DER Siting and Optimization tool to enable large scale deployment of DER in California

Project Report

Prepared by Lawrence Berkeley National Laboratory, SLAC National Accelerator Laboratory, Lawrence Livermore National Laboratory, Argonne National Laboratory, National Renewable Energy Laboratory, and Brookhaven National Laboratory for the United States Department of Energy, under the Grid Modernization Initiative.

Disclaimer

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Executive Summary

This report outlines the results of the project "DER Siting and Optimization tool to enable large scale deployment of DER in California" undertaken through collaboration between the Lawrence Berkeley National Laboratory, the Lawrence Livermore National Laboratory, the SLAC National Accelerator Laboratory, the Argonne National Laboratory, the Brookhaven National Laboratory and the National Renewable Energy Laboratory.

This project aims to address an emerging need for analysis and tools to understand the impact of DER adoption trends, driven by policies and incentives, on transmission and distribution system operations, and thus contribute key quantitative data to grid planning efforts. This document describes the architecture of the prototype software framework developed within the scope of the project, integration of underlying component models leveraged to power the new prototype, as well as demonstrations of the tools value when applied to three relevant uses cases.

The necessary functionality of the prototype has been identified at multiple levels: transmission, distribution, and behind-the-meter:

1. ability to run power flow analysis while considering the economics of grid planning and operations
2. behind-the-meter DER deployment considering economic optimization of end-use customer objectives
3. integration of transmission and distribution power flow models to assess impacts of DER deployment and operations on the bulk electric system
4. integration of geospatial data through the development mapping and visualization functionality

To achieve these capabilities, the tool leverages and integrates existing state-of-art tools for both behind-the-meter DER cost-optimization (DER-CAM) and distribution power flow analysis (GridLab-D, GridDyn), while also integrating new automation, mapping, and visualization capabilities (GIS).

The project also defined three use cases for to which the prototype software could be applied. The use cases are:

- Estimation of aggregated DER deployment across large geographic areas
- Estimation of optimal DER placement and DER impact on voltage stability at the distribution and transmission level
- Estimate of optimal hourly DER operational strategies by end-use customers

Examples results from each use case using the IEEE 123 standard test feeder to emulate distribution feeders in each of California's IOUs: PG&E, SCE, and SDG&E have been explored in subsequent sections.

Introduction

Background

The Grid Modernization Laboratory Consortium (GMLC)[1] was established as a strategic partnership between the U.S. Department of Energy and the national laboratories to bring together leading experts, technologies, and resources to collaborate on the goal of modernizing the national electric grid. One of the main components of this initiative is the Grid Modernization Lab Call, which is a comprehensive portfolio of research projects managed by the national laboratories.

This project, "DER Siting and Optimization tool to enable large scale deployment of DER in California", is part of the Pioneer Regional Partnerships established within the scope of GMLC and consists of a joint collaboration between the Lawrence Berkeley National Laboratory, the Lawrence Livermore National Laboratory, the SLAC National Accelerator Laboratory, the Argonne National Laboratory, the Brookhaven National Laboratory and the National Renewable Energy Laboratory. It aims to address needs identified in California to meet state goals of integrating distributed energy resources in grid planning efforts.

Brief Description

Different states throughout the country are developing aggressive DER penetration targets. California is in the forefront of those efforts with statewide goals to integrate 14 GW of distributed energy resources, including 12 GW of renewable energy, into distribution systems[2]. These ambitious goals require overcoming challenges created by the lack of comprehensive tools to understand most cost-effective locations DER and impact on overall-system reliability.

The goal of the project is to address this gap and increase the scope and visibility of grid planning efforts by developing a prototype software framework that couples behind-the-meter DER adoption models with T&D power flow co-simulation models, supported by geospatial

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[1] https://www.energy.gov/under-secretary-science-and-energy/grid-modernization-lab-consortium

[2] Russell, Jeffrey and Weissman, Steven, "California's Transition to Local Renewable Energy: 12,000 Megawatts by 2020" (2012). Center for Law, Energy & the Environment Publications. 34. http://scholarship.law.berkeley.edu/cleepubs/34; CPUC Energy Storage Proceeding (R.15-03-011); AB 2868 (2016)

visualization capabilities. This document describes the architecture of the prototype software framework developed within the scope of the project, as well as the uses cases that support and demonstrate its use.

Narrative

Current practices in grid planning typically rely on a series of methods where behind-the-meter DER, distribution, and transmission studies are conducted separately. Behind-the-meter adoption of distributed energy resources (DER) is commonly handled with forecasting methods based on historic data, and distribution and transmission planning typically rely on the use of specific power flow tools that evaluate different solutions for given operating conditions.

This practice limits the ability to perform holistic analyses that capture system-wide effects, which are particularly relevant in the context of high levels of behind-the-meter DER penetration and the associated reverse power flows and load ramping effects. Widespread rooftop PV, for instance, is currently leading to an important phenomenon commonly referred to as the “duck curve”, reflecting the dramatic changes in net loads during afternoon hours of PV production (Figure 1).

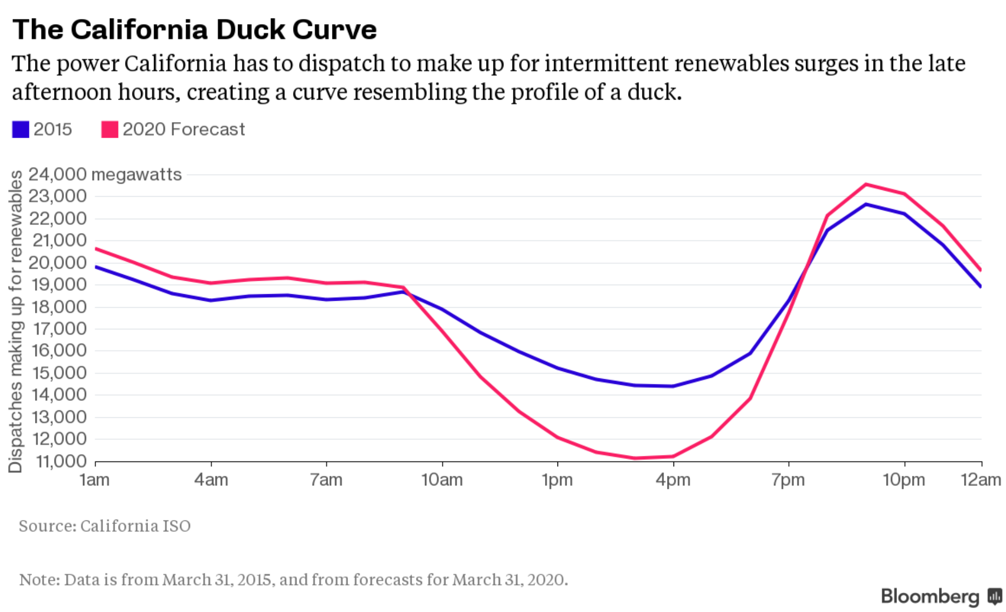

Figure 1 - California's "Duck Curve"

Thus, planning and operating the grid of the future requires understanding the drivers to private deployment and operation of behind-the-meter DER, predicting the most likely locations in the grid where these investments will be made, and estimating the corresponding grid impacts, both in the distribution and transmission infrastructure. It is the outcome of this holistic analysis that supports identifying locations with the highest need for intervention and upgrades.

To address this gap, the work conducted throughout this project led to the development of a prototype software framework that: a) integrates an optimization-based approach to estimate behind-the-meter DER investment and dispatch decisions with a Transmission & Distribution co-simulation model; b) contributes to the analytical framework developed for California's Distribution Resources Plans by providing mechanisms that go beyond current practices to enable additional flexibility to analyze DER deployment and operation scenarios.

The framework proposed in this project leverages existing capabilities currently available at the National Labs. Specifically, an upgraded and customized version of Lawrence Berkeley National Laboratory's behind-the-meter DER optimization engine DER-CAM[3] is used to find the most cost-effective behind-the-meter distributed generation and storage solutions and estimate private DER adoption patterns throughout distribution networks. These DER adoption results and corresponding dispatch decisions are reflected in distribution networks and integrated with Lawrence Livermore National Laboratory's Transmission and Distribution co-simulation platform, ParGrid[4], that couples GridLAB-D[5] distribution level network models with GriDyn[6] transmission level network models and allows estimating DER impacts throughout the bulk electric grid. DER adoption results, as well DER dispatch and system level impacts are visualized through a new mapping and visualization platform developed by SLAC National Accelerator Laboratory.

[3] https://building-microgrid.lbl.gov/projects/der-cam
[4] https://www.osti.gov/scitech/biblio/1238678-parallel-power-grid-simulation-toolkit
[5] http://www.gridlabd.org/
[6] https://github.com/LLNL/GridDyn

The software developed in this project can be used to support multiple use cases, including the estimation of aggregate DER deployment across large geographic areas, the estimation of hourly DER profiles based on the co-optimization of stacked revenue streams associated with behind-the-meter distributed energy resources, and the estimation of grid impacts of DER deployment both at the distribution and transmission level. These use cases can be analyzed for multiple DER portfolio options and under multiple policy scenarios and programs, such as economic incentives or net metering mechanisms.

In the remainder of this document we describe the architecture and different components of the prototype software framework and demonstrate its use under different use-cases and scenarios. Further, we discuss how the outcomes of this project can be leveraged to benefit California's Distributed Resources Plans, as well as its application across different territories.

Prototype software framework

Overview

The software framework developed throughout this project leverages existing technologies available at the National Labs participating in the effort. These include both DER-CAM, a behind-the-meter DER investment and optimization tool developed by LBNL, and ParGrid, a co-simulation platform for transmission & distribution networks developed by LLNL. The integration of these core components required new algorithms to enable interoperability between the tools, as well as new mapping and visualization capabilities developed by SLAC.

An overview of the software architecture is presented in Figure 2. As illustrated, the overall workflow consists of parsing network data to extract topology and load information, which is then subject to a load disaggregation process leveraging residential and commercial end-use load databases. The resulting data is used to create a range of representative behind-the-meter investment cases, which are optimized based on existing tariffs, policy incentives, and DER options. The DER deployments suggested by this analysis are then aggregated back at the distribution level, and the resulting grid impacts are estimated by means of power flow analysis. Both DER deployments and grid impacts can be analyzed using the mapping and visualization platform. Additional details on each of the software components are presented in the following section.

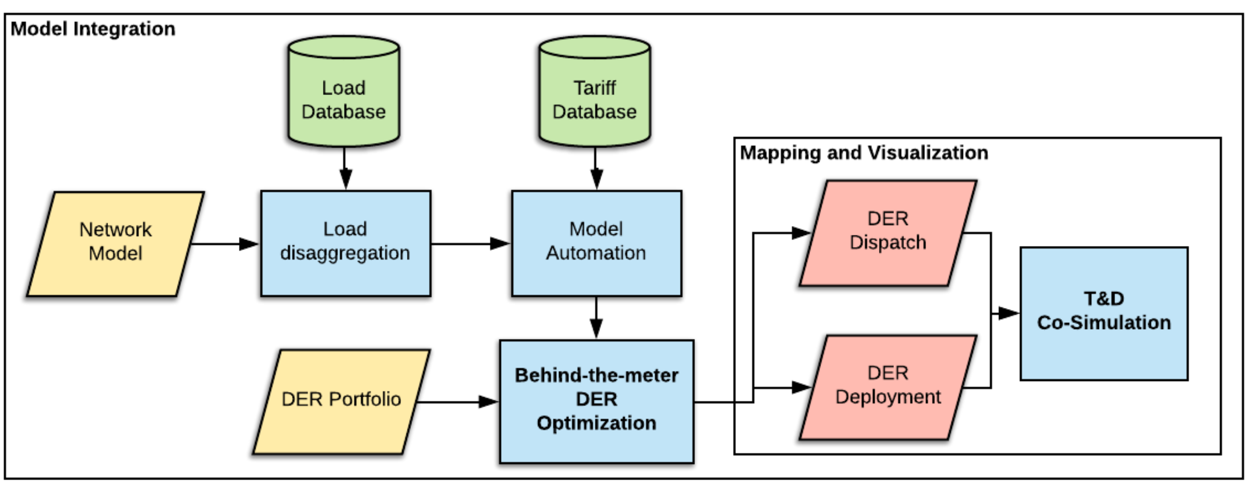

Figure 2 - Software architecture overview

DER-CAM

The Distributed Energy Resources - Customer Adoption Model[7] (DER-CAM) is a state-of-the-art decision support tool developed at LBNL with funding from the U.S. Department of Energy. It is used extensively both by academia and the industry to address the problem of optimally investing and scheduling DER and microgrids under multiple settings.

