterative method). Both analysis methods will be performed on an hourly base for the 24-hour period during a typical low-load and a typical high-load day for each month, a total of 576 hourly analyses.

Given that the Utilities are using different power flow analysis tools, SCE will consult with the ICA Working Group to ensure the power flow analysis tools use an equivalent approach for time series analysis so that the time series analysis is consistent among the three Utilities.

8) Avoid Heuristic Approaches, Where Applicable

a) There are no new modifications based on this Guidance requirement

Whenever applicable, SCE will base each step of its ICA methodology on actual data, proven methods, best practice, and standards. For example, the system models are validated using the best available data; the ICA limitation criteria are developed in compliance with the industry, state, and federal standards; and the ICA results will be compared against actual interconnection study results. If any heuristic approach is deemed necessary, SCE will disclose them in the project report.

3.3 Load Forecasting Methodology and ICA Tools

3.3.1 LOAD FORECASTING METHODOLOGY

1) General forecasting methodology

SCE's hourly load forecasting methodology is an expansion of current practices of determining the peak forecasts for distributed solar photovoltaics (DG PV), electric vehicles (EV), customer growth, and heat storm sensitivity created by SCE's distribution planners. Figure 4 illustrates SCE's hourly load forecasting methodology.

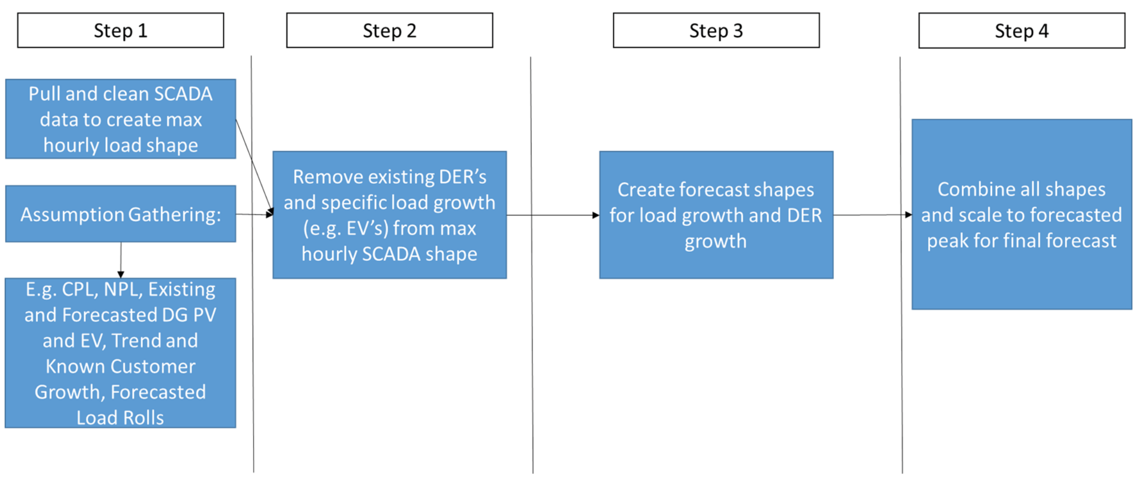

Figure 4 SCE hourly Load Forecasting Methodology DPA Selections

Step One:

The last historical year of hourly SCADA data for the circuit or substation is acquired and is corrected for abnormal events (e.g., load rolls and bad data reads). Due to changing customer mix over time, the last historical year of SCADA data is used to reflect the current customer mix.

In addition, existing and forecasted information needs to be obtained for future steps in this load forecasting process. This information includes DER, historical growth, and future customer growth.

Step Two:

After the shape has been corrected, the existing amount of DER's used in the forecasts are removed from the historical shape to create the base shape.

Step Three:

Once a base shape is determined, the next step creates forecasted shapes for all the DER's and load growth. This step uses normalized shapes and the magnitude of existing DER's/load plus the forecasted magnitudes. Sometimes there are different shapes for different years of DER penetration to account for changing technology.

Step Four:

Once all four growth curves discussed above are created they are combined by adding the forecasted load and DER's together to create the final forecasted shape. This final shape is then normalized and scaled to the criteria projected load (CPL) which represents a circuits or substations peak during a 1 in 10 heat storm. Sometimes a circuit constraint can be solved at low cost with a permanent load roll. If a permanent load roll is forecasted before the final study year an extra step is added to the process described above. This is done to reset the base load shape since the load being transferred is a blend of both existing and forecasted. The forecast is created first for the year where the load roll occurs, but the shape is not scaled to the CPL since the CPL is an adder for a heat storm. Instead the amount being transferred to or from the circuit is removed or added to the shape. This new shape now becomes the new historical load shape. The whole processes described above is then done again to create the final shape but starts with this new historical load shape in the year the load roll occurred.

2) Load and DER forecasts applicable to Demo A

Demo A will be conducted generally under a two-year growth scenario as required in the Final Guidance. SCE will include the investments planned to occur in the next two years. These planned investments may create additional hosting capacity on a distribution circuit, however, were not specifically developed for the purpose of increasing hosting capacity. Specially, SCE will use the following:

- Growth Scenario I as proposed in the DRP Applications

  SCE incorporates the Integrated Energy Policy Report (IEPR) "Trajectory" case's assumptions into its Growth Scenario I. The Trajectory case is intended to reflect a modest base scenario for California's resource and infrastructure planning to anticipate future energy infrastructure needs. Growth Scenario I is intended to provide a base case against which other scenarios can be compared. However, the IEPR Trajectory case does not include a forecast for storage and demand response. For storage, SCE utilizes the procurement targets established by the Commission in its LTPP decision D.13-10-040, which is the most recent Commission decision addressing storage procurement. For demand response, SCE utilizes the demand response assumption used in the LTPP's version of the Trajectory case.

- Growth Scenario III as proposed in the DRP Applications

Growth Scenario III represents a very high potential growth in the use of DERs to meet transmission system needs, resource adequacy, distribution reliability, resiliency, and long-term greenhouse gas (GHG) reductions, with key inputs drawn from achieving goals[7]. To capture an aspirational goal regarding DER adoption and integration, SCE develops a new forecast for solar PV, developed AAEE, Demand Response, CHP, EV, and storage assumptions that it believes will assist in achieving various goals provided in the Final Guidance.

3.3.2 TOOLS SUPPORTING ICA

SCE uses various tools to support the ICA assessment in Demo A:

1.) **CYMDIST 7.2:** Power flow analysis tool used to model and update distribution systems including but not limited to conductors/cables, line devices, loads and generation components and to perform iterative load flow analyses in order to identify the DER hosting capacity.
2.) **SCE's Load Forecasting Tool:** the load forecasting analysis tool used to develop forecasted peak demand and load profiles at feeder, substation and system levels.[8]
3.) **Python 3.4:** the dynamic object-oriented programming tool used to automate both the streamlined method and the iterative method as well as perform data analysis.
4.) **SAS Enterprise 9.4:** the advanced analytics and data management tool used to retrieve AMI data, perform statistical analysis, and conduct data validation.
5.) **Oracle 11g:** the informational management tool used for ICA results repository and post simulation analysis
6.) **ESRI ArcDesktop:** the maps and geographic information tool used for the ICA results visualization in DERiM.
7.) **Microsoft Office Suites:** the data process tools such as Excel and Access used for ICA streamlined method and relevant data processing.

3.4 Schedule

The Gantt chart in Figure 5 shows an overview of the SCE Demo A schedule. Table 3 provides the specific Demo A timeline dates, which may change depending on ICA Working Group coordination, requests, and recommendations. Finally,

Table 4 further describes the plan for ICA Working Group's monthly meeting in 2016. It does not include other Working Group activities, such as discussions on long-term refinements to ICA methodology.

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[7] Final Guidance, p.5.
[8] SCE has tested the LoadSEER software package from Integral Analytics and determined that the program's current functionality does not adequately meet the forecasting needs of the SCE distribution planning process.

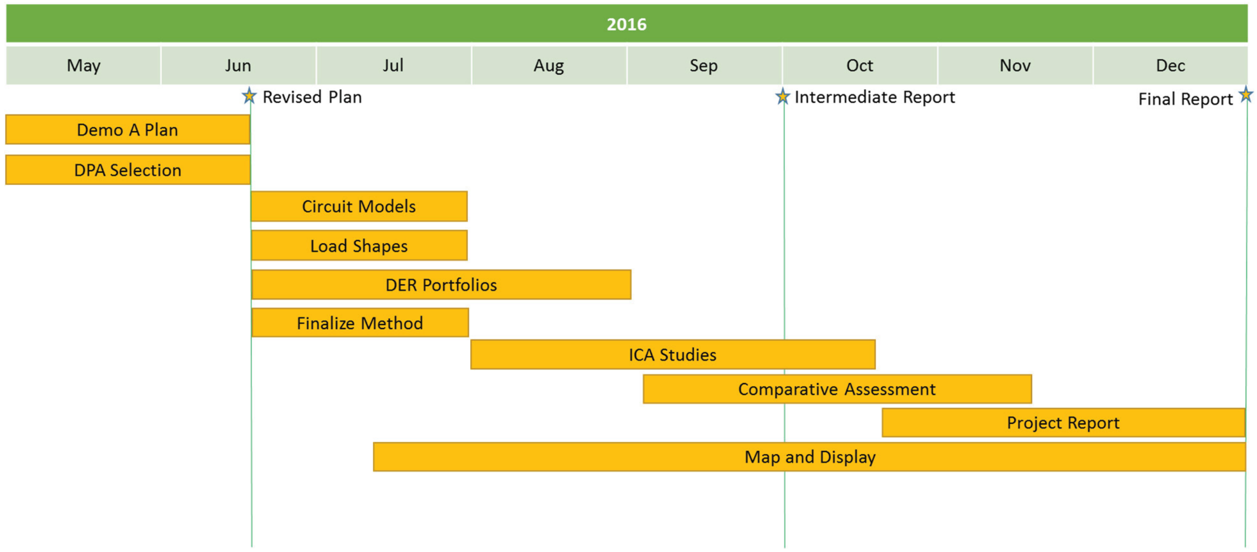

Figure 5 Schedule for SCE ICA Development

Table 3 Demo A Project Timeline

Task	Date Due
Initiate ICA Working Group	May 12, 2016
File Revised Demo A Plan	June 16, 2016
Meet Monthly to Monitor and Support Demo A	Q2-Q4, 2016
Execute Tasks on Selected Areas	Q3, 2016
Status Report to Working Group on Demo A	October 1, 2016
Finalize Results and Comparative Assessment	Q4, 2016
Final Report on Demo A	Q4, 2016

Table 4 ICA Working Group Activities

Month	Activity
June	Review consensus recommendations on Demo A project; Discuss implementation plan including DPA selection and comparative assessment.
July	Recommend the format for ICA Maps to be consistent and readable to all CA stakeholders.
August	Identify additional DER portfolio combinations and recommend methods for evaluation of hosting capacity for 1) DER bundles or portfolios, responding to CAISO dispatch; and 2) Facilities using smart inverters.
September	Discuss the uses of ICA analysis such as the streamlined Rule 21.
October	Review Demo A project progress and results; Discuss the data needs and requirements
November	Discuss the comparative analysis and recommend preferred ICA method.
December	Discuss lessons learned from Demo A project and provide recommendations for future roadmap

3.5 Additional Resources & Funding

SCE will need additional resources to implement Demo A with the required modifications in the ACR such as testing both streamlined method and iterative method and performing comparative assessment, demonstrating ICA methodology in two DPAs, and displaying ICA results in greater detail. However, at this time, SCE does not believe additional funding authorization is required.

3.6 Monitoring and Reporting Progress

SCE report Demo A progress at the monthly ICA Working Group meetings. As detailed in the schedule, SCE will submit an intermediate report third quarter 2016 to the ICA Working Group for the project progress; and a final project report fourth quarter 2016 to the CPUC Energy Division, who may provide further guidance on the content and format of the report. SCE will also submit the first intermediate status report on long-term ICA refinement by fourth quarter 2016 and the final report on long-term ICA refinement by second quarter 2017.

3.7 Availability of Project Files

The detailed ICA results will be made publicly available using SCE's DERiM as well as in a downloadable format. In addition, SCE will make electronic files used for Demo A available to the CPUC Energy Division and ORA to view and validate inputs, models, limit criteria, and results. Subject to appropriate confidentiality rules, other parties may also request copies of these files.

3.8 Comparative Assessment

SCE understands that it important to ensure consistency of the ICA methodologies across Utilities and to compare the output of the two methodologies to determine the ICA approach going forward.

SCE will test both the streamlined and the iterative methods in Demo A to help inform adoption of a single ICA method or combination of comparable methods to enable the following:

- ICA results to inform Rule 21 to modify fast track interconnections while also providing input to developers and customers where DER and combinations of DER can be deployed with little or no upgrade cost
- Scenario analysis across the distribution grid to inform planning for increased hosting capacity
- Methodology is flexible enough to model different DER types and DER portfolios

A detailed comparative assessment of the two methods will be performed using all the circuits within the selected DPAs. Both ICA methods are compared in the following aspects:

- Accuracy
- Consistency
- Computing needs and costs
- Computing time
- The ability to model various scenarios system wide, including different DER types DER portfolios

SCE will utilize existing resources such as EPRI's metrics with regard to hosting capacity as a starting point for comparative assessment.

All ICA results from both methods will be compared on a node-by-node basis, and the comparisons will be conducted by limitation category, by DER scenario, by location, by frequency and by duration. Essential statistics will be extracted from the full scale comparison to provide an indication of the consistency of the results from both methods.

The computing resources needed for both methods in Demo A will be recorded and used to estimate required computing resources for a system wide ICA. This information can provide information to help evaluate methods that may improve the computational efficiency of the ICA tools and process to calculate and update ICA values across all circuits more frequently and accurately.

With the knowledge obtained during the comparative assessment, both internally and externally, SCE will investigate the root causes of the differences observed in two methods to identify possible improvements to the results of each method, aiming to identify a best method for an efficient and effective system wide integration capacity analysis. Some specific aspects SCE will examine include:

- The capability of two methods capturing the impact of voltage regulation devices
- The capability of two methods capturing the impact of capacitor banks
- The impact of voltage determination mechanism in two methods
- The capability of two methods capturing the impact of phase imbalance (voltage and current)
- The capability of two methods capturing the impact of line capacitance and charging current
- The adequacy for serving as fast track screening for Rule 21.

In addition, SCE will work with other IOUs to apply both methods on six reference circuits (two circuits from each IOU's demo A study with anonymization). These six circuits will be used to compare the results from the ICA methods adopted by three Utilities to insure a consistent application.

3.9 Success Metrics for ICA Evaluation

ORA proposed twelve success criteria or metrics in the November 10, 2015 ICA workshop to evaluate ICA tools, methodologies, and results.

Table 5 lists these metrics and summarizes how SCE will apply these in Demo A.

Table 5 SCE Application of ICA Success Metrics

ORA proposed success criteria/metric	SCE application
Accurate and meaningful results • Meaningful scenarios • Reasonable technology assumptions • Accurate inputs (i.e. load and DER profiles) • Reasonable tests (i.e. voltage flicker) • Reasonable test criteria (i.e. 3% flicker allowed) • Tests and analysis performed consistently using proven tools, or vetted methodology • Meaningful result metrics provided in useful formats	SCE's ICA methodology will be developed based on reasonable and sound technical assumptions; heuristic approaches will be avoided wherever applicable. The limitation criteria evaluated will align with industry, state and federal standards as well as SCE's system design while ensuring consistency among Utilities. Inputs to the ICA methodologies such as load and DER profiles and circuit models will be validated. Demo A project will evaluate two power flow scenarios, representative load and DER growth scenarios to provide perspectives of the possible variation of ICA results in different conditions. The ICA results will be provided in sufficient details and in consistent formats so that stakeholders can easily utilize the information.
Transparent methodology	SCE's Demo A report will describe its ICA methodology in sufficient details with necessary support such as the conformed industry, state, and federal standards. In addition, SCE will work with ICA Working Group to provide necessary transparency.
Uniform process that is consistently applied	SCE's ICA methodology will be conducted using automated batch process so that a uniform process is applied to different areas and circuits.
Complete coverage of service territory	SCE will perform detailed ICA study in two selected DPAs in Demo A, and will expand the ICA study to the entire service territory though an enhanced and refined ICA methodology.
Useful formats for results	SCE will publish the ICA results in sufficient details using DERiM and in a downloadable format. SCE will also work with ICA Working Group to ensure a consistent and readable format for the maps and associated materials across all utilities so that all California stakeholders can obtain similar data and visual aspects.
Consistent with industry, state, and federal standards	SCE will develop the power system criteria based on industry, state and federal standards and clearly indicate these standards.

