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**ENERGY RESEARCH AND DEVELOPMENT DIVISION**

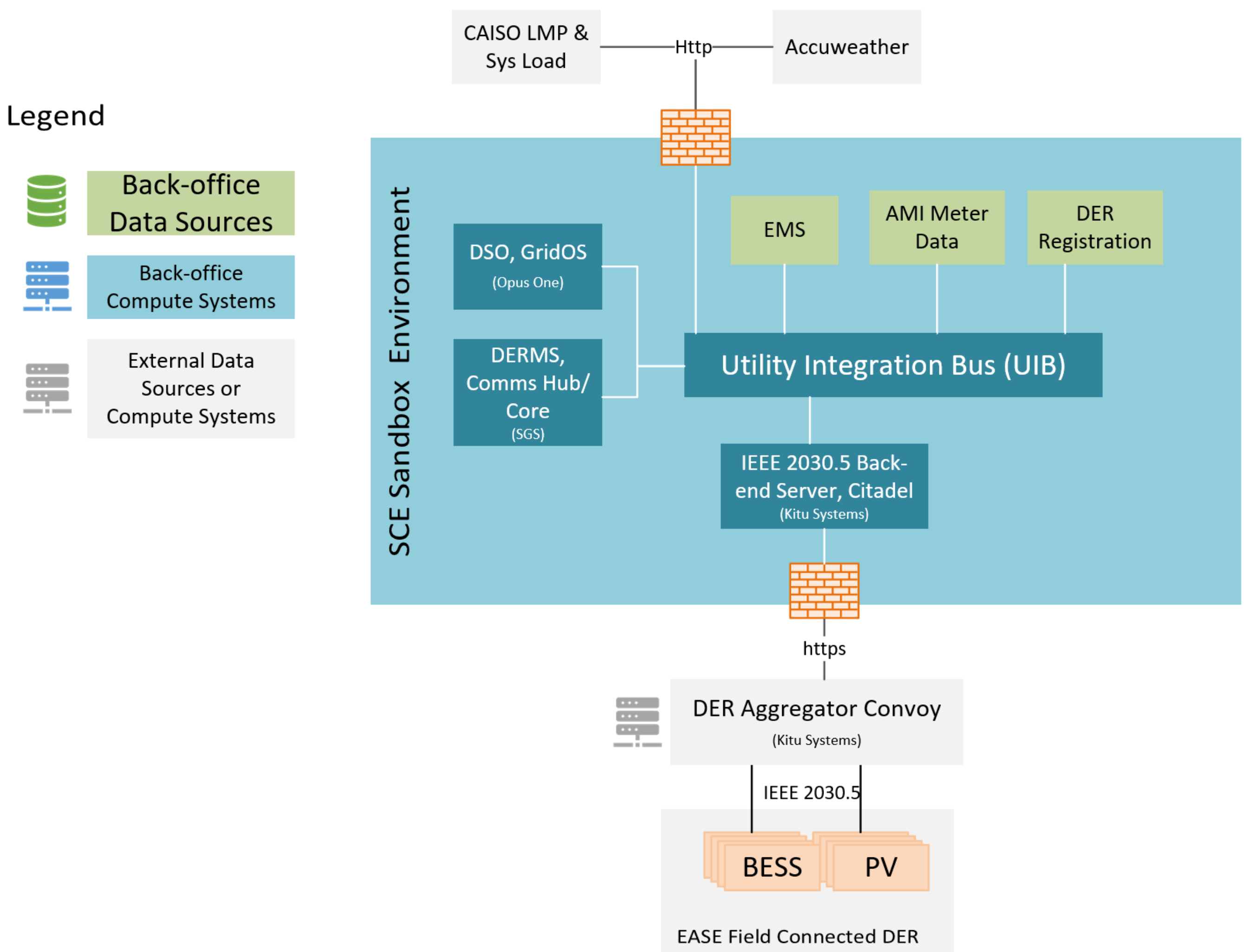
# Appendix A: EASE Architecture

**June 2024 | CEC-500-2024-064-AP**

# APPENDIX A:
# EASE Architecture

The EASE architecture, otherwise referred to as the Distributed Control Architecture (DCA), is a system-of-systems design to address the increasing volume of DER interconnections to the electric grid. Implementing the DCA will automate some of the manual processes related to DER interconnections. In turn, this will expedite the process to interconnect new DERs to the electric grid. By interconnecting a higher volume of DERs in a shorter amount of time, SCE will be able to accelerate support of federal and state regulations to reduce GHG. Figure A-1 is a high-level overview of the EASE architecture.

**Figure A-1: High-Level EASE Architecture**




Source: Southern California Edison

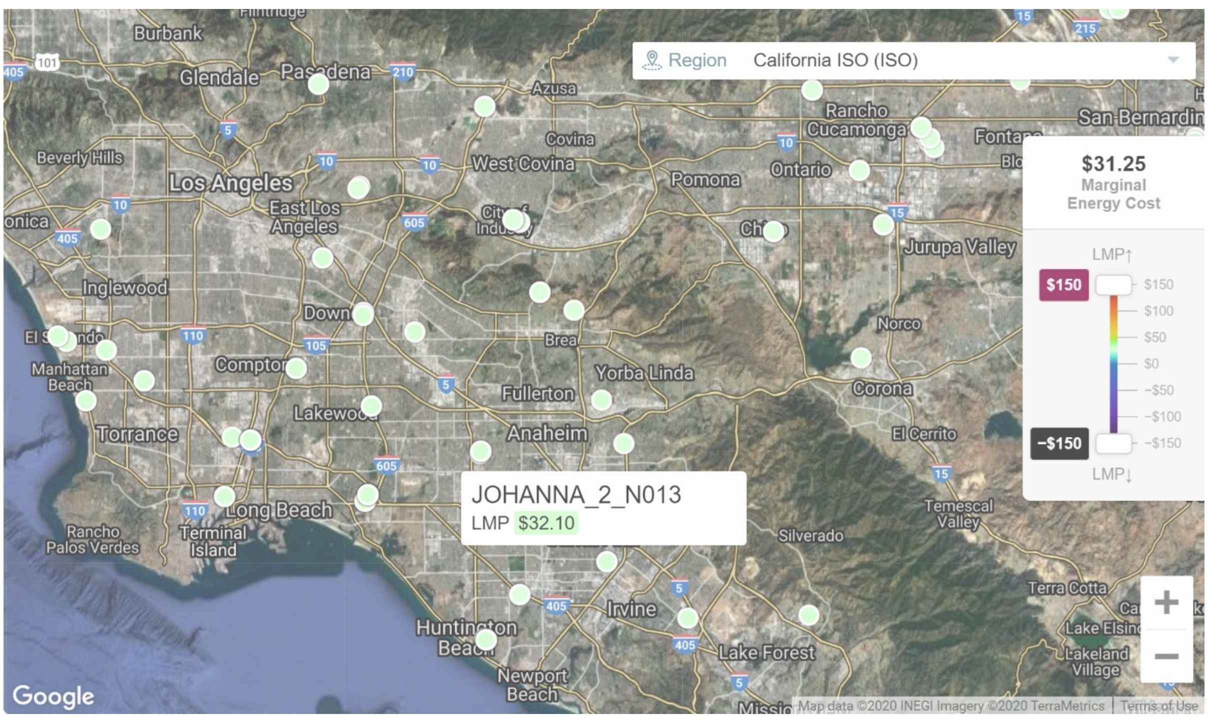
## Utility Integration Bus (UIB)

The UIB facilitates the data exchange across multiple systems via a secure infrastructure. Pertinent data will be published to the UIB and made available to other subscriber systems. The UIB provides a secure infrastructure and serves as a central repository of relevant data to perform functions related to the EASE use cases. For EASE, the UIB will integrate the following systems: DERMS, DSO, DER Registration, Utility Interconnection Portal, and DER Aggregator. In addition, the UIB will leverage the Distribution Management System (DMS), Meter Data, and DER Registration service data sources. Through this integration, data can be shared among the systems seamlessly and in a secured environment.

### CAISO LMP & System Load

The DSO uses CAISO market data to inform the valuation of the bids/offers that DERs can submit to provide services for specific market use cases. Specifically, the Locational Marginal Prices (LMP) for the "JOHANNA_2_N013" pricing node and system load data from SCE's Transmission System Access Charge (TAC) are used in calculating the optimal DER dispatches and recommended settlement, or payment, to the DER owner.

**Figure A-2: CAISO LMP Price Node**

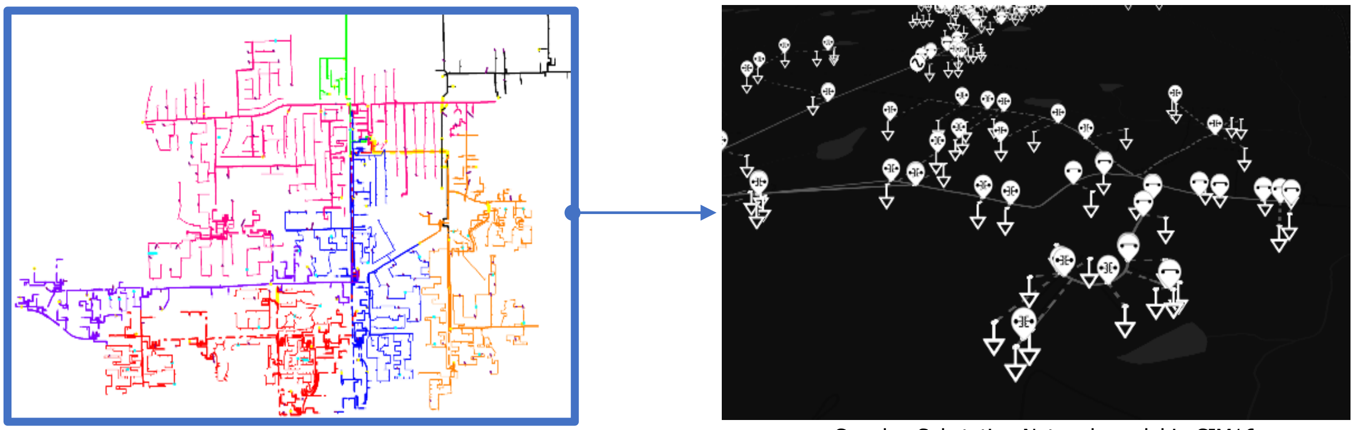



Source: Southern California Edison

### Network Model, AMI Load Data, and DER Registration

The Camden network model contains all customer AMI nodes, which are identified by their transformer structure IDs on the distribution network. SCE's Cyme network model was provided to Opus One Solutions to convert to a CIM16 compatible model, which can be visualized in the GridOS platform as shown in Figure A-3. The network model is used to perform optimal power flow calculations for EASE’s market-based use cases. Within the model Opus provisioned the 10,000 DER nodes represented in the model enabling DER communication. They are also able to consume the AMI data provided by the UIB into their network model. Finally, the DSO also consumes real-time feeder active power loading information to the DSO for intra-day load corrections.