The optimization model is formulated as a mixed integer linear program (MILP), and key inputs in DER-CAM include electric, heating, and cooling end-use customer loads, utility tariffs including electric and natural gas prices, techno-economic data of distributed generation technologies (including capital costs, operation and maintenance costs, electric efficiency, heat-to-power ratio, sprint capacity, maximum operating hours, among others) and circuit topology to model multi-bus systems.

Key outputs of DER-CAM include the optimal DER investment portfolio, the optimal sizing of each DER, the optimal placement of DER within the microgrid topology, and the optimal dispatch of all DER present in the solution, including any load management decisions such as load shifting, peak shaving, or load prioritized curtailments in the event of outages. In addition, DER-CAM outputs include extensive information on site-wide costs, energy consumption, and greenhouse gas emissions. Thus, the core application of the model is to find the optimal combination of technology portfolio, sizing, placement, and operation to supply all energy services required by the site under consideration, while optimizing the electric and heat energy flows to minimize costs and / or CO_2 emissions.

The targeted user-groups of DER-CAM include microgrid owners and site operators, industry stakeholders including equipment manufacturers, and policy makers. Key applications for microgrid owners and site operators include optimized investment recommendations based on site-specific loads, tariffs, and objectives. Applications for industry stakeholders include identifying cost and performance characteristics that will lead to adoption of their technologies in diverse segments of the market. For policy makers, key DER-CAM applications include

[7] https://building-microgrids.lbl.gov

determining high-level impacts on distributed energy resource penetration levels, and anticipating customer adoption behaviors given changes in electricity rates, demand-response programs, and different regulations.

DER-CAM supports a wide array of tariff designs found throughout the U.S. with time of use (TOU) rates, demand rates, and real-time pricing (RTP). Additionally, other specific programs can be analyzed, including feed-in tariffs, direct load control, and export.

In this project, DER-CAM was leveraged as the optimization backend that finds the most cost-effective behind-the-meter DER investment and dispatch decisions. This was done across the range of private customers connected to each transformer in distribution networks located in each of California's IOU service territories. In other words, DER-CAM was used to emulate the utility functions of private customers and estimate their decisions in reaction to external economic incentives.

GridLab-D

GridLab-D is an open source, free power distribution system simulation and analysis software developed by the U.S. Department of Energy (DOE) at Pacific Northwest National Laboratory (PNNL). GridLab-D integrates the distribution system physical model, commercial and residential building load models, market business models, and user behavior models that can simulate most of distribution system operations from seconds to decades. GridLab-D uses an agent-base modeling framework that is very flexible and can be easily connected to other third-party systems. GridLab-D uses three types of power flow algorithms: Forward Backward Sweep (FBS), Gauss Seidel (GS) and Newton Raphson (NR).

The GridLab-D system includes modules to perform the following system simulation functions:

- Power flow and controls, including distributed generation and storage
- End-use appliance technologies, equipment, and controls
- Consumer behavior including daily, weekly, and seasonal demand profiles, price response, and contract choice

- Energy operations, such as distribution automation, load-shedding programs, and emergency operations
- Business operations, such as retail rate, billing, and market-based incentive programs

In this project, GridLab-D was used to simulate power flows at the distribution system level, based on loads estimated using DER-CAM and as part of the T&D co-simulation process. Results obtained from GridLab-D include voltage magnitude, as well as active and reactive power.

GridDyn

GridDyn is a power system simulator developed at Lawrence Livermore National Laboratory. The name is a concatenation of Grid Dynamics, and as such usually pronounced as "Grid Dine". It was created to meet a research need for exploring coupling between transmission, distribution, and communications system simulations.

While good open source tools existed on the distribution side, the open source tools on the transmission side were limited in usability either in the language or platform or simulation capability, and commercial tools while quite capable simply did not allow the access to the internals required to conduct the research. Thus, the decision was made to design a platform that met the needs of the research project.

Building off prior efforts in grid simulation, GridDyn was designed to meet the current and future research needs of the various grid related research and computational efforts. It is written in C++ making use of recent improvements in the C++ standards. It is intended to be cross platform with regard to operating system and machine scale. The design goals were for the software to be easy to couple with other simulation and be easy to modify and extend. It is very much still in development and as such, the interfaces and code are likely to change, in some cases significantly as more experience and testing is done. It is our expectation that the performance, reliability, capabilities, and flexibility will continue to improve as projects making use of the code continue and new ones develop.

In this project, we leverage GridDyn to enable the coupling between Transmission and Distribution power flow simulations.

ParGrid

ParGrid is a software 'wrapper' developed at Lawrence Livermore National Laboratory. ParGrid integrates a coupled Power Grid Simulation toolkit consisting of a library to manage the synchronization and communication of independent simulations. The included library code in ParGid, named FSKIT, is intended to support the coupling of multiple continuous and discrete event parallel simulations. The code is designed using modern object-oriented C++ methods utilizing C++11 and current Boost libraries to ensure compatibility with multiple operating systems and environments.

Model Integration and Automation

Model integration and automation aims at integrating the DER adoption model, based on multiple DER-CAM runs, with power flow analysis tools, such as GridLAB-D. Thus, the integration platform needs to read GridLAB-D files, extract and disaggregate net loads into representative buildings, run DER-CAM cases for each building, aggregate the results and parse them back to the network model format to allow power flow analysis. This integration platform includes different parsers, data analytics and interoperability modules that allow DER-CAM to be used as an adoption model for steady state analysis of the distribution grid. From the implementation perspective, this platform requires a software architecture that integrates three different frameworks: GridLAB-D, describing input and output structures, GAMS, where DER-CAM source code is implemented, and Python, to implement data analytics algorithms and interoperability modules. Figure 3 presents the architecture of the model integration and automation.

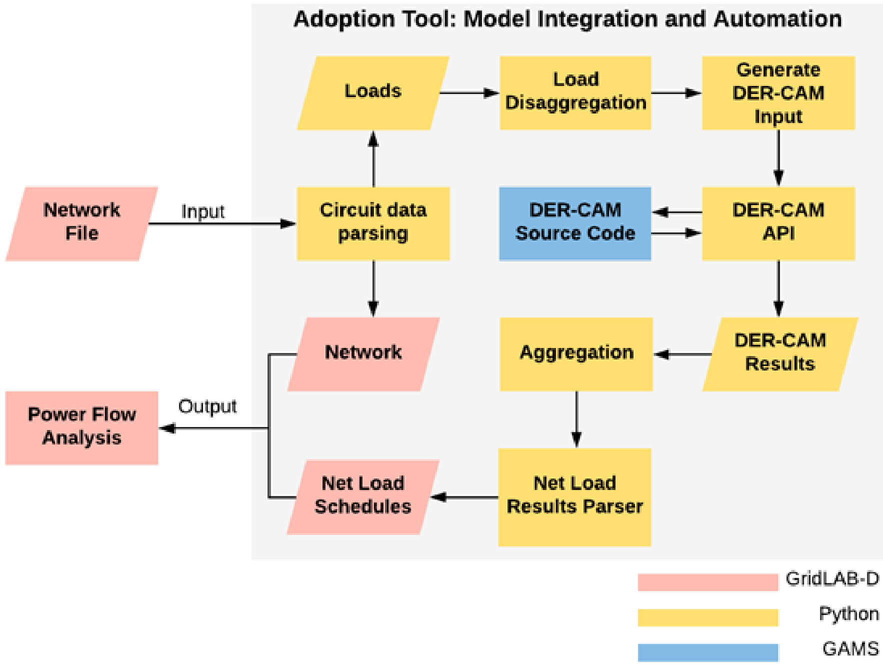

Figure 3 - Overview of Model Integration and Automation

Circuit data parsing: The first step in integrating DER-CAM with GridLab-D and enabling an integrated analysis consists of parsing distribution system data. This includes capturing the attributes of different network elements, such as load data from distribution transformers, or the length, impedance, and thermal limit from each line segment. In this project, we use the IEEE 123 standard test feeder to emulate distribution feeders across each of California's IOUs.

Load disaggregation: Given the scarcity of data typically found in distribution network models, an important step in enabling an integrated system analysis consists of creating disaggregated load profiles, particularly in cases where only representative data is available. We developed this capability starting both from "snapshot" data and time-series data, for a given set of user-defined assumptions (e.g. system peak timestamp, load classes, and customer distribution). Further, we implemented and tested several algorithms for disaggregation and optimized the process. This is illustrated in Figure 4, where the results obtained for different algorithms is presented (includes quadratic and mixed integer quadratic programming, with different supporting heuristics)

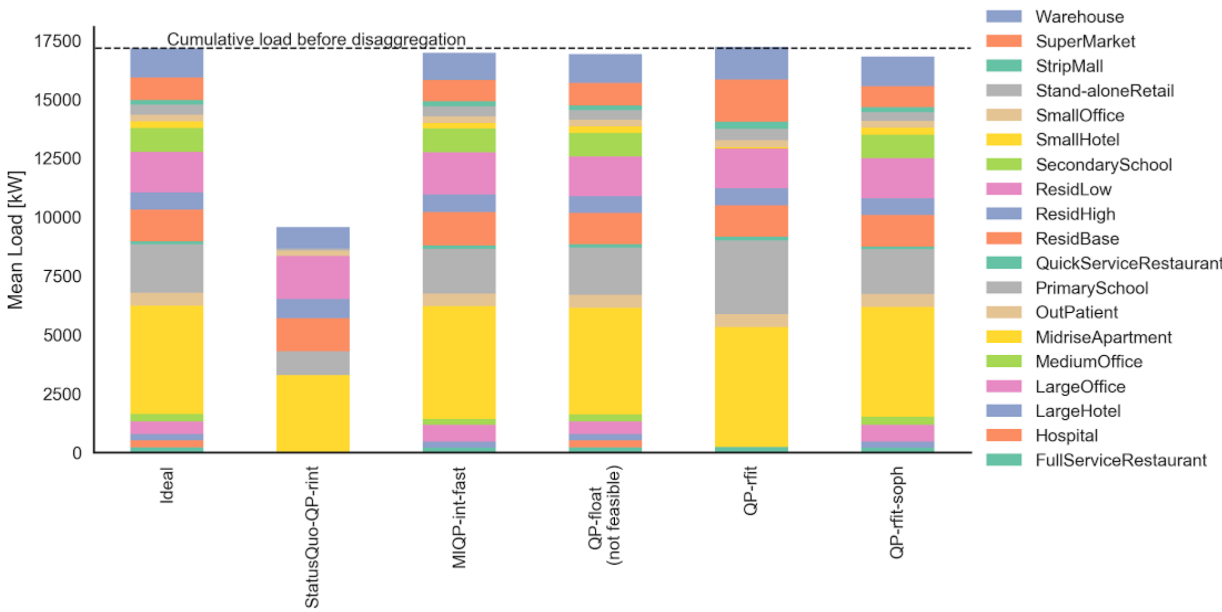

Figure 4 - Results of disaggregation for PG&E load data under different algorithms

Generate DER-CAM input: The next step in the integrated analysis consists of generating the input parameters required to create and execute a DER-CAM model based on the disaggregation results. This was achieved by developing API endpoints that enable streamlining the use of information from the different DER-CAM databases (e.g. building load and weather data) and by developing a Python web-client for the DER-CAM server, both of which were integrated in the software prototype.

Parsing and aggregation of DER-CAM results: Following the process of creating DER-CAM jobs and sending requests to the server, a new step of data parsing is required. A single DER-CAM model typically consists of several hundred thousand to a few million equations and variables, naturally leading to a very lengthy set of results. To limit the set of results to those relevant for the integrated analysis, we developed a parser that allows extracting and aggregating all meaningful DER-CAM results back to the node level.

Model automation: Performing a comprehensive analysis around the impact of DER on distribution networks and understanding how it may be influenced by different tariff levels, requires building and executing a very large number of models, both behind-the-meter and at the distribution system level. Different optimizations and simulations must be carried out for each modification made to each tariff of interest. To achieve this, we developed the API that enables executing an arbitrary number of DER-CAM runs and automate the respective power flow calculations.