Accommodates portfolios of DER on one feeder	SCE will analyze typical portfolios included in the ACR and additional portfolios identified by the ICA Working Group.
Reasonable resolution (a) spatial, (b) temporal	SCE will conduct ICA study down to all the nodes of each primary line sections of individual distribution feeders and perform hourly analysis for a 24-hour period during a typical low-load day and a typical high-load day for each month.
Easy to update based on improved and approved changes in methodology	SCE will conduct ICA study down to all the nodes of each primary line sections of individual distribution feeders and perform hourly analysis for a 24-hour period during a typical low-load day and a typical high-load day for each month.
Easy to update based on changes in inputs (loads, DER portfolio, DER penetration, circuit changes, assumptions, etc.)	SCE will develop the scripting in a standardized and modular style so that any approved changes in methodology can be incorporated without an extensive tool update.
Consistent methodologies across large Utilities	SCE's ICA methodologies will be aligned with the baseline methodology; in addition, SCE will work with other Utilities to conduct a comparative assessment of each ICA methodology on a common set of reference circuits to ensure the methodology consistency.
Methodology accommodates variations in local distribution system, such that case by case or distribution planning area (DPA) specific modifications are not needed	SCE's ICA methods will be designed and implemented in a batch process fashion based on standard input formats, the methodology can accommodate variations in local distribution systems and can be applied across the system without method customization or adjustment.

Appendix: Demonstration A Requirement Checklist

Requirement	ACR Description	ACR	Implementation Plan
Load forecasting and DER growth scenarios	IOUs shall use a transparent method for both load forecasting and DER growth in their ICA calculation methodology. DER growth scenarios will be approved in a separate Commission action. For purposes of both load forecasting and DER growth scenarios, Demonstration Project A shall be conducted using the following scenarios: • 2-year growth scenario as required in the Guidance and described above; and • Growth scenarios I and III as proposed in the DRP Applications. • Each scenario shall be conducted in two different DPAs that are selected to represent the range of physical and electrical conditions within the respective IOU distribution systems.	Section 1.1, p5	Section 3.3.1 (2), p 19
Baseline ICA Methodology Steps			
Establish distribution system level of granularity	Analysis shall be performed down to specific nodes within each line section of individual distribution feeders. Nodes shall be selected based on impedance factor, which is the measure of opposition that a circuit presents to electric current on application of voltage. Minimum and maximum (i.e. best and worst case) ranges of results shall be evaluated using lowest and highest impedance.	Section 1.3, p 6	Section 3.2.1 (1), p 9
Model and extract power system data	A Load Forecasting Analysis Tool (e.g. Load SEER) shall be used to develop load profiles at feeder, substation and system levels by aggregating representative hourly customer load and generation profiles.8 Load profiles shall be created for each DPA. The load profiles are comprised of 576 data points representing individual hours for the 24-hour period during a typical low-load day and a typical high-load day for each month (2 days * 24 hrs * 12 months =	Section 1.3, p 7	Section 3.2.1 (1) and (2), p 9

	576 points). A Power Flow Analysis Tool (e.g. CYMEDist for PG&E and SCE and Synergi Electric for SDG&E) shall be used to model conductors, line devices, loads and generation components that impact distribution circuit power quality and reliability. The Power Flow Analysis Tool shall be updated with the latest circuit configurations based on changes to the GIS asset map per the current practice of each utility.		
Evaluate power system criterion to determine DER capacity	The Load Forecast Tool and Power Flow Analysis Tool shall be used to evaluate power system criterion for the nodes and line sections that determine DER capacity limits on each distribution feeder. ICA results are dependent on the most limiting power system criteria. This could be any one of the factors listed in PG&E's Table 2-4 in their DRP Application under "Initial Analysis" and summarized below: (a). Thermal Criteria – determined based on amount of additional load and generation that can be placed on the distribution feeder, without crossing the equipment ratings. (b). Power Quality / Voltage Criteria – voltage fluctuation calculated based on system voltage, impedances and DER power factor. Voltage fluctuation of up to 3% is part of the system design criteria for all three utilities. (c). Protection Criteria – determined based on required amount of fault current fed from the sub-transmission system due to DER operation. This is an area that the Working Group shall further develop. A potential starting point is the approach of PG&E as follows: Reduction of reach concept for generators was used with 10% evaluation as a flag for issues with the protection schemes. PG&E assumes that DER inverters contribute 120% rated current compared to 625% rated current from synchronous machines for a short circuit on the terminals. (d). Safety/Reliability Criteria – determined based on operational flexibility that accounts for reverse power flow issues when DER/DG is generating into abnormal circuit operating scenarios. Other limitations supporting the safe and reliable operation of the distribution system apply.	Section 1.3, p 7-9	Section 3.2.1 (3), p. 10-11
Calculate ICA results and display on online map	The ICA calculations shall be performed using a layered abstraction approach where each criteria limit is calculated for each layer of the system	Section 1.3, p 9	Section 3.2.1 (4), p 11-12

	independently and the most limiting values are used to establish the integration capacity limit. The ICA calculations shall be performed in a SQL11 server database or other platform as required for computation efficiency purposes. The resulting ICA data shall be made publicly available using the Renewable Auction Mechanism (RAM) Program Map. The ICA maps shall be available online and shall provide a user with access to the results of the ICA by clicking on a feeder displayed on the map. For the purposes of Demonstration Project A, the current utility map displays shall be used until further direction on a common approach is provided by the Commission.		
Specific Modifications to Include in Baseline Methodology			
Quantify the Capability of the Distribution System to Host DER	(a) Devices that contribute to reactive power on the circuit (e.g. capacitors, etc.) and their effect on the power flow analysis shall be included in the power flow model	Section 1.4, P 9-10 (and Section 1.1, p 1-2)	Section 3.2.2 (1.a), p 12
	(b). Power flow analysis shall be calculated across multiple feeders, whenever feasible for more accurate ICA values. All feeders that are electrically connected within a substation shall be included in this analysis.	Section 1.4, P 9-10	Section 3.2.2 (1.b), p 12-13
	(c). The ICA shall be modified to reflect DERs that reduce or modify forecast loads.	Section 1.4, P 9-10	Section 3.2.2 (1.c), p 13
	(d). Disclose any unique assumptions utilized to customize the power flow model of each IOU and all other calculation that could impact the ICA values.	Section 1.4, P 9-10	Section 3.2.2 (1.d), p 13
Common Methodology Across All Utilities	The "baseline" methodology with modifications described in this ruling will be used as a provisional common ICA methodology used by all IOUs in the Demonstration A Projects. At this time, SCE and SDG&E are required to adopt the modified baseline methodology described in this ruling, which is derived from PG&E's basic methodology. SCE and SDG&E's power flow analysis and load forecast tool methodologies should be adapted, as required, using PG&Es methodology as the basis.	Section 1.4, p 10 (and Section 1.1, p 2)	Section 3.2.2 (2.a), p 13
Different Types of DERs	(a) The methodology shall evaluate the capacity of the system to host DERs using a set of 'typical' DER operational profiles. PG&E has developed a set of profiles that provide a starting point. These	Section 1.4, p 11 (and	Section 3.2.2 (3.a), p 13-14

	profiles are: Uniform Generation, PV, PV with Tracker, EV – Residential (EV Rate), EV – Workplace, Uniform load, PV with Storage, Storage – Peak Shaving, EV – Residential (TOU rate)	Section 1.1, p 2)	
	(b). ICA shall quantify hosting capacity for portfolios of resource types using PG&E's approach with representative portfolios of i. solar, ii. solar and stationary storage, iii. solar, stationary storage, and load control and iv. solar, stationary storage, load control, and EVs.	Section 1.4, p 11	Section 3.2.2 (3.b), p 14
	(c). Utilities shall propose a method for evaluating DER portfolio operational profiles that minimize computation time while accomplishing the goal of evaluating the hosting capacity for various DER portfolios system-wide.	Section 1.4, p 11-12	Section 3.2.2 (3.c), p 14
	(d) The ICA Working Group shall identify additional DER portfolio combinations	Section 1.4, p 12	Section 3.2.2 (3.d), p 14
Granularity of ICA in Distribution System	Locational granularity of ICA is defined as line section or node level on the primary distribution system, as specified in the PG&E methodology	Section 1.4, p 12 (and Section 1.1, p 2)	Section 3.2.2 (4.a), p 14
Thermal Ratings, Protection Limits, Power Quality (including Voltage), and Safety Standards	(a) Include all the different types of defined power system criteria and subcriteria in the analysis. i. In Table 2-4 in its DRP application, PG&E has indicated a set of power system criteria to be used in a "Potential Future Analysis." All items on this list should be incorporated to the extent feasible initially, with the objective of complete inclusion as the capabilities become available.	Section 1.4, p 12 (and Section 1.1, p 2)	Section 3.2.2 (5.a), p 15
	(b) Protection Limits used in ICA – The IOUs shall agree upon on a common approach to representing protection limits in the ICA.	Section 1.4, p 12	Section 3.2.2 (5.b), p 15
	(c) Utilities shall provide documentation to describe the ICA limit criteria and threshold values and how they are applied in the Demonstration A Projects, in an intermediate status report, due Q3 2016.	Section 1.4, p 13	Section 3.2.2 (5.c), p 15
	(d). Utilities shall provide documentation to identify and explain the industry, state, and federal standards embedded within the ICA limitation criteria and threshold values, and include this in Final Report due early Q4 2016.	Section 1.4, p 13	Section 3.2.2 (5.d), p 15

	(e). Included with ICA results for each feeder provide i. Feeder-level loading and voltage data, ii. Customer type breakdown, iii. Existing DER capacity (to the extent not already available).	Section 1.4, p 13	Section 3.2.2 (5.e), p 15
	(f). Identify feeders where sharing the information in paragraph "e" violates any applicable data sharing limitations.	Section 1.4, p 13	Section 3.2.2 (5.f), p 16
	(g). ICA results should include detailed information on the type, frequency, timing (diurnal and seasonal) and duration of the thermal, voltage, or system protection constraints that limit hosting capacity on each feeder segment. The information shall be in a downloadable format and with sufficient detail to allow customers and DER providers to design portfolios of DER to overcome the constraints. This information may include relevant load and voltage profiles, reactive power requirements, or specific information related to potential system protection concerns.	Section 1.4, p 13-14	Section 3.2.2 (5.g), p 16
Publish the Results via Online Maps	(a) All information made available in this phase of ICA development shall be made available via the existing ICA maps in a downloadable format. The feeder map data shall also be available in a standard shapefile format, such as ESRI ArcMap Geographic Information System (GIS) data files.21 The maps and associated materials and download formats shall be consistent across all utilities and should be clearly explained through the inclusion of "keys" to the maps and associated materials. Explanations and the meanings of the information displayed shall be provided, including any relevant notes explaining limitations or caveats. Any new data types developed in the ICA Working Group shall be published in a form to be determined in the data access portion of the proceeding.	Section 1.4, p 14 (and Section 1.1, p 2)	Section 3.2.2 (6.a), p 16
	(b) Existing RAM map information and ICA results shall be displayed on the same map. RAM information shall be the default information displayed on that map with ICA data available if the user specifies it.	Section 1.4, p 14	Section 3.2.2 (6.b), p 16-17

Time Series or Dynamic Models	ICA shall utilize a dynamic or time series analysis method as specified in the Guidance. This analysis shall be consistent among the three IOUs. The IOUs currently use different power flow analysis tools that may implement a time series analysis differently. The methodology used by the three IOUs should therefore be based on capabilities that are common among the tools that support a consistent result. IOUs shall consult with the ICA Working Group to ensure that the power flow analysis tools use an equivalent approach to dynamic or time series analysis.	Section 1.4, p 14-15 (and Section 1.1, p 2)	Section 3.2.2 (7.a), p 17
Avoid Heuristic approaches, where possible	There are no new modifications based on this Guidance requirement	Section 1.4, p 15 (and Section 1.1, p 2)	Section 3.2.2 (8.a), p 17
General Requirements			
Power Flow Scenarios	The Guidance Ruling required the IOUs to model two scenarios in their Demonstration A projects: (a) The DER capacity does not cause power to flow beyond the substation busbar. (b) The DERs technical maximum capacity is considered irrespective of power flow toward the transmission system.	Section 2, p 15 (and Section 1.1, p 4)	Section 2.1, p 5
Project Schedule	Demonstration A project schedules proposed in IOU Applications are modified and shall commence immediately with the issuance of this Ruling.	Section 2, p 16	Section 3.4, p 20-21
Project Locations	Demonstration A project locations proposed in the Applications are modified and shall include two DPAs that cover as broad a range as possible of electrical characteristics encountered in the respective IOU systems (e.g., one rural DPA and one urban DPA). The IOUs shall clarify if their originally proposed Demonstration A project locations satisfies one of the two required DPAs and what their other proposed DPA(s) are. The IOUs shall also justify in their detailed plans the basis for choosing each DPA for the Demonstration Projects.	Section 2, p 16 (and Section 1.1, p 3)	Section 2.2, p 5-6

Project Detailed 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 ICA Working Group on the development of the plan. The plan shall be submitted to the CPUC within as a status update within 45 days of this ruling and served to the R.14-08-013 service list. The ICA Demo A Plan shall include (a) Documentation of specific and unique project learning objectives for each of the Demonstration A projects, including how the results of the projects are used to inform ICA development and improvement; (b). A detailed description of the revised ICA methodology that conforms to the guidance in Section 1.3 and Section 1.4 above, including a process flow chart. (c). A description of the load forecasting or load characterization methodology or tool used to prepare the ICA; (d). Schedule/Gantt chart of the ICA development process for each utility, showing: i. Any external (vendor or contract) work required to support it. ii. Additional project details and milestones including, deliverables, issues to be tested, and tool configurations to be tested; (e). Any additional resources required to implement Project A not described in the Applications; (f). 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 Demonstration A project: 1) an intermediate report; and 2) the final report. (g). Electronic files shall be made available to the CPUC Energy Division and ORA to view and validate inputs, models, limit criteria, and results. Subject to appropriate confidentiality rules, other parties may also request copies of these files; (h). Any additional information necessary to determine the probability of accurate results and the need for further qualification testing for the wider use of the ICA methodology and to provide the ultimate evaluation of ex-post accuracy. (i). ORA's proposed twelve (12) criteria or metrics of success to evaluate IOU ICA tools, methodologies and results are adopted and should be used as guiding principles for evaluating ICA.	Section 2, p16-18	Section 3, p 7-24

Appendix B

Demonstration Project B Implementation Plan

Appendix B:

Demonstration B Implementation Plan

Southern California Edison

Contents

1 Summary

Pursuant to the May 2, 2016 *Assigned Commissioner's Ruling (1) Refining Integration Capacity and Locational Net Benefit Analysis Methodologies and Requirements; And (2) Authorizing Demonstration Projects A And* B ("ACR"), Southern California Edison ("SCE") submits this implementation plan for Demonstration Project B ("Demo B"). In this implementation plan, SCE describes the purpose, goals, and deliverables of Demo B. In addition, the SCE's implementation plan describes the details of the four phases of the Demo B: (1) planning area selection, (2) identification and description of distribution upgrade projects, (3) calculation of locational net benefits, and (4) visualization of information. A Gantt chart provides a detailed list of tasks and proposed schedule to accomplish Demo B. To ensure stakeholders are informed and involved in Demo B, a schedule of topics for the Demo B Working Group is also provided. Additional information on the proposed LNBA methodology and load forecasting methodology are provided in appendices of this plan. Finally, a matrix is provided in an appendix that matches the demonstration project requirements established in Attachment A to the ACR to the details in this implementation plan.