**Figure A-3: Camden Substation network model used by DSO to perform Optimal Power Flow calculations**



Camden Substation Network model in Cyme

Camden Substation Network model in CIM16

Source: Southern California Edison

### Weather Data

Weather data is ingested by the SCE UIB through a subscription to Accuweather. The weather data contains forecasted and observed values for variables such as temperature, humidity, and various irradiance parameters. Hourly day-ahead weather forecasts and a 36-hour look ahead weather forecast are ingested every 15-minutes during the intra-day. This is primarily used for PV generation forecasting for the day-ahead and the 15-minute intra-day intervals. The PV forecasts are used to inform the Optimal Power Flow (OPF) analyses that determine the cost or losses minimizing dispatch of DER on the evaluated circuits.

## Distribution Management System (DMS)

The DMS is the utility’s monitoring and control system for Distribution-level grid assets. This system is used to monitor and operate field equipment. In the scope of EASE, measurement values and equipment operation statuses will be ingested to the DMS via the UIB. The DER measurement values will be provided by the Optimization & Constraint Management System and the Aggregator Control System. System measurement values are provided to the DMS from other sources as part of normal operations. The system measurement values from the DMS will be provided to the UIB for ingestion and use by the Optimization & Constraint Management System and Aggregator Control System.

## DERMS: Feeder Net Load Optimization & Constraint Management System

The DERMS is responsible for dispatching the IEEE 2030.5 and DNP3 DER and is provided by Smarter Grid Solutions via their ANM Strata platform. Their real time control platform integrates with DER, external Aggregators and the UIB's data sources. The DERMS also receives DSO market dispatch schedules via the UIB to dispatch. The DERMS' constraint management system continuously monitors all its 96 circuit measurement points for grid constraints (i.e., overvoltage, undervoltage, or over-current on the distribution network). If a constraint occurs, it can override any dispatch schedule from the DSO and select the DER closest and best suited to resolve the constraints. The DERMS functionality for EASE is as follows:

- Contains a network model of the grid assets on Camden Substation.
- Receives real-time operation information from the utility-scale DERs/Aggregator and real-time circuit information from the DMS via UIB.
- Receives operation schedules from the DSO and transmits control setpoints to their respective DER via the DNP3 or IEEE 2030.5 DER communication protocol. See Figure A-2 for the DER Control Dispatch Pipeline.
- Performs voltage and constraint management at the feeder to mitigate circuit constraint violations as needed.

## Distribution System Operator (DSO) Platform

The DSO platform is provided by Opus One Solutions. The Opus One DSO platform, called GridOS-Transactive Energy Management Systems (GridOS-TEMS), provides the utility and the prosumer with separate interfaces to manage system and resource operation, respectively. The utility uses Opus One's GridOS-Distributed System Platform (GridOS-DSP), and the market participant uses the GridOS-Market Participant Interface (MPI). The GridOS software's sole point of integration is through SCE's Utility Integration Bus (UIB), which provides the GridOS software access to all data sources necessary for creation of dispatch schedules and prices to achieve Use Cases 6, 7, and 8. The system publishes those dispatch schedules to the DERMS via the UIB for dispatch.

## DER Registration/Provisioning Service

The Provisioning Service will be integrated to the UIB and will be used for automatic provisioning of new DERs. This service invoked by the Utility Interconnection Portal, via the UIB, when a DER has been provided Permission-to-Operate (PTO) by SCE. Once PTO is issued, the Provisioning Service will be notified and pull the data necessary for provisioning the DER equipment and interconnecting the DER to the grid. Then the Provisioning Service will take the appropriate action based on the type of DER (non-aggregated or aggregated).

### Utility Interconnection & Jurisdiction Portals

The existing SCE interconnection portal was enhanced to support requirements for the automated self-provisioning of DERs. These enhancements include additional data points required for self-provisioning of DER assets and integration with the local jurisdiction to facilitate automation of data transfer. The data from these portals will be integrated with the UIB to further automate the provisioning process by making the data available to systems subscribed to the UIB, namely the Provisioning Service.

### IEEE 2030.5 Server/Aggregator: Citadel/Kitu

The Aggregator, provided by Kitu Systems, is the DERMS' point of connection to all IEEE 2030.5 communicating DER. The DERMS can receive DER measurements from the IEEE 2030.5 communicable devices and can dispatch controls using the IEEE 2030.5 protocol.

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# Appendix B: DER Constraint Management

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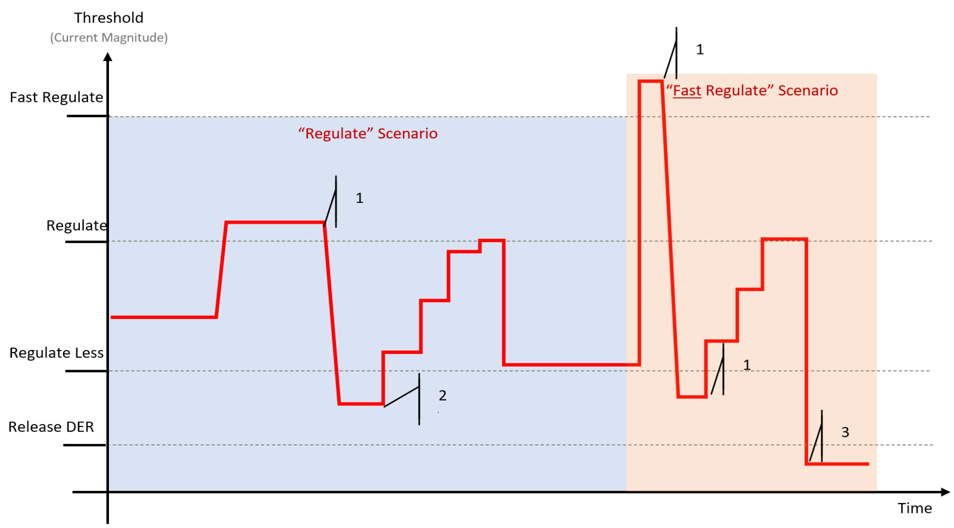
# APPENDIX B: DER Constraint Management

## Current Regulation Methodology

The following current regulation limits were programmed into the DERMS for the EASE project. Other various limits were tested depending on the characteristics of each feeder. Depending on the demand characteristics operators could elect to have tighter or wider gaps between the limits listed below. Note current is regulated in both the forward and reverse direction of a cable. Figure B-1 shows an example of a scenario where the "Regulate" and "Fast Regulate" current limits were breach, along with a description of the constraint management process listed below.

- **Step 1:**
    - **Regulate:** Current exceeds 95% of cable ampacity. If current does not drop below regulate limit after 5-minutes (user-configurable) the DERMS begins to mitigate the violation using local DER.
    - **-or- Fast Regulate:** Current exceeds 110% of cable ampacity. DERMS takes immediate action to reduce current using local DER.
- **Step 2 Regulate Less Margin:** Current dips below 80% of cable ampacity while the DERMS is attempting to mitigate "regulate" or "fast regulate". DERMS reduces the output/charge-rate of some DER in steps to allow for the current to slowly sit below the regulate limit to conserve DER capacity.
- **Step 3 Release DER:** Current dips below 75% of cable ampacity during a regulate/ fast regulate scenario. Current has been sufficiently reduced and DERMS is ok to releases DER to their default mode of operation.

