CALIFORNIA ENERGY COMMISSION

ENERGY RESEARCH AND DEVELOPMENT DIVISION

FINAL PROJECT REPORT

Electric Access System Enhancement

Assessment of a Distributed Energy Resource Management System for Enabling Dynamic Hosting Capacity

June 2024| CEC-500-2024-064

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ACKNOWLEDGEMENTS

A big thanks to our project manager, Alexandria Vallejo, to whom much of the success and timely completion of this project is owed. You brought the teams together to tackle and adapt to our biggest challenges and always had a knack for coming up with a plan B (and sometimes plan C). To quote Henry Ford, "Coming together is the beginning. Keeping together is progress. Working together is success." Thanks for leading the teams through uncertainty and making this project a success. Also, a huge thanks to Peter Kim for developing many of the essential tools required to scale our digital twin simulations to our 10,000 DER future-state levels. You helped us squeeze every ounce of performance out of our test bed to make the large-scale simulations possible. When people said something couldn't be done, you would famously say "sounds like a job for…Peter Kim." Lastly, thanks to all our project partners that made this project a success — we know that this project's breadth of requirements was challenging, but your hard work, dedication, and collaboration helped us make this demonstration a success.

PREFACE

The California Energy Commission's (CEC) Energy Research and Development Division supports energy research and development programs to spur innovation in energy efficiency, renewable energy and advanced clean generation, energy-related environmental protection, energy transmission, and distribution and transportation.

In 2012, the Electric Program Investment Charge (EPIC) was established by the California Public Utilities Commission to fund public investments in research to create and advance new energy solutions, foster regional innovation, and bring ideas from the lab to the marketplace. The EPIC Program is funded by California utility customers under the auspices of the California Public Utilities Commission. The CEC and the state's three largest investor-owned utilities—Pacific Gas and Electric Company, San Diego Gas and Electric Company, and Southern California Edison Company—were selected to administer the EPIC funds and advance novel technologies, tools, and strategies that provide benefits to their electric ratepayers.

The CEC is committed to ensuring public participation in its research and development programs that promote greater reliability, lower costs, and increase safety for the California electric ratepayer and include:

- Providing societal benefits.
- Reducing greenhouse gas emission in the electricity sector at the lowest possible cost.
- Supporting California's loading order to meet energy needs first with energy efficiency and demand response, next with renewable energy (distributed generation and utility scale), and finally with clean, conventional electricity supply.
- Supporting low-emission vehicles and transportation.
- Providing economic development.
- Using ratepayer funds efficiently.

For more information about the Energy Research and Development Division, please visit the CEC's research website (www.energy.ca.gov/research/) or contact the Energy Research and Development Division at ERDD@energy.ca.gov.

ABSTRACT

The Electric Access System Enhancement project demonstrated a scalable, interoperable, and cost-effective means of integrating high penetrations of distributed energy resources. The control architecture leveraged a distributed energy resource management system, a distribution system operator for transacting energy, and a third-party distributed energy resource aggregator platform. The project identified ways to enhance the customer interconnection process to the grid, improve access to information from distributed energy resources, and optimize their use to provide energy services in a simulated day-ahead shadow market while maintaining grid reliability. By integrating these capabilities into a scalable system of systems, the distribution system operator can effectively balance distributed energy generation and customer demand on the distribution network.

This capability would allow the grid to host more distributed energy generation than what can traditionally be hosted by distribution lines without expensive infrastructure upgrades. Hosting more distributed energy resources has the added benefit of supplying increased demand growth, sometimes beyond the capacity limits of the distribution network itself. This is known as a dynamic hosting capacity, which could help utilities manage the forecasted growth in electricity demand as California switches to electric vehicles and appliances. It could also help to establish energy storage and photovoltaic generation as a more stable generation resource mix, if managed appropriately, and provide sufficient resource adequacy for distribution capacity upgrade deferrals.

Keywords: distributed energy resource management system (DERMS), distribution system operator (DSO), distributed energy resource (DER) aggregator, transactive energy

Please use the following citation for this report:

Castaneda, Juan and Andrew Ioan. 2024. *Electric Access System Enhancement: Assessment of a Distributed Energy Resource Management System for Enabling Dynamic Hosting Capacity.* California Energy Commission. Publication Number: CEC-500-2024-064.

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Executive Summary

Introduction

Southern California Edison is planning for an evolving power grid in the coming decades and is working to decarbonize its electric power supply. It has detailed its plans to modernize the grid and reach carbon neutrality by 2045. To do that, Southern California Edison will need to reimagine the grid to support California's greenhouse gas reduction goals and the imperative for power to be carbon free by 2045. Compared to today, **2045 is expected to see a 60 percent increase in electricity demand and a 40 percent increase in peak load** that will have to be met by carbon-free generation sources. To integrate these clean energy sources into its distribution network, Southern California Edison will need a new computing architecture that can effectively manage the generation intermittency of distributed energy generation (e.g., rooftop solar photovoltaic generation) through energy storage and curtailment. Today, this system does not exist, and distributed energy resources are interconnected based only on the network's static hosting capacity. High concentrations of distributed energy resources require electricity network upgrades to ensure that the network can handle the unmanaged power flow between demand and generation. The existing system is not scalable for the volume of distributed energy generation concentrations needed to reach carbon neutrality and enable more customers to adopt these technologies. The concentration of distributed energy resources on the distribution network is growing, and customers can benefit by generating power to supply their own electricity needs. A control architecture is needed for distribution system operators to manage the growth of distributed energy resources on the distribution network and balance power consumption and generation from local distributed energy resources, similar to the way independent system operators balance electricity supply with demand on the bulk transmission system.

Project Purpose

The Electric Access System Enhancement project worked to streamline distributed energy resource interconnections, improve supervisory access to grid assets and distributed energy resources, and optimize them for grid reliability and market-based energy services. To achieve these goals, the research team implemented a control architecture that is a hybrid between a centralized and a distributed control architecture, allowing the utility to provision and host more distributed energy resources than is currently possible with existing systems. Under this control architecture, the utility would act as a centralized distribution system operator that performs territory-wide optimization of all distributed energy resources and resource aggregators to reliably supply demand to its customers on the distribution network. In turn, distributed energy resource aggregators would manage and optimize these systems under their assigned topology area to meet the overall dispatch objectives from the distribution system operator. The distribution system operator would allow the utility to manage these distributed resources to improve grid reliability and incentivize owners of these energy systems (such as households with rooftop solar installed) to provide market-based services and receive compensation. This platform could be used not only to host more distributed energy resources on the electric grid but also to supply more demand growth on the existing network (such as growth due to building electrification and electric vehicle adoption). This could lead to deferring distribution upgrades by leveraging non-wire alternative forms of generation capacity on existing networks. This would save ratepayers money in the long run and likely accelerate the downward cost trend of installing residential and commercial distributed energy resources.

Project Approach

The project was divided into a lab and a field demonstration of its distributed energy resource control use cases. The initial technology barriers were centered around developing a methodology of scaling the control architecture in an efficient manner. Also, the project team needed a way to simulate the distributed energy resource use cases that would be executed by the control architecture. Southern California Edison developed a "digital twin" replica model of a substation to simulate a real-time environment to validate the control architecture's use cases. This ensured interoperability could be validated among all control architecture systems prior to the field deployment using actual customer distributed energy resources.

Nontechnical barriers were mostly encountered in the field demonstration, during which customers were incentivized to purchase solar, or solar paired with energy storage systems, for their home or business that would then be used during the six-month field demonstration period. The field demonstration would be critical in understanding the gaps and real-world practicality of the use cases. Since customer acquisition for the field demonstration took place from April 2020 through May 2021, the COVID-19 pandemic presented a major challenge for engaging customers to sign up as participants in this pilot program and enroll their distributed energy resources in the simulated market demonstration. Technology costs were calculated in a cost-benefit analysis that estimated Southern California Edison's return on investment assuming the control architecture could effectively balance supply and demand per circuit within nominal limits.

In terms of engaging with external stakeholders, the project team also created a technical advisory committee (the members are listed in Appendix G). The goal was to share findings and receive feedback from experts in the field of deploying and operating distributed energy resource management solutions.

Project Results

Several benefits of the Electric Access System Enhancement control architecture would enable a utility to host more distributed energy resources territory-wide to balance supply with demand growth.

Enhanced Distributed Energy Resource Interconnection and Control

Streamlining the provisioning process for distributed energy resources was the first point of improvement for the control architecture. New and existing distributed energy resources had to be added to the various systems (distributed energy resource management system, distribution system operator, and distributed energy resource aggregator) in the control architecture prior to establishing end-to-end communication with the distributed energy resource via the aggregator. For the field demonstration, the distribution system operator was able to directly control and optimize the dispatch of a total of 31 customer inverters independently since it had the computational bandwidth. However, in lab simulations of 10,000 distributed energy resources on the Camden distribution substation, it was not possible to individually optimize all the distributed energy resources.

Using the Institute of Electrical Engineers 2030.5 communication protocol standard as a guide, distributed energy resources were grouped under the same switchable segment (with 178 nodes in total) into what is known as topology nodes. This dramatically simplified the computational resources required to optimize distributed energy resource dispatch schedules while still providing enough control granularity to effectively balance supply and demand on the network. In the future, distributed energy resource aggregators could be the utility's primary interface for individually addressing distributed energy resources within these topology nodes. This would allow the distribution system operator to manage higher-level primary feeder constraints more effectively at scale without the burden of having the distribution system operator optimize all customer distributed energy resources individually. Note that this would require distributed energy resource aggregators to have similar abilities to forecast their generation potential and accurately consider energy storage constraints when bidding their distributed energy resources into the distribution system operation market.