SCE has divided its implementation plan into four chapters:

- Chapter 2 describes the history of Demo B and its objectives.
- Chapter 3 describes the specific requirements described in the ACR for Demo B.
- Chapter 4 presents the four phases of the Demo B project.
- Chapter 5 highlights the schedule and working group discussion topics.

2 Demo B Intro & Objectives

On August 14, 2014, the California's Public Utility Commission ("Commission") issued Rulemaking (R.) 14-08-013 which established guidelines, rules, and procedures to direct California investor-owned electric utilities ("Utilities") to develop their Distribution Resources Plan ("DRP"). On February 6, 2015, the Commission released guidance[1] for the IOUs in filing their respective DRPs. This guidance included a requirement for a Utility to propose a demonstration project (*i.e.*, Demo B) that performed the Commission approved Locational Benefit Analysis ("LNBA") methodology for one distribution planning area ("DPA"). The LNBA will help specify the benefits that distributed energy resources ("DERs") can provide in a given location, particularly benefits associated with meeting a specific distribution need. Following the filing of the three Utilities' DRPs and workshops on LNBA, the Commission issued the May 2, 2016 ACR, which approved an LNBA methodology framework for Demo B and directed the Utilities to prepare an implementation plan for this Demo B.[2]

This detailed implementation plan describes how SCE will fulfill the Commission's requirements for Demo B. In addition to outlining the path forward for SCE, the implementation plan provides an overview of how SCE in Demo B intends to (1) demonstrate locational variability of DERs within the selected DPA, (2) develop requirements for DERs to meet in order to be considered to defer distribution infrastructure projects, and (3) test methods and applies lessons learned to future LNBA work.

The objectives of Demo B includes:

- Address all Commission requirements (See Appendix D);
- Demonstrate use of the LNBA methodology for identification of potential distribution infrastructure project deferral, including the development of DER requirements to provide T&D benefits;
- Demonstrate locational variability of DERs' T&D net benefits within the DPA(s) in contrast to current system-level approaches;
- Assess LNBA methods and review lessons learned.

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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* ("ACR") May 2, 2016, at pp. 25-34.

SCE notes that the following chapters of its implementation plan were developed in collaboration with Pacific Gas & Electric ("PG&E") and San Diego Gas & Electric ("SDG&E"). These chapters include: Chapter 3 – Summary of Demo B Area Selection Requirements and Deliverables, Chapter 4 – Description of Demo B process, and Chapter 5 – Detailed Schedule and Stakeholder Engagement. In addition, to comply with the Commission's directives to present an LNBA methodology consistent with the ACR's requirements, the Utilities have engaged Energy and Environmental Economics ("E3") to provide a model for estimating location-specific avoided costs of installing DERs based on the ACR's specific approved LNBA methodology framework. Appendix C presents this LNBA methodology and was prepared by E3. Appendix D provides a table that identifies where in this implementation plan SCE addresses each of the ACR's requirements.

3 Summary of Demo B Area Selection Requirements and Deliverables

3.1 Area Selection Requirements:

The Final Guidance instructed the Utilities, at a minimum, to evaluate two traditional utility projects, one near term (0- 3 year lead time) and one longer term (3 or more year lead time) project in a DPA. The ACR expanded the scope outlined in the Final Guidance to include at least one voltage support/power quality or reliability/resiliency project in addition to a traditional capacity related deferral opportunity. Selecting two or more DPAs was required only if both types of projects (capacity and voltage/reliability) were not located in the same DPA.[3] SCE is also required to identify all projects within the selected DPA(s) and assess the impact of two different DER growth scenarios on its LNBA results in the DPA.

SCE provides a detailed description regarding its DPA selection in Appendix A to this implementation plan.

3.2 Demo B Final Deliverables

The final deliverables of Demo B will include:

1. Demo B Final Report
    1. Description of all projects identified in the selected DPA(s) under two DER growth scenarios;
    2. DER attributes for deferrable upgrades;
    3. Detailed description of the LNBA methodology 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] final methodology;
    4. Lessons learned and recommendations for refining and expanding LNBA
2. Machine-readable and map-based results layered over the online ICA map.
    1. LNBA heatmap;
    2. DER growth heatmap;
    3. Descriptions for all projects in selected DPA(s).

[3] Demo A & B ACR, at pp. 24.
[4] Demos A & B ACR, at p. 32.

4 Description of Demo B Process

4.1 Summary of Demo B Process

The activities that SCE will undertake in Demo B are categorized into four phases:

1. Planning Area Selection
2. Identify and Describe Distribution Upgrade Projects in Selected Planning Area
3. Calculation of Locational Net Benefits
4. Visualization of Information

4.2 Phase 1: Planning Area Selection

SCE has identified and presented to the LNBA Working Group (WG) a proposed DPA for Demo B. In addition to the commission requirements summarized earlier, the SCE proposed DPA for Demo B will also be the focus of Demo A – the Integration Capacity Analysis demonstration project. SCE's proposed DPA represent a broad cross section of the types of customers, weather, geography and level of development found throughout SCE's service territory.

SCE proposes that the DPA selections be finalized at the LNBA WG meeting subsequent to the filing of this Implementation Plan. Previously provided DPA information is included here in **Appendix A**.

4.3 Phase 2: Identify and Describe Distribution Upgrade Projects in Selected Planning Area

This section outlines the LNBA specific analysis method in terms of identifying a full range of applicable electric services and quantifying DER capabilities to provide such services in place of upgrade projects.

A five-step approach is suggested for this work as shown in Figure 1, which addresses the entire process of project selection, project cost estimation, service qualification and cost calculations for the qualified services. These steps will be undertaken under the two required DER growth scenarios.

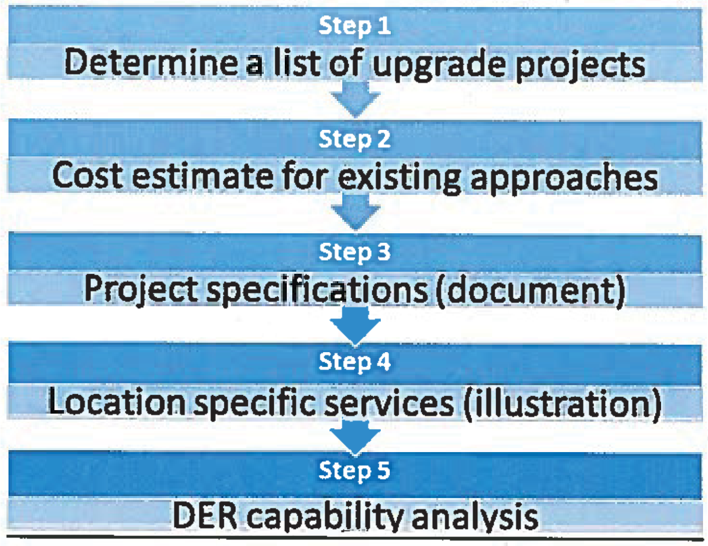

Figure 1 - Project identification and service qualifications

SCE has an iterative distribution planning process which identifies needed work using information about installed equipment and its performance and forecasts of future conditions that this installed equipment could experience. Recognizing the importance of this forecast of future conditions, the May, 2016 ACR requested each Utility include a description of its load forecasting methodology in this implementation plan. SCE's load description is included as Appendix B.

Per the May, 2016 ACR, SCE will modify its standard planning forecast to incorporate DER growth scenarios 1 and 3 from the July 1, 2015 DRP, respectively. These scenarios represent the IEPR trajectory case and a very high DER growth scenario. The base case will use scenario 1 and a sensitivity analysis will re-evaluate steps 1-5 using the very high DER growth scenario.

4.3.1 STEP 1: DETERMINE A LIST OF UPGRADE PROJECTS[5]

Given the future work identified in each Utility's distribution planning process under these modified forecasts, the first step of Demo B is to identify the full range of electric services that can potentially result in avoided cost, once DER units are deployed and utilized. The service coverage will account for all locations within the DPA selected for the analysis. The list will include any and all electrical services that can be identified through investigation of processes involving determination and planning for distribution grid upgrade projects in three categories of:

- Utility distribution planning processes
- Circuit reliability/resiliency improvement processes

[5] See section 4.4.1(A) and (B) and 5.1 of 5/2/16 ACR

- Maintenance processes

To assess the value of a service through DER, first, a comprehensive list of locations and project types will be prepared as applicable in three project areas of: capital upgrade projects, circuit reliability enhancement projects, and maintenance projects. The timeframe of interest to identify projects covers four horizons:

- Near term forecast (1.5-3 years),
- Intermediate term (3-5 years),
- Long term (5-10 years), and
- Ultra-long-term forecast that extends beyond 10-year horizon if supported in existing tools

For the selected DPA, SCE will consult with its internal teams responsible for distribution planning, reliability, district planning, and electric distribution operations, and maintenance to identify upgrade projects for the selected DPA. These will include thermal capacity upgrades (*e.g.*, feeder reconductors or additions, new transformer banks), voltage-related upgrades (e.g. voltage regulators, capacitors, VAR compensators), instrumentation and controls (e.g. SCADA and distribution automation upgrade projects, automation of voltage regulation equipment, voltage instrumentation), reliability upgrades (*e.g.*, cable and equipment replacement projects, customer/feeder reduction projects), and maintenance projects (*e.g.*, pole testing and tagging).

Each upgrade project will be described in detail, including a description of the underlying need, equipment lists and project specifications. Each project will be described in terms of the associated electric services, such as voltage control/regulation. In characterizing each service, the following key definitions and questions will be addressed:

- A detailed description of the service
- How is the service provided today?
- What are the requirements for the service?
- How does location impact the service?
- How would DER provide this service?
- What is the value of the service today at the specific location for the project
- What changes would be required for DER to provide this service, if applicable?

By virtue of investigating services associated with specific upgrades in the selected DPA, only electric services that could result in "avoided costs" will be included. One exception is conservation voltage reduction (CVR), which is effectively an energy efficiency service that DERs may be able to provide but which is not typically associated with distribution upgrade projects.

Any DER-related installation and operation aspects that are necessary for interconnecting to the utility grid and operating in conjunction with the grid to produce power will not be considered as DER services.

SCE will develop a preliminary list of electric services that are currently provided to customers or potentially can be offered to customers. In addition, a review of industry reports will be performed to expand the list. The literature search will include resources such as CPUC and other PUCs applicable regulation, California ISO and other ISO planning and operations procedures, and industry publications, and specialized literature on related topics (*e.g.*, value of solar, etc.). SCE will identify key features of these services, assess how DER may benefit/impact them, and outline how the latter could be evaluated.

In addition to reviewing internal processes to determine services, SCE will leverage industry experience in this area based on the work done by utilities in other states where high penetration levels of PV systems exist, such as Hawaiian Electric, PEPCO Holdings Inc., Duke Energy, Eversource, etc. to gather data on service classifications and value proposition for DERs.

4.3.2 STEP 2: COST ESTIMATE FOR EXISTING APPROACHES[6]

For each project identified and documented in step 1, the existing planning-level cost estimation approaches will be utilized to determine planning/budgetary cost estimates for the project.

For instance, the planning-stage cost of a cable replacement project will be calculated based on costs associated with several items, such as:

- Development costs, including siting, permitting and insurance
- Engineering and design costs
- Equipment selection and material procurement costs
- Construction and installation costs
- Inspection, commissioning and energizing costs
- Project management and site supervision costs

The above cost items may be estimated on a unit cost or percentage basis. For instance, material costs may be calculated based on the cable price per miles; however, project management may be calculated as a percentage of the total construction and engineering costs (e.g. 5 to 10% of the lump sum value).

SCE will use publically available cost information wherever possible so that this information can be shared among the Utilities and other stakeholders. Any confidential cost information will not be shared with third parties (including other the Utilities).

4.3.3 STEP 3: PROJECT SPECIFICATIONS:

As part of this step, a specification sheet will be prepared for each planned project identified in step 1. The specification sheet will include:

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[6] *See* ACR, at Sections 4.4.1(A) and (B).

- Project Definition: a description of various needs underlying the identified grid upgrade project. Projects are categorized as one of the following:
    - Sub-transmission, substation and distribution capacity capital and operating expenditures;
    - Distribution voltage and power quality capital and operating expenditures;
    - Distribution reliability and resiliency capital and operating expenditures.
- Project Characterization: determination of electrical parameters for each grid upgrade project, including:
    - Total capacity increase (firm capacity and timing of need);
    - Real and reactive power management schemes;
    - Power quality requirements; and
    - Reliability and resiliency targets.
- Project equipment list: a list of all components and tools required to complete the project, including the specific equipment listed in section 5.5.1:
    - Voltage Regulators;
    - Load Tap Changers;
    - Capacitors;
    - VAR Compensators;
    - Synchronous Condensers;
    - Automation of Voltage Regulation Equipment;
    - Voltage Instrumentation.
- Project services and specifications: specifications on how a project will provide the specific services required, including the specific services listed in section 4.4.1:
    - Voltage control or regulation services
    - Reactive supply services
    - Frequency regulation services
    - Power quality services (e.g. mitigation of harmonics, spike, flickers, etc.)
    - Energy loss reduction services
    - Equipment life extensions
    - Improved SAIFI, SAIDI, and MAIFI
    - Conservation voltage reduction
    - Volt/VAR optimization

4.3.4 STEP 4: LOCATION SPECIFIC SERVICES

In the next step, a spreadsheet will be prepared to provide location-specific list of applicable electric services for each planned distribution upgrade project, for example by feeder or line section. The spreadsheet will be used to develop an illustrative map of the size, types and distribution of the services by the project locations.

4.3.5 STEP 5: DER CAPABILITY ANALYSIS[7]

In this step, a DER capability analysis will be performed to determine whether a DER can provide the services and if yes, what DER technologies and features will be required to meet the service classifications. The analysis will determine DER characteristics and requirements to provide various electrical services identified and described in Step 3 for each upgrade project and the locational requirements identified in Step 4.

SCE will consider all applicable DER technologies including, per section 4.4.1(B):

- Synchronous generator based DERs that are fueled by renewables or reduce GHG emissions, such as fuel cells, internal combustion engines, and combined heat and power (CHP) plants, or any other similar technologies;[8]
- Power electronic based DERs utilizing "standard" (conventional) inverters/converters (with limited power factor or control capabilities), such as presently deployed UL-certified PV inverters; and
- Power electronic based DERs utilizing "smart" (advanced) inverters/converters functionalities, such as bidirectional and four-quadrant battery energy storage systems, and advanced PV inverters.

A high-level qualification table, as an example, is shown below.

Table 1 – Qualification of DER capability in providing a special service

Services	CHP	Standard Inverters				Smart Inverters			
		PV	Fuel Cell	Wind Type 4	Energy Storage	PV	Fuel Cell	Wind Type 4	Energy Storage
Voltage control/regulation	High (certain types)	None	None	None	Medium (kVA limit)	Medium (Production Priority)	Medium (Production Priority)	Medium (Production Priority)	High (certain types)
Reactive supply	High (certain types)	Low (limited pf range)	Low (limited pf range)	Low (limited pf range)	Medium (kVA limit)	Medium (Production Priority)	Medium (Production Priority)	Medium (Production Priority)	High (certain types)
Frequency regulation	Low (slow response time)	None	None	None	High (certain types)	Low (uni-directional)	Low (uni-directional)	Low (uni-directional)	High (certain types)

In addition to the DER capabilities to provide the service, SCE will investigate and describe any changes that need to be applied into existing processes to support certain services through DERs.