Mapping and Visualization

The mapping and visualization tool is developed using the Django framework. Django is a high-level Python Web framework that is widely used within industry. The goal of the mapping and visualization tool is to parse, clean and visualize data from the co-simulation components (GridDyn, Gridlab-D and DERCAM), and the GIS information. All the source code and documentation are made available at https://github.com/eckara/GMLC. The developed tool can be host as a web-page, or it could be run locally using Python.

The landing page includes brief description of the project, and the DER penetration scenarios included in the co-simulation analysis as shown in Figure 5. The visualization tool provides two different views for the distribution system, and a single view for the transmission system results. The distribution system results encapsulate DERCAM and Gridlab-D results, and the transmission system results show the GridDyn results. These views can be accessed through the navigation bar.

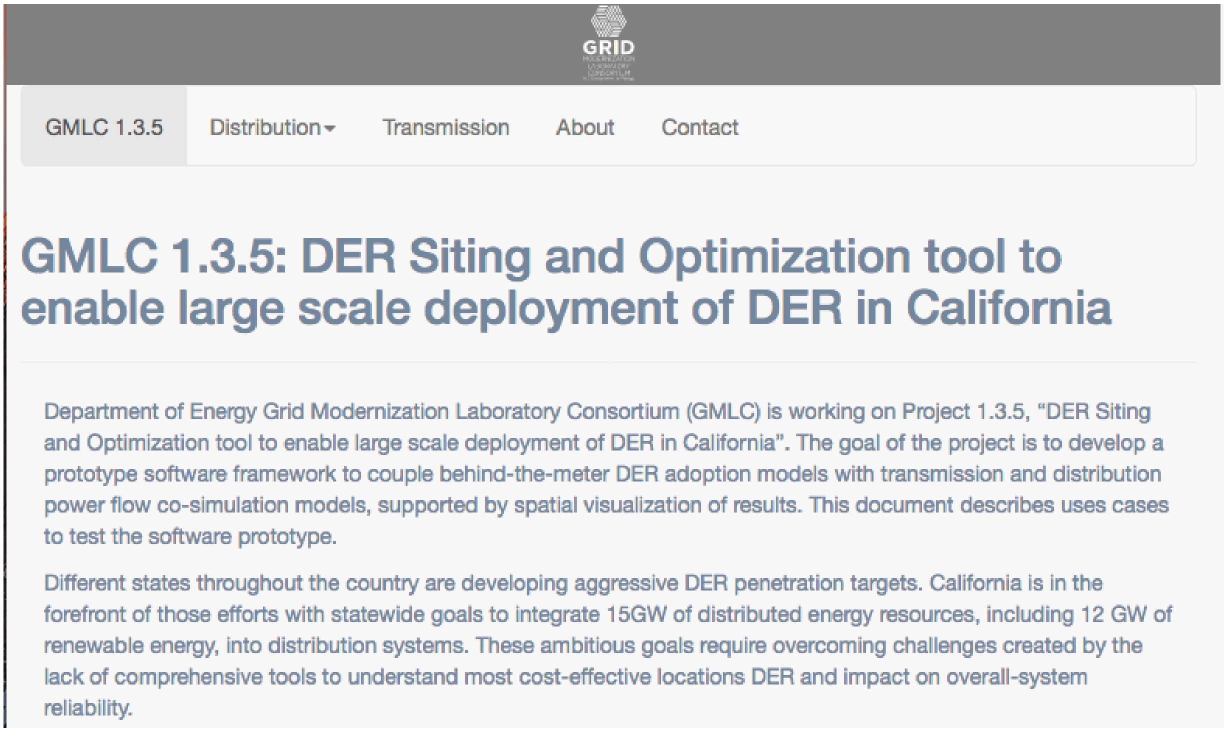

Figure 5 - Landing page of the mapping and visualization tool

The distribution system utility view shown in Figure 6 automatically grabs available scenario results in different territories and populates a drop-down menu for the user the select from. This view defaults to the previous query by the user, or to PG&E base scenario as default.

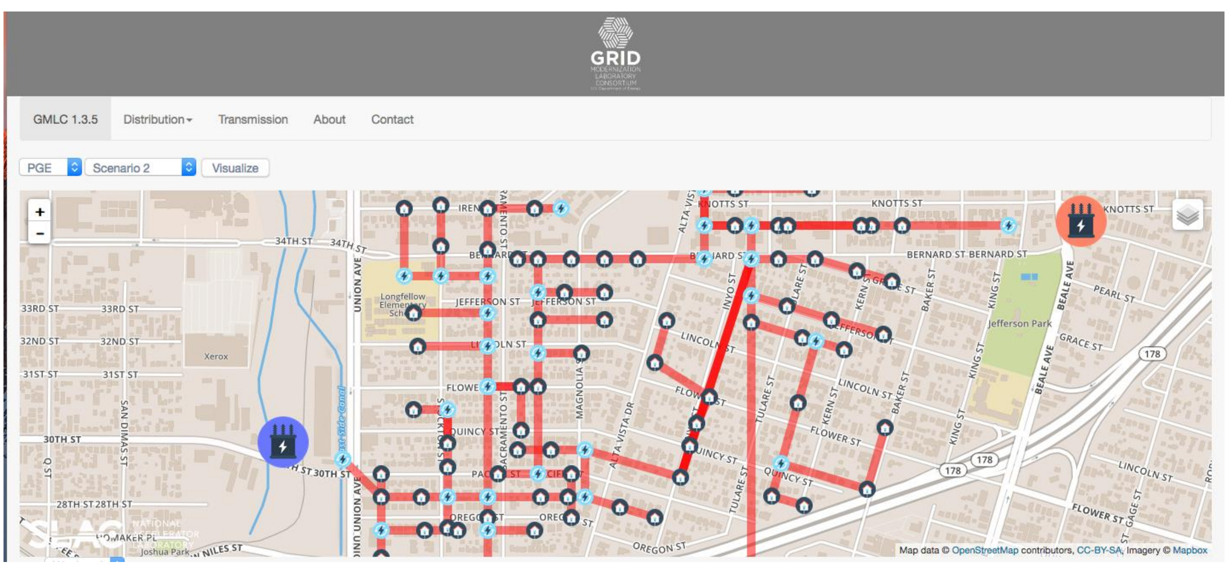

Figure 6 - Distribution system utility view

The utility view includes a map of the system including the lines, substations, nodes and homes. The home, node and line elements on the map are interactive, and can be clicked to update the results presented in the graphs below the map. This interaction is obtained via dc.js, a high-level interactive data visualization library.

The graphs include a pie chart capturing the overall generation per end use type, an area chart showing the average monthly purchase as well as generation time series, a pie-chart which shows the overall monthly utility purchase portions per month, voltage magnitude on nodes, active power flows and reactive power flows on all three phases. If the user is interested in results from a certain node or a line element only, it is possible to click those elements on the map, and update the results displayed on the graphs. It is also possible to filter through weekend and weekday load profile results, and different months using the monthly utility purchase pie chart. In Figure 7, we demonstrate this capability on node 40 for the month of August on PG&E territory, and assuming possible investment in behind-the-meter PV.

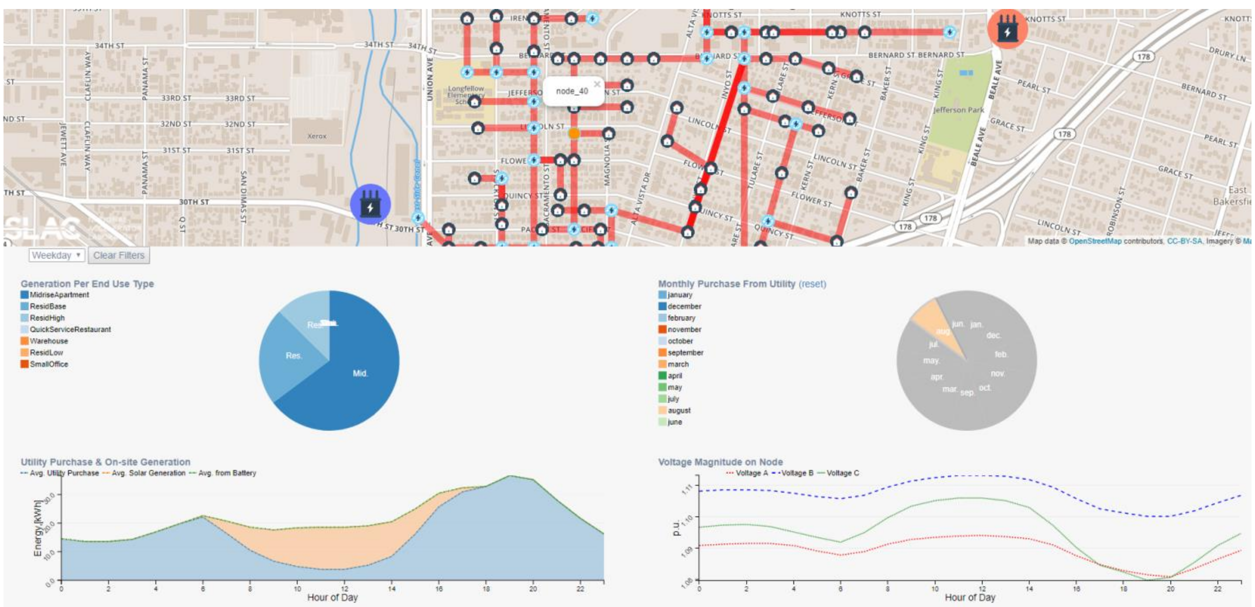

Figure 7 - Distribution system utility view, filtered results

Note that it is possible to see the hourly solar generation within a typical weekday during the month of August, furthermore, we observe the imbalance at the node voltages, in particular an increase on Voltage B hinting that an unbalanced amount of solar generation panel could be connected to Phase B. Finally, the generation per end use type pie-chart shows that all the PV installations are on residential locations for this node.

Another key view for the mapping and visualization tool is the comparison view. The comparison view makes it possible to compare two scenarios side by side and is very similar to the utility view in terms of filtering function. A snapshot of the comparison view is given in Figure 8 for reference, where the results are shown for the same node both in the reference (do-nothing) and PV deployment scenario.

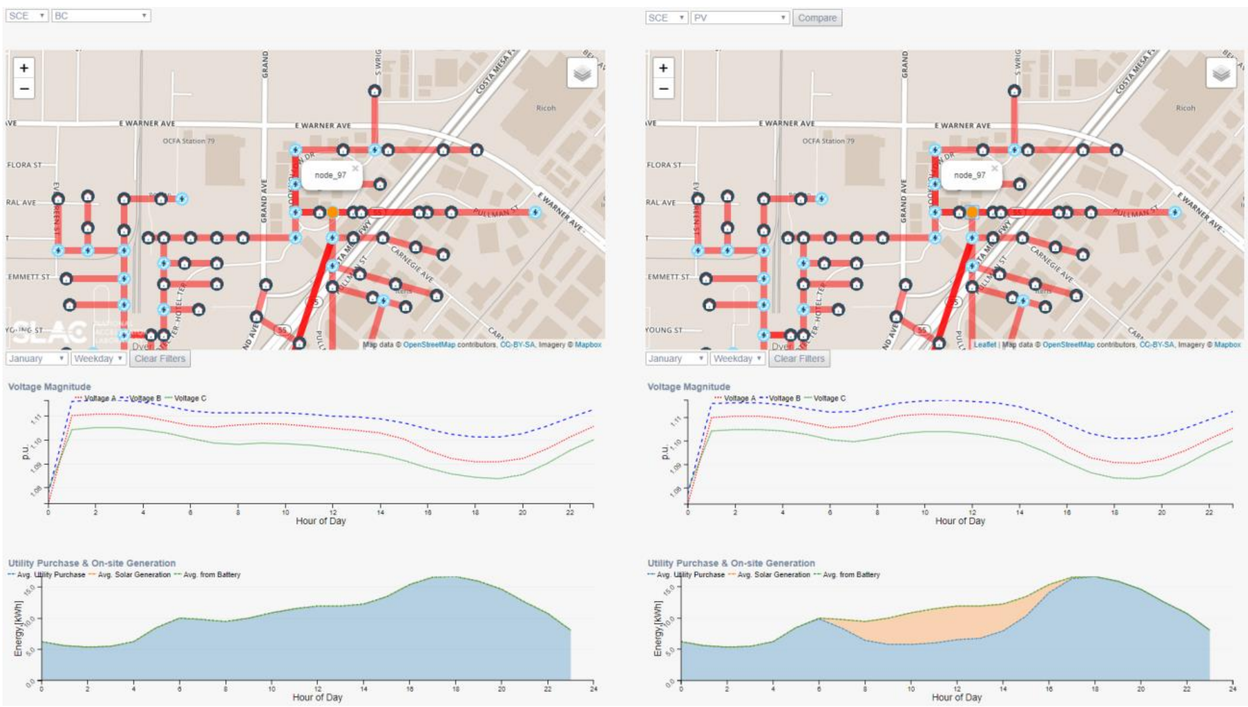

Figure 8 - Distribution system comparison view

The transmission view includes the buses captured in the diagram given in Figure 9. These are included in the transmission simulation for different scenarios, with loads from SCE, PGE and SDGE to see impacts on the transmission network.