**Figure B-1: Current Regulate Limits**



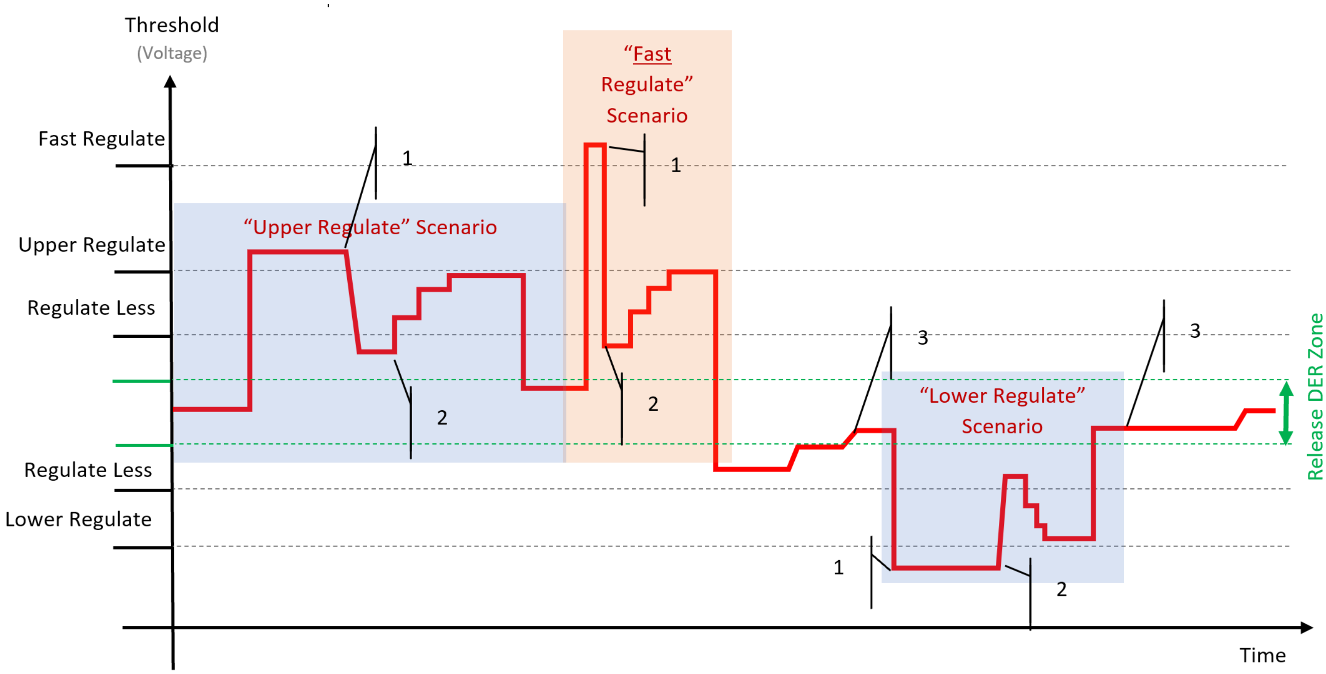

Source: Southern California Edison

## Voltage Regulation Methodology

The following limits have been programmed into the DERMS. Note that current is regulated traveling either in the forward or reverse direction of a cable. Figure B-2 shows an example of an upper regulate, fast regulate, and lower regulate voltage constraint breach illustrating the Constraint Management Operation process listed below.

- **Step 1:**
  - **Fast Upper/Lower Regulate:** Voltage exceeds 110% of the nominal value. DERMS takes immediate action to reduce or boost voltage between 95% to 105% of nominal using local DER.
  - **-or- Upper/Lower Regulate:** Voltage exceeds 105% or drops below 95% of the nominal voltage value. DERMS monitors for several minutes/seconds (user-configurable) until it begins to mitigate the violation between 95% to 105% of nominal using local DER.
- **Step 2 Regulate Less:** Voltage dips/rises between 96% to 104% of nominal while the DERMS is attempting to mitigate "regulate" or "fast regulate". DERMS reduces the output/charge-rate of some DER in steps to allow for the voltage to slowly sit below the regulate limit to conserve DER capacity.
- **Step 3 Release DER:** Voltage dips/rises dips below 97% to 103% of nominal during a regulate/fast regulate scenario. Voltage has stabilized and DERMS is ok to releases DER to their default mode of operation.

**Figure B-2: Voltage Regulation Limits**




Source: Southern California Edison

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# Appendix C: Industry Presentations & Publications

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# APPENDIX C:
# Appendix Title

| Forum Name | Delivery Method | Location | Timeframe |
|---|---|---|---|
| DistribuTECH 2018 | Presentation | San Antonio, TX | January 2018 |
| DOE Solar Energy Technologies Office (SETO) 2018 Portfolio Review | Presentation, Report, Panelist | Washington D.C. | February 2018 |
| IEEE Power & Energy Society (PES) Transmission & Distribution (T&D) Conference & Exposition | Presentation | Denver, CO | April 2018 |
| Emerging Technologies Review by University of California – Santa Barbara | Presentation | Santa Barbara, CA | May 2018 |
| Centre for Energy Advancement through Technological Innovation (CEATI) Smart Grid Conference | Presentation | Anaheim, CA | October 2018 |
| Technical Advisory Committee (TAC) Review of EASE Use Cases | Discussion & Use Case Review | Virtual | October 2018 |
| IEEE Conference on Technologies for Sustainability (SusTech) | Technical Paper & Presentation | Long Beach, CA | November 2018 |
| 2019 Centre for Energy Advancement through Technological Innovation (CEATI) Smart Grid Conference | Presentation | Palm Springs, CA | November 2019 |
| Technical Advisory Committee | Presentation | Web-based | November 2019 |
| 2020 Southern California Edison National Engineering Week | Poster Presentation | Pomona, CA | February 2020 |
| Innovative Smart Grid Technologies (ISGT 2020) | PowerPoint Presentation | Washington DC | February 2020 |
| Solar Energy Technologies Office Peer Review | Poster Presentation | Virtual | April 2020 |
| California Energy Commission Critical Project Review | PowerPoint Presentation | Virtual | April 2020 |
| SEPA Conference: Grid Evolution Summit | PowerPoint Presentation | Virtual | August 2020 |
| 2020 EASE Technical Advisory Committee | PowerPoint Presentation | Virtual | December 2020 |
| CAISO T&D Interface Coordination Working Group | PowerPoint Presentation | Virtual | January, 2021 |
| Utility Analytics Summit - Distribution Market Deployment to Enable Mass Optimization of Customer DER | PowerPoint Presentation | Virtual | May 4th, 2021 |
| 44th PLMA (Peak Load Management Alliance) Conference - Mass Optimization of DERs Using Distribution Pricing | PowerPoint Presentation | Virtual | November 10th 2021 |
| DOE SETO Colloquium – SCE's Customer Acquisition Strategy for EASE | PowerPoint Presentation | Virtual | November 9th, 2021 |
| 2021 (Final) EASE Technical Advisory Committee | PowerPoint Presentation | Virtual | December 20th, 2021 |

Source: Southern California Edison

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# Appendix D: Circuit Measurement Points

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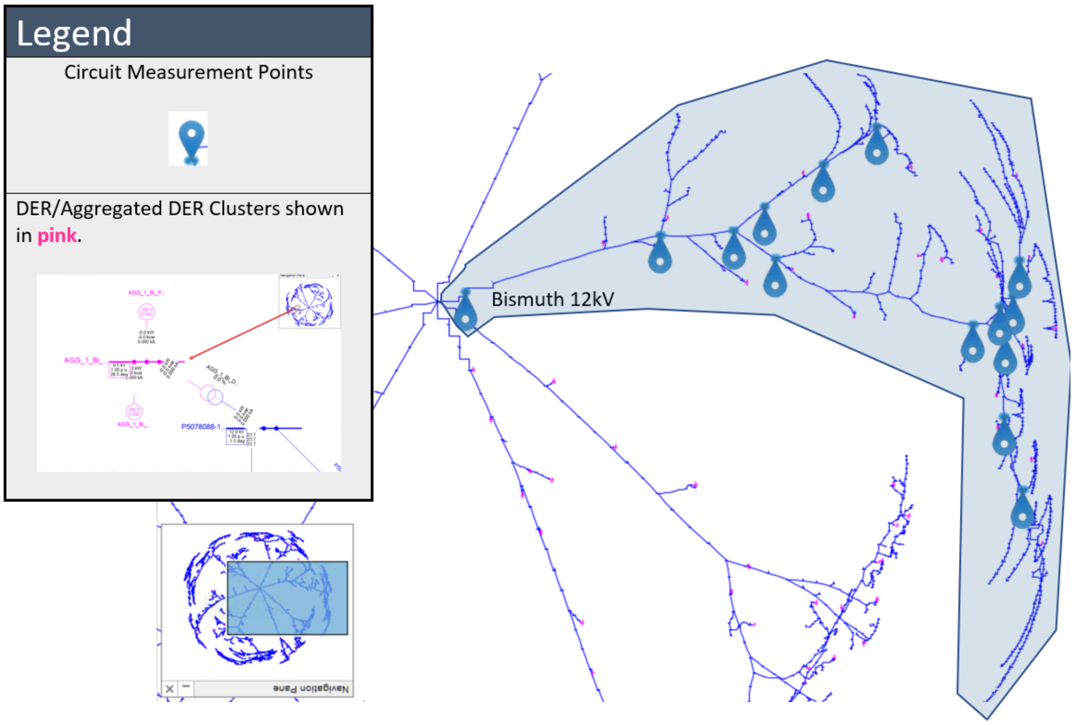
# APPENDIX D:
# Circuit Measurement Points

The following map illustrates the DERMS circuit measurement points monitored by the DERMS during this simulation along with the DER/Aggregated DER clusters managed by the DERMS.




## Voltage Constraint Limits

| Measurement Point | Lower Regulate | Release Lower | Release Upper | Upper Regulate | Global Regulate |
|---|---|---|---|---|---|
| MP_1_BI_V | 11400 | 11760 | 12240 | 12600 | 13200 |
| MP_2_BI_V | 11400 | 11760 | 12240 | 12600 | 13200 |
| MP_3_BI_V | 11400 | 11760 | 12240 | 12600 | 13200 |
| MP_4_BI_V | 11400 | 11760 | 12240 | 12600 | 13200 |
| MP_5_BI_V | 11400 | 11760 | 12240 | 12600 | 13200 |
| MP_6_BI_V | 11400 | 11760 | 12240 | 12600 | 13200 |
| MP_7_BI_V | 11400 | 11760 | 12240 | 12600 | 13200 |
| MP_8_BI_V | 11400 | 11760 | 12240 | 12600 | 13200 |
| MP_9_BI_V | 11400 | 11760 | 12240 | 12600 | 13200 |
| MP_10_BI_V | 11400 | 11760 | 12240 | 12600 | 13200 |
| MP_11_BI_V | 11400 | 11760 | 12240 | 12600 | 13200 |
| MP_12_BI_V | 11400 | 11760 | 12240 | 12600 | 13200 |
| MP_13_BI_V | 11400 | 11760 | 12240 | 12600 | 13200 |
| MP_14_BI_V | 11400 | 11760 | 12240 | 12600 | 13200 |