[7] *See* section 4.4.1(C) of ACR.

[8] *See* DRP Final Guidance, pg. 14-15.

4.4 Phase 3: Calculation of Locational Net Benefits

A total avoided cost will be calculated for each location in the selected DPA(s). Per table 2 of the Appendix to the ACR, this will include the following components:

1. Avoided T&D
2. Avoided Generation Capacity
3. Avoided Energy
4. Avoided GHG
5. Avoided RPS
6. Avoided Ancillary Services
7. Renewable Integration Costs, Societal Avoided Costs and Public Safety Avoided Costs

Components 2-6 above will be borrowed from the DERAC model with exception that a flexibility factor will be added to incorporate avoided flexible capacity into Component 2. Component 7 will be described qualitatively with the exception that the default renewable integration costs from the RPS Proceeding will be incorporated.

The deferral value for each project will be calculated using the Real Economic Carrying Charge method. These will be assigned to one of the four subcategories below:

1. Sub-transmission, substation and distribution capacity capital and operating expenditures
2. Distribution voltage and power quality capital and operating expenditures
3. Distribution reliability and resiliency capital and operating expenditures
4. Transmission capital and operating expenditures

The Utilities have engaged E3, the original developer of the DERAC tool, to develop detailed LNB methodologies and a tool implementing those methodologies. A preliminary description of the detailed methodologies is provided here in **Appendix C.**

This tool will be made public as will inputs and other data to the extent this information is not confidential. As indicated previously, SCE will use public inputs and data wherever possible.

4.5 Phase 4: Visualization of Information

As part of this task, the LNBA Demo B maps will be created such that they can be overlaid on the Integration Capacity Analysis results. Per section 4.4.2 of the 5/2/2016 ACR, three separate maps will be created:

1. Locations of upgrade project areas with details, associated services and, where appropriate, location-specific DER specifications
2. DER growth heat maps
3. LNBA results heat map showing the total avoided cost across selected DPAs based on public information

The maps will include opportunities for conservation voltage reduction (CVR) and volt/VAR optimization services, and any additional services that are deemed feasible in the analysis.

5 Detailed Schedule and Stakeholder Engagement

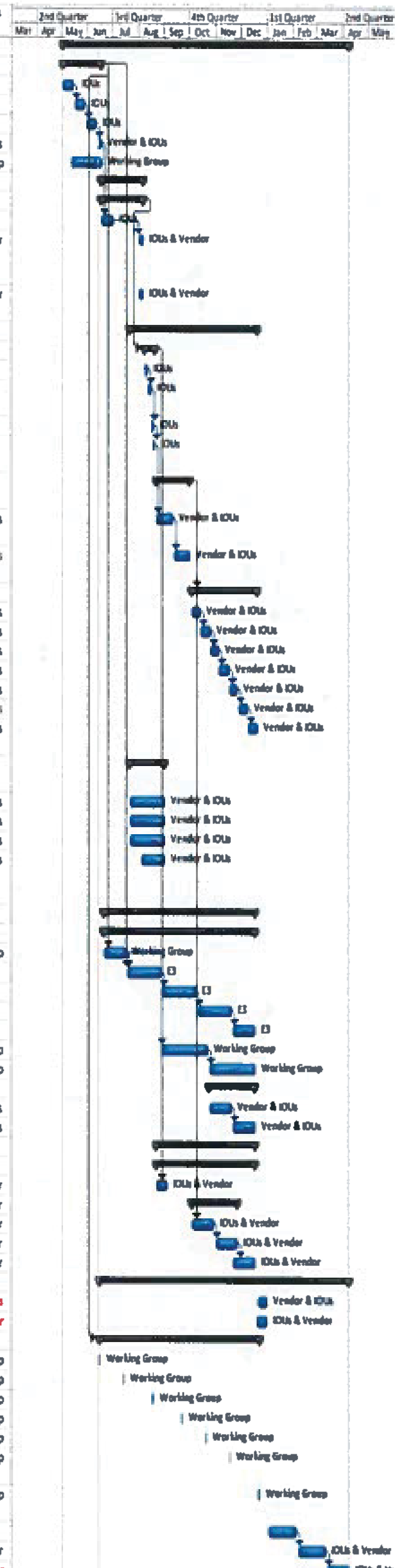
5.1 List of Tasks and Schedule

The Gantt chart below captures the proposed implementation plan for the LNBA to be conducted by SCE. The schedule consists of six primary tasks. The first and last tasks address the initial planning, and the monitoring and reporting of progress, respectively. The remaining tasks contain the detailed activities required to execute the four phases of the project described in detail in Chapter 4, namely Phase 1 - Planning Area Selection, Phase 2 - Identify and Describe Distribution Upgrade Projects in Selected Planning Area, Phase 3 - Calculation of Locational Net Benefits and Phase 4 - Visualization of Information.

To ensure progress is monitored, the schedule makes provision for monthly working group meetings. These meetings will have two goals: the first is to review activities and track progress; the second is to focus on key technical aspects relevant to activities at that juncture in the project. The Gantt chart identifies the technical focus area for each meeting.

Some of the activities have to be executed sequentially and the Gantt chart documents these dependencies. Some of the activities are time-bound and must be completed by a certain date, and the Gantt chart back-calculates the sequencing of activities to ensure the deadlines are met. The Resource Names column identifies which of the team members is responsible for executing that specific activity. When more than one name is listed, the first team member listed has lead and any subsequent team member(s) have supporting roles.

ID		Task Mode	Task Name	Duration	Start	Finish	Predecessors	Resource Names
1			LNBA Demo B	246 days	Mon 5/2/16	Fri 4/7/17		
2			Complete and File Implementation Plan	34 days	Mon 5/2/16	Thu 6/16/16		
3			Methodology description	10 days	Mon 5/2/16	Fri 5/13/16		IOUs
4			Load forecasting description	10 days	Mon 5/16/16	Fri 5/27/16	3	IOUs
5			Initial considerations for DPA selection and Demo projects	10 days	Mon 5/30/16	Fri 6/10/16	4	IOUs
6			Prepare schedule and Gantt chart	4 days	Mon 6/13/16	Thu 6/16/16	5	Vendor & IOUs
7			Working group participation and reporting	26 days	Thu 5/12/16	Thu 6/16/16		Working Group
8			Phase 1 - Planning Area Selection	36 days	Fri 6/17/16	Fri 8/5/16		
9			Characterization and selection of DPAs	36 days	Fri 6/17/16	Fri 8/5/16		IOUs
10			Perform load forecasting	10 days	Fri 6/17/16	Thu 6/30/16	6	IOUs
11			List of all upgrade projects in DPAs (cable replacement, SCADA enhancement, equipment change, etc.) - Irrespective of DER scenarios	5 days	Mon 8/1/16	Fri 8/5/16	10	IOUs & Vendor
12			List of all voltage support/power quality or reliability/resiliency related projects	5 days	Mon 8/1/16	Fri 8/5/16		IOUs & Vendor
13			Phase 2 - Identify and Describe Distribution Upgrade Projects	108 days	Thu 7/21/16	Mon 12/19/1		
14			Finalize selection of Demo B Projects and Areas	10 days	Mon 8/8/16	Fri 8/19/16	9	IOUs
15			Select one Capital project	3 days	Mon 8/8/16	Wed 8/10/16		IOUs
16			Select one voltage quality / reliability / maintenance related project	3 days	Thu 8/11/16	Mon 8/15/16	15	IOUs
17			Select one near term and One long-term time frame	2 days	Tue 8/16/16	Wed 8/17/16	16	IOUs
18			Select territory diversity (e.g. one urban and one rural area) projects	2 days	Thu 8/18/16	Fri 8/19/16	17	IOUs
19			Determine additional upgrade projects based on the two DER growth scenarios	30 days	Mon 8/22/16	Fri 9/30/16		
20			Include projects from distribution planning process, circuit reliability improvement process, and maintenance process	15 days	Mon 8/22/16	Fri 9/9/16	18	Vendor & IOUs
21			Identify possible elimination or incremental upgrade projects based on High DER forecast	15 days	Mon 9/12/16	Fri 9/30/16	20	Vendor & IOUs
22			Document upgrade projects	56 days	Mon 10/3/16	Mon 12/19/1	19	
23			Location and type of projects	8 days	Mon 10/3/16	Wed 10/12/1		Vendor & IOUs
24			Project specifications	8 days	Thu 10/13/16	Mon 10/24/1	23	Vendor & IOUs
25			Parameters of the projects	8 days	Tue 10/25/16	Thu 11/3/16	24	Vendor & IOUs
26			Need identified in upgrade project	8 days	Fri 11/4/16	Tue 11/15/16	25	Vendor & IOUs
27			Equipment necessary for upgrades	8 days	Wed 11/16/1	Fri 11/25/16	26	Vendor & IOUs
28			Estimated cost of upgrade using traditional methods	8 days	Mon 11/28/1	Wed 12/7/16	27	Vendor & IOUs
29			Determine timeframe of upgrades (short-term, near-term, and long-term)	8 days	Thu 12/8/16	Mon 12/19/16	28	Vendor & IOUs
30			Review and finalize full range of electric services by DER for avoided costs in all locations	30 days	Thu 7/21/16	Wed 8/31/16		
31			Identify need attributes that DERs could potentially defer	30 days	Thu 7/21/16	Wed 8/31/16		Vendor & IOUs
32			Identify area in which DERs must locate to mitigate need	30 days	Thu 7/21/16	Wed 8/31/16		Vendor & IOUs
33			Identify location-specific electric services associated with p	30 days	Thu 7/21/16	Wed 8/31/16		Vendor & IOUs
34			Determine DER capabilities and specifications to offer the services include capabilities of standard and smart inverters as well as synchronous machines	20 days	Thu 8/4/16	Wed 8/31/16		Vendor & IOUs
35			Phase 3 - Calculation of Locational Net Benefits	130 days	Mon 6/20/16	Fri 12/16/16		
36			Develop LNBA tool (E3 tool) plus additions	130 days	Mon 6/20/16	Fri 12/16/16		
37			Methodology	20 days	Mon 6/20/16	Fri 7/15/16	2	Working Group
38			RECC method for avoided cost of projects	30 days	Mon 7/18/16	Fri 8/26/16	2,37	E3
39			DERAC values for energy and capacity	30 days	Mon 8/29/16	Fri 10/7/16	38	E3
40			Include flexible capacity "flexibility factor"	30 days	Mon 10/10/1	Fri 11/18/16	39	E3
41			Include renewable integration costs	20 days	Mon 11/21/1	Fri 12/16/16	40	E3
42			Determine a list of potential societal or public avoided costs	40 days	Mon 8/29/16	Fri 10/21/16	37	Working Group
43			Defining the associated project specific metrics	40 days	Mon 10/24/1	Fri 12/16/16	42	Working Group
44			Calculate total LNB for Demo B specific locations and projects	40 days	Mon 10/24/1	Fri 12/16/16		
45			Perform LNBA for Demo B Project group 1 (capacity type)	20 days	Mon 10/24/1	Fri 11/18/16		Vendor & IOUs
46			Perform LNBA for Demo B Project group 2 (non-capacity typ	20 days	Mon 11/21/1	Fri 12/16/16	45	Vendor & IOUs
47			Phase 4 - Visualization of Information	85 days	Mon 8/22/16	Fri 12/16/16		
48			Create a LNBA map by locations	85 days	Mon 8/22/16	Fri 12/16/16		
49			Initial mapping of upgrade projects (spreadsheet and visuali	10 days	Mon 8/22/16	Fri 9/2/16	14	IOUs & Vendor
50			Present services on maps and describe in writing	40 days	Mon 10/3/16	Fri 11/25/16		IOUs & Vendor
51			Develop machine readable format (Spreadsheet)	20 days	Mon 10/3/16	Fri 10/28/16	19	IOUs & Vendor
52			Develop scripts and tools for transferring to maps and visu	20 days	Mon 10/31/1	Fri 11/25/16	51	IOUs & Vendor
53			Examine and publish overlay on the map (go live)	20 days	Mon 11/21/1	Fri 12/16/16	52	IOUs & Vendor
54			Monitoring and Reporting	213 days	Wed 6/15/16	Fri 4/7/17		
55			*Demo B Report*	*8 days*	*Wed 12/21/1*	*Fri 12/30/16*		*Vendor & IOUs*
56			*Intermediate report on long term enhancements*	*10 days*	*Mon 12/19/1*	*Fri 12/30/16*		*IOUs & Vendor*
57			Reporting to the working group	136 days	Wed 6/15/16	Wed 12/21/1		
58			June Meeting (LNBA Plans submitted to CPUC June 16th)	1 day	Wed 6/15/16	Wed 6/15/16		Working Group
59			July Meeting (Review Demo Project B and data)	1 day	Wed 7/13/16	Wed 7/13/16		Working Group
60			August Meeting (Update on Pilot Projects)	1 day	Wed 8/17/16	Wed 8/17/16		Working Group
61			September Meeting (LNB Methodology: Deep Dive)	1 day	Wed 9/21/16	Wed 9/21/16		Working Group
62			October Meeting (LNB Maps: Discussion on Output Format)	1 day	Wed 10/19/1	Wed 10/19/1		Working Group
63			November Meeting (LNB Methodology: Calculated LNBs from Pilot Projects and Development of Requirements)	1 day	Wed 11/16/16	Wed 11/16/16		Working Group
64			December Meeting (Report Submitted/ LNB Maps: Lessons Learned and Future Refinements)	1 day	Wed 12/21/16	Wed 12/21/16		Working Group
65			Stakeholder Review	25 days	Mon 1/2/17	Fri 2/3/17		
66			Enhancements	25 days	Mon 2/6/17	Fri 3/10/17	65	IOUs & Vendor
67			*Final report*	*20 days*	*Mon 3/13/1*	*Fri 4/7/17*	*66*	*IOUs & Vendor*



5.2 Stakeholder Engagement: Working Group Report out Schedule and Metrics

The schedule below provides an expected ordering of Demo B report outs to the LNBA WG in 2016. It does not include other WG activity, such as discussions on long-term refinements to LNBA.

1. June (Complete) – Working group role and review of Demo B requirements
2. June (Complete) – More detail on Implementation Plans, including preliminary discussion of DPAs
3. July – LNBA methodology deep dive
   - Utilities and possibly their consultant(s) will present for discussion the Implementation Plan process and detailed methodologies. Areas for additional clarification or development will be identified.
4. August – Review Demo B progress and data on upgrade projects
   - Utilities will present preliminary list of upgrade projects in Demo B DPAs.
5. September – Review Demo B progress and review preliminary list of electric services
   - Utilities will review their preliminary list of electric services associated with project upgrades with the LNBA WG as part of the group's activities, incorporate comments and suggestions, answer questions, and identify gaps that require more extensive research.
6. October – Mapping and output format
   - Utilities will seek input on the format of LNBA results, prioritization of LNBA map features.
7. November – LNBA methodology deep dive #2
   - Utilities will present for discussion Demo B process and methodologies to date, with an emphasis on areas identified in July for additional clarification or development. If possible, a preliminary version of the E3 tool will be shared at this point.
   - Utilities will present for discussion preliminary results obtained via their independently prepared demonstration projects on upgrade deferral values and DER requirements.
8. December – Present draft Demo B Project Report and lessons learned
   - Utilities will present draft Demo B report and LNBA maps and will seek input on lessons learned from Demo B and recommendations. Utilities will compare calculated LNB results to existing system-wide estimates of T&D benefits.

In addition, SCE proposes to report out their estimated percent completion metric on the major phases and steps identified in this document on a monthly basis.

6 Conclusion

SCE's implementation plan highlights the purpose, goals, and requirements for Demo B. SCE's work plan includes four phases of described above. In addition, this plan outlines the schedule of tasks and stakeholder engagement. Additional information provided in the appendices provide detailed information on SCE's load forecasting methodology and the proposed LNBA methodology. Finally, a mapping matrix provided in the appendix is included. This matrix provides information on how this implementation plan will fulfill the requirements of the ACR.