The control architecture reached a critical milestone when it successfully provisioned up to 1,000 distributed energy resources per day during a stress test within the digital twin model, while the distribution system operator was dispatching and optimizing distributed energy resources in real time. The distribution system operator was then able to communicate with and dispatch to newly provisioned distributed energy resources the next day as part of its daily optimization routine. Controls and measurements were communicated between the distributed energy resources and their management system via the Institute of Electrical and Electronics Engineers 2030.5 communication protocol for residential/commercial customer-owned distributed energy resources or Distributed Network Protocol 3 communication protocols for utility-owned and large commercial customer-owned distributed energy resources.

Improved Access to Information From Network and DER

This project simulated how improved sensing throughout each major branch in the Camden Substation 12-kilovolt network could be used for detecting constraint violations. With high concentrations of distributed energy resources, voltage stability could be maintained using these energy resources alone, without the need of capacitors to regulate voltage within 5 percent of nominal voltage.

Using DER Efficiently Based on System Load and Electricity Prices

In lab simulation stress tests, the distribution system operator optimized the dispatch of 10,000 distributed energy resources comprising 30 megawatts of solar photovoltaics and 40 megawatts per 117 megawatt-hours of battery energy storage systems for a single distribution substation. Distributed energy resources within Camden Substation's 12-kilovolt network were optimized for two objectives: the lowest cost to serve electricity and minimal line losses for the distribution substation, while maintaining nominal voltage and current levels throughout the network. Optimizations were scaled to be performed daily on a per-feeder basis (seven total on Camden) through alternating-current optimal power flow simulations. Optimal power flow simulations calculated the optimal distributed energy resource dispatch for the day-ahead at

3:00 p.m. in hourly intervals. During the market operating day, the distribution system operator re-evaluated real-time conditions every 15-minutes to adjust schedules to any changes in forecasted distributed energy generation or network demand. In terms of selecting between optimization objectives, loss-optimized dispatches were better suited for managing circuits with high demand, since the losses associated with transmitting higher currents from the substation to a far-away customer could be reduced. Cost-optimized dispatches were better suited for circuits that had lower demand, since distributed energy resources were more likely to export or import power from the grid at maximum nameplate capacity more frequently to maximize financial gain from high or low electricity price fluctuations.

Enabling Dynamic Hosting Capacity Territory-wide to Supply Demand Growth

The three prior capabilities allowed the distribution system operator to effectively balance distributed energy generation and customer demand on the distribution network. This capability allowed the grid to host more distributed energy resources than can traditionally be hosted by distribution lines without expensive infrastructure upgrades. Hosting more distributed energy resources has the added benefit of supplying increased demand growth, sometimes beyond the traditional static capacity limits of the distribution network itself. This is known as a dynamic hosting capacity, which could help utilities manage the forecasted growth in electricity demand as California switches to electric vehicles and appliances. This could also help to establish energy storage and photovoltaic generation as a less intermittent generation resource mix when paired and would allow for distributed energy resources to reliably supplement a larger portion of carbon generation sources (for example, natural gas plants).

Technology Transfer Activities

Southern California Edison intends to make its electric power supply carbon free for its customers. It has a plan and a timeline for how to improve its grid control system and these are shared in its whitepaper, *Reimagining the Grid*. Electric Access System Enhancement's insights feed directly into several grid control requirements.

Several insights and processes from this project will be put into production in Southern California Edison's development of its Grid Management System Distributed Energy Resource Management System Optimization Engine and Short-term Forecasting Engine; initial deployments are expected to be released in late 2024. The Distributed Energy Resource Management System Optimization Engine will follow a very similar process of calculating the next day's distributed energy resource dispatches in the day-ahead market using locational marginal price, load, and weather data as inputs. There will also be a larger variety of market and grid reliability dispatch objective functions to choose from, as well as the ability to consider how traditional voltage and load regulating grid assets (such as capacitors, tap changes, regulators, etc.) will impact the day-ahead optimization process.

The Electric Access System Enhancement project team presented its project findings at various conferences and forums and published a technical paper with the Institute of Electrical and Electronics Engineers. The industry presentations and publications are listed in Appendix C – Industry Presentations & Publications. At the Institute of Electrical and Electronics Engineers Conference on Technologies for Sustainability, the project team shared its vision and approach for developing a scalable and interoperable software for distribution system operators to optimize distributed energy resources for providing grid services and participating in energy markets. At the California Independent System Operator Transmission and Distribution Interface Coordination Working Group, Southern California Edison showcased its working distribution system operator energy market and illustrated how distributed energy resources could respond to locational marginal prices at wholesale nodes and provide grid services on the distribution network. And, finally, at the Department of Energy Solar Energy Technology Office Colloquium, the project team discussed the challenges of, and lessons learned from acquiring and enrolling customers with distributed energy resources in this project and highlighted the value of offering incentives and rewards to customers for providing grid services. These are a few of several presentations and publications that helped disseminate the project findings and learnings, demonstrate the benefits of the distribution system operator software, and identify potential risks and opportunities for future work. The company will continue to share learnings from this project through other upcoming opportunities that may present themselves.

Benefits to California

The architecture demonstrated under the Electric Access System Enhancement project enables the distribution system operator to effectively balance distributed energy generation and customer loads on the distribution network. This capability allows the grid to host more distributed energy resources than traditionally possible, supports local load growth (which is expected to increase due to electrification), and could allow the distribution network to operate beyond its traditional capacity constraints. This has several benefits to customers:

- A reduction in greenhouse gas emissions
- Improved economics of distributed energy resource adoption and integration into the grid
- A more efficient supply to customers
- Deferred capacity upgrades for utilities

By joining a distributed system operation market, distributed energy resource owners can get paid for the services they provide with their energy resources. These services include energy, capacity, ancillary services, and demand response. This can help distributed energy resource owners and aggregators earn more money and lower their costs. For example, in a field demonstration in Santa Ana, California, residential customers with a 5-kilowatt solar photovoltaic and 2-hour battery energy storage system could make up to $462 in 2021 by participating in the simulated distributed system operation market. Over 10 years, this could add up to $4,600 for the customer and improve their return on investment. More participation in the energy market can also lower electricity prices for consumers by increasing competition and reducing the market power of individual suppliers. The distributed system operator software can also support local generation on the grid, which can be more efficient and reduce losses as compared to using power from faraway plants.

Distributed energy resources can help reduce greenhouse gas emissions by increasing the share of renewable energy in the electricity mix and reducing reliance on fossil fuels. They also provide flexibility and resilience to the grid by allowing customers to generate, store, and manage their own electricity demand. By integrating distributed energy resources with smart technologies and digital platforms, customers can use electricity more efficiently and shift their consumption patterns to match renewable generation availability. This maximizes the amount of demand that can be served with distributed energy resources and reduces the dependence on fossil fuels, ultimately lowering greenhouse gas emissions. Combined with Southern California Edison's investments in renewables on the bulk-grid system, by 2045, Southern California Edison expects to see a 339 million-metric-ton reduction in the carbon dioxide equivalent of greenhouse gases. A distribution operation system that more efficiently integrates and utilizes aggregate market resources could help Southern California Edison achieve its target for decarbonizing its electric supply by 2045.

The distributed system operation market can also help utilities avoid costly upgrades in some areas. Utilities can use existing distributed energy resources and encourage more distributed energy adoption in areas where the grid needs more capacity. A simple analysis showed that Southern California Edison could recoup its investment of over $400 million in its Grid Modernization plan by avoiding some upgrades by 2040. It could save another $300 million by 2045 when it reaches carbon neutrality. This assumes Southern California Edison can use the right mix of controllable distributed energy resources with a distribution system operator and assumes that distributed energy resource growth reaches the 10 gigawatts of storage and 30 gigawatts of generation expected on the distribution network by 2045. These savings can lower the electricity prices for customers, especially with a greater electric load from building and vehicle electrification.

Chapter 1: Introduction

Southern California Edison's Move to Carbon Neutrality

Southern California Edison (SCE) is planning for an evolving power grid in the coming decades and is working to decarbonize its electric power supply. It has detailed its plans to modernize the grid and reach carbon neutrality in two whitepapers: *Reimagining the Grid* (SCE, 2020) and *Pathway 2045,* both by Edison International (SCE, 2019).

Reimagining the Grid is a comprehensive assessment of how the grid must change to support California's greenhouse gas reduction goals and the imperative for power to be carbon free by 2045. Compared to today, **2045 will see a 60 percent increase in electricity demand and a 40 percent increase in peak load** that will have to be met by carbon-free generation sources.

Integrating more carbon-free generation sources requires a computing architecture that can dynamically manage often intermittent carbon-free generation sources at higher concentrations than those seen today. By effectively managing distributed energy resources (DERs), intermittency power can be stored and delivered as needed to match demand.

Addressing the Technology Gap

The computing architecture that can effectively manage the generation intermittency of DERs through energy storage and curtailment does not exist; and SCE does not have the capability to host a large volume of DERs on its circuits without a distributed energy resource management system (DERMS) and a distribution system operator (DSO) market platform. DERs are only interconnected based on the network's static hosting capacity. High concentrations of DERs require network upgrades to ensure that the unmanaged power flow between demand and generation can be handled by the network.

SCE has approximately 200 megawatts (MW) of storage and more than 4 gigawatts (GW) of solar. Also, DER concentrations are not high enough throughout the territory to support the DER service use cases in this report. Today SCE serves 23 GW of peak demand territory-wide, but this is projected to increase by 40 percent (32 GW) by 2045 due to the electrification of the state's economy and population growth. In the future, 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 DERs and wires-only solutions. This could incentivize more people to participate in the DSO market, leading to increased DER adoption.

As the economy becomes more dependent on electricity as its primary fuel, it is projected that up to 50 percent of single-family homes in California will have customer-sited solar, driven by improved economics, building codes, and supportive, 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.