## Current Constraint Limits

| MP | Regulate Less Margin | Regulate | Global Regulate |
|---|---|---|---|
| MP_1_BI_I | 378 | 449 | 520 |
| MP_2_BI_I | 484 | 575 | 666 |
| MP_3_BI_I | 736 | 874 | 1012 |
| MP_4_BI_I | 484 | 575 | 666 |
| MP_5_BI_I | 484 | 575 | 666 |
| MP_6_BI_I | 484 | 575 | 666 |
| MP_7_BI_I | 484 | 575 | 666 |
| MP_8_BI_I | 480 | 570 | 660 |
| MP_9_BI_I | 480 | 570 | 660 |
| MP_10_BI_I | 484 | 575 | 666 |
| MP_11_BI_I | 484 | 575 | 666 |
| MP_12_BI_I | 484 | 575 | 666 |
| MP_13_BI_I | 90 | 106 | 123 |
| MP_14_BI_I | 484 | 575 | 666 |

Source: Southern California Edison

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# Appendix E: DER in 9.2.1 Simulation

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# APPENDIX E:
# DER in 9.2.1 Simulation

This table lists the DER monitored by DERMS during constraint management simulation on Bismuth 12kV. In total, the DERMS was monitoring 37 individual DER assets or aggregated DER clusters in the table below during the Constraint Management simulation on task 9.2.1.

| # | DER/Cluster ID | kVA | kWh | DER Type | Connection Type | Protocol |
|---|---|---|---|---|---|---|
| 1 | AGG_1_BI_PV | 250 | n/a | Photovoltaic | Aggregated DER Cluster | IEEE 2030.5 |
| 2 | AGG_2_BI_PV | 250 | n/a | Photovoltaic | Aggregated DER Cluster | IEEE 2030.5 |
| 3 | AGG_3_BI_PV | 250 | n/a | Photovoltaic | Aggregated DER Cluster | IEEE 2030.5 |
| 4 | AGG_4_BI_PV | 250 | n/a | Photovoltaic | Aggregated DER Cluster | IEEE 2030.5 |
| 5 | AGG_5_BI_PV | 250 | n/a | Photovoltaic | Aggregated DER Cluster | IEEE 2030.5 |
| 6 | AGG_6_BI_PV | 250 | n/a | Photovoltaic | Aggregated DER Cluster | IEEE 2030.5 |
| 7 | AGG_7_BI_PV | 250 | n/a | Photovoltaic | Aggregated DER Cluster | IEEE 2030.5 |
| 8 | AGG_8_BI_PV | 250 | n/a | Photovoltaic | Aggregated DER Cluster | IEEE 2030.5 |
| 9 | AGG_9_BI_PV | 250 | n/a | Photovoltaic | Aggregated DER Cluster | IEEE 2030.5 |
| 10 | AGG_10_BI_PV | 250 | n/a | Photovoltaic | Aggregated DER Cluster | IEEE 2030.5 |
| 11 | AGG_11_BI_PV | 250 | n/a | Photovoltaic | Aggregated DER Cluster | IEEE 2030.5 |
| 12 | AGG_12_BI_PV | 250 | n/a | Photovoltaic | Aggregated DER Cluster | IEEE 2030.5 |
| 13 | AGG_13_BI_PV | 250 | n/a | Photovoltaic | Aggregated DER Cluster | IEEE 2030.5 |
| 14 | AGG_1_BI_BESS | 250 | 500 | Energy Storage | Aggregated DER Cluster | IEEE 2030.5 |
| 15 | AGG_2_BI_BESS | 250 | 500 | Energy Storage | Aggregated DER Cluster | IEEE 2030.5 |

| # | DER/Cluster ID | kVA | kWh | DER Type | Connection Type | Protocol |
|---|---|---|---|---|---|---|
| 16 | AGG_3_BI_BESS | 250 | 500 | Energy Storage | Aggregated DER Cluster | IEEE 2030.5 |
| 17 | AGG_4_BI_BESS | 250 | 500 | Energy Storage | Aggregated DER Cluster | IEEE 2030.5 |
| 18 | AGG_5_BI_BESS | 250 | 500 | Energy Storage | Aggregated DER Cluster | IEEE 2030.5 |
| 19 | AGG_6_BI_BESS | 250 | 500 | Energy Storage | Aggregated DER Cluster | IEEE 2030.5 |
| 20 | AGG_7_BI_BESS | 250 | 500 | Energy Storage | Aggregated DER Cluster | IEEE 2030.5 |
| 21 | AGG_8_BI_BESS | 250 | 500 | Energy Storage | Aggregated DER Cluster | IEEE 2030.5 |
| 22 | AGG_9_BI_BESS | 250 | 500 | Energy Storage | Aggregated DER Cluster | IEEE 2030.5 |
| 23 | AGG_10_BI_BESS | 250 | 500 | Energy Storage | Aggregated DER Cluster | IEEE 2030.5 |
| 24 | AGG_11_BI_BESS | 250 | 500 | Energy Storage | Aggregated DER Cluster | IEEE 2030.5 |
| 25 | AGG_12_BI_BESS | 250 | 500 | Energy Storage | Aggregated DER Cluster | IEEE 2030.5 |
| 26 | AGG_13_BI_BESS | 250 | 500 | Energy Storage | Aggregated DER Cluster | IEEE 2030.5 |
| 27 | PV_1_BI | 250 | n/a | Photovoltaic | Utility-scale/ Commercial | DNP3 |
| 28 | PV_2_BI | 250 | n/a | Photovoltaic | Utility-scale/ Commercial | DNP3 |
| 29 | PV_3_BI | 250 | n/a | Photovoltaic | Utility-scale/ Commercial | DNP3 |
| 30 | PV_4_BI | 250 | n/a | Photovoltaic | Utility-scale/ Commercial | DNP3 |
| 31 | BESS_1_BI | 1000 | 4000 | Energy Storage | Utility-scale/ Commercial | DNP3 |
| 32 | BESS_2_BI | 250 | 1000 | Energy Storage | Utility-scale/ Commercial | DNP3 |
| 33 | BESS_3_BI | 250 | 1000 | Energy Storage | Utility-scale/ Commercial | DNP3 |
| 34 | BESS_4_BI | 250 | 1000 | Energy Storage | Utility-scale/ Commercial | DNP3 |

| # | DER/Cluster ID | kVA | kWh | DER Type | Connection Type | Protocol |
|---|---|---|---|---|---|---|
| 35 | BESS_5_BI | 250 | 1000 | Energy Storage | Utility-scale/ Commercial | DNP3 |
| 36 | BESS_6_BI | 250 | 1000 | Energy Storage | Utility-scale/ Commercial | DNP3 |
| 37 | BESS_7_BI | 250 | 1000 | Energy Storage | Utility-scale/ Commercial | DNP3 |
| | **Totals** | **10000** | **16500** | | | |

Source: Southern California Edison

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# Appendix F:  DER Acquired for EASE

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# APPENDIX F: DER Acquired for EASE

In total, EASE has acquired 31 inverters, where 17 of the 34 inverters are online and the remaining are under construction. Note that some systems have both PV and BESS connected to the same inverter (DC-coupled), so in total EASE has acquired 5 BESS and 39 PV DER.

| Inverter # | EASE DER Name | Manu-facturer | Inverter Model | Type | Individual CEC AC Size kW | kWh | Circuit |
|---|---|---|---|---|---|---|---|
| 1 | ACT_1_AY_BESS | Generac | x7602 | PV & BESS | 6.26 | 17.1 | ALLOY |
| 2 | ACT_2_AL_PV | SMA | Sunny Boy 6.0-US | PV | 5.12 | n/a | ALUMINUM |
| 3 | ACT_3_AL_PV | SMA | Sunny Boy 6.0-US | PV | 5.46 | n/a | ALUMINUM |
| 4 | ACT_4_AL_PV | SMA | Sunny Boy 6.0-US | PV | 5.24 | n/a | ALUMINUM |
| 5 | ACT_5_AL_PV | SMA | Sunny Boy 6.0-US | PV | 5.24 | n/a | ALUMINUM |
| 6 | ACT_6_AL_PV | SMA | Sunny Boy 6.0-US | PV | 5.37 | n/a | ALUMINUM |
| 7 | ACT_7_AL_PV | SMA | Sunny Boy 6.0-US | PV | 5.22 | n/a | ALUMINUM |
| 8 | ACT_1_BI_PV | SMA | Sunny Boy 6.0-US | PV | 5.137 | n/a | BISMUTH |
| 9 | ACT_1_CO_PV | SMA | Sunny Boy 6.0-US | PV | 3.75 | n/a | COBALT |
| 10 | ACT_2_CO_PV | SMA | Sunny Boy 6.0-US | PV | 7.17 | n/a | COBALT |
| 11 | ACT_3_CO_PV | SMA | Sunny Boy 6.0-US | PV | 5.44 | n/a | COBALT |
| 12 | ACT_4_CO_PV | SMA | Sunny Boy 6.0-US | PV | 5.46 | n/a | COBALT |
| 13 | ACT_5_CO_PV | SMA | Sunny Boy 6.0-US | PV | 5.46 | n/a | COBALT |
| 14 | ACT_6_CO_PV | SMA | Sunny Boy 3.8-US | PV | 3.54 | n/a | COBALT |
| 15 | ACT_7_CO_PV | SMA | Sunny Boy 6.0-US | PV | 5.12 | n/a | COBALT |
| 16 | ACT_8_CO_PV | SMA | Sunny Boy 6.0-US | PV | 5.46 | n/a | COBALT |
| 17 | ACT_9_CO_PV | SMA | Sunny Boy 6.0-US | PV | 4.78 | n/a | COBALT |
| 18 | ACT_10_CO_PV | SMA | Sunny Boy 6.0-US | PV | 6.14 | n/a | COBALT |
| 19 | ACT_11_CO_PV | Generac | x7602 | PV | 6.107 | n/a | COBALT |
| 20 | ACT_12_CO_PV | Generac | x7602 | PV | 5.832 | n/a | COBALT |
| 21 | ACT_13_CO_PV | SMA | Sunny Boy 6.0-US | PV | 5.62 | n/a | COBALT |
| 22 | ACT_14_CO_BESS | Generac | x7602 | PV & BESS | 6.909 | 17 | COBALT |
| 23 | ACT_15_CO_BESS | Generac | x7602 | PV & BESS | 4.299 | 11.115 | COBALT |
| 24 | ACT_1_CA_PV | SMA | Sunny Boy 6.0-US | PV | 5.075 | n/a | CADMIUM |
| 25 | ACT_2_CA_PV | SMA | Sunny Boy 6.0-US | PV | 5.075 | n/a | CADMIUM |
| 26 | ACT_1_TI_BESS | Generac | x7602 | PV & BESS | 6.8 | 11.4 | TITANIUM |

| Inverter # | EASE DER Name | Manu-facturer | Inverter Model | Type | Individual CEC AC Size kW | kWh | Circuit |
|---|---|---|---|---|---|---|---|
| 27 | ACT_1_UR_PV | SMA | Sunny Boy 6.0-US | PV | 3.684 | n/a | URANIUM |
| 28 | ACT_8_AL_PV | SMA | Sunny Boy 6.0-US | PV | 8.195 | n/a | ALUMINUM |
| 29 | ACT_9_AL_PV | SMA | Sunny Boy 6.0-US | PV | 5.369 | n/a | ALUMINUM |
| 30 | ACT_10_AY_PV | SMA | Sunny Boy 6.0-US | PV | 3.77 | n/a | ALLOY |
| 31 | ACT_17_CO_PV | SMA | Sunny Boy 6.0-US | PV | 5.383 | n/a | COBALT |
| | | | | **Totals** | **167.485** | **56.615** | |