7 APPENDIX A: DPA Selection

In SCE's Distribution Resource Plan (DRP), the DPA for this demonstration was proposed to be selected from its service territory in Orange County, California.[9] SCE proposed the DPA for Demo B to be selected from this area because this region was identified as area with ongoing grid modernization and ongoing Distributed Energy Resource (DER) integration activities. In addition to the criteria above, SCE intended to leverage two projects, its Preferred Resources Pilot (PRP) project and its Integrated Grid Project (IGP) to further incorporate data and/or resources from these activities into its Demo B.

SCE further refined its selection of the DPA by identifying the area served by two "A" level substations. The two "A" level substations were identified as

- Johanna "A" level substation and
- Santiago "A" level substation

Both these substations serve the Orange County area. The area served by these substations was directly affected by the closure of the San Onofre Nuclear Generating Station (SONGS). SCE's recent load forecasts also identified load growth in excess of 3% per year through the year 2022 in this area. Moreover, the area is part of SCE's Preferred Resources Pilot region, and the Integrated Grid Project is also located within this region. Due to these factors, the area provides an excellent forum to select a DPA for the Demonstration B project.

However, the recent Demo A & B ACR refined the ICA and Locational Net Benefits Analysts (LNBA) methodologies. As mentioned above, Section 4 (*LNBA Methodology and Demonstration Project B*) of **Attachment A** of the Demo A & B ACR affirmed the requirement to select a DPA that included both one near term (0-3 year project lead time) and one longer term (3 or more year lead time) project. The ACR ruling also expanded the scope of SCE's Demonstration B project to include at least one voltage support/power quality- or reliability/resiliency-related deferral opportunity in addition to one or more capacity-related opportunities. The guidance directed SCE to evaluate a non-capacity related opportunity and directed SCE to select another

[9] DRP Chapter 2; Section E.2 – Demonstration and Deployment Area

DPA if both the capacity related opportunity and non-capacity related opportunity did not fall within the pre-selected DPA.

With that direction, SCE re-evaluated its DPA for the Demonstration B project. Based on the ruling SCE re-defined its DPA specifications to include the following criteria:

- One near term infrastructure project (0-3 years lead time)
- One longer term infrastructure project (3 or more years lead time)
- One of the following criteria:
  – Voltage support / power quality project
  – Reliability / resiliency improvement related project
- One (or more) capacity related project

Based on the above criteria, SCE selected five substations within Rector subtransmission system as its DPA for Demo B study. Within the selected DPA, at a minimum, the following projects are identified:

- A distribution substation capacity increase project in conjunction with a new distribution circuit project at Goshen Substation, OD June 1, 2019.
- Re-conductor of Rector-Lourich-Octol-Tipton-Tulare 66 kV subtransmission line, OD June 1, 2024. Based on system diagrams and normal operating conditions it was determined that the subtransmission line served as a source for three distribution substations – Lourich, Octol and Tulare substations.
- A need for voltage support due to the loss of Goshen Hanford Laurel subtransmission line. Power flow studies were conducted and it was observed that SCE's Mascot Substation experienced low voltage due to the loss of the above mentioned subtransmission line.
- A project that required the construction of a new distribution circuit to serve a developed area. The circuit was forecasted to serve load growth in the area served by SCE's Hanford Substation by the year 2020.

The figure below shows the selected DPA (highlighted in blue), which is located at Central Valley of SCE's service territory. Table 1lists the characteristics of the selected area.

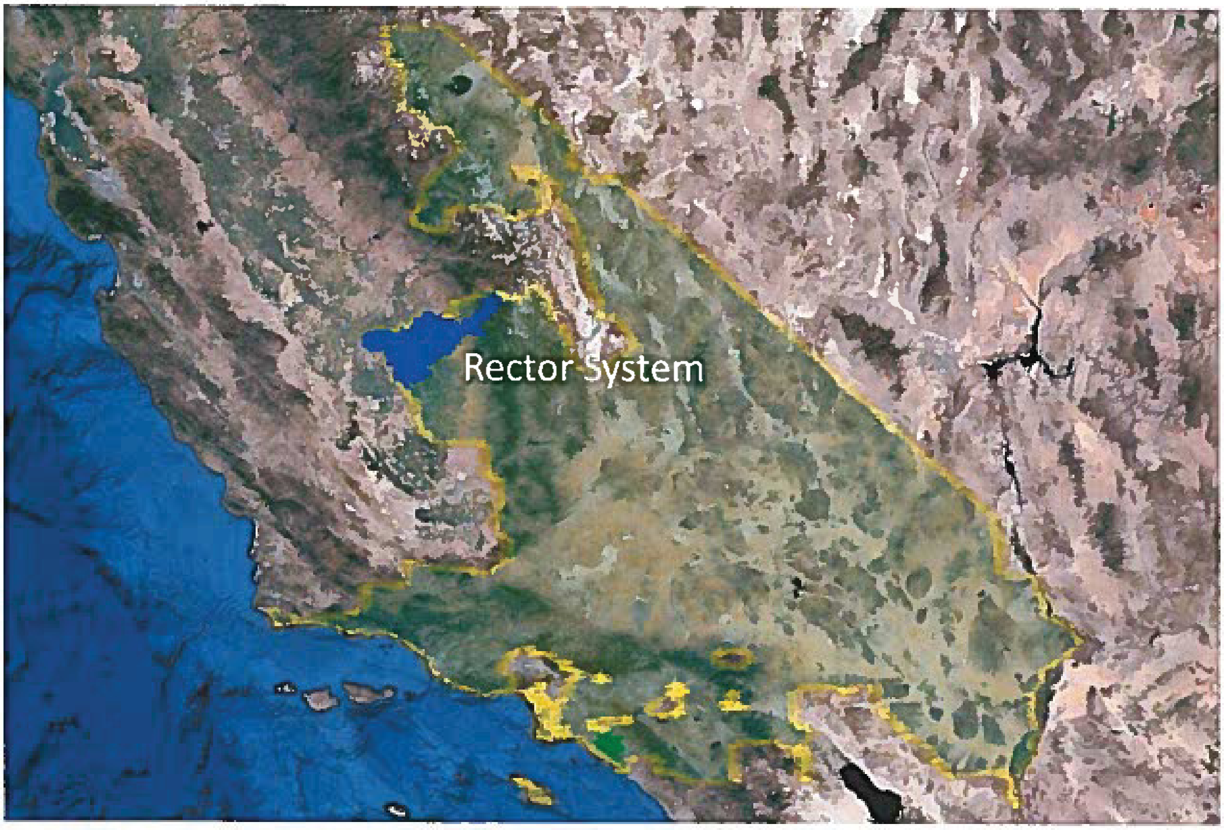
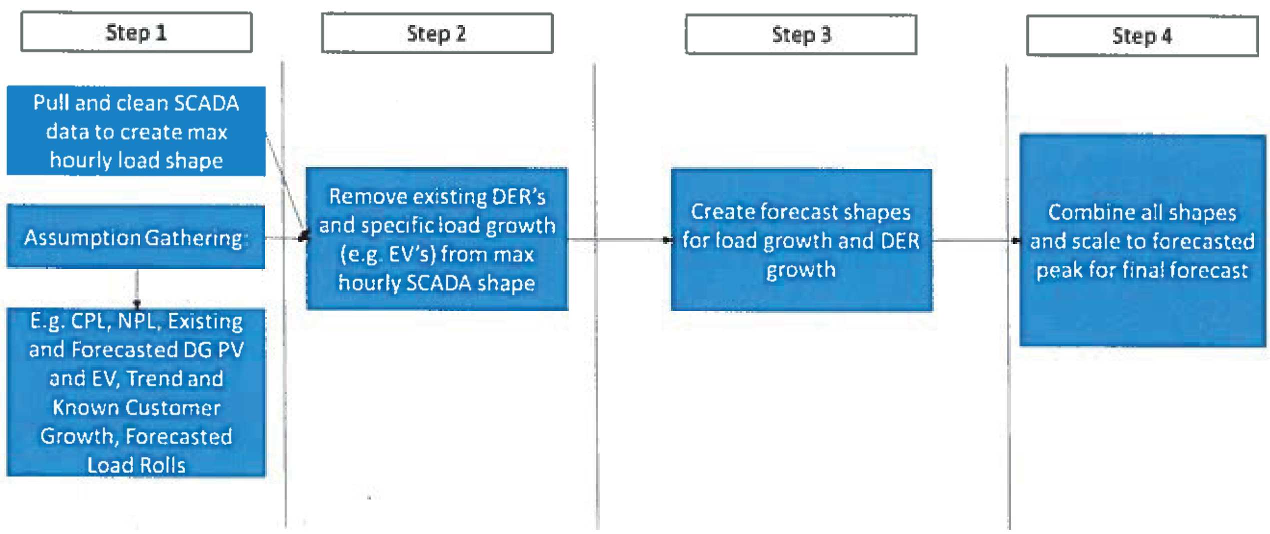


Table 2 DPA Characteristics Overview

	Rector
Substations	Goshen 66/12, Hanford 66/12, Mascot 66/12, Octol 66/12, Lourich 66/12 and Tulare 66/12
Area	Central Valley
Service Area Size	120 mi^2
No. Feeders	49
No. Customers	49,700
2016 Projected Load	314 MVA
No. Service transformers	9,617
Load types	Mixture of Residential and Commercial, with significant agricultural loads
Special Notes:	Load growth driven by drought

8 APPENDIX B: Load Forecasting Methodology



SCE's hourly load forecasting methodology is an expansion of current practices of determining the peak forecasts for distributed solar photovoltaics (DG PV), electric vehicles (EV), customer growth, and heat storm sensitivity created by SCE's distribution planners. As indicated in the figure above, SCE's hourly load forecasting methodology occurs in four major steps.

Step One:

The last historical year of hourly SCADA data for the circuit or substation is acquired and is corrected for abnormal events (e.g., load rolls and bad data reads). Due to changing customer mix over time, the last historical year of SCADA data is used to reflect the current customer mix.

In addition, existing and forecasted information needs to be obtained for future steps in this load forecasting process. This information includes DER, historical growth, and future customer growth.

Step Two:

After the shape has been corrected, the existing amount of DER's used in the forecasts are removed from the historical shape to create the base shape.

Step Three:

Once a base shape is determined, the next step creates forecasted shapes for all the DER's and load growth. This step uses normalized shapes and the magnitude of existing DER's/load plus the forecasted magnitudes. Sometimes there are different shapes for different years of DER penetration to account for changing technology.

Step Four:

Once all four of the growth curves discussed above are created they are combined by adding the forecasted load and DER's together to create the final forecasted shape. This final shape is then normalized and scaled to the criteria projected load (CPL) which represents a circuits or substations peak during a 1 in 10 heat storm. Sometimes a circuit constraint can be solved at low cost with a permanent load roll. If a permanent load roll is forecasted before the final study year an extra step is added to the process described above. This is done to reset the base load shape since the load being transferred is a blend of both existing and forecasted. The forecast is created first for the year where the load roll occurs, but the shape is not scaled to the CPL since the CPL is an adder for a heat storm. Instead the amount being transferred to or from the circuit is removed or added to the shape. This new shape now becomes the new historical load shape. The whole processes described above is then done again to create the final shape but starts with this new historical load shape in the year the load roll occurred.

9 APPENDIX C: Proposed Locational Net Benefit Analysis Modeling for Demonstration B

9.1 Introduction

E3 was retained by the Utilities in this proceeding to build a simple model for estimating location-specific avoided costs of installing distributed energy resources (DERs) based on a specific approved LNBA methodology framework provided to the utilities by Assigned Commissioner Picker's ruling of May 2, 2016 (ACR) for Demonstration B.[10] The model is based upon the ACR's requirements and publicly available information. The Utilities requested E3 prepare this model to ensure consistency with the prescriptive directives of the ACR regarding the structure of the LNBA and to facilitate Commission evaluation of the LNBA methodology. This appendix describes the modeling used for calculating the locational net benefits (LNBs) for the Utilities' Demonstration B projects (Demo B Modeling), and was developed by E3. The model (LNBA tool) will be made public to allow for review of the methodology, but actual utility-specific input values are not intended to be disclosed to market participants.

The Demo B Modeling includes system level avoided costs associated with load changes from DERs, including those from the DER Avoided Cost (DERAC)[11] (avoided energy, generation capacity, losses, ancillary services and avoided RPS and GHG compliance costs), flexible resource adequacy (RA) capacity, and an integration cost adder. E3 presents a framework to calculate local avoided costs of DERs in greater detail than in previous tools. This involves replacing the T&D component used in the DERAC explicitly with more detailed and location-specific avoided cost categories indicated in the ACR:

1. Avoided sub-transmission, substation and distribution capacity capital and operating expenses;
2. Avoided distribution voltage and power quality and operating expenditures;

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[10] The ACR can be found here: http://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M161/K474/161474143.PDF
[11] The latest DERAC tool is available here: https://ethree.com/public_projects/cpuc5.php

3. Avoided distribution reliability and resiliency capital and operating expenditures;
4. Avoided transmission capital and operating expenditures;

   In addition, conservation voltage reduction (CVR) opportunities will be considered.

E3 has investigated how each of the above potential avoided costs can be calculated for Demo B through discussions with the Utilities. The following methodological components are employed in the Demo B Modeling for each of the above avoided costs:

1. **Avoided sub-transmission, substation and distribution capacity capital and operating expenses.**

   These projects are needed to safely and reliably accommodate load-growth. The avoided cost for this category follows the deferral methodology presented in the document below. Operating expenses would be an annual savings during the years of deferral or an ongoing annual savings if the project can be avoided. If the construction of the original project would reduce capital and/or operating expenses elsewhere, those cost savings would be accounted for to correctly evaluate the *net* change in capital and operating cost.

2. **Avoided distribution voltage and power quality and operating expenditures**

   The driver for some of these investments could also be load growth. The LNBA model will allow avoided cost estimation for such growth-related investments. These projects may be more localized due to, for example, voltage issues at the end of a circuit. Depending on the nature of the voltage and power quality avoided upgrade identified, the geographic scope of these projects may be different from upgrades identified in category 1. Several category 2 sub segments may exist within the affected region of a category 1 upgrade. Volt/VAr opportunities are considered in this category.

   DERs have identified as causing potential voltage issues, particularly in the case of distributed generation photovoltaics (DGPV). Currently DER penetration has not been large enough to cause voltage issues that require utility corrective projects. Hence DERs installed prior to smart inverter rollout would not avoid any system upgrade projects.

Smart inverters are designed to mitigate the voltage issues, and it is expected that smart meter development and deployment will be sufficient to mitigate DER-caused voltage issues that may occur in the future. Since going forward smart inverters will be a mandatory requirement in the Utilities' Rule 21 interconnection tariffs, which should provide opportunities for mitigating these potential voltage issues in the interconnection process. Consequently, voltage projects driven by DER penetration are not considered in this analysis. Furthermore, improvements beyond current standards for voltage and power quality are assumed to have zero avoided cost value because there are no investments scheduled to improve voltage beyond Rule 2 value and power quality.

3. Avoided distribution reliability and resiliency capital and operating expenditures

Reliability and resiliency projects are primarily driven by factors such as equipment age and condition, equipment location and system configuration, remote communication and control and disturbance events that result in outages. The provision of reliability and resiliency improvements would require the ability of the DER to improve system metrics such as SAIDI, SAIFI and MAIFI. There may be cases where unloading of the demand on existing equipment could allow for the existing equipment to continue to provide adequate service and defer equipment upgrades or replacements (e.g.: where the load reduction allows for an existing backtie to support the cutover of load during a disturbance event). The LNBA tool would use the deferral methodology to develop avoided costs for the demand reductions needed to relieve the existing equipment in those cases.