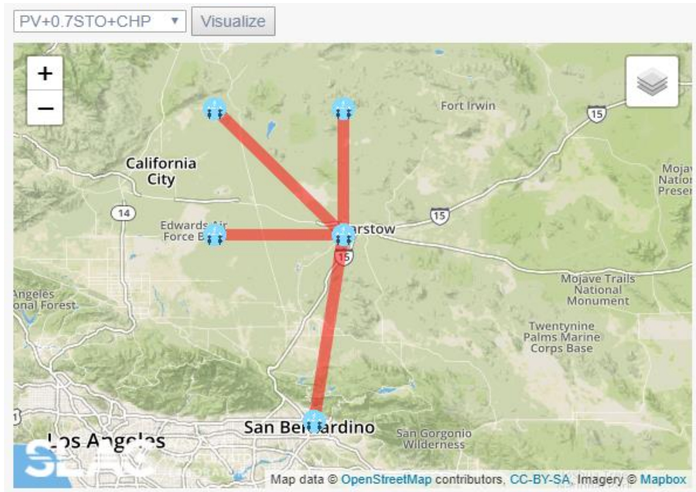

Figure 9 - GIS Transmission view

The transmission results obtained from GridDyn includes voltage magnitude and angle, active and reactive power on buses, as well as, active and reactive power from and to at each line. These results are displayed on the transmission view, and similar interaction exists for each node and line on the map.

Distributed Resources Plans

One of the key contributions delivered by this project consists of extending or complementing the analytical framework developed under the context of California's Distributed Resources Plans (DRP).

In this section, we summarize the current DRP legislation and analytical framework, and detail the different areas where the outcomes of this project may be beneficial.

Legislation and Overview

On October 7, 2013, California Assembly Bill 327 (AB 327) was signed into law by Governor Jerry Brown. As part of this Bill, Section 769 laid the groundwork for future planning focused on the integration of distributed energy resources (DER) into California's distribution electric system. Scheduled to take effect January 1, 2014, this section of the public utilities code required the three IOUs to file separate distribution resources plan (DRP) proposals by July 1, 2015. The DRP was designed to serve as a foundation for integrating DERs into shorter and longer-term planning and operations. The code described the structure and requirements for the reports to be written by each of the IOUs and served to identify optimal locations for DER deployment as well as present the path forward to thinking about DER integration into the existing distribution system. The text box below provides an excerpt containing this portion of the legislation.

As stated in the code, "distributed energy resources," also commonly known as DER, refer to distributed renewable generation resources, energy efficiency (EE), energy storage, electric vehicles (EV) and demand response (DR) technologies, most of which are located on the customer-side of the meter, e.g., "behind the meter." One of the challenges in establishing consistent DER integration techniques is that each technology has different technical, installation, and operating characteristics that need to be considered.

To help meet the goals stipulated in Section 769, the California Public Utilities Commission (CPUC) initiated a rulemaking, R.14-08-013 in August 2014 with the goal of establishing policies, procedures, and rules for the development of the DRPs. Appropriately named, R. 14-08-013 is titled Order Instituting Rulemaking Regarding Policies, Procedures and Rules for Development of Distribution Resources Plans Pursuant to Public Utilities Code Section 769, the Assigned Commissioner's Ruling on Guidance for Public Utilities Code Section 769 – Distribution Resource Planning.

This Order provided a schedule for stakeholder engagement with the IOUs, including a workshop and conference as well as consideration of a think piece written by California Institute of Technology's Resnick Sustainability Institute titled "More than Smart: A Framework to Make the Distribution Grid More Open, Efficient, and Resilient." This paper was designed to provide "strategic frameworks and guiding principles" for stakeholders and policymakers in the development of the DRPs. The paper presented four principles for consideration:

Distribution planning should start with a comprehensive, scenario driven, multi stakeholder planning process that standardizes data and methodologies to address locational benefits and costs of distributed resources.

California's distribution system planning, design and investments should move towards an open, flexible, and node-friendly network system (rather than a centralized, linear, closed one) that enables seamless DER integration.

California's electric distribution service operators (DSO) should have an expanded role in utility distribution operations (with CAISO) and should act as a technology-neutral marketplace coordinator and situational awareness and operational information exchange facilitator while avoiding any operational conflicts of interest.

Flexible DER can provide value today to optimize markets, grid operations and investments. California should expedite DER participation in wholesale markets and resource adequacy, unbundle distribution grid operations services, create a transparent process to monetize DER services and reduce unnecessary barriers for DER integration.

These four principles represent what the CPUC refers to as the More Than Smart initiative that are included in the CPUC's Formal Guidance to the IOUs (CPUC Final Guidance Assigned

Commissioner Ruling on Distribution Resource Plans, Filed February 6, 2015 under OIR 14-08-013). For each regulated utility, the Formal Guidance provided the exact structure for the DRP.

California Public Utilities Code Section 769

http://leginfo.legislature.ca.gov/faces/codes_displaySection.xhtml?lawCode=PUC&sectionNum=769

DIVISION 1. REGULATION OF PUBLIC UTILITIES [201 - 3260]

(Division 1 enacted by Stats. 1951, Ch. 764.)

PART 1. PUBLIC UTILITIES ACT [201 - 2120]

(Part 1 enacted by Stats. 1951, Ch. 764.)

CHAPTER 4. Regulation of Public Utilities [701 - 920]

(Chapter 4 enacted by Stats. 1951, Ch. 764.)

ARTICLE 3. Equipment, Practices, and Facilities [761 - 788]

(Article 3 enacted by Stats. 1951, Ch. 764.)

Section 769.

769. (a) For purposes of this section, “distributed resources” means distributed renewable generation resources, energy efficiency, energy storage, electric vehicles, and demand response technologies.

(b) Not later than July 1, 2015, each electrical corporation shall submit to the commission a distribution resources plan proposal to identify optimal locations for the deployment of distributed resources. Each proposal shall do all of the following:

(1) Evaluate locational benefits and costs of distributed resources located on the distribution system. This evaluation shall be based on reductions or increases in local generation capacity needs, avoided or increased investments in distribution infrastructure, safety benefits, reliability benefits, and any other savings the distributed resources provide to the electrical grid or costs to ratepayers of the electrical corporation.

(2) Propose or identify standard tariffs, contracts, or other mechanisms for the deployment of cost-effective distributed resources that satisfy distribution planning objectives.

(3) Propose cost-effective methods of effectively coordinating existing commission-approved programs, incentives, and tariffs to maximize the locational benefits and minimize the incremental costs of distributed resources.

(4) Identify any additional utility spending necessary to integrate cost-effective distributed resources

into distribution planning consistent with the goal of yielding net benefits to ratepayers.

(5) Identify barriers to the deployment of distributed resources, including, but not limited to, safety standards related to technology or operation of the distribution circuit in a manner that ensures reliable service.

(c) The commission shall review each distribution resources plan proposal submitted by an electrical corporation and approve, or modify and approve, a distribution resources plan for the corporation. The commission may modify any plan as appropriate to minimize overall system costs and maximize ratepayer benefit from investments in distributed resources.

(d) Any electrical corporation spending on distribution infrastructure necessary to accomplish the distribution resources plan shall be proposed and considered as part of the next general rate case for the corporation. The commission may approve proposed spending if it concludes that ratepayers would realize net benefits and the associated costs are just and reasonable. The commission may also adopt criteria, benchmarks, and accountability mechanisms to evaluate the success of any investment authorized pursuant to a distribution resources plan.

Review of Key Components of California DRPs

On July 1, 2015, all six regulated investor-owned utilities in California submitted their DRP applications for approval by the CPUC. In this section we provide a summary of some of the key components of the reports for the three main IOUs in the state – Pacific Gas & Electric, Southern California Edison, and San Diego Gas & Electric.

As previously mentioned, the Formal Guidance for the DRPs to the IOUs asked each utility to address a series of analytical frameworks as a means of facilitating the integration of DERs in a potential future with enhanced DER penetration. The three analytical frameworks include – integration capacity analysis, optimal location benefit analysis, and DER growth scenarios. For the three major IOUs, we discuss each of these frameworks.

Integration Capacity Analysis

Although slight differences exist, each of the three major California IOUs adhered to a consistent methodology for conducting their integrated capacity analysis (ICA). Here we summarize what was done for each of the major utilities.

Pacific Gas & Electric

Pacific Gas & Electric (PG&E) represents one of the largest combined natural gas and electric utility companies in the U.S. As the largest investor-owned electric and gas utility operating in the state of California, PG&E covers over 70,000 square miles and serving approximately 16 million people in the northern half of the state. The DRP submitted by PG&E helps support the Smart Grid Program, Electric Program Investment Charge (EPIC), and GRC-funded initiatives and facilitate modernization of its electric distribution system as well as accommodate two-way flows of energy and energy services. As stated, the DRP will help with "enabling customer choice for new technologies and services and providing new opportunities for new DERs to be integrated onto the grid."

PG&E performed the Integration Capacity Analysis (ICA) as a way of determining the amount of potential available DER within the distribution system. The analysis considered more than 3,000 distribution feeders containing roughly 500,000 nodes across more than 100,000 line sections. The line sections that PG&E chose represent those most impacted by changes in installed DER, while the nodes chosen represent the broad range of hosting capacity that consider varying levels of impedance in the system. The methodology PG&E used to perform the ICA is similar to the EPRI approach for representing the hosting capacity for PV interconnection. The Formal Guidance required each of the 3 major utilities to use similar approaches to maintain consistency and transparency among these utilities.

The PG&E ICA used a load forecasting tool, LoadSEER by Integral Analytics, to assess the impacts on load and generation as a means of informing potential future investments. For the ICA, PG&E developed hourly load profiles at the feeder, substations, and system level using SCADA metering data for approximately 245 Distribution Planning Areas designed to represent a typical day for various customer types in the PG&E service territory. A power flow modeling tool, CYMDIST by CYME International was also used in the ICA to assess impacts on power flow down to the transformer level within the distribution system. The tool considered conductors, line devices, loads, and generation. Using both the load forecasting tool and the power flow model, PG&E evaluated various power system criteria including thermal limits, power quality or voltage limitations, protective line limitations including fuses and relays, and various safety/reliability issues. Taken from the PG&E DRP, Figure 10 below shows the various criteria considered in the power flow analysis as indicated by the Initial Analysis, together with additional consideration for future analysis (PG&E DRP, pg. 33).

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

Figure 10 - Criteria for Power System DER Capacity Limits

In the PG&E ICA analysis, the thermal limits for each hour were assumed for each substation transformer, circuit breaker, primary conductor as well as main/tap line devices. For this set of equipment, the ICA compared on an hourly basis whether the DER asset is within these limits. With respect to protection criteria, the ICA considered that DER can lower the amount of fault current that is coming from the substation and that a possible fault contribution from the DER might trip the feeder or impact fuse limits of a device. For power quality, the ICA considered voltage flicker and modeled the maximum DER size that keeps the voltage flicker below a given threshold. And considering safety and reliability, the ICA avoids potentially unsafe islanding situations as well as limiting transmission system DER penetration. Whatever power system criterion that has the most limiting capacity impacts establishes the ICA result for that line section.