Source: Southern California Edison

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# Appendix G: Customer Locations on Camden Substation

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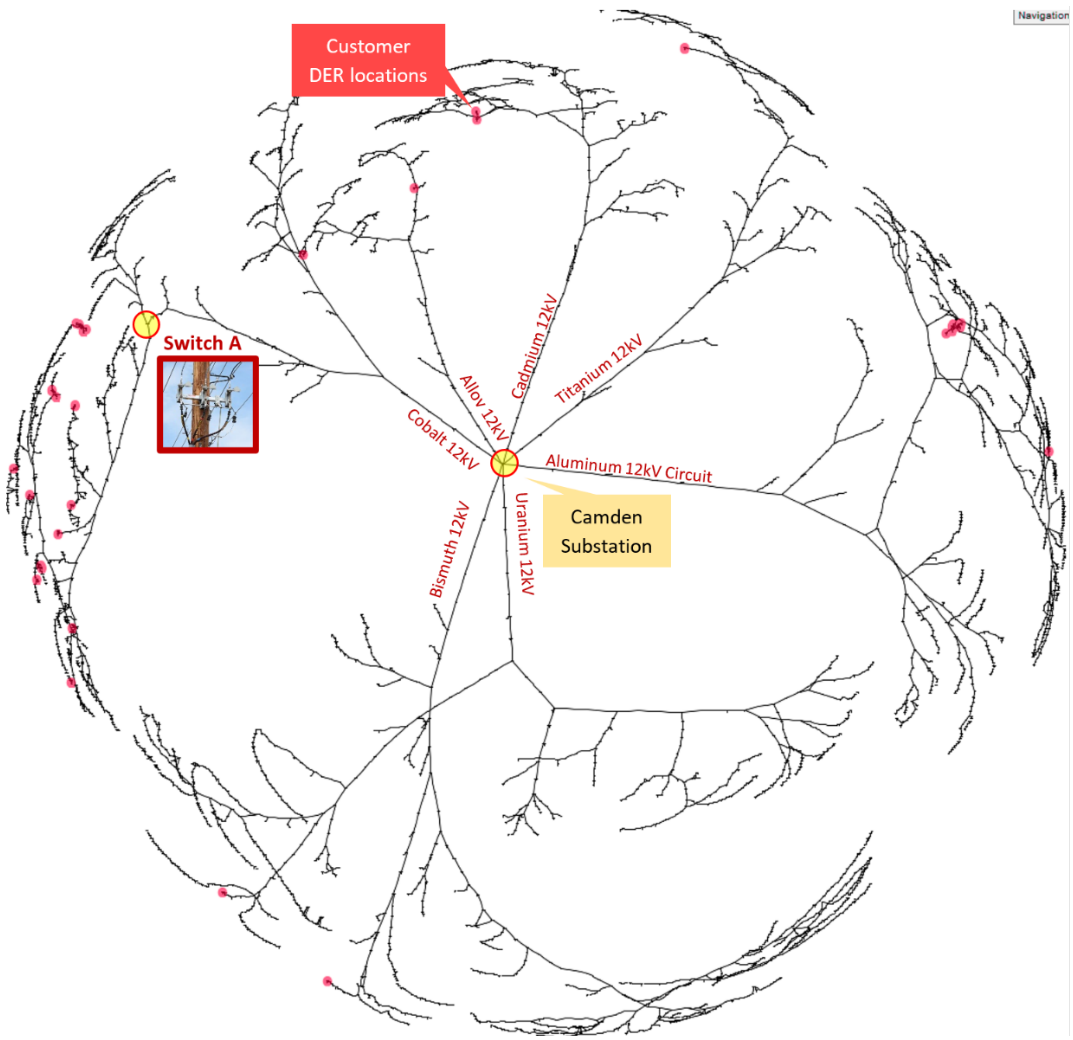
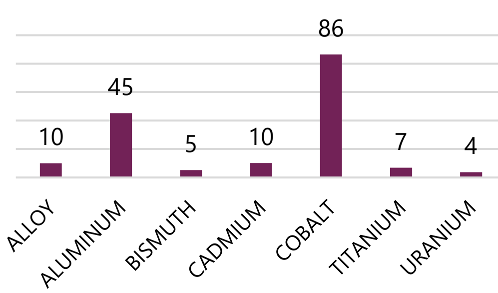
# APPENDIX G:
# Customer Locations on Camden Substation

The red dots in the diagram below show the locations of each of the customer DERs and their relative position on the radial distribution network of Camden substation. It also indicates the two-circuit measurement points on Switch A and at the Feeder Head.




| | Quantity | Generation Output (kW) | Storage (kWh) |
|---|---|---|---|
| Total customers | 24 | | |
| | | | |
| PV only inverters | 27 | 143 | |
| PV & BESS Inverters | 4 | 24 | 56 |
| Inverter Total | 31 | 167 | 56 |

DER Capacity (kW) by Circuit




Source: Southern California Edison

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# Appendix H: EASE Project Partners and Technical Advisory Committee

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# APPENDIX H: EASE Project Partners and Technical Advisory Committee

In terms of engaging with external stakeholders, the project team also created a technical advisory committee with the members listed below. The goal was to share findings and receive feedback from experts in the field of deploying and operating DER management solutions.

- Electric Power Research Institute
- ComEd
- Navigant
- Smarter Grid Solutions
- ConEd
- Quanta
- University of California, Riverside
- General Electric
- California Independent System Operator
- University of California, Irvine
- California Institute of Technology
- California Energy Commission
- Department of Energy

The EASE project team was composed of the following organizations.

- Southern California Edison (SCE): Lead Organization and System Integrator
- Smarter Grid Solutions (SGS): Distributed Energy Resource Management System (DERMS)
- Opus One Solutions: Transactive Energy Platform for Distribution System Operator functions
- Kitu Systems Inc: Third Party DER Aggregator Platform
- Clean Power Research, Inc: Interconnection Portal
- National Renewable Energy Laboratory: Solar PV forecasting expertise
- City of Santa Ana: Field demonstration site

ENERGY RESEARCH AND DEVELOPMENT DIVISION

# Appendix I: Case Study on Dynamic Hosting Capacity

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# APPENDIX I: Case Study on Dynamic Hosting Capacity

The benefits of DSO use-cases were quantified using actual field-tested customer DER that were under the control of EASE's control architecture. After outlining the demonstrated benefits, a cost-benefit analysis was done to determine the value these benefits have for utilities and its customers. The analysis will detail the investments needed to construct the DCA and then quantify the benefits to customers in cost savings and improved air quality. The main benefits to ratepayers include potential cost-savings from deferring capacity upgrades to the grid and the overall reduction in greenhouse gas emissions. These savings and reduction in greenhouse gases are consequences of customers adopting more DER, which would provide more local generation on the grid that could be used to power customer electricity demand. Additionally, as sectors of the economy powered by fossil fuels are electrified, local sources of greenhouse gas emissions will continue to decline.

SCE can use the DSO's DER optimization capabilities to host more gross customer demand than is traditionally possible today. The benefit of the DSO is that it has the situational awareness and forecasting ability to optimize the generation export/import of controllable DER to reduce the net demand during peak hours of the day for each feeder territory wide. This would extend the life of distribution equipment while increasing network capacity, which will be vital as customers shift toward all electric appliances and vehicles. This high-level analysis will characterize the potential savings in implementing this system.

SCE's Grid Modernization Plan filed in the 2021 General Rate Case (GRC) was estimated to cost over $400 million to modernize SCE's grid control systems (SCE, 2019). These investments would improve SCE's situational awareness of grid demand, DER generation forecasting, and develop the systems required to optimize controllable DERs to balance DER generation and demand. These new systems include the sub-systems demonstrated in EASE but also encompasses other grid systems that were out of scope for the project. These investments will represent the estimated total cost required to enable the full capabilities of the DSO and modern grid asset control applications.

**Figure I-1: SCE Grid Modernization Investments**


Source: Southern California Edison

Next, the estimated potential savings that could be realized through distribution deferrals was derived from SCE's 2020 and 2021 Grid Needs Assessment (GNA) and Distribution Deferral Opportunity Report (DDOR) (SCE, 2020). SCE has published GNA and DDOR to the California Public Utilities Commission (CPUC) since 2018. To maintain consistency, data prior to 2020 has been omitted from this analysis since the project description categories have changed after 2020. Table I-1 reflects the various capital costs associated with SCE serving the “MW Need” for its wires-only construction projects throughout the year. Capacity upgrade projects on existing distribution lines with less than a 16 MW need account for $274 million in deferral costs from 2020 and 2021. New power line construction projects were not included because they are likely new connections to SCE’s grid, not upgrades. Finally, IT costs are generally incurred when new equipment needs to be integrated with existing SCADA systems. Comparing these savings in Table I-1 to its estimated $400 million investment in Grid Modernization, SCE could fully recover its investment costs in roughly four years assuming there were already sufficient controllable DER concentrations on the grid today and a DSO system in place to manage them.