There may also be cases where the ability to operate an area as an island (e.g.: micro-grid applications) offer the opportunity for extensive DER in combination with other enabling technologies and investments to defer or replace the need for traditional reliability improvements to the area. The LNBA Tool deferral framework could be applied in those cases, by evaluating DER impacts on load in all hours rather than just the peak period.

4. Avoided transmission capital and operating expenditures

The framework can be applied to any level of geographic specificity from line segment to CAISO system level. DERs can have avoided costs related to several levels. Load-growth-driven transmission avoided costs can either be calculated the same way as category 1 investment deferrals using system level data inputs, or estimates from other modeling approaches such as the NEM public tool can be used.

This category potentially overlaps with local RA capacity. In the cases where RA capacity is an avoided cost applicable to installed DER in the region, the model will use the lower of 1) the incremental value of local RA above system RA capacity, or 2) the avoided cost of an identified transmission project that would eliminate the local RA price premium (using the deferral methodology described below for transmission and sub-transmission level investments).

Conservation voltage reduction

Benefits in this category include greater energy efficiency and potentially reduced wear and tear on equipment such as tap changers. Unlike the other distribution value streams discussed above, the benefits of CVR would not accrue from the deferral of planned utility investments, but rather from energy savings and potentially distribution expense savings. As such, CVR would not be evaluated using the deferral methodology in the LNBA Tool, but would be incorporated via an adder to the avoided cost of energy.

The benefits of CVR will only be achievable if the DER is operated in a coordinated fashion by the utility to lower the voltage and avoid energy consumption. Evaluation of CVR strategies and their potential impacts remain ongoing, and the magnitude of any adder would be specific to both the area of concern and the DER technologies and enabling technologies under consideration. The determination of any adder would be conducted outside of the LNBA Tool.

The avoided costs identified in the above categories are determined in the Demo B Modeling by calculating the deferral value of the projects identified to address a need on the system, whether they are for local or system level transmission infrastructure, voltage and power quality, or reliability and resiliency.

9.1.1 OTHER LNBA TOOL FUNCTIONALITY

In addition to estimating the localized avoided cost of the distribution services listed above, the LNBA tool will assign the costs to the local peak period, allow for avoided costs to be aggregated or pancaked when a DER in an area can affect multiple projects, and calculate the avoided cost benefits of various DER options.

The LNBA tool uses hourly allocation factors to represent the relative need for capacity[12] throughout the year. Three options for determining the hourly allocation factors are discussed here.

To determine the avoided cost benefits of DER technologies, the LNBA Tool calculates the coincidence of the technology's dependable capacity contribution with the capacity need. For example, solar peaking in daytime hours will have very little dependable capacity contribution, and therefore deferral value, for an investment on a nighttime peaking feeder.

The use of dependable capacity, rather than the simple expected capacity contribution from DERs is important as the distribution areas become smaller and the number of feasible DER become smaller and therefore less diverse. Dependable capacity is also important for areas with high levels of DER that are weather sensitive (such as PV), as weather variations could result in large variations in net loads for the area. Dependable capacity contribution is the number of MWs of peak load reduction that a DER technology can be relied upon to produce for the purposes of capital investment planning. The model will include inputs for the Utilities to define a level of risk at the distribution level that helps determine a DER's dependable capacity contribution. Techniques to determine the dependable capacity contribution are presented for different DER types.

The LNBA Tool will incorporate the system benefits from the CPUC Avoided Cost Model (ACM) that is currently being updated. The Tool will also add the value of flexible capacity (an avoided cost component that is not included in the ACM update at this time).

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[12] Throughout this document "capacity" refers to distribution capacity unless indicated otherwise, such as generation capacity or DER nameplate capacity.

9.2 Methodology

The locational avoided cost of installing a DER is the deferral benefit of moving distribution system upgrade projects relating to new T&D capacity from the original installation year to a year in the future. The T&D capacity value of a DER resource is dependent on how much capacity a resource can reliably offer during peak load times, and the subsequent realizable deferrals. For example, consider energy efficiency measures that on aggregate reduce load by 1 MW during peak load hours. Assuming that 1 MW reduction can be reliably counted on during peak load hours, the contribution towards deferral will be 1 MW. However, distribution planners have to be confident that, firstly, the energy efficiency measures are providing a dependable reduction of 1 MW, and secondly that the measures meet criteria necessary to result in deferrals.

Assessing whether a DER plan meets these criteria, and defining the assessment criteria themselves, are covered in the following methodology sections:

Deferral Value. Different methods for evaluating deferral benefits, given forecasted future net loads, are described. Uncertainty around the expected deficiency that triggers the distribution system project can be incorporated as sensitivities in the model. Adequately determining the load forecast specific to the distribution system below the point of deferrable project is important to ensure deferrals can actually be realized. Load forecasting and its treatment in deferral evaluation are discussed. Finally, this section covers the minimum deferral criteria.

1. **DER measure of coincidence with peak load.** The coincidence of the DER's reduction in load with the highest load hours is essential. The higher the coincidence, the greater the measure's contribution to peak load reductions, and the higher it's capacity value. To evaluate this coincidence, the LNBA Tool calculates a probability of capacity need for all of the distribution area peak hours. This is discussed below in section 9.2.2. The uncertainty in load growth is incorporated through sensitivities, while the uncertainty around DER impact is incorporated through calculating a dependable output of DER.
2. **Dependable output of DER.** This is the load reduction caused by a DER measure that a resource planner can trust to actually occur, and can therefore factor into decisions on what capacity to build. The actual dependable load reduction can vary depending on the risk profile of the local system, and the set of resources installed. This can take the form of a derate on output for measures such as energy efficiency and storage to account for outages. However, determining

the dependable load reduction is particularly important for weather-dependent DERs because of the uncertainty in their output. Dependable capacity will also depend on the penetration of existing DER due to shifting coincidence with load as more DER is added. The methodology for calculating dependable capacity is explained in section 9.2.3.

9.2.1 DEFERRAL VALUE

9.2.1.1 Distribution Plan

The estimation of T&D project capacity costs requires the development of a T&D supply plan. T&D capacity projects should include only work and materials that could be deferred by DERs. To the extent there are non-deferrable costs identified, these will be described, quantified and ultimately excluded from the deferral benefit calculation. Examples of costs that would not be included are:

- Costs for related work that is not deferrable by DERs - Facilities that are not deferred should be excluded because adoption of DERs has no effect on them. For example, a new circuit may relieve capacity constraints, but also eliminate the cost of connecting a new subdivision to the utility grid. If a DER defers the need for a new circuit but the utility must proceed with the work of connecting a new subdivision, then the latter's costs could not be deferred, and the costs should be excluded from the deferral benefit.
- Sunk costs - Expenditures that would need to be made prior to date when the utilities could defer the project should be excluded, as those costs also cannot be deferred.

The distribution plan costs should also be adjusted for any higher costs that the utility might incur from deferring construction. An example of this type of cost is storage fees. In one local integrated resource planning (LIRP) study performed by E3, a utility had already commissioned the construction on long lead time custom underground cable. The cable could not be re-sold to any other utility, nor could the utility store the cable on its properties. The cost of storing the cable at the manufacturer or third party sites was high enough to rule out any DER opportunities for cost effective deferral of the underground project. The higher costs from deferral should be reflected through a high equipment inflation rate. For example, if the cost of the project would increase by 10% each year the project is deferred, an inflation rate of 10% should be used instead of a default CPI-based inflation rate (typically 2% or lower).

There is uncertainty in the cost of facilities until they are procured because of changes in the cost of equipment between the time the plan is developed and the actual procurement of the equipment. The project costs will be represented by high, medium, and low estimates.

9.2.1.2 Deferral Value

The essence of the Deferral Value is the present value revenue requirement cost savings from deferring a local expansion plan for a specific period of time. The LNBA Tool is proposed to estimate deferral value in three ways discussed below.

1. **Discrete Deferral Value ($).** The present value of savings accrued by deferring a project are calculated using the Real Economic Carrying Charge (RECC). RECC converts capital cost into an annual investment cost savings resulting from a discrete period of deferral. The Discrete Deferral value will require the user to specify the number of years of deferral (e.g.: 3 years). The value will be presented as:
    a. High, medium and low dollar savings ($) along with information on the peak reductions needed to attain those savings. Peak reductions would be shown as:
        i. High, medium and low peak MW reduction, with indication of peak hours (month, hour range, etc). The range of peak load reduction is driven by the load forecast and the uncertainty around it.
        ii. High, medium and low nameplate DER installs by technology to attain the reduction if each were the only technology implemented. The model includes a relationship between installed nameplate and dependable capacity.
2. **Discrete Savings per kW ($/kW).** This is the Discrete Deferral Value divided by the kW needed to attain the deferral. High medium and low savings per kW would be produced. High would mix high cost and low kW, medium would be medium cost and medium kW, and Low would be low cost and high kW. Three sets of values would be produced:
    a. High medium and low $/kW values, where the kW is the peak load reduction. This is not specific to a DER technology.
    b. High medium and low $/kW values, where the kW is DER nameplate kW required to achieve the deferral. These values would be technology specific.
    c. Low value of zero if insufficient peak reduction were available to enable deferral.

3. **Avoided Cost ($/kW-yr).** This is the single year discrete deferral value (calculated following the methodology above in 1.) divided by the kW needed to attain the deferral. High medium and low savings per kW-year would be produced. This is calculated similar to the Discrete Savings per kW, except that a single year deferral is used. Note that if there are multiple investments in the plan with different service lives, the RECC for each would vary. Two sets of values would be produced:
    a. High medium and low $/kW-yr values per kW iof peak load reduction. As discussed above, the range would be produced by combining the range of investment costs and the range of needed kW, and is not DER technology specific.
    b. High, medium and low $/kW-yr values per kW of DER nameplate. These values would be technology specific. As discussed above, the range would be produced by combining the range of investment costs and the range of needed kW. The range will not reflect uncertainty in peak contributions from technologies.

9.2.1.3 Formulas and Example Calculations

Figure 2 illustrates a situation where a network T&D investment is needed and the project cost. The project is needed to prevent the load growth (net of naturally occurring DER) from exceeding the T&D facility's load carrying capability and allows time for project deployment prior to the actual overload. In Figure 3, the utility is targeting incremental load reduction from the red line to the green line to allow the investment to be deferred by 3 years. The deferred project's cost is slightly higher due to equipment and labor inflation costs, but this would be more than offset by the financial savings from being able to defer the project.

Figure 2. Investment in distribution project due to load growth

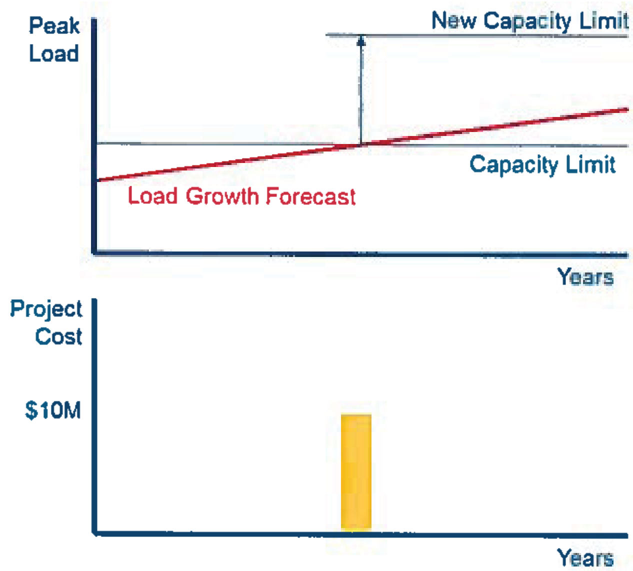
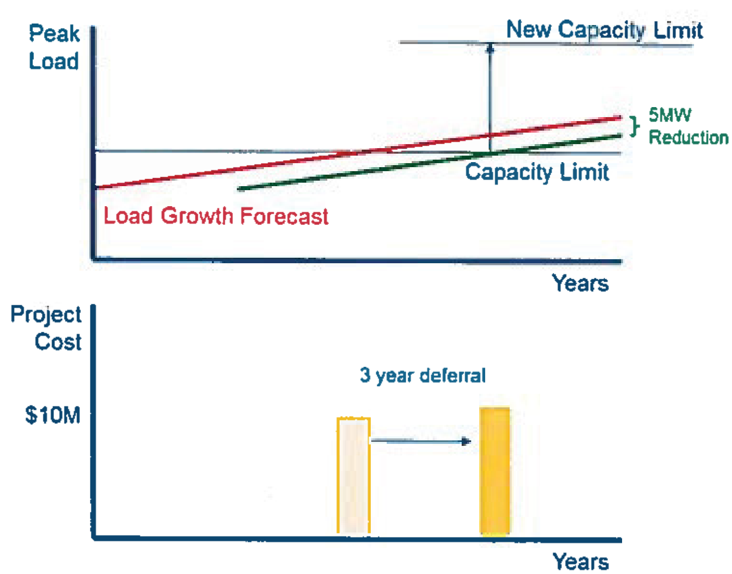


Figure 3. Project deferral of distribution investment



Other Assumptions:

- Original Investment cost (low, med, high): $8M, $10M, $15M

- Annual incremental operating cost: \$0.1M, \$0.2M, \$0.4M
- Asset life: 40 years
- Load reduction needed for 2 year deferral: 4MW, 6MW, 8MW
- Load reduction needed for 1 year deferral: 2MW, 3MW, 4MW
- Revenue Requirement Scaling factor: 150%
- WACC: 7.5%
- Inflation: 2%
- *RECC = 5.24%*

Note that the quantities and inputs used in this example are purely illustrative and may not resemble the inputs used in Demo B or their ranges.

Discrete Deferral Value

The savings of one year of deferral (\$/yr) is:

$$SavingsOne = TDCapital[y] * RECC * RRScaler[y] + \Delta O\&M$$

The savings of multiple years of deferral is:

$$SavingsTotal = SavingsOne * \sum_{d=1}^{D} \left(\frac{1+i}{1+r}\right)^{d-1}$$

Where:

TDCapital	=	Capital cost of the investment in year y. Note that the capital cost should be entered in the year that the expenditure stream is committed, which is likely to occur before the in-service year. The costs are lumped together to the commitment date, rather than the construction dates. However, if the project is structured such that there are major work stages that could be deferred separately, then each of the stages of work could be entered as a separate lump sum corresponding to each independent commitment date. Similarly, if there are multiple projects that have different commitment dates within the analysis horizon, each of those projects could be entered as independent lump sum values.
RECC	=	Real economic carrying charge. $RECC = \frac{(r-i)}{(1+r)} \frac{(1+r)^n}{[(1+r)^n-(1+i)^n]}$

RRScaler[y] = Revenue requirement scaling factor to convert direct capital costs to revenue requirement levels in year *y*. The scaling factor reflects the cost impacts of factors such as taxes, franchise fees, return on and of capital, administrative overhead, and general plant costs. The scaling factor can also vary with the utility book life of each asset.

ΔO&M = Incremental annual cost of O&M associated with the investment

i = *Inflation for T&D equipment*

r = *Discount rate (WACC)*

n = *Deferred Asset's life*

D = *Total years of deferral*

Table 3: Example Discrete Deferral Results ($millions)

Item	Variable	Low	Med	High
Investment Cost	TDCapital ($M)	$ 8.00	$ 10.00	$ 15.00
	RECC	5.25%	5.25%	5.25%
	RRScaler	150%	150%	150%
Incremental O&M	□O&M ($M/yr)	$ 0.20	$ 0.30	$ 0.40
One year Deferral	**SavingsOne ($M)**	**$ 0.83**	**$ 1.09**	**$ 1.58**
Two year Deferral	**SavingsTotal ($M)**	**$ 1.62**	**$ 2.12**	**$ 3.08**

One year savings based on reductions of 2MW to 4MW, during the hours of ...
Two year savings based on reductions of 4MW to 8MW, during the hours of...