Project Purpose

The Electric Access System Enhancement (EASE) project was conceived to fill the technology gap that currently prevents SCE from hosting a large volume of DERs on its circuit. EASE would streamline DER interconnections, improve supervisory access to grid assets and DERs, and optimize DERs for grid reliability and market-based energy services. The objectives under this project were responsive to the U.S. Department of Energy's broader goals within its Enabling Extreme Real-time Grid Integration of Solar Energy grant research program. To achieve these goals, the EASE research team implemented a control architecture that was a hybrid between a centralized and a distributed control architecture. Under this control architecture, the utility would act as a centralized distribution system operator that performs territory-wide optimization of all DERs and DER aggregators, to reliably supply demand to its customers on the distribution network. In turn, DER aggregators would manage and optimize DERs under their assigned topology area to meet the overall dispatch objectives from the DSO. The DSO would allow the utility to manage DERs to improve grid reliability and incentivize DER owners to provide market-based services and receive compensation.

In the future, this platform could be used not only to host more DERs but also to supply more demand growth on the existing network. This can potentially defer distribution upgrades by leveraging non-wire alternative forms of generation capacity on existing networks. This would save ratepayers money in the long run and likely accelerate the downward cost trend of installing residential and commercial DERs.

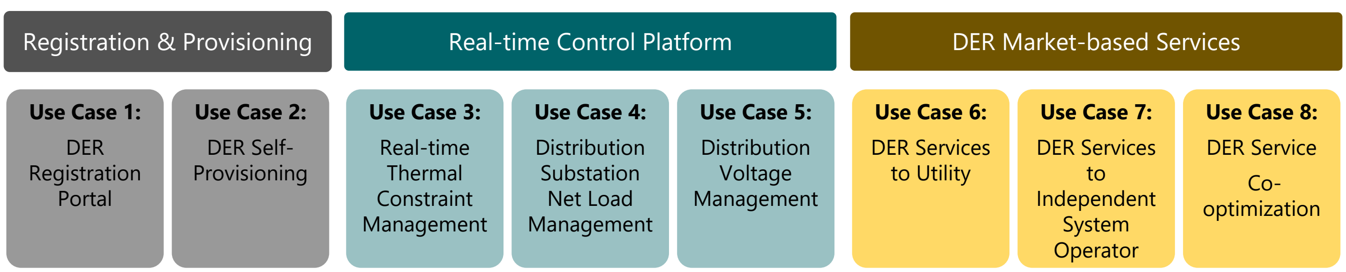
Chapter 2: Project Approach

Project Scope

The Electric Access System Enhancement (EASE) project was designed to streamline DER interconnections, improve supervisory access to grid assets and DERs, and optimize their use for grid reliability and market-based services.

To achieve these goals, the EASE research team implemented a scalable, hybrid-control architecture that was both centralized by the DSO and distributed among DER aggregators. This would allow the utility, as the DSO, to manage the overall distribution network while relying on DER aggregators to execute specific topology-group optimization objectives. The control architecture would allow the utility to manage DERs to improve grid reliability and provide market-based services that benefit the utility, utility customers, and the California Independent System Operator (California ISO). The project's use cases are contained within three categories as summarized in Figure 1.

Figure 1: Overview of EASE Use Cases



Source: Southern California Edison

DER Registration and Provisioning: EASE created an online registration portal to allow customers to apply for connection online and provide more visibility into the timescales and costs associated with interconnection (Use Case 1). Self-provisioning of generators would also ensure that DERs could be remotely commissioned and registered within the DERMS. This would reduce overall interconnection time and on-site commissioning time for larger resources (Use Case 2).

Real-time Control Platform: EASE established a real-time control platform that would enable the utility to maximize the available DERs and load hosting capacity on the network. This platform would be used to manage new generation against thermal and voltage constraints. The real-time control platform would be able to communicate with individual devices and aggregators, which would enable net load management of different distribution substations within the test network (Use Cases 3, 4, and 5).

DER Market-based Services: Finally, EASE provisioned market-based DER services using the DSO. These market-based services comprised dispatch schedules and prices calculated through a system integrated with SCE's utility integration bus (UIB) and were carried out using the real-time control platform described in category two. The platform would enable energy services to be traded between the California ISO, other DERs, the utility, and other customers to increase network use and provide local resiliency (Use Cases 6, 7, and 8).

The EASE project team was composed of the following organizations:

- Southern California Edison (SCE): lead organization and system integrator
- Smarter Grid Solutions: DERMS platform
- Opus One Solutions: transactive energy platform for DSO functions
- Kitu Systems Inc: third-party DER aggregator platform
- Clean Power Research, Inc: interconnection portal
- National Renewable Energy Laboratory: solar photovoltaic forecasting expertise
- City of Santa Ana: field demonstration site

Project Challenges

The main technology barrier for implementing the control architecture was developing a scalable architecture that could be used for controlling DERs territory wide. In addition, developing a secured connection to external DER aggregators was essential to enabling the DSO to communicate and manage multiple third-party DER aggregators. The nontechnical barriers of this project involved incentivizing customers to purchase solar or energy storage systems for their homes and businesses that would then be used during the six-month field demonstration. Integrating the control architecture within SCE's production systems was the biggest challenge for the project team, especially the deployment of a secure connection to a third-party DER aggregator that would ultimately dispatch and monitor customer DERs. It is uncommon for SCE's production systems to control a third-party entity that, in turn, controls DERs, and this functionality had not yet been used at such a capacity with the Institute of Electrical and Electronics Engineers (IEEE) 2030.5 communication protocol. Moreover, product vendors had to migrate their lab deployments into SCE's production environment and face additional scrutiny regarding patching requirements, cybersecurity penetration testing, and source code scans. Aside from challenges related to implementing the EASE control architecture, the COVID-19 pandemic posed a significant challenge to the project's attempt to acquire 100 customers for the field demonstration. From 2020 to mid-2021, the project team was able to acquire only 31 DERs in the Camden Substation area located in Santa Ana, California. For reference, it was found that, in ideal conditions, the 31 DERs would have at most a 1.5 to 2 percent impact on local distribution network switch current or voltage levels, which may not be significant enough to identify during testing. The Lessons Learned section of DERs in Chapter 3 describes how this lower number of customers affected test results and which use cases were affected.

Technology Costs

The capabilities demonstrated in EASE are on SCE's grid modernization roadmap for future technologies to deploy. In its Grid Modernization Plan, SCE estimated that it would cost more than $400 million to make the investments needed to improve its computing capabilities (SCE, 2021). These capabilities would increase situational awareness of the grid, better forecast demand, and optimize DERs to generate power when needed most. This cost was used as the estimated technology cost to enable the capabilities of the DSO system once it reached production.

SCE's planned investments in Grid Modernization — Over $400 million

Technical Advisory Committee

The following organizations were members of EASE's technical advisory committee that provided feedback on the project's results. Members of the California ISO provided feedback and insight as to how services provided by DERs (Use Cases 6 to 8) should be valued within the DSO, using real-time electricity prices from the ISO. The project team met with members of Quanta to discuss the project team's experience in trying to acquire customers to purchase DERs for the project as it related to SCE's Alberhill project, which also performed a propensity analysis to gauge customer interest in purchasing solar and storage systems.

- Electric Power Research Institute
- Commonwealth Edison Company
- Navigant
- Smarter Grid Solutions
- Consolidated Edison
- Quanta
- University of California, Riverside
- General Electric
- California Independent System Operator (California ISO)
- University of California, Irvine
- California Institute of Technology
- California Energy Commission (CEC)
- U.S. Department of Energy

Chapter 3: Project Results

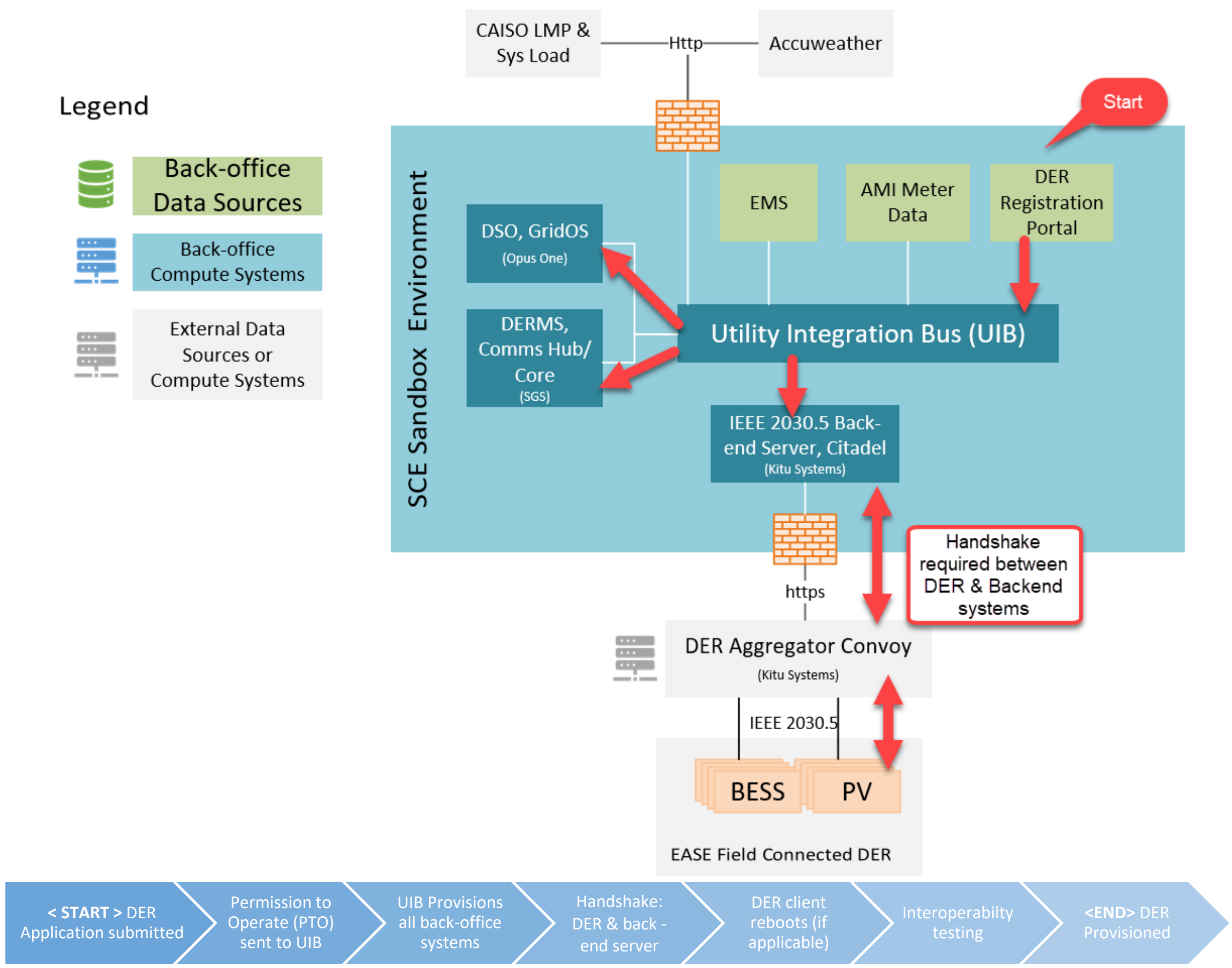
DER Provisioning

This section describes the method used in the DER provisioning process and discusses the lab and field test results. Lessons learned from the lab and field tests are discussed at the end.