**Table I-1: Potential savings (millions) through <16 MW capacity distribution upgrade deferrals from 2020 and 2021**

| Year | Number of Projects | Deferred MW | Substation Costs | Primary Feeder Costs | IT Costs | Total Deferral Costs (<16 MW capacity) |
|---|---|---|---|---|---|---|
| 2020 | 93 | 255.1 | $62.4 | $96.6 | $0.2 | $159.1 |
| 2021 | 98 | 41.2 | $26.4 | $89.2 | $0.2 | $115.8 |
| Total | 191 | 296.3 | $88.8 | $185.8 | $0.4 | $274.9 |

Source: Southern California Edison

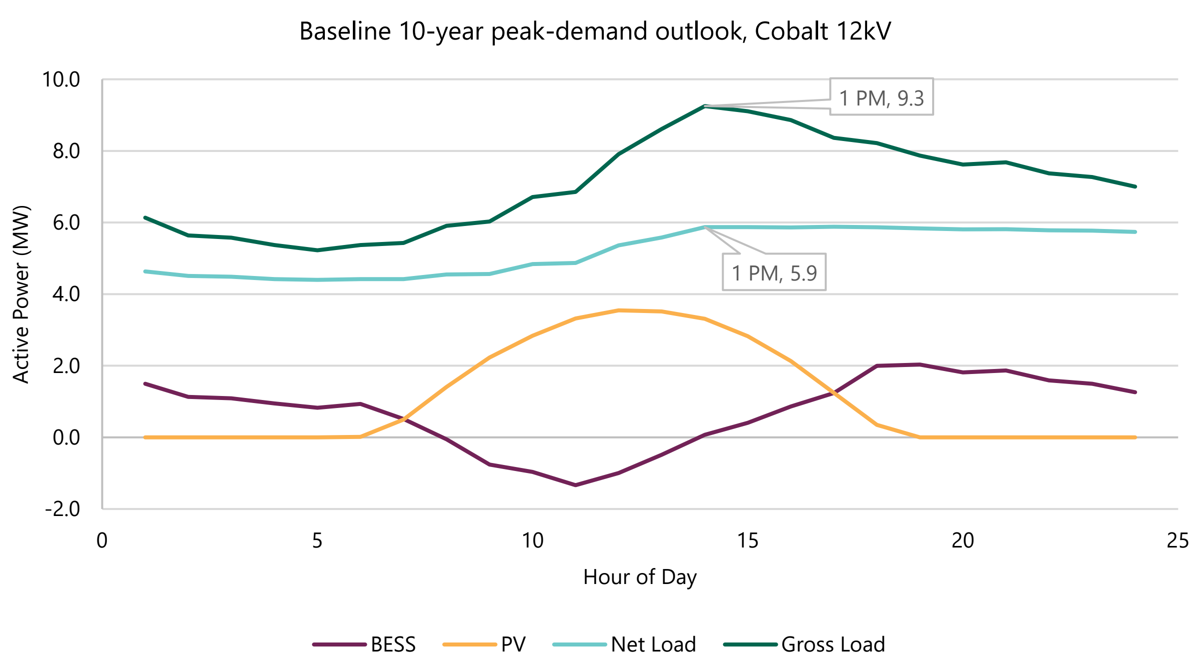
Although these savings seem significant, the reality is that today most new capacity upgrade projects are not eligible for DER deferrals since the concentrations of DER are not high enough, or cost-competitive to defer wire upgrades. DER deferral eligibility is analyzed on an annual basis for all new projects in SCE’s Locational Net Benefit Analysis (LNBA) process. This process examines all the infrastructure upgrade projects identified in SCE’s distribution planning process, maintenance work notifications from SCE’s Distribution Inspection and Maintenance Program, and projects in SCE’s reliability program. Through this process, SCE explores different methodologies and analyses to assess the locational benefits of DERs to achieve grid upgrade project deferral. At the time this report was drafted, 4.5% of all projects (totaling 69 MW of the 646 MW) from 2020 and 2021 were eligible for DER capacity deferrals but are still under investigation. DER must still be price competitive to be awarded the deferral project to serve that megawatt need, which is still a challenge. Currently DER are not considered for their other value-stacking benefits (e.g., voltage & reactive power control), but this is under development in the DDOR process. The number of DER awarded for deferral projects is expected to grow as installation costs decline in the future. This is discussed in greater detail in the next section, the “Case Study on How Capacity Deferrals Could Work”.

In addition, SCE does not have the capability to manage controllable DER at scale is in development in its Grid Management System DERMS, estimated for an initial release sometime in 2024. This will maximize SCE’s capability leverage the full potential of DER throughout the territory to enable a dynamic hosting capacity on feeders as adoption of behind the meter DER become more widespread. The next section will leverage forecasts in DER prices to estimate how many DER will be on SCE’s distribution network over the coming years.

## Case Study on How Capacity Deferrals Could Work

To see how the DSO would be able to defer a distribution upgrade, the EASE team performed a case study on how a circuit loaded past its planned loading limit could be operated with the DSO. Figure I-2 shows the 10-year outlook of peak demand conditions for each hourly interval on the Cobalt 12 kV circuit. The DSO's objective was to reduce the demand on the circuit using the high concentrations of DER from EASE's 10,000 DER simulation tests in an offline planning simulation. Cobalt 12kV contained 4.5 MW of PV and 6 MW / 17 MWh of BESS that were optimized to reduce network losses at the feeder by the DSO. Weather data for August 2021 was used to simulate the season when PV generation was at its peak. Through its AC loss-optimized power flow simulation the DSO substantially reduced the net load of the feeder to 5.9 MW despite there being 9.3 MW of gross customer demand. Note that the planned loading limit of a 12kV feeder is 12 MW (proportional to its voltage-level). As a result, this planning study showed that Cobalt's 10-year peak demand used 77% of the feeder capacity but was reduced to 50% of its circuit capacity using the DSO's optimal dispatch schedule.

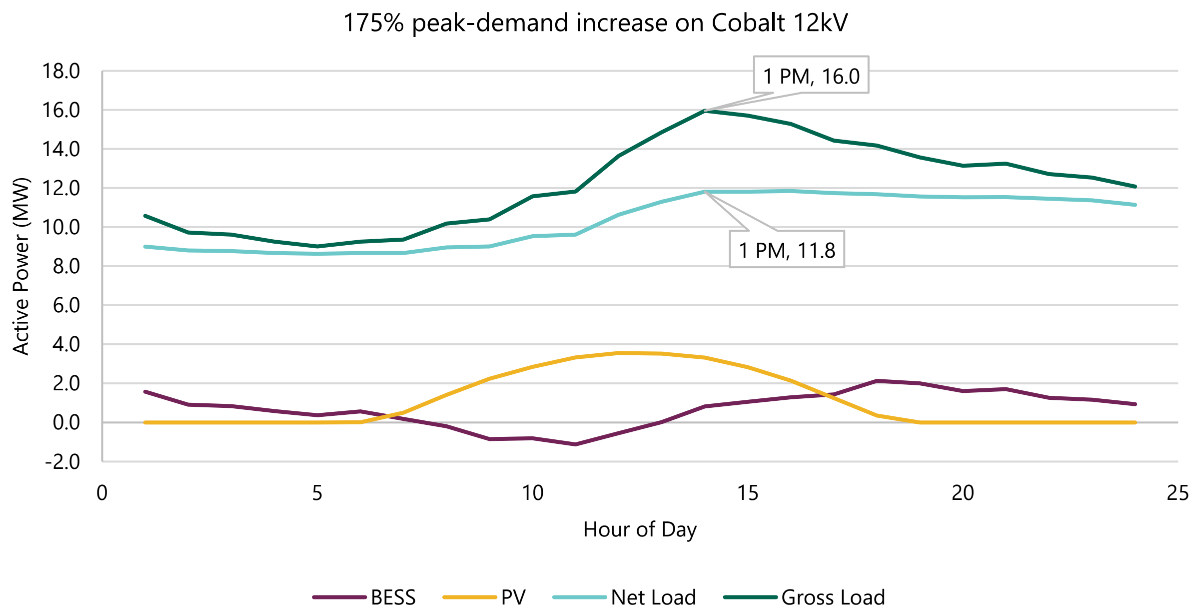
**Figure I-2 – Baseline Peak Demand conditions over 10-year outlook**




Source: Southern California Edison

**Deferral Upgrade Scenario:** To show how the DSO could be used to defer a distribution system upgrade, the previous scenario was repeated assuming that gross demand on Cobalt 12kV increased by 175% (or 6.7 MW). This increased peak demand to 16 MW exceeding Cobalt 12kV's planned loading limit by 133% (or 4 MW). The DSO once again performed an AC loss-optimized power flow simulation to dispatch DER to reduce network losses. The results are shown below in Figure I-3, where the DSO was successful in maintaining a net load below the 12 MW planned loading limit. Note that the ratio between demand, BESS, and PV play a critical role in determining how much capacity a circuit could defer depending on where the circuit reaches its period of peak-demand. This highlights that DER could be used in a more centralized manner to both the customer and utility's benefit to better serve more customer demand than traditionally possible with wires alone.