Discrete Savings per kW

DiscreteperkW = SavingsTotal / MWNeed * 1000

Where

SavingsTotal = The Discrete Deferral value for D number of years of deferral, in millions

MWNeed = MW reduction needed to attain D years of deferral

Table 4: Example of Discrete Savings per kW (based on load reduction need, not DER technology) for a 2 year deferral

Value	Variable	Low	Med	High
Two-year Deferral	SavingsTotal ($M)	$1.62	$2.12	$3.08

MW Need (Hi, Med, Lo)	MW Need (2 yr)	8	6	4
Discrete savings per kW	DiscreteperkW	$202	$353	$770

Note that there will be zero savings if insufficient MW reductions are modeled to allow deferral of the project

Avoided Cost ($/kW-yr)

AvoidedCost = SavingsOne / MWNeed * 1000

Example of avoided costs per kW-yr (based on need, not DER technology)

Table 5: Example of Discrete Savings per kW (based on load reduction need, not DER technology) for a 1 year deferral

Value	Variable	Low	Med	High
Discrete one yr value	SavingsOne ($M)	$0.83	$1.09	$1.58
MW Need (Hi, Med, Lo)	MW Need (1 yr)	4	3	2
Avoided Cost	AvoidedCost	$207	$362	$790

Note that these avoided costs assume a one year deferral of the investment, and actual benefits per kW would likely vary, and potentially be zero if insufficient MW reductions are modeled to allow deferral.

9.2.1.4 Determination of Needed Load Reductions

The load reduction used in the calculation of the deferral value should reflect the distribution planners' expectation of needed peak reductions. In some applications, annual load growth has been used as a proxy for the needed load reductions; in other studies, peak capacity deficiency has been used. For the intended use of locational values for targeted DER, we recommend an initial deferral value assuming a three year deferral driven by a peak load reduction equal to the cumulative three-year deficiency.

E3 has been working on locational deferral projects for over twenty years, and has observed that multi-year deferrals of at least two or three years, as opposed to single year deferrals, are generally viewed as necessary to warrant the extra effort required to implement a targeted program and reschedule a distribution project. The use of the three years allows the deferral values to reflect this reality, and allow the load reductions to reflect a combination of immediate first year deficiency need as well as load growth over the second and third years.

Related to the question of *how much* load reduction is required is the question of *when* that load reduction is required to be operational in order to achieve a distribution project deferral. In situations where the load reduction is uncertain, it may be necessary for the observed load reductions to take place before deferring a project. For long-lived DERs, that results in only a small financial impact to the utility as payments for DERs are made earlier than needed (only a financing cost of money loss). For short-lived measures like demand response, and especially demand response that pays annually for participation, the early implementation of measures before they are actually needed to avoid capacity could result in significantly increased costs for the program. For example, assume that targeted DR would pay $10,000 annually for peak load reduction. If the reduction is not needed until 2020, but the effort begins in 2017, then $30,000 in payments are made for years 2017-2019 that are not assisting the deferral of the 2020 project (other than providing some risk reduction).

We expect that the need for early load reduction will decrease as targeted implementation were to gain more experience so that distribution planners could have more certainty of the ability of the program to deliver load reductions on time. However, in the early years, we do expect that some early implementation will be necessary, and would be reasonable.

9.2.2 DETERMINING DER MEASURE COINCIDENCE WITH PEAK LOAD HOURS

9.2.2.1 Peak capacity allocation factors

To allow calculation of DER coincidence the peak load hours, the LNBA Tool calculates hourly allocation factors to represent the relative need for capacity reductions during the peak periods specific to each distribution area. The concept is based on the Peak Capacity Allocation Factor (PCAF) method first developed by PG&E in their 1993 General Rate Case that has since been used in many applications in California planning[13].

The peak hours could be defined in three ways:

1. Specification of months and hours. E.g.: peak period is July and August hours between 4pm and 7pm on weekdays.
2. Specification of area peak threshold. The peak period would consist of all hours with forecasted demand above the specified threshold MW. The forecasted demand would be net of all existing

[13] For example, PCAFs were used recently in a CPUC report quantifying distributed PV potential in California: http://www.cpuc.ca.gov/NR/rdonlyres/8A822C08-A56C-4674-A5D2-099E48B41160/0/LDPVPotentialReportMarch2012.pdf

and forecast naturally occurring generation (both behind the meter and in-front of the meter) located downstream from the planned distribution investment.

3. Statistical specification. The peak period would consist of all hours with demand within one standard deviation of the single hour maximum peak demand for the area. In other words, the area peak threshold is calculated by the LNBA Tool based on the variability of the area loads.

The relative importance of each hour is determined using weights assigned to each peak hour either 1) in proportion to their level above the threshold, or 2) on a uniform basis. Hours outside the peak period are assigned zero weight and zero value.

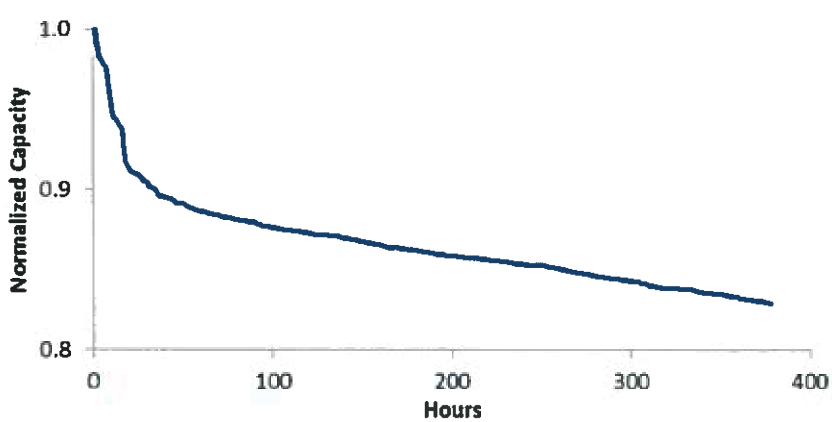
The formula for peak capacity allocation factors (PCAFs) using proportional weights is shown below.

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

Where *Thresh[yr]* is the load in the threshold hour or the highest load outside of the peak period.

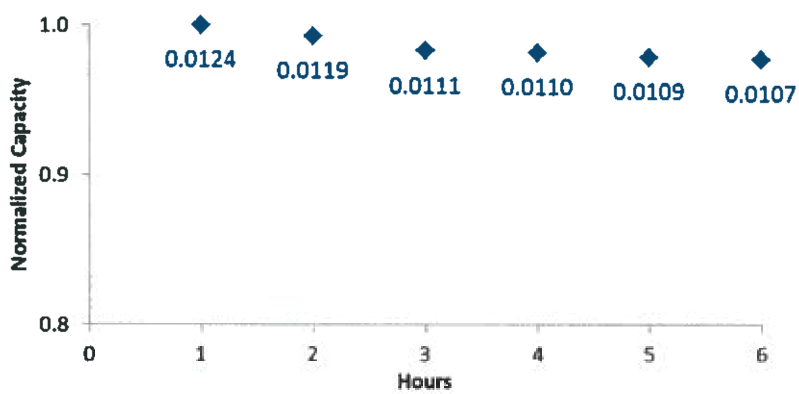
Once the PCAFs have been determined for each hour of the year, these are multiplied by the dependable output of each DER shape to determine the dependable MW contribution to peak load reductions. The following series of figures show an example of this process using the statistical peak period definition. One standard deviation from the top of the load duration curve above leaves the following hours with higher load than the threshold.

Figure 4. Example of PCAF calculation



This relatively flat load duration curve has more hours above the threshold than other peakier load duration curves – in this case, there are 378 hours. A PCAF is assigned to each one of these hours using the formula above. The following chart shows the PCAFs for the top 6 hours of the load duration curve as an example. The number below each plotted hour's normalized load represents the PCAF relative importance to peak load reductions. They are unitless, sum to one over the hours above the threshold, and can be thought of as the weights in a weighted average calculation of a particular resource's capacity contribution.

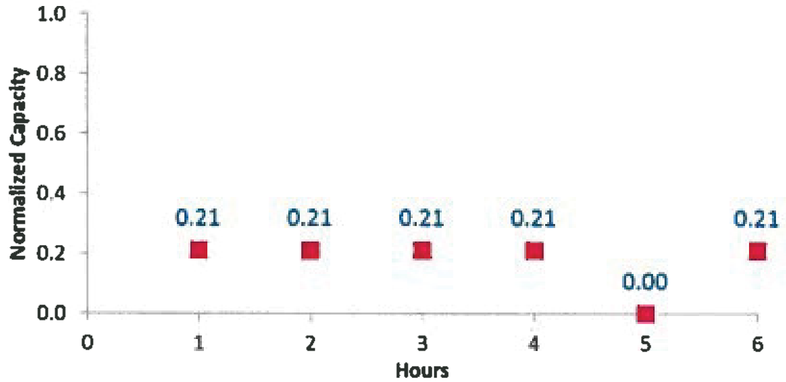
Figure 5. PCAFs for top 6 hours of load duration curve



9.2.2.2 Coincident Dependable Capacity

The next step in determining a distributed resource's dependable capacity contribution to peak load reductions is to determine the coincidence of the resource's output with the highest load hours. Dependable capacity contribution is the load reduction that the utility would trust to use in planning for deferrals, and ways of calculating it are discussed in more detail in Section 9.2.3, *Determining the dependable output of a DER measure*. The figure below shows example hourly normalized dependable load reductions (DLR_h) for a portfolio of commercial air conditioning (AC) energy efficiency (EE) resources in the 6 highest load hours. A normalized capacity of 1 represents the maximum load reduction achievable over the previously installed AC technology. These represent the dependable output of the measure - what the utility can count on in each hour to reduce load.

Figure 6. Hourly dependable capacity factors for EE output during the 6 highest load hours



To calculate the dependable MW contribution of the EE measure, the following formula is used:

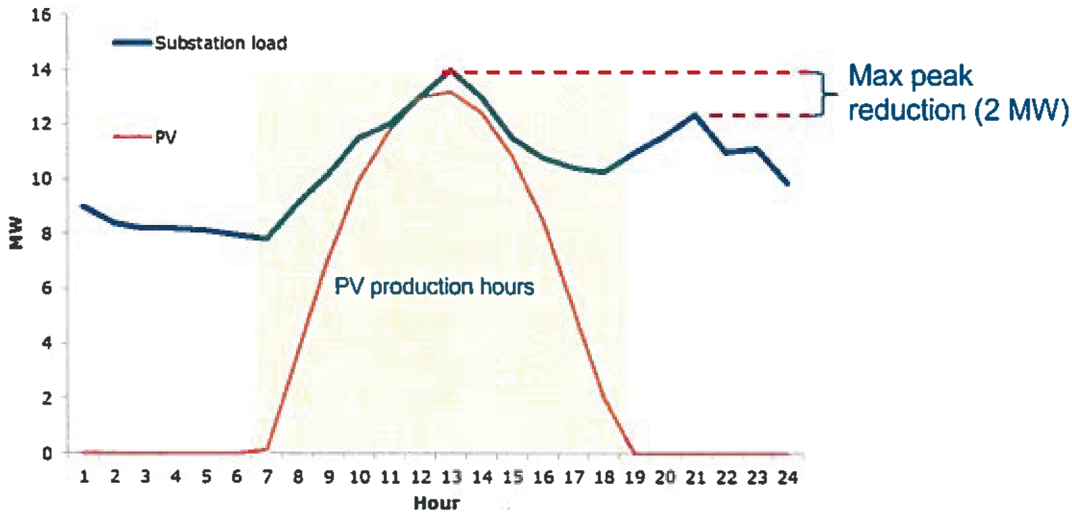
$$DepMW = \sum_{h\in(H|L_h\geq threshold)} DLR_h \times PCAF_h$$

The sum is performed over the hours in the total number of hours in the year (H) in which the load (L_h) is greater than the threshold (378 hours in the example). 20.5% of the EE measure's maximum capacity impact qualifies towards load reductions. Therefore, of the maximum capacity impact of a portfolio of new AC units of 1 MW, only 205 kW is counted towards deferring the distribution investment based on the combined effects of the distribution circuit load shape and the load shape of the DER. This produces a reasonable estimate of the dependable capacity or load reduction of the DER resource that can be used in planning and valuation models.

9.2.2.3 Dynamic nature of PCAFs

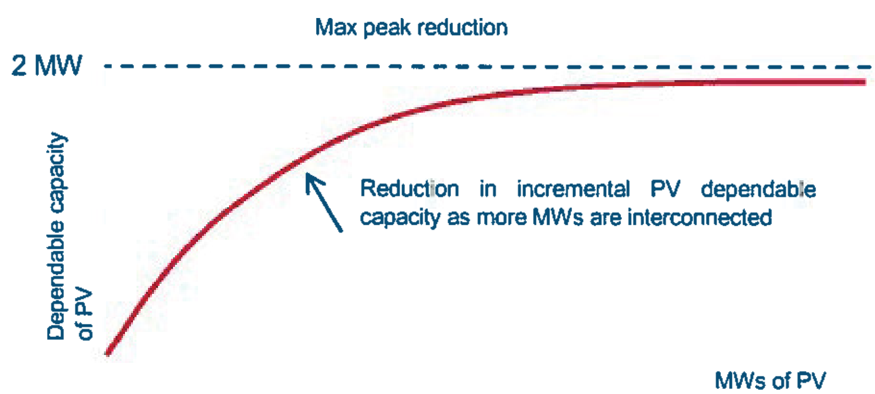
Note that as the load changes with load growth and DER implementation, the PCAFs will change. This is shown in the following example where the deferrable investment is at a substation. In this example PV is installed below the substation. The shape of the aggregate PV below the substation is shown below the substation load curve. As the level of PV increases, the daytime peak is reduced. However, there is a point where further increases in PV may reduce the daytime peak but will not reduce the peak load at the substation because of the evening peak is higher than the day time net peak.

Figure 7. The limit to peak load reductions



In this example, the effectiveness of standalone PV at reducing the peak diminishes as the peak is shifted away from the middle of the day, approaching an asymptote at the maximum peak load reduction (2 MW in the example). This is shown in the following figure.

Figure 8. Diminishing marginal dependable capacity of standalone PV



This effect is prominent with daytime peaking DER resources such as PV, however all DER measures have interactions with the load shape, and each other, that may result in diminishing capacity returns. DER resources can also complement each other, offering more capacity together than either one can alone. PCAFs must therefore be updated whenever the load shape, net of DER output, changes significantly. This is particularly true when calculating local distribution capacity benefits, because the DER measures added to reduce peak load may be a significant fraction of the total load.

Note: The complexities of dynamic PCAFs are important for a complete understanding of the interaction of DER and distribution needs. However, it remains unclear at the present whether such effects will be modeled in the Demo B projects and the associated LNBA tool.

9.2.2.4 Reflecting the impact of already installed DER on the peak hour risk

The next section discusses in detail the ways to model the dependable output of DER. The greater the number of DER measures installed, the closer the dependable output is to the expected output, but also the higher the risk of variation for weather sensitive DER. These facts raise the question of whether the dependable output for DER should only be considered for incremental DER, or should also be considered in determining the impact of existing installed DER on the hourly peak period loads used to develop the PCAFs.

Net approach

The standard approach is to use area demands that are net of historical DER. We refer to this as the "net" approach. The net approach is appropriate when there is a relatively low amount of DER in an area, or that DER is consistent and predictable in its impact on the area. The net approach involves calculating the coincidence of the dependable capacity shape for a marginal DER addition with the net load shape (net of previously installed DER measures). Using this method, the risk of not meeting load reductions associated with previously added MWs of DER is not captured. At higher penetrations of weather-dependent DER in a local area, particularly one with not much geographic diversity, a single year's net load shape may not be enough data to base capital planning decisions on because the uncertainty around previously installed DERs will not be factored into them.