Provisioning Methods

The provisioning process of a new DER into the control architecture was initiated when a DER was given permission to operate by SCE, as depicted in Figure 2. DER nameplate information, such as the maximum and minimum active and reactive power, DER type, storage capacity, and installed location, were submitted to the UIB. The DERMS, DSO, and IEEE 2030.5 server then subscribed to the provisioning event and added the DER into their systems. This provisioning process was designed to run in the background of the real-time operation of existing DERs. The control architecture was tested to handle 1,000 DER registrations a day.

Figure 2: DER Provisioning Process

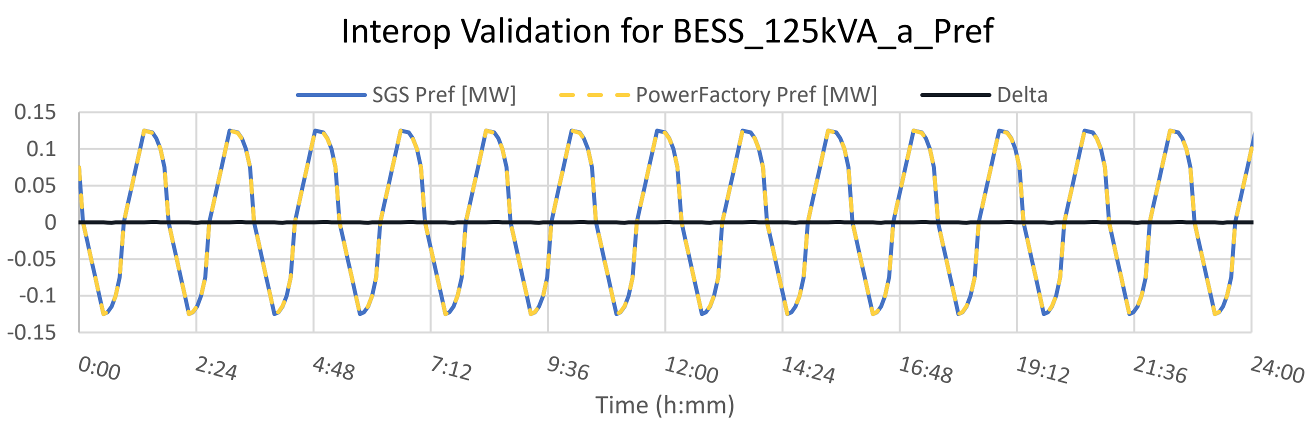


Source: Southern California Edison

Interoperability Testing

After DERs were provisioned into the control architecture, their connection was validated through interoperability tests. For initial lab testing, individual and aggregate device tests were leveraged to see whether the DER control setpoints were actioned by the simulated inverters. Figure 3 shows an example of a single DER interoperability test where controls (labeled PowerFactory Pref [MW]) were sent to a newly provisioned battery that was charged and discharged at its maximum nameplate rating of 125 kilovolt-amperes (kVA). The expected result was that the measured output (labeled SGS Pref [MW]) would follow the dispatched control, and the delta would be zero (black line).

Figure 3: DER Interoperability Validation



Source: Southern California Edison

This test was repeated for each newly provisioned DER to ensure interoperability. The following criteria were assessed for interoperability:

- 100 hours of uninterrupted connectivity and operation at all nodes
- Operation of all inverter quadrants
- No break in communication such that all controls and measurements were exchanged between the DER and DERMS/DSO systems
- Minimal difference between control and measured output of inverter

Lab Validation

Scalability testing of the control architecture solution was validated using the PowerFactory model of the Camden Substation as a digital twin for provisioning a simulated DER into the DERMS, DER aggregator, and DSO. This tested the provisioning process under a high applicant throughput scenario where 1,000 simulated DERs were provisioned into the control architect-ture through the DER utility portal over a 10-day period (10,000 DER interconnections total). The scalability testing considered the approximate DER asset distribution by size and type, as shown in Table 1.

Table 1: DER Asset Distribution by Size and Type

DER Size	4.5 kW	500 kW	1,000 kW	1,400 kW	Total
BESS Quantity	4,450	37	7	1	4,495
PV Quantity	5,479	26	-	-	5,505
Total Quantity	**9,929**	**63**	**7**	1	**10,000**

BESS= battery energy storage system; PV=photovoltaic

Source: Southern California Edison

In addition to testing provisioning capacity, this test evaluated how well the control architecture would continue incorporating more DERs into its DER optimization objectives as new DERs were provisioned at the end of each day. The optimization objectives tested during scalability testing were the DERMS' constraint management and feeder net load management optimizations. Provisioning among the control system and the DER had to be completed for the 10,000 DERs in a reasonable amount of time, such that they could be used the next day. For scalability testing, a batch file was used with the DER provisioning information listed in Table 2. This file was uploaded to the DER registration portal to simulate 1,000 applications being submitted all at once. The DER provisioning event then published newly added DERs among the various systems of the control architecture (DERMS, DSO, and DER aggregator) and was ready to use for the next day's DER optimization control scheme. Table 2 provides a description and an example of the data fields that were updated in preparation for testing.

Table 2: Data Field Descriptions and Values

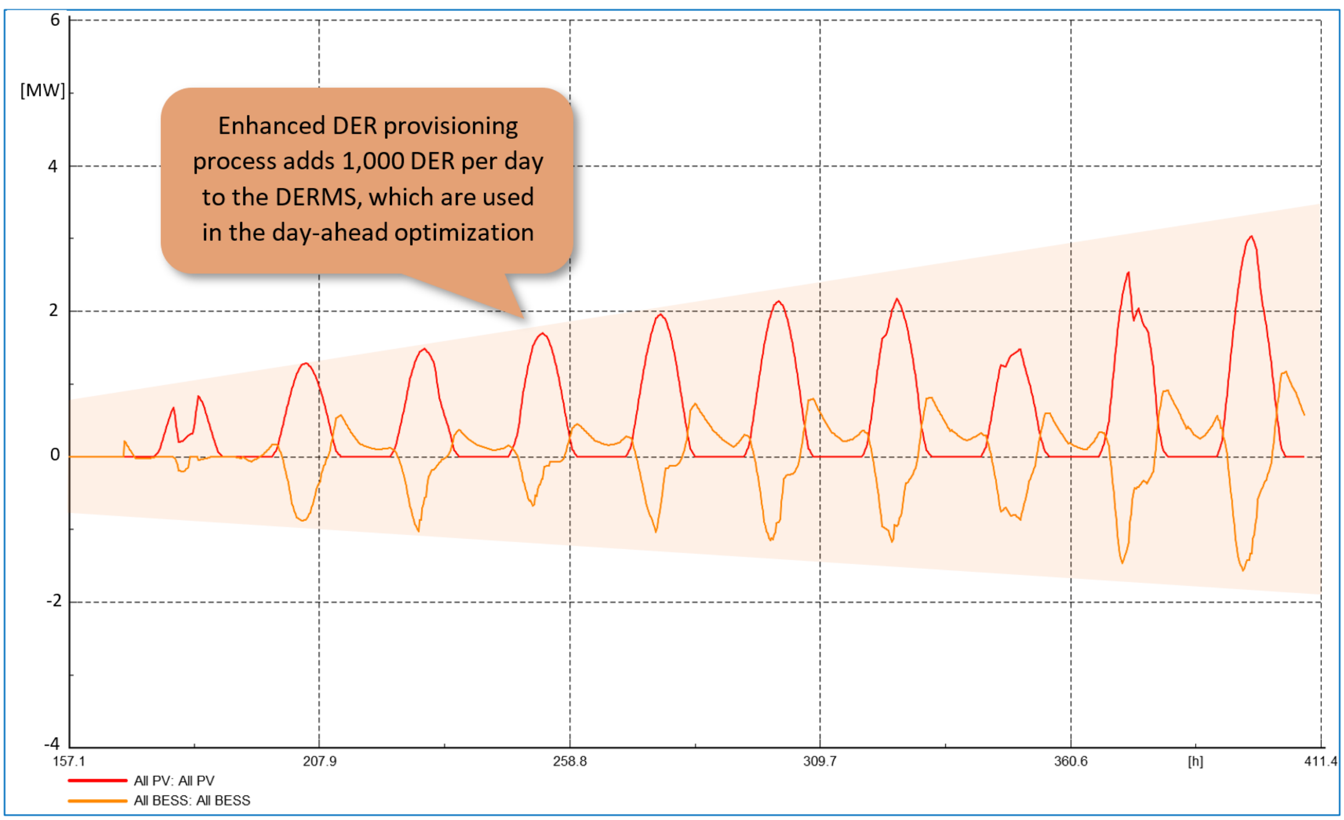
Data Field	Definition	Initial Value
{data: Application Type 2}	Type of interconnection application	New registration
{data: DER Type}	Type of DER	Energy storage or photovoltaic
{data: Max P (kW)}	Max active power output	Based on DER size in model
{data: Min P (kW)}	Min active power output	0
{data: Max Q (kVAR)}	Max reactive power output	Based on DER size in model
{data: Min Q (kVAR)}	Min reactive power output	0
{data: Battery Capacity (kWh)}	BESS energy output	Based on BESS size in model
{data: DER Control Type}	DER control method	Aggregated (IEEE 2030.5) or Directly Controlled (DNP3)
{data: DER LFDI}	Unique ID for aggregated DERs	(variable)
{data: Topology Node ID}	Topology relationship for aggregated DERs	(variable)
{data: Aggregator ID}	Aggregator relationship for aggregated DERs	Camden
{data: Communication Device Serial Number}	Device serial number for directly controlled DER	(variable)