The results of the ICA are provided on a public-facing website called the Renewable Auction Mechanism (RAM) Map. The map shows each line by color coding the maximum DER capacity as a way of informing DER developers and customers where the most attractive or constrained areas for DER siting are located. Also provided as part of the results of the ICA are the total DER capacity by each PG&E county, indicating that Fresno County has the greatest potential for DER growth within this service territory at more than 316 MW followed by Santa Clara (171 MW), Contra Costa (154 MW), Alameda (141 MW), and Kern counties (124 MW). As the DRP states, the results from the ICA are only considered up to the substation level and therefore does not account for impacts or influences occurring in the transmission system.

Along those lines, it is important to note here that the power flow modeling considered in the LBNL-led GMLC project offers a much more sophisticated representation of not only the distribution system flow components but also includes consideration of the upstream transmission system impacts, as discussed in Section 1.3.

Southern California Edison

Southern California Edison, a subsidiary of Edison International, is the 2nd largest electric utility in California, serving more than 14 million people and covering more than 50,000 square miles in the Central, Coastal, and Southern portions of the state. SCE maintains more than 105,000 miles of distribution line and 1.4 million electricity poles. Acknowledging that the electric grid of the future will look a lot different than it does today, SCE is focusing its distribution planning efforts that consider bidirectional flow from a variety of different generation sources with widely varying usage characteristics. In 2015, SCE estimated more than 4,300 MW of DER deployed in its service territory, more than half comprised of energy efficiency or demand response and most of the other half from distributed renewable resources. The DRP is well aligned with SCE's Energy Efficiency, California Solar Initiative, and Self Generation Incentive Programs that will incentivize expected DER adoption.

The methodology used by SCE to perform the ICA is consistent with the other California IOUs. SCE's ICA quantifies the DER potential within its service territory considering constraints of thermal ratings, protection system limits, and power quality and safety standards of existing equipment similar to what PG&E considered. SCE partnered with EPRI to help benchmark results and review hosting capacity parameters. SCE also worked with Cooper Power Systems' CYME Distribution Analysis and Scripting Tool as a means of performing the ICA by modeling the distribution system down to the line level. Each distribution circuit was divided into four line segments as a way of enabling flexibility in managing loads, especially with high levels of DER.

SCE considered a group of 30 representative circuits using a k-means clustering technique to allow for ease of scaling across the entire service territory. The distance from the substations to the circuit and its inherent resistance was used as a direct means of extrapolating results from the ICA to each circuit in the territory. As such, the hosting capacity decreases as the resistance from the source substation increases. Based on the representative circuits assumed in the analysis, higher voltage lines have a higher hosting capacity. SCE believes the approaches used for the DRP will be useful for future analyses.

Per the Formal Guidance, the results of the ICA were made available through publicly available website showing geospatial maps of the DER hosting capacity down to the circuit level. SCE's mapping tool, DERiM, was designed for customers and developers to easily view specific locations and allow for filtering by voltage size or hosting capacity threshold as a way of informing potential developers.

San Diego Gas & Electric

San Diego Gas & Electric, a division of Sempra Energy, is the third largest regulated public utility in California, serving 3.6 million people through 1.4 million metered customers spanning 4,100 square miles across San Diego and Orange counties. As of May 2015, the utility estimated a total of 17,000 PEVs.

Consistent with PG&E and SCE, SDG&E's ICA methodology are similar with slight differences as a result of design standards and operating criteria. For the DRP, SDG&E worked with Integral Analytics (IA) to serve as a secondary check of SDG&E methodology. As was done in PG&E, the LoadSEER software package was used to provide spatial load forecasting. Each distribution circuit was divided into three zones and simulated to add DER generation to each zone until one or more limits was exceeded. The model was run by placing the max generator at the end of each zone and run with a power flow model to check for voltage threshold violations (> +/- 3%), thermal exceedances of equipment, and any faults on the line. If the scenario passed these 3 criteria, the line was assumed to be ok with this capacity amount for DER. Each circuit is evaluated at two distances from the main feeder representing rural and urban locations. The three same limits – thermal, voltage, and protection that were considered by PG&E and SCE are part of the SDG&E ICA and provided as a publicly available webpage mapping RAM tool.

Optimal Location Benefit Analysis

The Guidance Ruling directs the structure of the locational net benefits methodology. The approach is consistent across the utilities, with SDG&E and SCE referring to it as the Locational Net Benefits Methodology (LNBM) in the DRPs. Using this methodology, the results presented in the DRP provides the potential cost, either avoided or increased, as a result of DER placement at specific locations within the distribution system. As a starting point, each utility used the CPUC-approved Cost-Effectiveness Calculator developed by E3 as well as other components not referred to as the Guidance Ruling's value components. With coordination among the CPUC, SCE, SDG&E, and PG&E as well as other stakeholders, the E3 model selected for this analysis was the Distributed Energy Resources Avoided Cost Calculator (DERAC).

Starting with the DERAC tool and then with additional considerations, the locational benefit analysis considers nine components as described below:

1. The first is the "Sub-Transmission, Substation, and Feeder Capital and Operating Expenditures" which represent the avoided or increased costs associated with changes in forecast load growth. This consideration includes possible deferred need to invest in substation or distribution line upgrades as a result of more DER penetration. The analysis considered estimates the locational impact as the difference between the deferral benefits and the capacity-related costs for interconnecting DERs at the feeder level. Because different DER technologies provide benefits at different times of the day, the analysis needs to consider the hourly profile of say the DG PV generation together with load profile at the site and

its ability to offer economic benefits without potentially exacerbating the duck-curve phenomenon.

2. The “Voltage and Power Quality and Operating Expenditures” represent the voltage or power quality impact as a result of DER output typically occurs during peak load periods and is represented as the difference between the deferral benefits and the voltage or power quality costs of interconnecting DERs at the feeder level.

3. The “Electric Distribution Reliability/Resiliency Capital and Operating Expenditures” component represents the deferred or accelerated need for additional reliability or resiliency investments, which typically is of concern during peak load hours and is considered at the feeder level.

4. The “Deferred Electric Transmission Capacity Capital and Operating Expenditures” as its name suggests refers to the avoided or increased transmission line or substation costs associated with potential enhanced DER. This component is represented as the difference between the deferral benefit and the transmission capacity costs for interconnecting DERs at the substation level.

5. The “System or Local RA Costs” are the avoided or increased costs incurred to procure RA capacity. The amount of DER capacity not including what is considered in the CEC IEPR load forecast or other studies used to estimate RA requirements using an Equivalent Load Carrying Capability (ELCC) approach. The marginal ELCC is used to determine the impact due to DERs and uses a price forecast of system RA to estimate the price impact at the LCR area level. “Flexible RA” refers to the avoided or increased costs when flexible RA capacity is procured. The amount of flexible RA is determined as the difference with and without DER in place and considers the hourly dispatch constraints throughout the day of resources like PV.

6. The “Generation Energy and GHG” represent the avoided or increased cost to purchase electricity and the related cost of GHG emissions using hourly load profiles specific to each DER that would be translated to an impact on cost including the state’s Cap and Trade GHG emissions cost. This component would be considered at the CAISO PNode level. “Energy Losses” are the avoided or increased electricity costs

due to losses on the T&D system that result from either an increase or decrease in DER presence in the system. For this component, an hourly loss factor is estimated based on whether the DER asset is not generating and losses are present or vice-versa at the line section level. "Ancillary Services" are the avoided or increased costs to procure ancillary services using a PG&E rule of thumb that ancillary service costs can be captured by increasing the energy price forecast by 1 percent, a common assumption also used in the DERAC tool. "RPS" is the avoided or increased costs to procure energy to meet RPS requirements based on a determined RPS price premium.

7. The "Renewable Integration Costs" are the avoided or increased generation-related costs associated with integrating renewable resources. For DERs that avoid RPS procurement from wind or solar, the integration cost for the wind and solar is also avoided. For DERs that are wind or solar, an integration cost is included.
8. The "Societal Avoided Costs Linked to Deployment of DERs" are the avoided or incremental costs to society that are not tied to utility rates or costs.
9. The "Public Safety Avoided Costs Linked to Deployment of DERs" are the decreased or increased safety costs not represented in other components of the analysis.

With these considerations, the locational benefits methodology can easily be integrated into long-term planning initiatives including the CEC IEPR, and CPUC TPP and LTPP as the future of DER evolves over time.

DER Growth Scenarios

A total of three 10-year scenarios of forecasted DER growth by technology through 2025 are presented as part of the growth scenarios required in each DRP. Included with each scenario is an estimate of the DER geographic dispersion down to the feeder level and distribution planning impacts. The growth scenario analysis considered a wide range of DER technologies at or above 20 MW in size – energy efficiency, demand response, distributed generation in the form of solar PV, CHP, or fuel cells, retail storage, PEVs, CHP on a CHP Feed in Tariff Program, wholesale solar and biomass, and wholesale storage.

According to the DRP, the approach used to conduct the growth scenario analysis represents an industry-leading effort by the major IOUs in California as the Guidance Ruling required geospatial dispersion of DER growth scenarios. The three scenarios are generally consistent with the CEC IEPR forecasts:

- Scenario 1 – Trajectory (or Expected) DER Growth is similar to CEC's CED/IEPR DER forecast
- Scenario 2 – High DER Growth reflects adoption that is possible with increased policy interventions and technology/market innovations
- Scenario 3 – Very High DER Growth is a scenario that is only likely to occur with significant policy interventions

Scenario 1 is designed to represent a modest base case scenario for California's resource and infrastructure planning with little change from existing procurement policies or business practices. This case assumes no additional demand-side small PV or CHP so Scenario 1 assumed procurement targets for both as established by CPUC in its LTPP. This scenario was designed to largely mimic CEC's 2014 IEPR 'trajectory' case.

Scenario 2 is similar to the CEC's IEPR High Growth case plus additional information from DER developers and LSEs regarding their forecasted DER. The major IOUs issued a solicitation on the DER service list requesting third party DER owners and/or vendors to provide any non-confidential DER growth forecast data for consideration in Scenario 2. This scenario assumes more cost-effective PV, moderate residential Zero Net Energy driven adoption, and some relief to market barriers for DER growth.

Scenario 3 represents a very high potential DER growth assumption that incorporates the state's goals for GHG reductions, resource adequacy, transmission system needs, and distribution reliability and resiliency. This case takes into consideration the Governor's 2030 Energy Policy Goals of 50% of electricity from renewables, 50% reduction in petroleum-fueled cars, 50% reduction in electricity used in existing buildings, Zero Net Energy Goals, the

Commission's 2020 Energy Storage requirements, and the Commission's Demand Response Goal of 5% of peak load among others.

The figures below show the estimated impact from each growth scenario over time for two of the three major IOUs in California, PG&E and SDG&E, respectively. SCE did not provide a comparable illustration in their DRP.

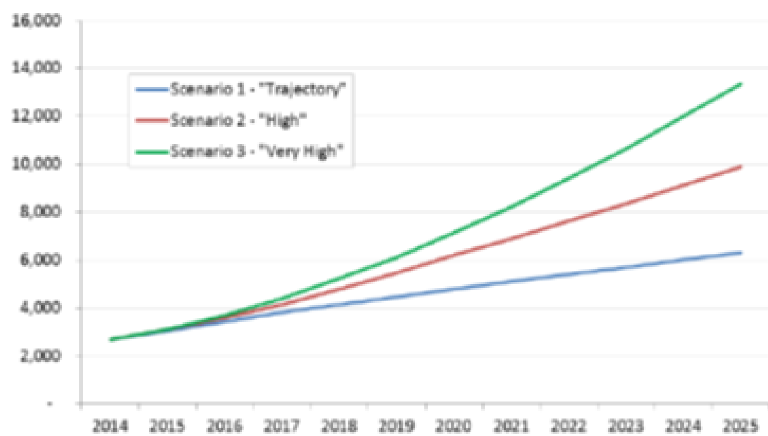

FIGURE 2-27: DERS AGGREGATE ESTIMATED IMPACT AT SYSTEM PEAK (HE 17 AUG) – CUMULATIVE POST 2007

Figure 11 - PG&E Estimated Impact on System Peak under Growth Scenarios

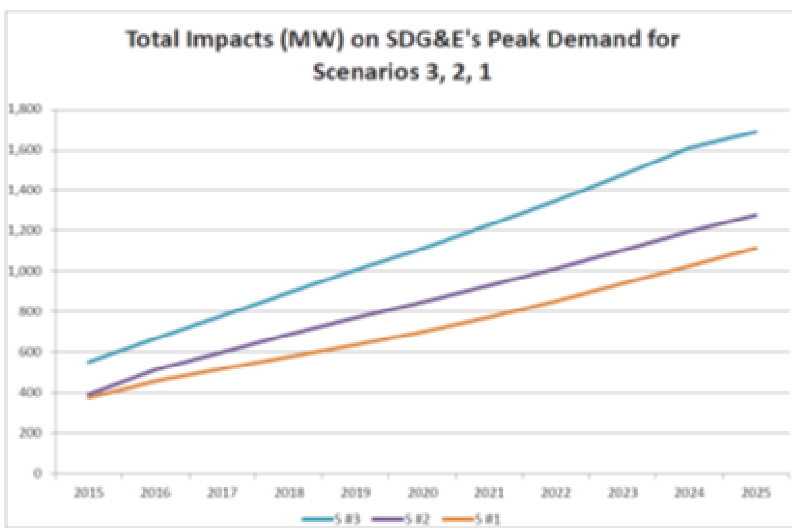

Figure 12 - SDG&E Estimated Impact on Peak Demand under Growth Scenarios

Extending the Benefits of California Utility DRPs to Current Work

The DRPs support California's energy policy initiatives of achieving year 2020 and 2050 greenhouse gas (GHG) reduction targets while recognizing the important role that DERs may have in meeting these goals. They also support the modernization of the electric distribution system to accommodate bi-directional flow of electricity as well as provide graphical geospatial animations for DERs opportunities. The efforts of the DRP have laid important groundwork in the state's mission in envisioning a future that can efficiently and successfully accommodate a large amount of DER. The efforts of this project are a direct complement to many key facets of the DRPs as discussed below.