**Figure I-3 – Load growth Scenario, 175% (4 MW) increase Peak Demand Scenario**

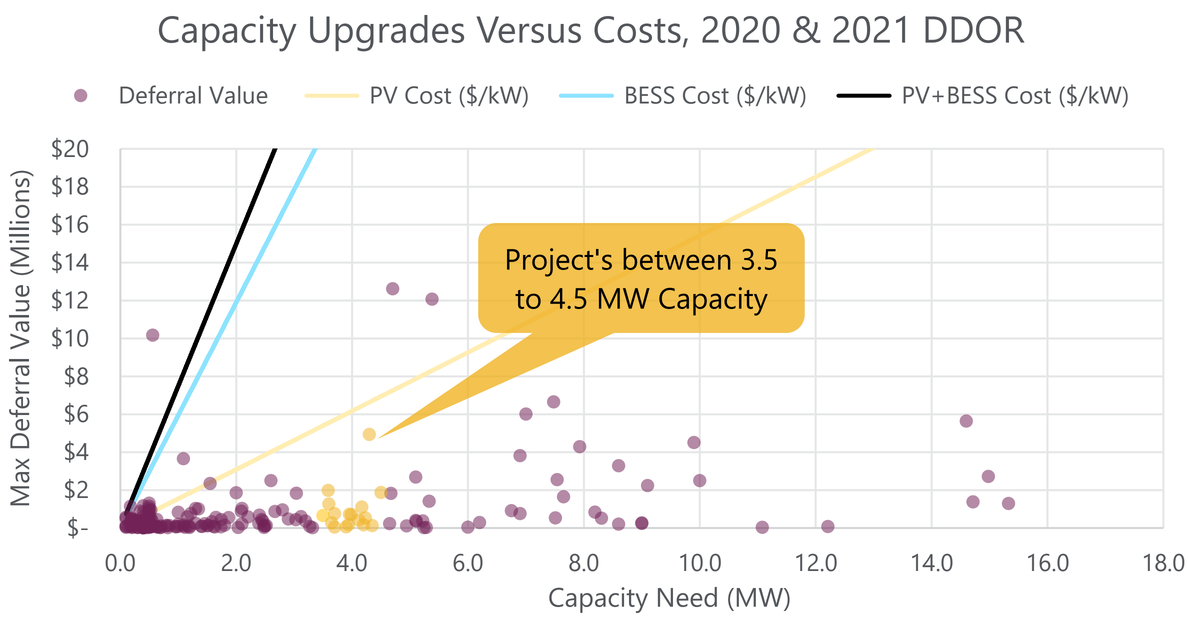



Source: Southern California Edison

**Calculating Deferred Capital Costs:** Calculating the deferral cost of a specified megawatt need can vary significantly per location and asset type upgrade. For example, projects of the same megawatt need could require underground or overhead power lines, be of various cable types and lengths, require additional upgrades to neighboring equipment already installed, and can also vary with the cost of raw materials; all of which have an impact on the final deferral value.

Because of this high variability between the project cost and capacity installed, a dollar range was highlighted for a similar megawatt need from the Cobalt 12kV 4 MW load growth scenario in Figure I-3. The range of capacity projects examined were between 3.5 MW and 4.5 MW to provide a range of costs within this capacity range. This is plotted in Figure I-4, where a project's (max deferral) value is plotted against the capacity size (in MW) of the project. Note that the current installation cost estimates for PV and BESS, and PV + BESS combined systems are also plotted to visualize the differences in cost between wires-only projects versus DER deferrals today. Wires-only projects above the PV + BESS cost trajectories are estimated to be more costly than a DER deferral project. In the future these DER costs per kW should decrease, initially allowing DER to be more cost competitive in low-capacity projects that are high in cost for a wires-only construction in Figure I-4. The amount of energy storage needed may cause this to vary between projects and is not reflected in Figure I-4. Based on the data in Figure I-4, project costs ranged from to $47K to $4.9 million, and averaged $923K for projects in this 3.5 MW to 4.5 MW install capacity range.

**Figure I-4: Max need during 2021 deferral period (MW)**




Source: Southern California Edison

For a single DER, or DER Aggregator, to be awarded to serve a megawatt need they must be cheaper construct than the maximum deferral value of a wires-only installation. Those DER also need to be committed to serve that megawatt need for a deferral period, which on average is 9 years for this sample size of circuits in Figure I-4. Note that Figure I-4 only shows the cost per kilowatt for energy storage, as opposed to kilowatt-hour (kWh), to normalize the cost of storage to capacity. Energy storage capacity (kWh) is assumed to be sized as a 2-hour battery. As a result, their locational net benefit is calculated in Equation I-1, where the DER would be paid to serve a megawatt need over a deferral period.

**Equation I-1: Locational Net Benefit Value in $/MW-year**

$$Locational\ Net\ Benefit\ [\frac{\$}{MW\text{-}years}] = \frac{Deferral\ Value[\$]}{MW\ Need\ [MW] * Deferral\ Period\ [yrs]}$$

This $/MW-year figure represents the maximum amount of money a DER would be compensated for serving 1 MW of power for one year in that area. This would allow DER, or DER Aggregators, to be compensated for their capacity contribution over the deferral period. Therefore, DER competing with wires-only solution could be challenging in the near-term given the current cost of installation for DER. Looking back at the Cobalt 12kV case study in Figure I-3, its 4 MW capacity need ranged from to $47K to $1.3 million, yielding a locational net benefit ranging from $1.2/kW to $123.2/kW over a 10-year deferral period. DER installation costs are expected to drop in the future and will likely increase their ability to compete with wires solutions as more controllable DER come online.

It is possible to calculate the financial feasibility of deferring 4 MW with DER from Figure I-3's case study using today's wires-only and DER cost per kilowatt. The average deferral value of a

4MW (+/- 0.5 MW to allow for a margin of error) capacity upgrade from 2020 to 2021 was $923K within SCE's territory, which yields $23.09 per kilowatt served each year for the locational net benefit. By comparison, in 2021 the average installation costs for a solar system in California was $4,050 to $4,610 per kilowatt for a 25 to 30-year system (normalized to $135 to $153/kW-year). The average cost of an energy storage system ranged from $4870 to $5,850 per kilowatt ($487 to $585/kw-year) for an 8 to 10-year rated system before capacity degradation becomes an issue (State of California, 2021). A sample calculation is shown in Equation I-2 for a PV system using the same locational net benefit equation:

**Equation I-2: Normalized LNBA for a PV system with 30-year lifespan**

$$\begin{aligned} Normalized\ LNBA &= Average\ PV\ Cost\ [\frac{\$}{kw}] * \frac{Max\ DDOR\ Planning\ horizon}{PV\ lifespan\ years * deferral\ period} \\ &= \frac{\$4{,}050 + \$4{,}610}{2} * \frac{10\ years}{30\ years * 10\ year\ deferral} \\ &= \frac{\$144.3}{kW - year} \end{aligned}$$

At those price-points DER would not be cost-effective to serve the 4 MW capacity need based on the wires-only locational net benefit for this project specifically. These DER installation costs are expected to go down in the future and will likely increase in cost-competitiveness as more controllable DER come online. Estimates for when capacity projects may be more cost competitive with DER are discussed in the Forecasted DER Concentrations section that follows.

This shows that by capital expenditure costs alone, installing DER may not be as cost effective as wires alternatives. If customers could also enroll their DER in a DSO market via their aggregator that would further incentivize customers to adopt DER since they're compensated for their DER's participation. This would effectively help to reduce the levelized cost of electricity for a particular location through participating in the energy market. In the EASE project's field demonstration, customers were estimated to earn a maximum of $346 for a 5kW system in 2021 by participating in the simulated DSO market for their <10 kW PV and BESS systems. Additionally, if customers were compensated for the $23.09/kW locational net benefit used for the case study in Figure I-3, the average 5-kW system would be compensated $116 per year to satisfy this need. In total, the customer could stand to make $462 in revenue from the capacity deferral and DSO participation annually. Over a 10-year period this could yield around $4,600 for a 5kW PV and BESS system. This does not factor in the energy customers will save in their energy bill over the 10-year timeframe.

This shows that even with today's DER prices per kilowatt, a DSO market could improve a customer's return on investment in DER. More work needs to be done from an economic and policy standpoint to better define how this type of system could work with DER. More work would also need to be done to better simulate this marketplace. The EASE project demonstrated that the price of energy could influence how DER are optimized to benefit the grid, but what was missing was how the DSO energy market could impact the levelized cost of energy capacity in SCE's GNA once this system is implemented in the future. Other value-stacking DER benefits (voltage & VAR control) could also be valued as a service to improve DER versatility. Currently levelized costs of energy for DER tend to exclusively include energy savings accrued over time without optimizing their usage. This could provide an additional value stream in the locational net benefit calculation for DER and make them more cost-competitive in capacity upgrade projects.

## SCE's Current DER Capacity

DER Aggregators will need a portfolio of generation and storage to compete with wires-only capacity projects. The projected decrease in the cost of photovoltaics and energy storage will close the gap between DER and wires only-solutions. This could further incentivize more people to participate in the DSO's market and increase DER adoption.

The number of DER installed in SCE territory today is 4.7 gigawatts of photovoltaics and energy storage, where PV make up 95% of the total generation (see Table I-2). For comparison, SCE's peak system load reached 23 gigawatts in 2020 (CAISO, 2019). Note that this analysis only focuses on PV and BESS since those are the initial DER types designed to work with the DSO. The low amount of energy storage limits the ability to store and export energy off-solar-peak generation hours to support the DER services that the DSO would provide. It also reduces are ability to secure a firmer DER generation portfolio that could account for generation intermittency.

**Table I-2: PV and BESS in SCE Territory**

| DER Type | Sum of MW |
|---|---|
| ENERGY STORAGE | 232 |
| PHOTOVOLTAIC | 4498 |
| Grand Total | 4730 |

Source: Southern California Edison

For a comparison as to how much DER a feeder would need to defer capacity, all DER use-cases for EASE were accomplished with a 3:4 ratio of solar and BESS capacity per customer, with each BESS having a 2-to-4-hour battery (30 MW PV, 40 MW / 80 MWh of storage). The drawback to a portfolio mix with a 3:4 ratio of PV to BESS is that batteries are less likely to receive a full charge during winter months or cloudy days. Having a higher ratio of PV to BESS increases the likelihood that BESS can be adequately charged during the winter or cloudy days, which contributes to a more-firm DER generation portfolio.