Gross Approach

The alternate approach is to use area loads that are reconstructed to reflect what they would have been without DER and then subtract out the dependable (not historical) amount of existing DER output and demand reduction. We refer to this as the "gross" method because it requires a reconstruction of total customer usage prior to reductions from DER. This method would incorporate the risk criterion (i.e. the percentile, or other risk metric) into the contribution of all DER towards peak load reductions. This option is better capable of reflecting the risk of the entire installed DER portfolio of not providing expected peak load reductions – a risk level that may be significant at high penetrations of weather-dependent DER in low geographic diversity regions.

The gross approach is the more conservative option, it is more appropriately applied across all geographic levels of the system from line segment up to system level since it incorporates changing amounts of geographic diversity, and the first approach is inconsistent since it only applies a risk derate to the marginal kW of DER and not to the existing installations. However, there will still be some geographic diversity effect captured in the first method that is reflected in the load shape of the DER resources.

The gross approach is also more data intensive, requiring knowledge of all existing DER installations down to the smallest geography considered in the model including their load shapes. This level of data is unlikely to be available system wide. At lower levels of DER penetration, the first approach using the net load shape will approximate the second most closely at lower DER penetration levels. As levels increase, the risk associated with the existing resources in delivering expected capacity reductions will also increase.

Whether gross load or net load is used in the analysis depends on the data availability on the particular part of the network being studied and the amount of weather sensitive DER already installed in that part of the network. *The method(s) that is(are) used for the Demo B projects are unclear at the time of this writing.* In either case, whether Net or Gross approaches are used, the objective of the analysis is to estimate the avoided distribution costs impact of incremental DERs in a particular location.

9.2.3 DETERMINING THE DEPENDABLE OUTPUT OF A DER MEASURE

As mentioned above, the ability for DER to defer a distribution system project depends upon the coincidence of the DER with the distribution area peak needs, as well as the dependability of those DER reductions. The prior section's discussion of PCAFs addressed the coincidence of DER. This section addresses the dependability of DER. 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 those DER in an area increases.

The dependable output of a DER measure varies by the acceptable risk level for an area. For example, a planning rule could be to accept a level of DER output that the DER measure is at or above more than 97% of the time during peak load hours. DER measure output can be derated to meet the defined planning criteria. The derate is determined by several factors:

1. Whether it can be reliably called or controlled during peak load hours,
2. what the outage rate of the measure looks like,
3. in the case of renewable generation, what is the uncertainty around the output,
4. the geographic diversity and number of installed measures, and
5. The impact of a circuit outage on the ability of the DER to perform.

These factors influence the measure impact/production shape and the derate to a greater or lesser extent. For example, energy efficiency is not 'dispatched', but is built into the infrastructure of the building or building appliances. However, energy efficiency measures tend to be installed in large numbers, reducing the uncertainty around its output and converging on a relatively low derate. Likewise, measure impact/production shapes should reflect the diversity of installing a portfolio of new systems across customers, capturing the effect of many systems contributing at the same time to load reductions. DR, on the other hand, must be controlled in the absence of a strong price signal. Estimating the derate factors comes from experience over time with installed measures. Assuming the outages reflected in the derate are uncorrelated with time of day or year, the derate can be uniformly applied to an hourly measure impact shape. This is the dependable measure output.

An alternative to calculating a weather-dependent DER derate directly (for example, in the case of PV), a dependable output shape can be determined. First, find the distribution of PV output in each hour and season. These can be formed from the aggregate output of all weather-dependent DER below the deferrable investment on the distribution system. From these distributions take the percentile corresponding to the planning rule appropriate for the area. For example, if 97% reliability is required, the model will take the 3rd percentile of each hourly and seasonal distribution. The result is a level of output from PV that in each hour of the year, PV would be expected to produce at or higher than for 97% of the time. This is the dependable PV measure output. The advantage of using this method is that for investments with very little geographic diversity in the region electrically downstream, the dependable MWs in each hour from weather dependent DER will be low because the shape without diversity benefit is more likely to be strongly affected by cloud cover etc. Conversely, investments with a lot of geographic diversity downstream will have relatively high dependable MWs in each hour because of the diversity benefit to the aggregate shape of the weather-dependent DER resource.

The dependable output of dispatchable resources depends on them being dispatched for local T&D capacity benefits. However, whether they are used for T&D deferral or not will depend on the value to the customer of T&D deferrals vs other value streams such as system capacity or ancillary services. The output of dispatchable DERs may be partially or fully derated if they are dispatched for another purpose. Only DER with contractual obligations to prioritize T&D functions will receive local T&D capacity benefits in the model.

9.2.3.1 Modeling of Dispatchable Resources

The dependable output of a dispatchable resource is dependent on the dispatch used. These resources need to be dispatched for distribution benefits for dependable deferrals. If dispatched for system benefits, they may need to be significantly derated for distribution deferrals – particularly if the local distribution load shape is very different from the system load shape, or if storage is dispatched for other value streams such as ancillary services. Programs for an effective distribution deferral dispatch regime for DR and storage are beyond the scope of this framework. However, one method could include contracted utility control of storage during only high distribution load hours, and leaving the storage device to operate for highest value at all other times. Essentially a call option on the DER with a strike (trigger) set by distribution operations based on local reliability assessments.

When DERs are dispatched for distribution benefits the constraints on dispatch, and the uncertainty on load levels when the dispatch calls have to be made, factor into calculation of the DER dependable capacity contribution. For example, both storage and DR must be dispatched ahead of time based on forecasted loads. The forecast error determines the level of coincidence between storage and DR with the peak hours. There are further constraints to consider. For example, DR may only be called a certain number of times per year, and both storage and DR have limitations on the length of their discharge periods.

The LNBA Tool will model the dispatch of DERs using perfect foresight under two different program options: first is a customer controlled dispatch against customer rates, with an optional utility call for local or system capacity benefits; second is a utility controlled dispatch against utility energy prices, capacity and T&D needs. These dispatch regimes will be subject to the technical constraints of the resources being modeled. Demand response will be dispatched assuming perfect forecasting, and capturing the effects of limits on annual calls, and length of discharge period. Perfect forecasting overestimates the effectiveness of dispatchable DER. However, it can be combined with a user inputted derate to account for that. The derate can be set by the utilities in future applications of the framework to approximate the effect of uncertainty. Dispatches for DERs will be done for a single year.

9.3 Avoided Costs from DERAC

The DERAC model will be replaced by an Avoided Cost Model (ACM) that is currently being updated. A draft ACM was made available to stakeholders on June 1, 2016, and final model is scheduled to be released in the beginning of July 2016. The following avoided cost components will be transferred from the ACM into the LNBA Tool to allow for DER resources to be evaluated with a full set of avoided cost values.

- Generation system capacity avoided cost
- System energy avoided cost, day ahead market, net of embedded CO2 costs (not LMP values).
- Ancillary service costs (included as a percentage adder to energy prices)
- Energy losses avoided costs (for delivery to secondary voltage)
- CO2 costs (embedded in energy market prices, but separated out for reporting purposes)

- RPS adder costs (cost of the above market price of renewables multiplied by the percentage of retail sales that must be met by RPS qualified resources).

The costs are generated hourly, and forecasted out for 30 years. The hourly variation in avoided costs are based on 2015 historical energy prices and forecast changes in market clearing prices due to increased renewable generation serving the state. Historical energy price shapes could be updated to account for the increase in renewables and in particular as a result of the increase in solar penetration.

9.4 Avoided costs outside of DERAC

9.4.1 FLEXIBLE RA

The LNBA team has identified two methods for including flexible RA in the model. A preferred method has not yet been selected. One option is to calculate the flexible RA impact of a DER by taking its output change over the three-hour period starting in the hour indicated in the table below (from the 2016 Flexible Capacity Needs Assessment (FCNA)[14]) for November (the month with the highest 3 hr ramp):

Table 5: 2016 Forecasted Hour in Which Monthly Maximum 3-Hour Net load Ramp Began

Month	Starting Hour	Month	Starting Hour
Jan	14	Jul	12
Feb	15	Aug	12
Mar	16	Sep	14
Apr	16	Oct	15
May	16	Nov	14
Jun	15	Dec	14

This uses the expected DER profile. Adjustments for dependability (see prior section) would not be required as the flexible RA impacts accrue at the system, not the local distribution area level.

[14] https://www.caiso.com/Documents/FinalFlexibleCapacityNeedsAssessmentFor2017.pdf

A second alternative is a user input factor that translates MW of DER into a MW increase/decrease of flexible RA requirement. This is easily done for solar, wind and EE, since these are explicitly represented in the CAISO hourly data that is used to create a forecast of net load to determine the flexible RA requirement[15].

9.5 Process and implementation

9.5.1 SYSTEM DISAGGREGATION LEVEL

The methodology above can be applied to all levels of the electricity grid from bulk system down to circuit. Tailoring the framework to each level requires data specific to the loads and DER impacts experienced at that level. Applying the framework to a distribution planning area, for example, will potentially include several different avoidable T&D investments. DER located at the end of a feeder line could potentially have local line segment voltage impacts, substation equipment deferral, and sub-transmission deferral, in addition to avoided costs at the system level. System level non-transmission related avoided costs will be calculated using the DERAC. However, the remaining T&D avoided cost components are calculated using the above framework using the level of system disaggregation appropriate to each identified deferrable system upgrade. Below are presented examples of the level of system disaggregation and the data needs for each of the avoided cost categories identified in the introduction of this document.

9.5.2 DATA REQUIREMENTS

The data requirements for evaluating project deferrals will vary depending on the level of granularity of the analysis. Evaluation of loads and planned T&D investments require the following:

- Information about load growth related T&D investments planned for the future, including timing, costs, and development lead times.
- Hourly loads by planning area. Depending on the granularity of the analysis, loads will be needed for the system downstream of each planned T&D investment. (Loads should reflect any expected

15 https://www.caiso.com/informed/Pages/StakeholderProcesses/FlexibleCapacityNeedsTechnicalStudyProcess.aspx

system reconfigurations). The corresponding load growth, including any potential changes in shape expected over time if available, is also needed.

Characterization of the DER being evaluated for deferral varies by technology type. The following information is required.

- Dispatch constraints for dispatchable DER. The notification time and discharge period are required for DR and storage. Additionally, the maximum number of calls on DR is needed.

The level of system disaggregation needed is dependent on the specific avoidable investments identified. An example is shown below for the first category – avoided sub-transmission, substation and feeder capital and operating expenses.

9.5.2.1 Example data needs for Avoided sub-transmission, substation and feeder capital and operating expenses

Example: a new transformer bank at a substation identified as necessary to meet future projected load growth.

Grid disaggregation level: the substation and all loads and DER electrically downstream of the substation.

Data required:

- Aggregated load data from electrically downstream of the substation

- Aggregated DER impact shapes from all non-dispatchable DERs installed downstream of the substation (to allow determination of the weather sensitivity and aggregate dependability of both existing and incremental DER in the area). Hourly output shapes for potential incremental non-dispatchable DER that are weather matched to the load data. For EE these include end use specific impact shapes. For PV, as much data as available from all geographically diverse PV locations downstream of the project is important to develop dependable capacity contributions. Capturing the diversity effect becomes more important as the geographic area downstream of a project becomes larger, such as at sub-transmission level.

- Aggregated dispatchable DER technologies and the tariffs/programs used to operate them

9.5.3 INCORPORATION INTO UTILITY PLANNING PROCCESSES

The LNBA Tool is designed to satisfy the requirements of Demo B Modeling, as well as provide a learning platform for the utilities and stakeholders to become experienced with the LNBA needs and opportunities. The LNBA Tool is a "research tool" and not a "production grade" tool that could be integrated efficiently into utility planning processes.

While developing the specifications for the LNBA Tool, the team has considered some of the issues that could arise with the implementation of the methodology into the utility planning processes. While the list is not extensive at this point, the issues would include the following:

- **Project identification and lead times.** Projects will need to be identified early to allow sufficient time for DER implementation. The development lead time on T&D investments determines the point at which demonstrable load reductions must be made to defer an investment. This may correspond to the time at which equipment needs to be procured to complete construction of a T&D facility on time. The demonstration criteria may include either all required load reductions to be demonstrated, or some fraction of load reductions. Project lead time may decrease, or the demonstration criteria may change over time as the utilities gains more experience with DER programs.
- **Project Cost Estimates.** Project costs will be necessarily vague and generic for projects planned for many years in the future. Deferral plans should be updated every year to reflect more accurate cost estimates as project installation dates become closer and specific project plans are developed.

10 APPENDIX D: Demonstration B Requirement Checklist

Requirement	ACR Description	ACR	Implementation Plan
DPA Selection/Projects for Deferral	In selecting which DPA to study, the Utilities 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 Demonstration 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 Utility does not include noncapacity-related opportunities, the Utility must evaluate a noncapacity project in another DPA.	4.1; pg 24	3.1, Appendix A - 7; pg 7, 22-24
LNBA Methodology Requirements	The approach is to specify a primary analysis that the Utilities shall execute and a secondary analysis that the Utilities 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 Utilities 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 25	4.4, Appendix C - 9; pg 15, 27-54
Table 2	Primary Analysis	4.3; pg 26, 27	4.4; pg 15
LNBA Specific Requirements			

Project Identification	The Utilities 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 28	4.3.1; pg 10-11
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 28	4.3.1; pg 11
Cost of Projects	Use existing approaches for estimating costs of required projects identified	4.4.1 (1)(B)ii; pg 28	4.3.2; pg 12
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 28	4.3.1; pg 11
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 29	4.3.4; pg 13-14
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 standard and 'smart' inverters and synchronous machines.	4.4.1 (1)(B)v; pg 29	4.3.5; pg 14

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 29	4.3.3; pg 13
Computer 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 30	4.4; pg 15
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 30	4.3.3; pg 13

Transmission CapEx	For avoided costs related to transmission capital and operating expenditures, the Utilities 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 Utilities shall provide work papers with a clear description of the methods and data used. If the Utilities 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 30, 31	Appendix C - 9.1; pg 29-30
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 Utilities shall provide a clear description of the methods and data used.	4.4.1 (3); pg 31	N/A, Demo B LNBA Methodology focuses on the Primary Analysis in Table 2 of the ACR only.
Flexible Generation	For the avoided cost of generation capacity for any DERs which provides flexible generation, the Utilities shall apply a method, such as the "F factor" which has been proposed for the Demand Response Cost-effectiveness Protocols.46 The Utilities shall provide work papers with a clear description of the methods and data used.	4.4.1 (4); pg 31	4.4 & Appendix C - 9.3.1; pg 15, 49-50
Avoided Energy - LMPs	For the secondary analysis, the Utilities 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 Utilities shall provide work papers with a clear description of the methods and data used.	4.4.1 (5); pg 31	N/A, Demo B LNBA Methodology focuses on the Primary Analysis in Table 2 of the ACR only.

Avoided Costs - Renewable Integration, Societal, and Public Safety	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 Utilities shall propose their methods for including these values or descriptions in the detailed implementation plans	4.4.1 (6); pg 31, 32	4.4; pg 15
Methodology Description	The Utilities 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 32	Appendix C - 9; pg 27-54
Software and Data Access	The Utilities 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 32	3.2; pg 7-8
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 32	Appendix C - 9.2; pg 32-33
Other Related LNBA Requirements			
Heat Map	The Utilitie'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 be also be required as determined in the data access portion of the proceeding.	4.4.2 (1); pg 32	3.2, 4.3.4, 4.5, 5.2; pg 7-8, 13-14, 15-16, 19
DER Growth Scenarios	The Utilities 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 32	3.1, 3.2, 4.3; pg 7, 9
General Requirements			

Equipment Investment Deferral	The Utilities 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 33	4.3.3; pg 13
Implementation Plan	The Utilities shall submit detailed implementation plans for project execution, including metrics, schedule and reporting interval. To the extent practicable, the Utilities 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 33, 34	5, Appendix B – 8, Appendix C – 9; pg 17-20, 25-26, 27-54
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 Demonstration B project: 1) an intermediate report; and 2) the final report.	5.1 (d)(iv); pg 34	5.2; pg 19-20