Transmission System Feedback

The DRPs submitted by the utilities served as an important foundation for thinking about the longer term vision of enhanced DER penetration throughout California. Some parts of the DRPs considered analysis down to the transformer or feeder level with sub-daily time steps, but power flow modeling performed in the ICA analysis was confined to the distribution system. The power flow modeling considered in this project offers a much more sophisticated representation of not only the distribution system flow components with the use of GridLAB-D, but also includes consideration of the upstream transmission system impacts in a dynamic feedback loop using LLNL's GridDyn model. This project benefits from the simultaneous use of both power flow models that are coupled into what's called ParGRID. Use of this modeling framework will provide a more realistic view of impacts to both the distribution and transmission systems that system operators can potentially be used to assess current and future scenarios of enhanced DER adoption in California as well as aid in potential DER investment planning.

Greenhouse Gas Emissions

The state is keenly focused on doing all it can to meet the ambitious GHG targets for 2020 and 2025 and have ensured that guiding work products like the CEC IEPR or the CAISO Long Term Procurement Plan as well as the DRPs issued by the utilities serve this goal. At the heart of the this project, DER-CAM is able to consider DER technologies that are aligned with reducing emissions in the state as well as provide the underlying information required to quantify the resulting benefits.

Alleviating the Duck Curve

As previously mentioned, the large amount of rooftop solar PV in California is resulting in a daily load profile referred to as the proverbial duck curve. According to a recent report by NREL, the outlook through 2020 as forecasted by CAISO shows this load imbalance to continue to be accentuated as a result of continued growth in PV. The technological limitations of solar PV and its reliance on hours of the day when the sun is available leads to the phenomenon of over-generation in the afternoon when the sun is shining and a dramatic increase in net load after the sun sets (NREL 2015). This phenomenon highlights the need for flexible resources that the DRPs have stated should be able to quickly adjust to changes in grid conditions throughout the day. This project directly addresses this concern with consideration of various DER options that can help alleviate the steepness of the curve in the late afternoon at time. The inclusion of storage coupled with PV as a DER portfolio option is one example that considers the subset of customers that can participate in demand-response programs.

Graphical User Interface

The DRPs offer a geospatial mapping of DER forecasted capacity by technology type, providing a broad overview and perspective of the most attractive DER locations across the state that can be assessed from a web API. These maps were produced down to the feeder level across the service territory for two forecast years, 2020 and 2025. Prior to the DRPs, no visual depictions were publicly available that could provide such a broad overview of DER potential across the state while still displaying information down to the feeder level. In this project, enhanced geospatial visualization capabilities have been developed that can display this same level of information enhanced for both the distribution as well as transmission impacts from the various DER options, a significant enhancement to what was developed in the DRPs.

Neutral perspective

The DRPs that were issued under the state's PUC Section 769 as discussed in this section were developed by each utility, albeit in coordination with other stakeholder entities. As such, it can be argued that the results presented in each plan provide a biased perspective of DER capability and future potential. Although somewhat different in scope, this project offers a neutral perspective across all three major IOUs that can be used by stakeholders and policymakers to help make informed decisions about potential future DER investments.

Prototype Software Framework Demonstration

To highlight the potential applications of the tool delivered by this project, the team carried out a demonstration study built around distinct use cases, as described in the following sections. Each of these use cases was evaluated considering different DER portfolio options to further illustrate the flexibility of the model.

Use cases

Use case 1: Estimating the aggregated deployment of DER

The large-scale penetration of behind-the-meter DER in distribution networks has the potential to significantly impact bulk electric systems. These impacts are driven primarily by DER penetration levels (i.e., total installed capacity) as well as by how DER deployments are distributed throughout distribution networks.

The first use case developed for the prototype software framework developed in this project targets the ability to quickly assess the large-scale potential for DER deployment based the cost-effectiveness of behind-the-meter DER investments.

This analysis is done considering how different customer classes are distributed over different service territories, and the cost-benefit analysis is performed individually for each customer class by leveraging the optimization capabilities available through DER-CAM. The optimization results are then aggregated to the feeder level, suggesting the potential for deployment of different DER.

Use case 2: Estimating optimal DER locations with respect to DER impact on voltage stability

The ongoing discussion on large-scale integration of DER in distribution networks is largely revolving around impacts that include frequency control, voltage stability, and reliability. These impacts are dependent not only of the nature, sizing, and dispatch of different DER, but also, and very importantly, on their location with respect to the grid.

Given the integrated nature of the software framework developed in this project, behind-the-meter DER investment and dispatch decisions can be translated directly into grid impacts by means of power flow studies that reflect changes in net loads introduced by behind-the-meter

DER. This is addressed in the second use-case enabled by the software developed by this project: understanding optimal locations for DER deployment considering their impact on voltage stability.

Use case 3: Estimating optimal DER operational strategies

The impact of DER in different grid elements is highly dependent on DER operation and dispatch decisions. Specifically, as DER reach high penetration levels, important challenges can be observed as a result of ramping events, backfeed, and variability in output associated with non-dispatchable resources. This requires a study on optimal DER operational strategies, reflecting cost-optimal decisions from a private behind-the-meter perspective as a result of existing economic incentives, and address how operational strategies and dispatch decisions are reflected in different DER portfolios.

Datasets

Energy end-use loads

One of the core capabilities of the software platform developed in this project is the ability to simultaneously analyze behind-the-meter DER deployment across all customer classes connected to distribution feeders. This capability is supported by the different software modules developed by the project, but also by the energy load databases gathered and processed for this purpose.

These energy loads are collected from the U.S. DoE Residential Consumption Survey and from the U.S. DoE Commercial Reference Building Types. The datasets contain one year of hourly data for multiple end-use loads, including electricity consumption, heating, and cooling, and were processed and formatted to fit the standard DER-CAM classification and format.

Presented in Table 1 is a summary of key data collected for the 19 representative building categories available in the datasets, reflected for the San Francisco International Airport TMY location. Similar data is available for all other TMY locations throughout the US, including sites in each of California’s IOU service territories used in this project. Further, these datasets facilitate the process of extending the analysis to different geographic regions.

Table 1 - Representative building types

	Building Type	Floor Area (ft^2)	Floors	Maximum electricity demand [kW]	Total electricity consumption [MWh]	Total gas consumption [MWh]	Highest average daily gas cons. [kWh]
C & I	Large Office	498,588	12	1,504	5,734	540	3,011
	Med. Office	53,628	3	208	646	8	26
	Small Office	5,500	1	16	59	5	30
	Warehouse	52,045	1	70	226	92	779
	Retail	24,962	1	70	259	92	603
	Strip Mall	22,500	1	68	257	95	578
	Primary Sch.	73,960	1	281	801	244	1,303
	Sec. School	210,887	2	1,005	2,565	885	5,471
	Supermarket	45,000	1	309	1,581	554	2,447
	Quick Restr.	2,500	1	31	180	176	581
	Full Restr.	5,500	1	52	290	329	1,192
	Hospital	241,351	5	1,423	8,452	3,937	12,190
	Out.Pt Health	40,946	3	267	1,182	789	2,343
	Small Hotel	43,200	4	109	541	178	610
	Large Hotel	122,120	6	425	2,302	1,999	6,440
Res.	Midrise Apt.	33,740	4	52	215	82	355
	BASE	2,090	3	1.9	7	14.2	66.2
	LOW	1,045	2	0.9	3.7	0.8	8.6
	HIGH	3,135	4	2.6	9.7	19.2	97

Load disaggregation

Performing transformer load disaggregation was based on data collected from the U.S. Census Bureau American Housing Survey, and from the U.S. EIA Commercial Buildings Energy Consumption Survey (CEBECS). This data is summarized in Table 1.

Table 2 - Customer distribution per sector and building type

Sector	Share of total [%]	Building type	Share of sector [%]
Commercial	50.9	Primary school	12.2
		Secondary school	2
		Hospital	0.2
		Outpatient care	2.7
		Large office	0.5
		Medium office	2.4
		Small office	24

		Warehouse	26
		Supermarket	3.6
		Quick-service restaurant	4.4
		Full-service restaurant	4.4
		Stand-alone retail	9.2
		Strip mall	4.5
		Large hotel	0.7
		Small hotel	3.2
Residential	49.1	Midrise Apartment	3
		High	10
		Base	25
		Low	62

Tariff Data

The behind-the-meter analysis conducted to each of the customer segments is associated with one or more applicable tariffs per service territory. These tariffs drive the cost-benefit optimization process around the multiple value streams provided by DER and ultimately drives adoption.

Presented below is a summary of tariffs collected in this project for the PG&E service territory that apply to each of the building categories. Similar data has been collected for both SCE and SDG&E.

Table 3- Customer distribution per sector and building type

Type	Building Type	PG&E Electricity tariff scheme applied	PG&E Gas tariff scheme applied	Monthly rate
C & I	Large Office	E-20	G-NR1	D
	Medium Office	A-10	G-NR1	A
	Small Office	A-1, A-6	G-NR1	A
	Warehouse	A-10	G-NR1	C
	Stand-alone Retail	A-10	G-NR1	C
	Strip Mall	A-10	G-NR1	C

	Primary School	A-10	G-NR1	D
	Secondary School	E-19	G-NR1	E
	Supermarket	A-10	G-NR1	D
	Quick Service Restaurant	A-10	G-NR1	C
	Full Service Restaurant	A-10	G-NR1	C
	Hospital	E-20	G-NR1	E
	Outpatient Health Care	A-10	G-NR1	D
	Small Hotel	A-10	G-NR1	C
	Large Hotel	A-10	G-NR1	E
Res.	Midrise Apartment	E-1, E-1-TOU, EM	G-1	Res
	BASE	E-1, E-1-TOU	G-1	Res
	LOW	E-1, E-1-TOU	G-1	Res
	HIGH	E-1, E-1-TOU	G-1	Res

DER investment scenarios

For each of the customer segments and applicable tariffs under each service territory, different DER investment portfolio options were considered, with the purpose of capturing some of the indirect benefits of co-located DER that cannot be obtained in solutions that consist of PV or storage only. Each of these scenarios is presented below.

- **DER scenario 0 – No DER**

  Studying both the economic and grid impacts of widespread DER in the electric grid first requires establishing a reference point. This is addressed by a scenario where no new DER investments are allowed, and the network models are analyzed using only their reference loads. This scenario allows performing different before / after analysis.

- **DER scenario 1 – PV only**

  The State of California is currently in the forefront of Solar PV installations, with close to 600,000 solar projects currently deployed across the state totaling approximately 4.5 GW of installed capacity. In the pursuit for the aggressive statewide goals of DER and renewable penetration in the distribution network it is expected that PV will continue to play a fundamental role, and very high levels of PV penetration will likely continue to pose technical challenges as illustrated by the duck curve and its impact on both net loads and ramping requirements. To address this scenario, the first DER investment option considered in the demonstration focuses on the deployment of PV systems throughout the grid and includes PV deployments both for the residential and commercial sector.