Data Field	Definition	Initial Value
{data: Communication Device IP Address}	Device IP address for directly controlled DER	(variable)
{data: Feeder ID}	Feeder/circuit connectivity of DER	(Alloy, Aluminum, Bismuth, Cadmium, Cobalt, Titanium, Uranium)
{data: Node ID}	Connectivity node ID	(variable)
{data: Provisioning Status 4}	DER provisioning status	null

Source: Southern California Edison

Figure 4 shows the results of the feeder net load management optimization as it occurred in real-time over the 10-day period as 1,000 DERs were provisioned into the control architecture each day. The DERMS was demonstrated to manage all battery energy storage systems (BESS) and photovoltaic (PV) for the duration of the study, with the objective to flatten the feeder load for each of the DER's seven respective feeders on the Camden substation. Overall, energy storage systems were mainly charging during the daytime and discharging during the evening or early morning to support a flattened net load at the feeder head. Note that, in all charts going forward, positive active power profiles indicate DERs exporting power to the grid (generation) and negative values indicate customer demand, or energy storage importing power from the grid (load).

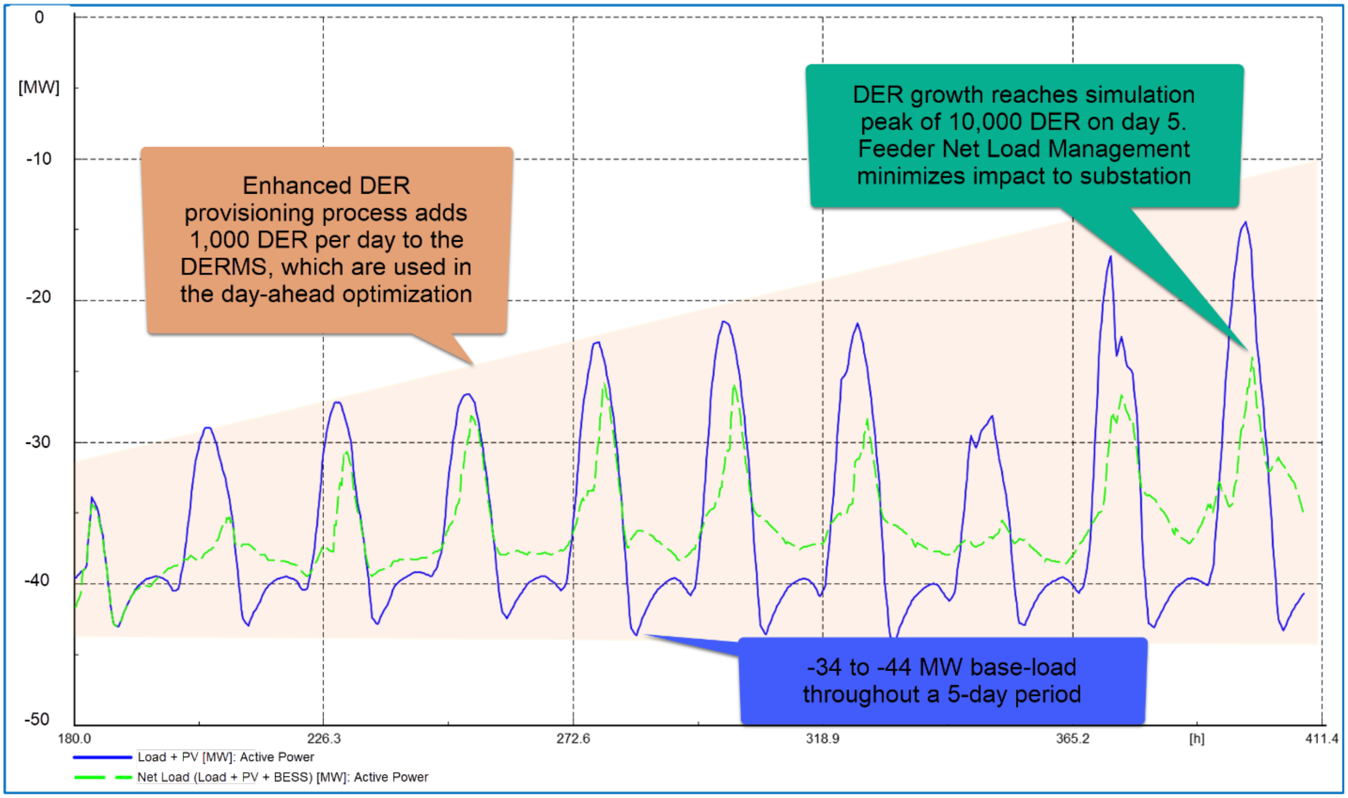
Figure 4: Substation Total Load PV Generation and BESS Contribution



Source: Southern California Edison

Figure 5 illustrates the impact the DERs had on the load throughout the 10-day period. Without a load leveling system in place, PV caused significant dips in power during the day when customer demand was typically at its lowest point. By day 10, all 70 MW/140 megawatt-hours (MWh) of DERs were added to the Camden Substation. The results show that using BESS and PV, the DERMS was successful in minimizing the rapid changes in net load on the feeder even as more DERs were provisioned.

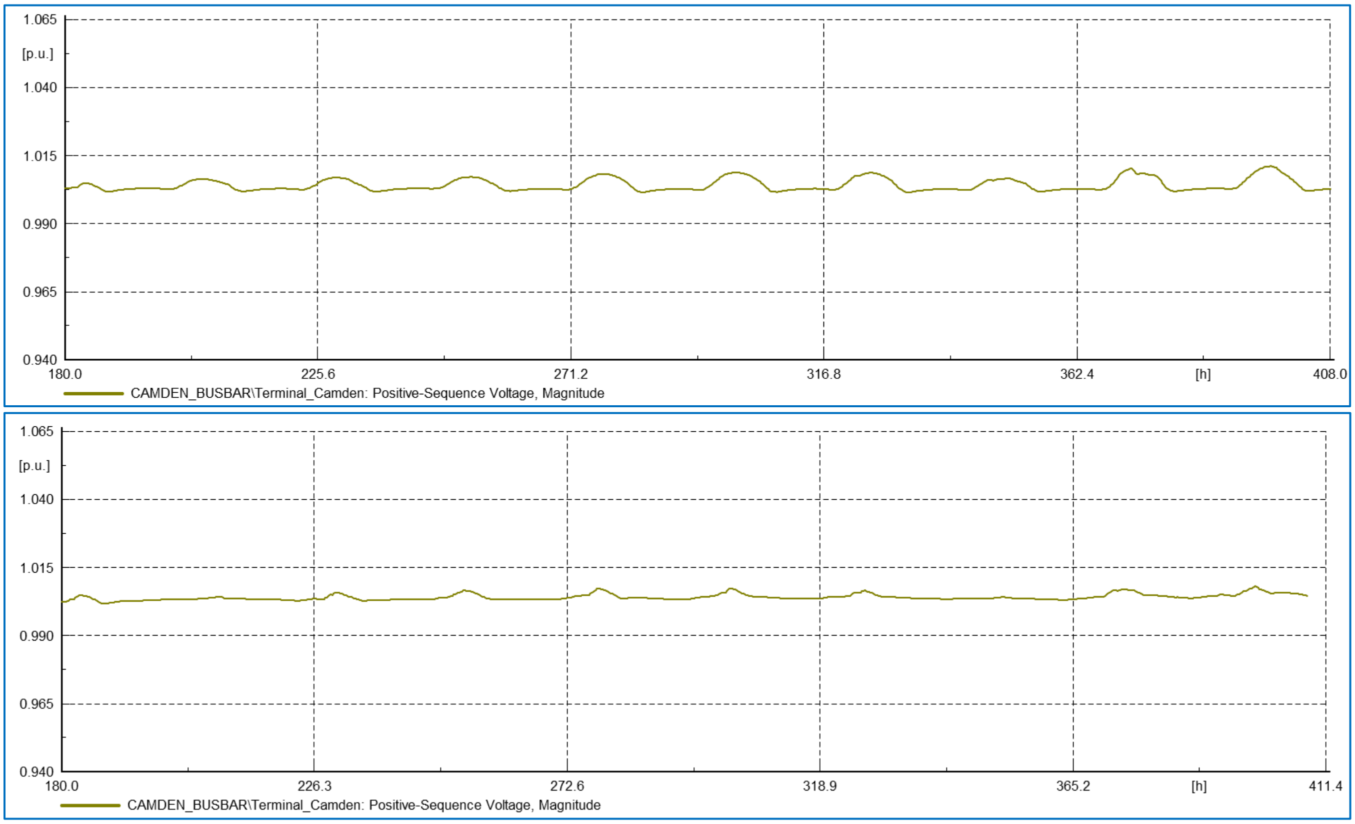
Figure 5: System Net Load Without and With Optimum Battery Contribution



Source: Southern California Edison

During the 10-day test, the voltage at the substation was also monitored to ensure the DERMS was able to manage voltage within the nominal limits. The top plot in Figure 6 shows the voltage profile without any battery contribution, and the bottom plot shows the voltage with BESS operation. Although voltage fluctuations were typically more stable at the substation, these values were well within the acceptable operation limits of 5 percent of nominal, especially having provisioned the 10,000 DERs. Voltage variations were roughly 1 percent less when energy storage contributed to flattening the net load profile. Note that branch voltage fluctuations may have been different depending on the circuit load and the DER concentrations in each area.