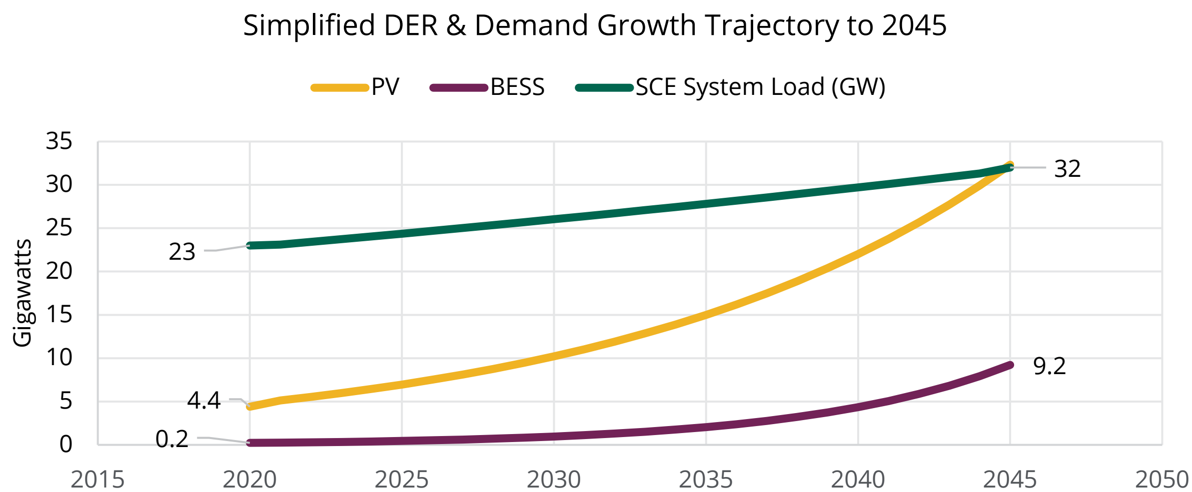
## Forecasted DER Concentrations

This analysis that follows is meant to provide rough estimates of potential savings from using existing capacity upgrades to primary feeders and substations of less than 16 MW. It does not set distribution deferral targets for SCE. The analysis uses data from the Grid Modernization Plan, the 2020 and 2021 GNA and DDOR, and SCE's Pathway 2045 targets for DER levels on the distribution systems. It also assumes that California's GHG reduction targets will be met by its proposed target dates.

As the economy becomes more dependent on electricity as its primary energy source, up to 50% of single-family homes in California are projected to have customer-sited solar, driven by improved economics, building codes and supportive but equitable policies. This will provide approximately 30 GW of generation capacity and 10 GW of customer-sited storage by 2045 (SCE, 2019). Grid modernization will need to keep pace to ensure interconnection and interoperability of DERs with the grid. Even with these generation and storage capacity forecasts, it is difficult to estimate where the highest concentrations, and ratio, of DER there will be on the grid. Note that this analysis is not meant to focus on when DER will be cost-competitive, since that will vary depending on the size and cost of a given capacity upgrade project and any additional incentives to increase adoption. Rather this analysis will focus on SCE's projections for DER concentrations in the future, and what that could mean in terms of capacity deferral opportunities for the utility.

To get a high-level estimate for future distribution deferral savings, the generation, storage, and demand ratios territory-wide can be generalized to come up with an estimate of the total capital deferral opportunity. A simplified analysis was performed assuming exponential/linear trend to reaching SCE's Pathway 2045 forecasts for DER and demand growth shown in Figure I-5. These estimates show an exponential trend from today's DER capacity today extending out to 2045, where an estimated 10 GW of storage and 30 GW of generation will be added to the distribution network. The grid will see its 23 GW peak system load increase by 40% to 32 GW by 2045 due to electrification of the economy (SCE, 2017).

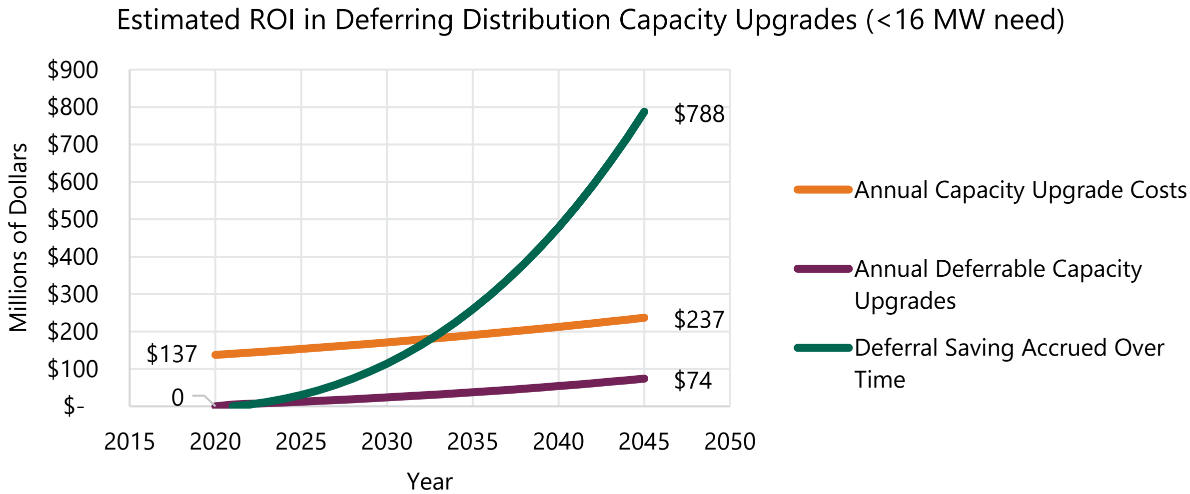
**Figure I-5: Simplified DER & Demand Growth Trajectories to 2045**




Source: Southern California Edison

Using the DER demand growth estimated trajectories in Figure I-5, it's estimated that by 2045, the DSO would have high enough PV and BESS concentrations to offset 31% of all new capacity deferral costs. This is shown in Figure I-6, where the annual deferral savings of $74 million is 31% of the total $237 million estimated for capacity upgrade costs up to 16 MW in size. This final estimate for 2045 was calculated by dividing the lowest concentration DER (10 GW of storage) by the peak system load (32 GW), where peak system load is assumed to be in the afternoon/evening where storage is the limiting resource to meet capacity needs on the distribution network. Also, this calculation assumes that the average hourly peak demand will continue to be in the afternoon/evening when storage is required to provide the necessary capacity, like what's shown in Figure I-3. Note that peak demand may occur at different times depending on the customer usage for a particular feeder, but this analysis was generalized to align peak loading with today's typical system peak loading.

**Figure I-6: Estimated Return on Investment (ROI) from Capacity Deferrals**




Source: Southern California Edison

Furthermore, Figure I-6, assumes that the cost of 16 MW, or less, capacity deferral projects remain consistent through 2045 but grows in value due to inflation. The annual deferral savings also grows year-over-year as the DER growth trajectories increase territory-wide from Figure I-5. This allows us to calculate the deferral savings accrued over time, which estimates that SCE could recover over $400 million of its investments in its Grid Modernization plan around the year 2040 through distribution deferrals. An additional $300 million in savings could be accumulated between 2040 and 2045 in Figure I-6, when SCE reaches carbon neutrality. This assumes SCE could continue to defer projects using the necessary combination of controllable DER with a DSO. Overall, these savings would help to drive the cost of electricity down, which will benefit customers since their overall electricity bills will increase due to the electrification of vehicles and appliances. The exact quantity in savings is unknown at this point and would have to be further studied.

**Figure I-7: GHG Reduction Targets**


Source: Southern California Edison

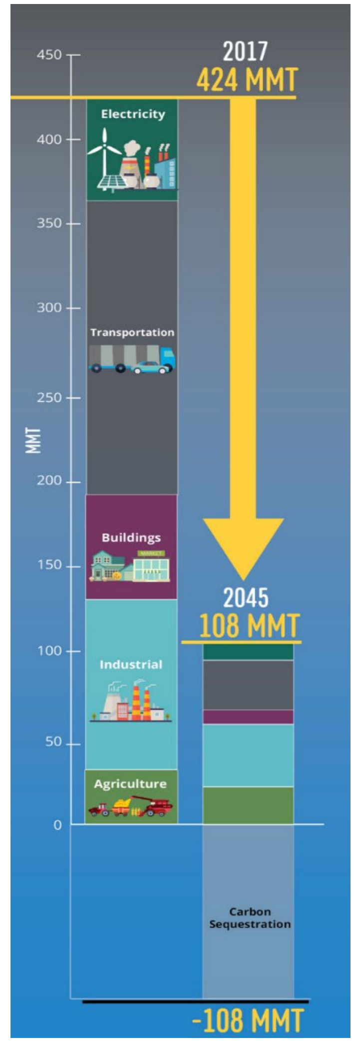
## Reduction in Greenhouse Gas Emissions

Combined with SCE's investments in renewables on the bulk-system, by 2045, SCE expects to see a 339 MMT reduction in greenhouse gases as shown in Figure I-8. This assumes that the targets for interconnecting clean sources of energy and shifting to electricity as the primary energy source for transportation, buildings, industrial plants, and agriculture is met. Another 108 million metric tons will need to be sequestered for SCE to meet its goal of carbon neutrality by 2045.

The clean energy and grid investments required to meet 2045 goals is a tremendous economic development opportunity for California. As California decarbonizes, energy must remain affordable for all the state's consumers, including the most vulnerable residents.

Robust, coordinated, and targeted policies are needed to clean the power supply; build, operate and maintain a reliable and resilient grid; and move customers to adopt new technologies and programs. Advancing and scaling up adoption of new technologies will require incentives, regulations, and other market transformation policies. Most importantly, through this transition, all California residents will benefit from greatly reduced greenhouse gas emissions and new economic opportunities.

**Figure I-8: Greenhouse gas emission reductions to meet California targets (in million metric tons)**




Source: Southern California Edison