- **DER scenario 2 – PV and storage**

  Following the analysis of pure PV installations, the second scenario of DER investment options addresses the coupling of PV and storage solutions. The inclusion of storage introduces flexibility in the ability to participate in price-driven demand response programs such as time-of-use rates and demand charges by shifting customer loads, but also addresses generation intermittency and enables dispatching PV generation making it a natural extension to DER Portfolio Option 1. Further, the coupling of PV and storage solutions enables exploring different economic dispatch strategies that reflect the context of different customer segments and the relationship between different energy loads and tariffs, thus creating a scenario where the optimized dispatch may provide additional information and value against the standardized dispatch strategies currently being employed in conventional methods to assess the impact of DER penetration.

- **DER scenario 3 – PV, storage, and CHP**

  While PV and storage solutions may prove cost effective both at the residential and commercial building sectors, it is more likely that conventional generators and CHP systems will only play a significant role for larger commercial and industrial loads, particularly in the presence of heat loads where CHP systems may become very cost-effective. To accommodate such cases, a third DER investment option was considered where both conventional generators (internal combustion engines and microturbines) and CHP units will be contemplated in the set of possible DER investments.

- **DER scenario 4 – Net-metered PV, storage, and CHP**

One of the key influencing factors of behind-the-meter DER impacts on distribution networks is the backfeed that PV installations introduce when exporting power back to the distribution utility. This is typically done under a feed-in or net-metering mechanism, which enable all PV generation to be effectively compensated at a rate equal to the electricity purchase price. Net-metering and other export compensation mechanisms can significantly influence the cost effectiveness of storage solutions, and to study this effect a fourth DER investment scenario is considered building upon scenario 3, where PV exports are enabled under net-metering agreements.

- **DER scenario 5 – PV, subsidized storage, and CHP**

  One of the key challenges of renewable generation is tied to the intermittency of the solar (and wind) resource, and the steep ramping phenomena occurring in later hours of the day as the sun is setting. Storage systems are a natural solution to address these issues, as they provide the buffer needed to both absorb intermittency and shift load throughout the day. However, high investment costs are still one of the main barriers to their widespread deployment. In the fifth DER investment scenario we analyze a potential subsidy to storage deployment.

Key Results

Load disaggregation

The load disaggregation process was applied to the IEEE 123 feeder using data for each of California's IOUs, and constrained by building distribution data collected from the U.S. Census Bureau American Housing Survey, and from the U.S. EIA Commercial Buildings Energy Consumption Survey (CBECS), as described in Table 3. The energy loads for the PGE, SCE, and SDGE service territory were based on TMY locations 724940 - SF Intl. AP, 723815 -Barstow Daggett AP, and 722906 - SD North Island NAS, respectively. The results obtained by the load disaggregation process are summarized in Table 4.

Table 4 - Customer distribution per sector and building type

IOU	MApt	FFRest	RBase	RHigh	RLow	SOffice	Wrh
PGE	34	1	250	105	603	3	1
SCE	32	1	256	105	598	3	1
SDGE	34	1	258	106	611	3	1

Use case 1: Estimating the aggregated deployment of DER

The load disaggregation results obtained for the IEEE 123 feeder in each of the IOU service territories suggest a highly residential distribution of customers, where only a small number of commercial buildings (fast food restaurant, small office, and warehouse) are found. This result suggests that conventional generators and CHP units may not be particularly relevant solutions, as the magnitude and relation between electric and heating loads typically found in residential buildings is not conducive to CHP applications. This hypothesis is confirmed by the results obtained in the optimization runs, as DER investment scenarios 2 and 3 lead to nearly identical results. In fact, conventional generators were only suggested as cost-effective investments in warehouse buildings in the SCE service territory.

Taking this into account, our analysis focuses on PV and storage solutions.

Table 5 – Total PV and Storage capacities deployed under each utility and DER scenario

IOU	Scenario	PV [kW]	STO [kWh]
PGE	0. No DER	0	0
	1. PV	1026	0
	2. PV+STO	1036	38
	3. PV+STO+CHP	1036	38
	4. PV+STO+CHP+NM	3804	0
	5. PV+0.7STO+CHP	1183	444
SCE	0. No DER	0	0
	1. PV	770	0
	2. PV+STO	770	0
	3. PV+STO+CHP	761	0
	4. PV+STO+CHP+NM	6370	0
	5. PV+0.7STO+CHP	761	0
SDGE	0. No DER	0	0

1. PV	1271	0
2. PV+STO	1598	1183
3. PV+STO+CHP	1598	1183
4. PV+STO+CHP+NM	4079	0
5. PV+0.7STO+CHP	2800	6595

Use case 2: Estimating optimal DER locations with respect to DER impact on voltage stability

The second use case enabled by the developed software allows users to examine the impact of DER adoption patterns on voltage stability at locations throughout the modeled distribution and transmission networks. This information can then be employed to identify potential problems from DER adoption trends, then create strategies, whether technical or regulatory, to mitigate these problems before they emerge.

Depending on their type and operational patterns, DER can have either positive or adverse effects on voltage stability. To illustrate this, some examples have been collected from the modeled network. Figure 13 shows the voltage profile for a node at the periphery of the modeled distribution network (node 85) for a typical January weekday, as modeled under the SDG&E utility. The top plot shows the voltage profile under the no DER base-case scenario, while the bottom plot shows the voltage for a scenario where net-metered PV is permitted, along with storage and CHP. As this plot shows, the base-case voltage is already quite high, exceeding the typical acceptable range of 0.95 to 1.05, and appears to be approximately 1.1 for much of this test day. The introduction of power injections from net-metered PV at this node, however, appears to exacerbate the problem of excessive voltage during midday hours when PV generation (and consequently PV exports) is high.

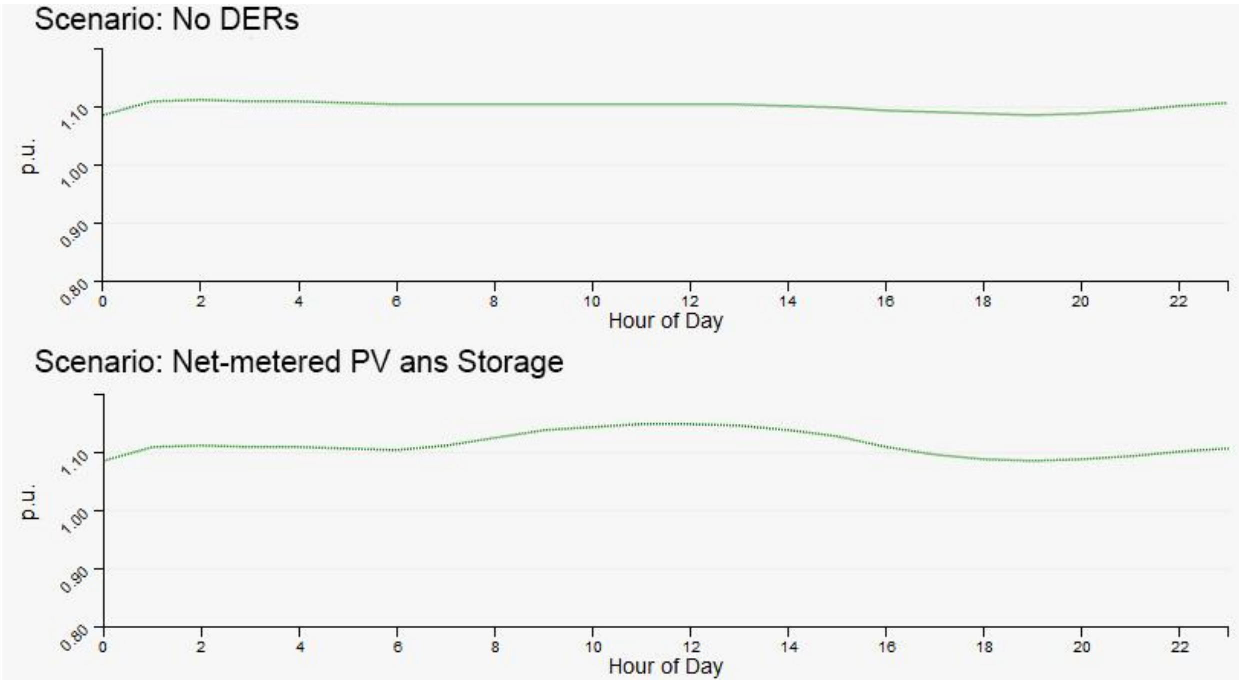

Figure 13 – Example voltage profiles for node in distribution network, showing potential adverse effect of net-metered PV on voltage stability.

Similarly, the impact of DER scenarios on the transmission system can also be explored. Refer to Figure 9 for the example transmission system modeled in this demonstration. Results for transmission level voltage stability are shown in Figure 14 for a typical January weekday for three separate DER adoption scenarios. The first plot shows the base-case hourly voltage profile with no DER deployment. The second shows PV and subsidized storage. As the results of use case 1, shown in Table 5, demonstrate, the availability of subsidized storage increases overall demand for PV quite substantially for both the PG&E and SDG&E utilities. Despite high levels of PV adoption, the use of storage mostly mitigates any adverse impacts at the transmission level, as midday voltage levels only rise marginally above the observed peak of the base-case scenario.

By contrast, the final scenario: net-metered PV and storage substantially increases the total observed PV deployment in all utility scenarios, but do not drive the adoption of storage. Consequently, power injections from excess PV generation at midday will drive up observed voltage levels during sunny, midday hours, and increases the observed peak voltage to 1.027

p.u. This trend is similar to that observed in the distribution example; however the magnitude of the impact is less significant on the larger-scale transmission system.

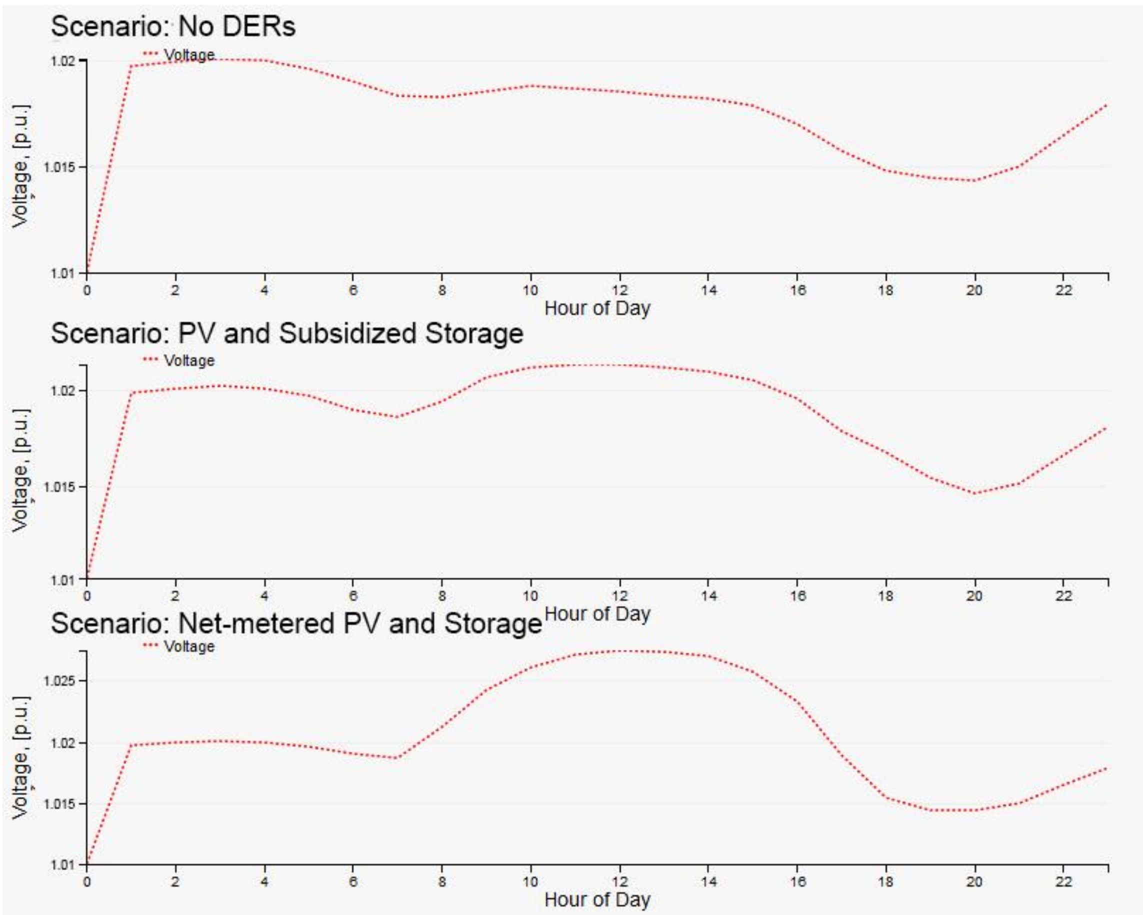

Figure 14 – Transmission level voltage for Barstow, CA node in example transmission model for 3 DER scenarios show the impact of PV and storage adoption and operation strategies on larger-scale system performance.