Figure 6: Camden Substation Voltage Profile Without and With BESS Contribution



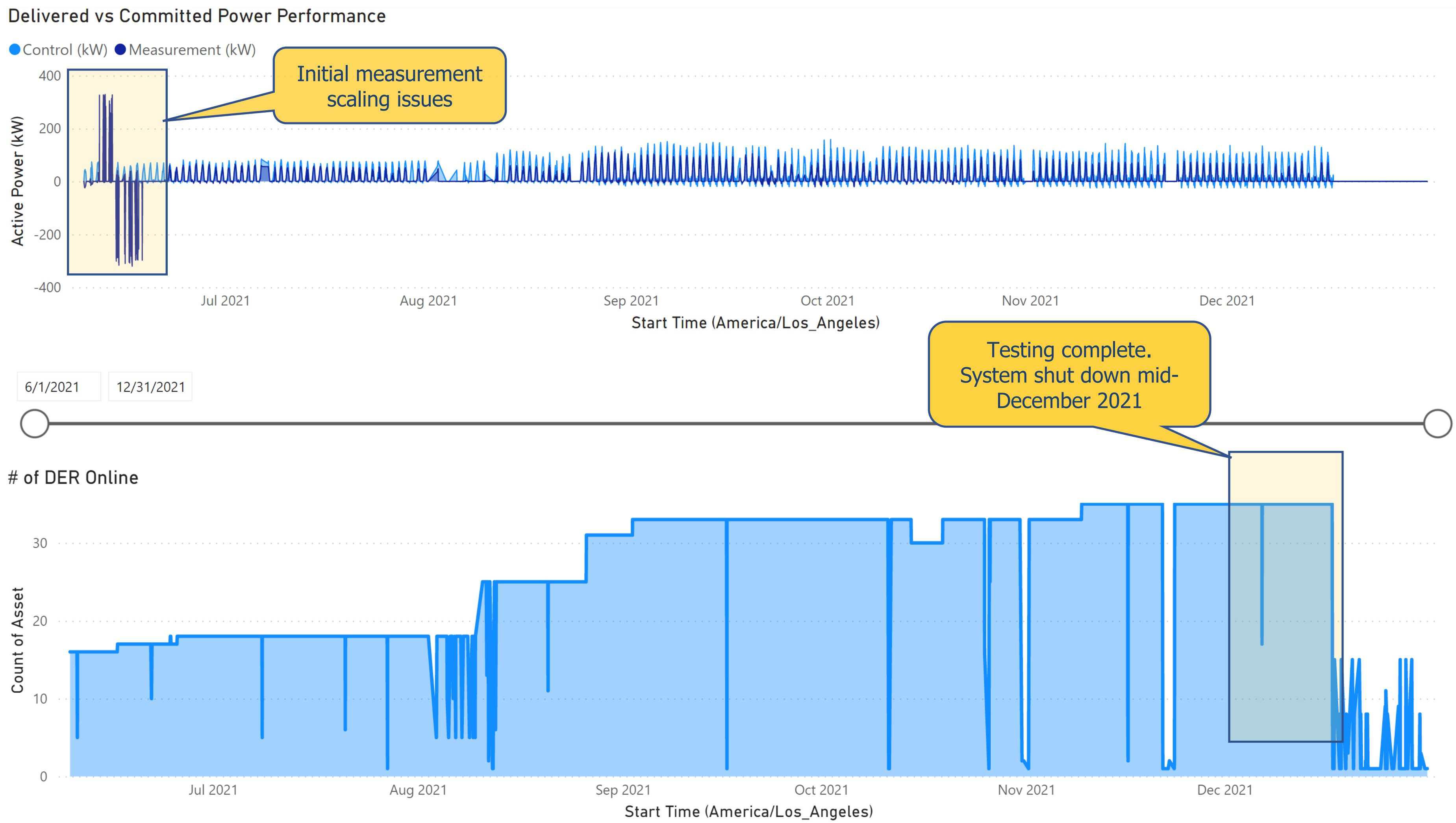
Camden Substation voltage profile without (top) and with (bottom) BESS contribution.

Source: Southern California Edison

Field Validation

For the field demonstration, the provisioning process was identical to what was demonstrated in the lab, but it occurred on a much smaller scale. As DER customers had their solar and battery systems installed, they were provisioned into the system in small batches. Figure 7 shows the timeline when DERs were provisioned into the control architecture. Initially there were 17 inverters that were provisioned into the system at the start of June 2021; by November 2021, all 31 inverters had been provisioned after some installation delays. Initially, there were minor issues with provisioning in June 2021, where measurements were not scaled with the correct multiplier, but this was corrected with a software update. Occasionally, the subsystems of the control architecture went down temporarily throughout the testing period, typically due to various bugs that were identified and fixed. By mid-December 2021, all EASE software systems were shut down within SCE's data center and were no longer communicating with the DER aggregator, signaling the end of field testing.

Figure 7: DER Provisioned Over Time in Field Demonstration



Source: Southern California Edison

Lessons Learned

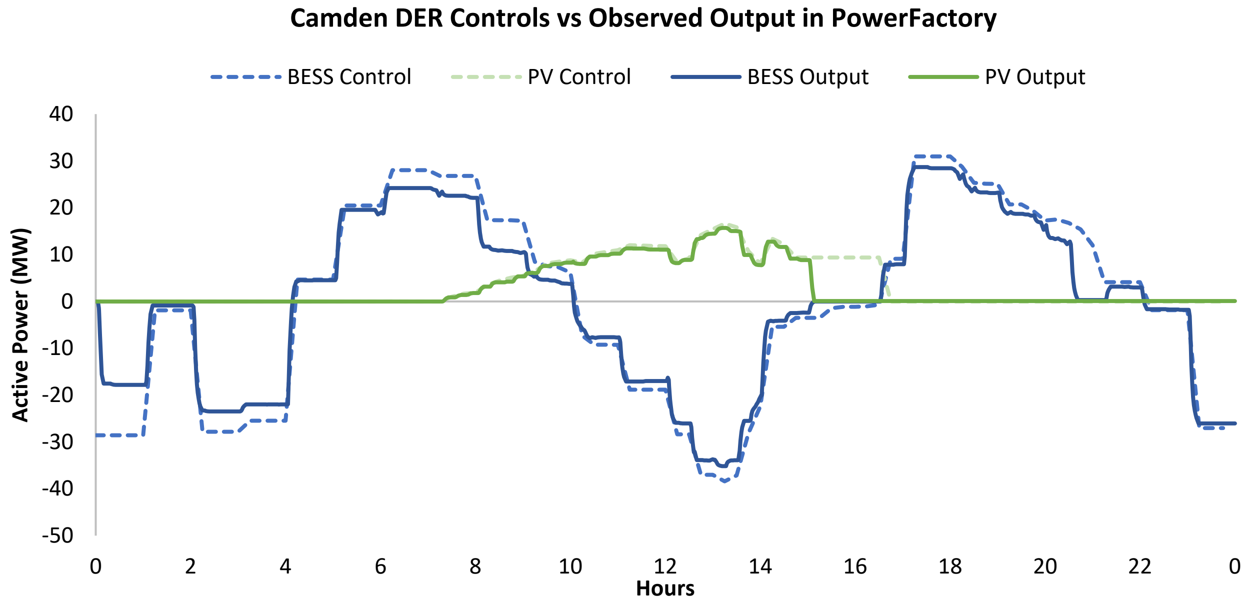
The following section lists the lessons learned and final takeaways from the provisioning process, comparing both the lab and the field results. The DER provisioning process initially seemed robust in terms of 1) provisioning a large volume of DERs and 2) validating interoperability on individual inverters.

Issues of Scaling and Validating Provisioning Interoperability

Interoperability testing worked well with a small number of DERs, but the system had to be scaled to allow for 10,000 DERs to be provisioned into the control architecture. There were initial challenges with reliably provisioning all DERs, even though these systems were designed to handle the throughput of 1,000 provisioning requests daily. To address this, SCE worked with vendors to refine the system processes and ensure that each provisioning event was detected and processed correctly.

Provisioning issues also revealed a gap in the control architecture's ability to validate device interoperability at scale. During initial lab tests, interoperability was verified by comparing the aggregate power dispatched by the DERMS to the measured output of the simulated inverters, as shown in Figure 8. This provided a quick way of analyzing interoperability for the 10,000 DERs on Camden Substation without significant automation development. However, this strategy was unreliable, since the simulated inverter output often did not match the measured output for aggregate PV and BESS, as shown in Figure 8. These mismatches could have been caused by brief communication failures during real-time operation and inverter output losses, making this process somewhat inaccurate for ensuring that all DERs were successfully provisioned. For scalability, implementing automated health checks throughout the provisioning process would have helped troubleshoot these issues at scale. This improvement in a production system is discussed later in this section under Implementing Automated Health Checks.