Use case 3: Estimating optimal DER operational strategies

The third use case enabled by the software developed in this project is the estimation of optimal behind-the-meter DER operational strategies under different retail rates and DER deployment scenarios.

Specifically, this use case allows for understanding hourly profiles either under various DER deployment scenarios, examining simpler scenarios, such as PV-only, or more complex scenarios that simultaneously consider multiple DER options, such as PV, electric storage, and CHP. Furthermore, the use case allows users to explore the impact of specific incentives such as Net-metering of PV exports or subsidies for storage capital costs. These different possibilities were considered in the analysis conducted as part of the prototype demonstration, as illustrated below. In this case, we analyze the optimal DER operational strategies focusing on the Midrise apartment building type, focusing on the SDG&E service territory. Specifically, we analyze the hourly load profile for a typical weekday in January, for each of the DER investment scenario outlined below:

- PV only
- PV and storage
- PV, storage, and CHP
- Net-metered PV, storage, and CHP
- PV, subsidized storage, and CHP

The results obtained suggest no CHP deployment, which is consistent with the observed end-use loads and applicable tariffs. For this reason, we only address PV and storage deployment in the discussion below.

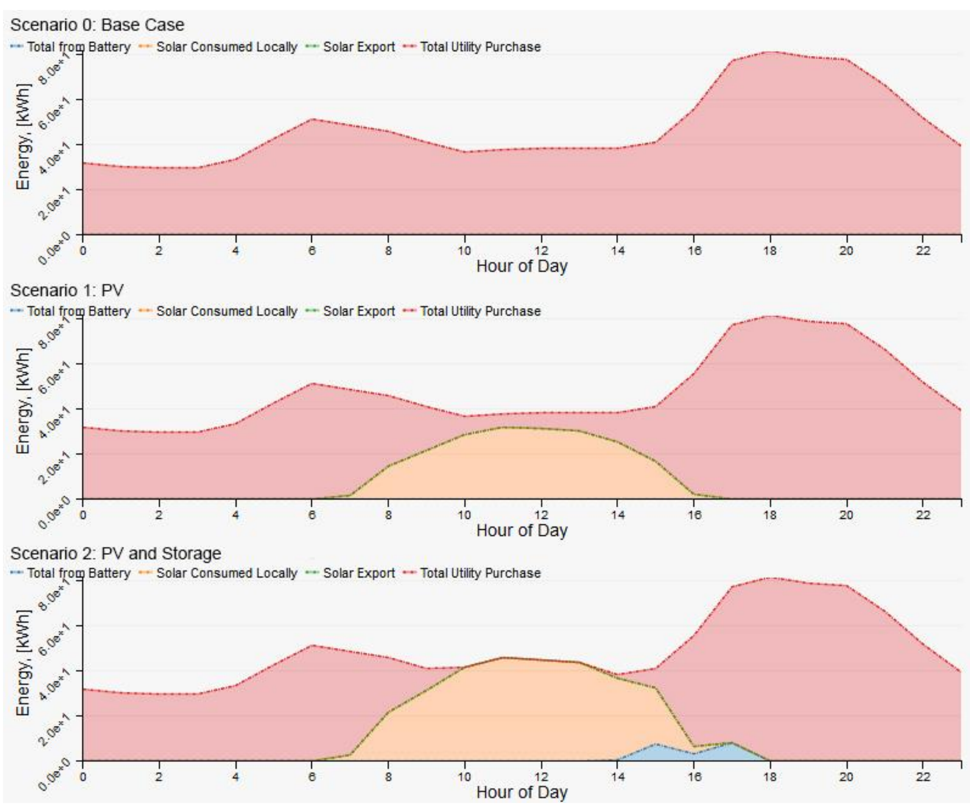

Figure 15 – Example generation and purchase profiles for SDG&E, midrise apartment building on a January weekday for DER scenarios 0-2.

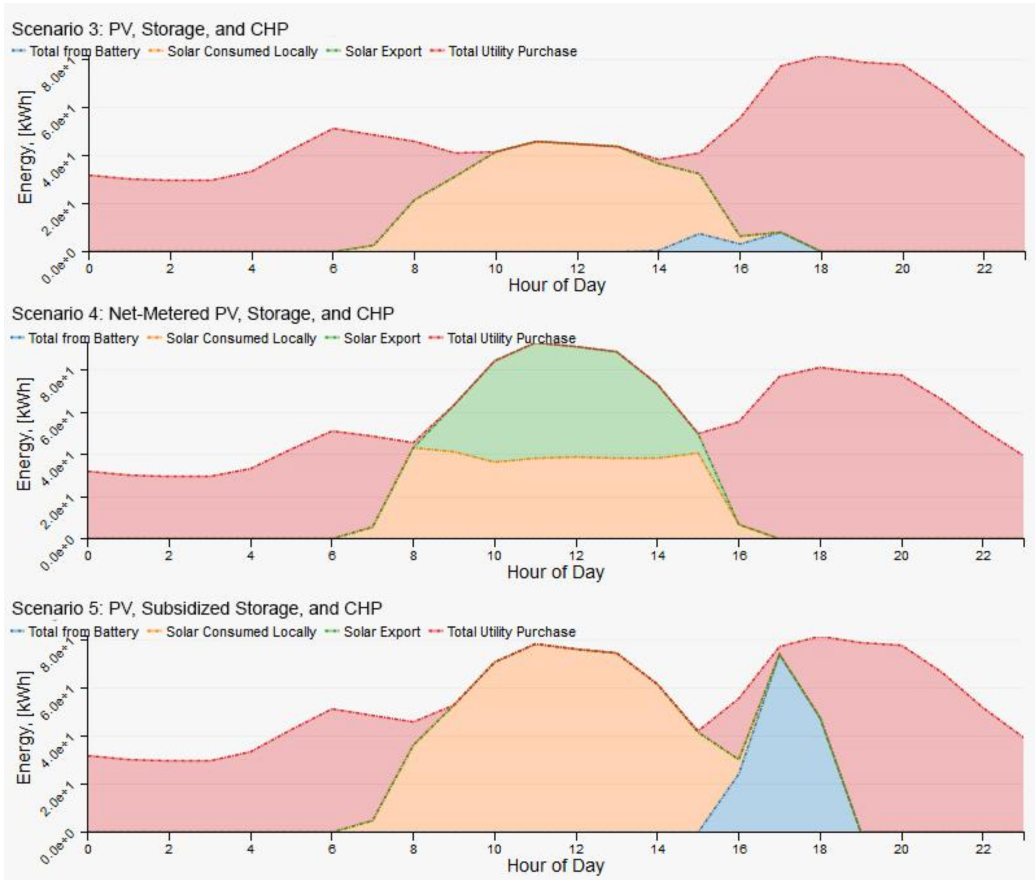

Figure 16 - Example generation and purchase profiles for SDG&E, midrise apartment building on a January weekday for DER scenarios 3-5.

The results of each DER scenario for the selected building, utility, and day are plotted in Figures Figure 15Figure 16. As observed in these figures, PV investment is cost-effective considering only utility cost offsets, and even in scenario 1 we see a significant PV capacity deployment in the mid-rise apartment building. This result is based on the assumption that there is enough area available to install PV capacity exceeding the peak electric load by up to 20%, yet this condition is not binding the overall capacity deployment. Analyzing this result, we observe that the PV generation does not directly contribute to reducing peak loads, which occurs in the later evening after PV generation has ramped down, Consequently, the PV generation profile has a significant impact in ramping effects both in the morning and in the evening, suggesting that by itself PV deployment in this building type may have a negative impact in grid operations.

Scenario 2 introduces the option to deploy storage along with PV. When analyzing this scenario, we observe a small deployment of storage capacity. This storage capacity allows for a larger total deployment of PV compared to scenario 1, and appears to absorb the PV generation in excess of loads during the midday hours. The excess PV generation stored in the battery is subsequently discharged in the later afternoon, which contributes to both a reduction in the magnitude of peak load and a shift in its occurrence from 6 to 7 pm, possibly contributing to alleviate local grid conditions.

Scenario 3 introduces the option to consider CHP. However, due to the local load characteristics, costs, and incentives, no CHP is selected. Consequently, the results from Scenario 3 will appear identical to those from Scenario 2.

Scenario 4 allows for PV injections under a net metering agreement. Because this creates an additional revenue stream for PV beyond self-consumption, a significant impact in the overall PV capacity and corresponding generation is observed. Because excess generation can be immediately injected back into the distribution grid, the system sees diminished value from storage, and thus selects none. Because no storage exists, the results exhibit the same potentially problematic patterns as those observed under Scenario 1. Namely, peak loads in the later evening are not reduced at all, and ramping is exacerbated between midday hours, where net loads and negative to evening hours where peak loads occur.

Finally, scenario 5 describes a hypothetical 30% subsidy on storage costs. As with scenarios 1-3, power injection from excess PV generation is not permitted. In this case, we find that the optimal DER deployment solution includes a significant storage component, which not only leads to reducing peak loads and shifting the period of peak consumption from 6 to 7 pm, but also leads to a shift in the ramping effect to a later period in time, along with a more pronounced ramp when compared to the reference load profile.

These operation patterns emerge in response to the specific economic conditions, most importantly the utility tariff. But it is important to note that the deployment of a meaningful capacity of storage, as seen in Scenario 5, enables end-use customers to engage in highly responsive behaviors to reduce their utility costs. There is a clear potential for utility to adopt varied tariff rates and structure to incentivize customers to utilize storage resources and drive more grid-supportive charge/discharge behaviors.

Conclusions

This report documents the work conducted throughout the project "DER Siting and Optimization tool to enable large scale deployment of DER in California".

Initial work on the project focused on defining the scope and performance goals of the prototype software framework at multiple levels: transmission, distribution, and behind-the-meter; as well as the technical requirements to meet those goals. These include a) the ability to run power flow analysis while considering the economics of grid planning and operations, b) behind-the-meter DER deployment and economic optimization, c) the integration of transmission and distribution power flow models to assess impacts of DER in the bulk electric system, and d) the development mapping and visualization functionality to add valuable geospatial data to the tool's analysis and results.

The project included the development of a proof of concept for the framework, where a software prototype was developed and used to carry out a demonstration of each of its defined use cases:

- Estimation of aggregated DER deployment across large geographic areas
- Estimation of optimal DER placement and DER impact on voltage stability at the distribution and transmission level
- Estimate of optimal hourly DER operational strategies by end-use customers

Results from each use case can be analyzed under multiple DER portfolio options and policy scenarios (e.g. tariffs, subsidies, and net-metering mechanisms). To achieve these capabilities, the tool leverages and integrates existing state-of-art tools for both behind-the-meter DER cost-optimization (DER-CAM) and distribution power flow analysis (GridLab-D, GridDyn), while also integrating new automation, mapping, and visualization capabilities. The architecture of prototype model and the integration each model component has been outlined.

Finally, a demonstration of the prototype model's capabilities was conducted using the IEEE 123 standard test feeder to emulate distribution feeders in each of California's IOUs: PG&E, SCE, and SDG&E. Example results are presented and discussed for each use case to illustrate the value of the tool to various research questions and how outcomes of this project can be leveraged to the address the challenges of distributed renewable integration in California and throughout the entire U.S.

The results obtained in the demonstration highlight how adoption patterns of DERs will vary in response to external conditions and incentives, as well as quantifying potential impacts of those adoption patterns on transmission and distribution systems. This allows policy-makers and others to better understand the impacts of their decision-making, identify potential problems, and most importantly thoroughly test future interventions.