Figure 8: Aggregate DER Controls vs Observed Output in Real-time Software-in-the-loop Simulation

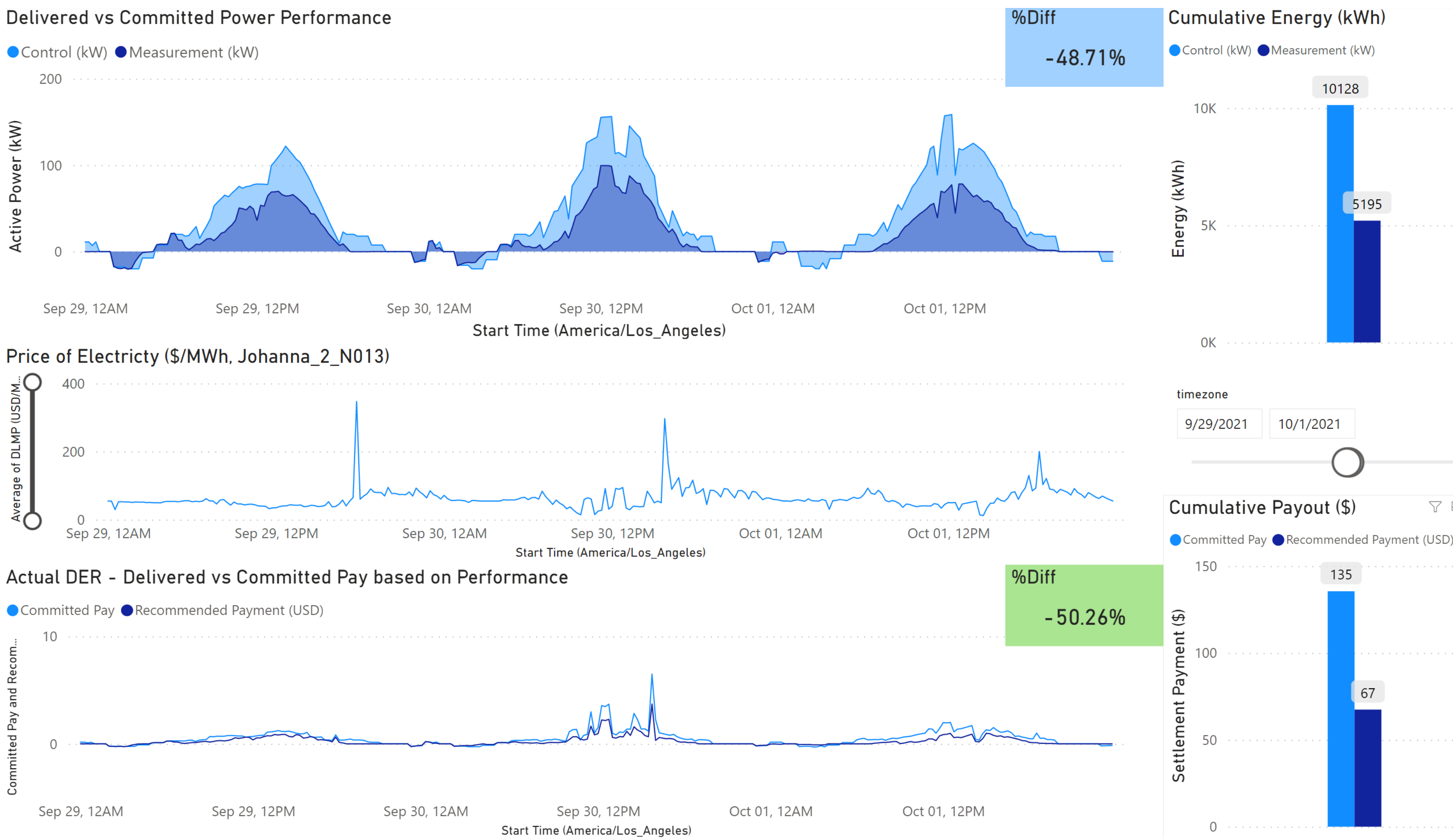


Source: Southern California Edison

Dashboards Provided a More Reliable Way to Manage Resources

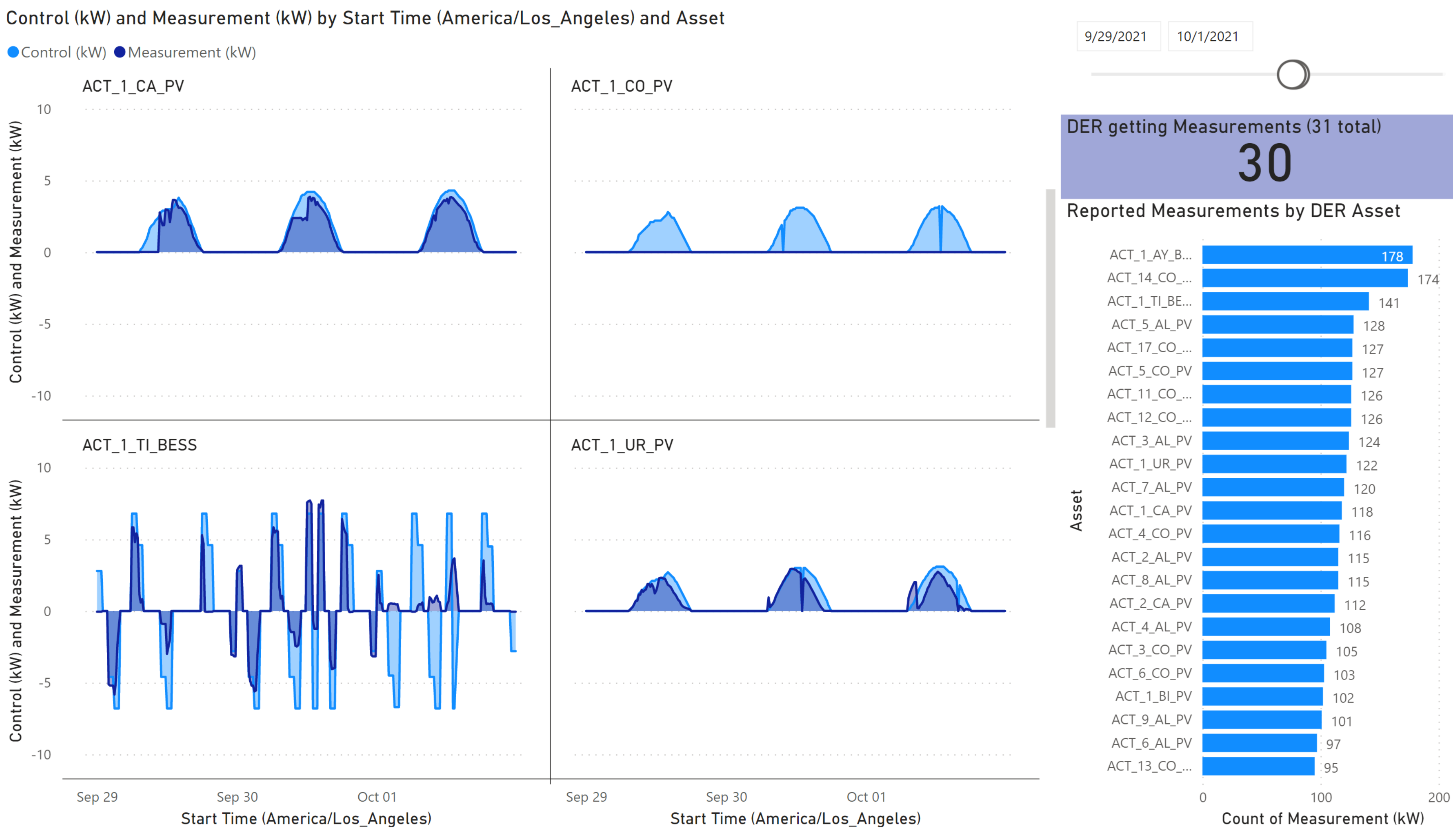
A slightly more robust approach to interoperability testing was implemented for the field deployment of 31 DERs. Several dashboards were constructed to pull data from control architecture systems to reflect the state of operation of the control architecture at scale. They were essential for getting an operator view of the system's overall performance and allowed the operator to drill more deeply into the behavior of individual DERs. Aggregate and individual DER controls were tracked in Figure 9 and Figure 10, respectively, to gauge their performance for a given substation, and these dashboards were designed to be scaled across multiple substations. It also showed how many of the total DERs were transmitting measurements back to the control architecture, along with the difference between controls issued versus the measured inverter output over the selected date range. This information could then be actioned through automated alerts, where operators were notified of an unresponsive DER. A DER owner or aggregator could also be contacted to reconnect the DER. This helped to automate the identification process of DERs with interoperability or communication issues. Note that, during field testing, it was common for DERs to fall short of the dispatched control due to unforeseen cloud coverage, insufficient solar array output to meet the targeted control, or round-trip direct current (DC) to alternating current (AC) conversion losses.

Figure 9: Sample Dashboard of Aggregate DER Performance



Source: Southern California Edison

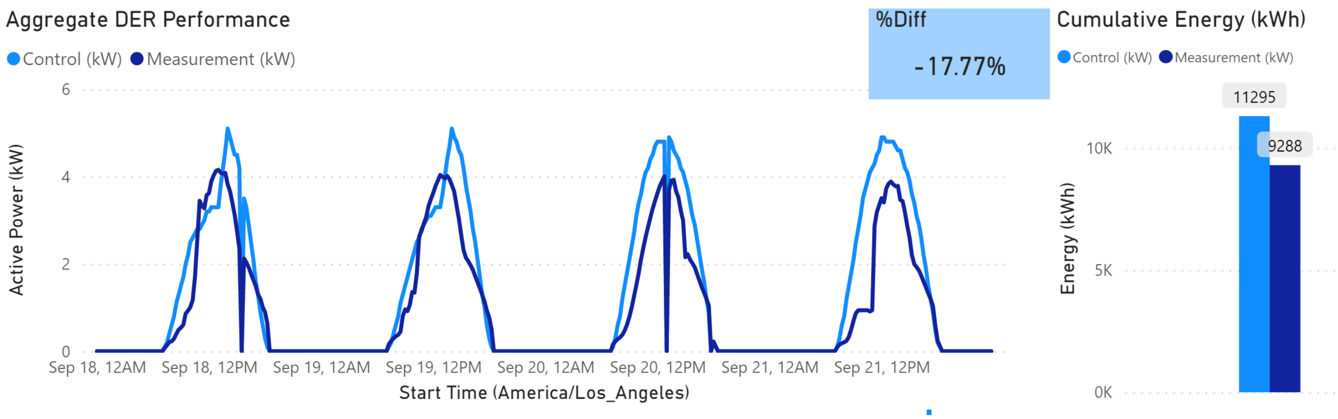
Figure 10: Sample Data Dashboard of Individual DER Performance



Source: Southern California Edison

Aggregate DER performance was tracked using the measured systemwide DER output and was often used to identify systemwide issues. Figure 11 shows an example of this, where the percent difference (denoted as % Diff) between the control and the measured PV output was normally -17.77 percent on average, but higher differences could have been attributed to communication issues. To make this more scalable territory-wide, this could be automated, such that abnormally high percentage differences in the aggregate or in individual DERs would trigger an automated task to perform internal process checks or would contact the appropriate parties (such as the DER aggregator or customer) in their system appeared offline.

Figure 11: Total Delivered vs Committed Performance of All DERs



Source: Southern California Edison

Implementing Automated Health Checks

Automated interoperability tests and inverter client health checks were lacking in the EASE control architecture's lab and field implementation. These improvements will be essential to alerting and resolving DER provisioning or communication issues at scale. Often when DERs were unresponsive, several steps were taken to manually identify the source of error. If a large group of DERs was unresponsive, it was likely a back-end system that had gone offline. If a single DER or a handful of DERs was offline, there were more likely customer network issues, where the DER had lost connection to the home Wi-Fi. The project team developed the dashboard tools to identify these issues but lacked the ability to resolve them in a quick and automated fashion. Communication issues were common and sometimes took several hours or days to resolve. Ultimately, this led to some DERs not performing the required services as scheduled throughout the day, which could affect grid stability in the future (depending on the scale of the event) if the pool of participating DERs were larger. This is a critical finding in that DER aggregators and the DSO may need to build contingency into how much energy they are able to reliably supply.

DER Constraint Management

This section will discuss the methodology used in the DERMS Constraint Management process, along with lab and field tests results. Lessons learned from the lab and field tests are discussed at the end.

Methods

Typically, hosting capacity is a static value, assigned to a feeder, calculated through engineering studies. Real-time constraint management was designed to manage thermal and voltage violations that could occur throughout the network, to operate the system reliably under uncommon high demand scenarios and improve the DER hosting capacity. Like with capacitors/regulators or shunt reactors, DERs could be used to regulate voltage, current, and power quality at scale in real-time if violations occur. Constraint management applies to all types of generation, regardless of technology or ownership model (for example, aggregator, utility-owned, customer-owned). The DERMS can temporarily override the DSO's market-based dispatch objective to instead use DERs to alleviate a significant thermal or voltage violation on specific areas of the network. This system acts independently of the DSO and serves as a safety net using the same pool of customer DERs.

Figure 12 outlines the steps required to configure and operate the DERMS' constraint management system. First the utility had to integrate supervisory control and data acquisition (SCADA) sensory information throughout the network (from switches, capacitors, breakers) to provide systemwide visibility for the DERMS. The EASE project assumed that a total of 96 voltage and current sensors were available for the DERMS; these are shown in blue in Figure 13 and Figure 14. The utility then had to set its voltage and current limits for each of these locations, which were automatically derived from the network model by default. Operators then configured individual limits. Once measurements points were defined and limits set within the DERMS, the DER had to be provisioned into the DERMS through the control architecture provisioning process shown in Figure 12. Once the DER was provisioned, the DERMS used the DER's nameplate ratings and connected location to conduct the sensitivity analysis. The sensitivity analysis quantified each DER's ability to influence voltage and current throughout its connected feeder.

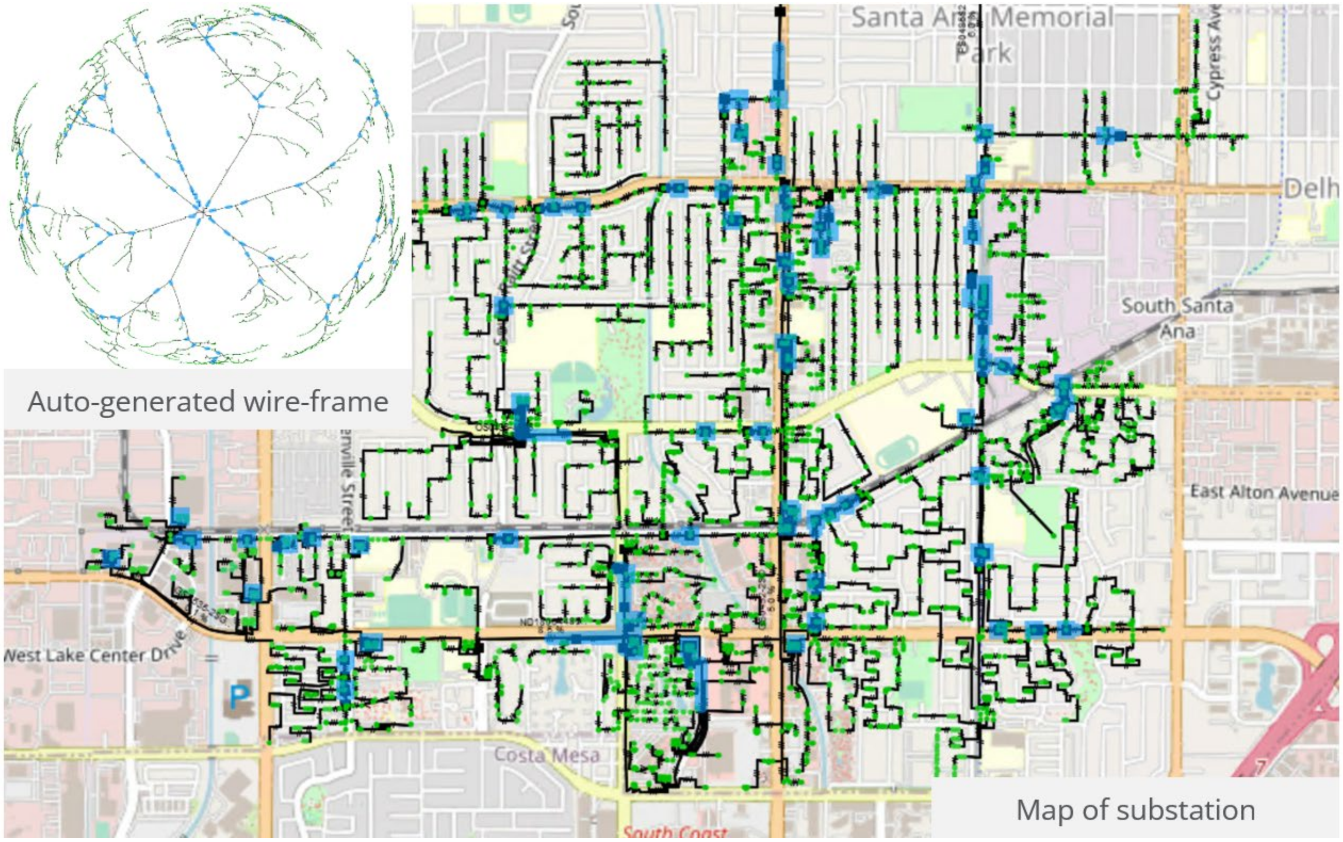
Figure 12: Constraint Management Setup Process

1. Operator to identify measurement points on the circuit
2. Operator to set voltage and current regulation thresholds in DERMS (ideally pulled from ADMS)
3. DERMS enrolls all provisioned DERs in constraint management program
4. DERMS performs a sensitivity analysis on the network for each DER

1. DERMS detects the breach on a circuit measurement point
2. DERMS selects required dispatch and appropriate DER to alleviate the constraint
3. DERMS slowly releases DER output capacity if voltage/current drops below the "Regulate Less" limit.
4. DERMS releases control back to the DER once current/voltage drops below "Release" limit.

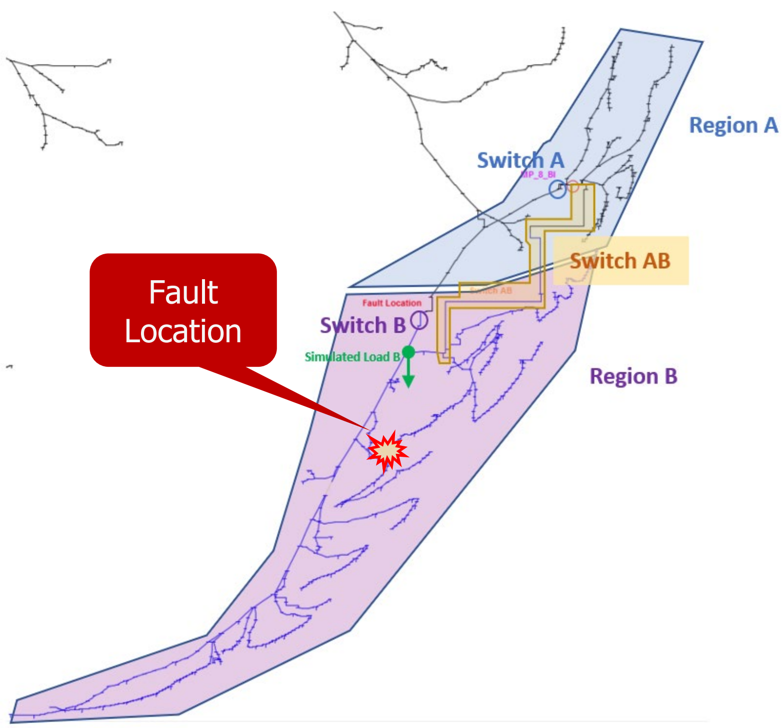
Source: Southern California Edison

Figure 13: Map of 96 Circuit Measurement Points Monitored by DERMS



Source: Southern California Edison

Figure 14: Network Configuration on Bismuth 12 kV Circuit for Constraint Management Simulation



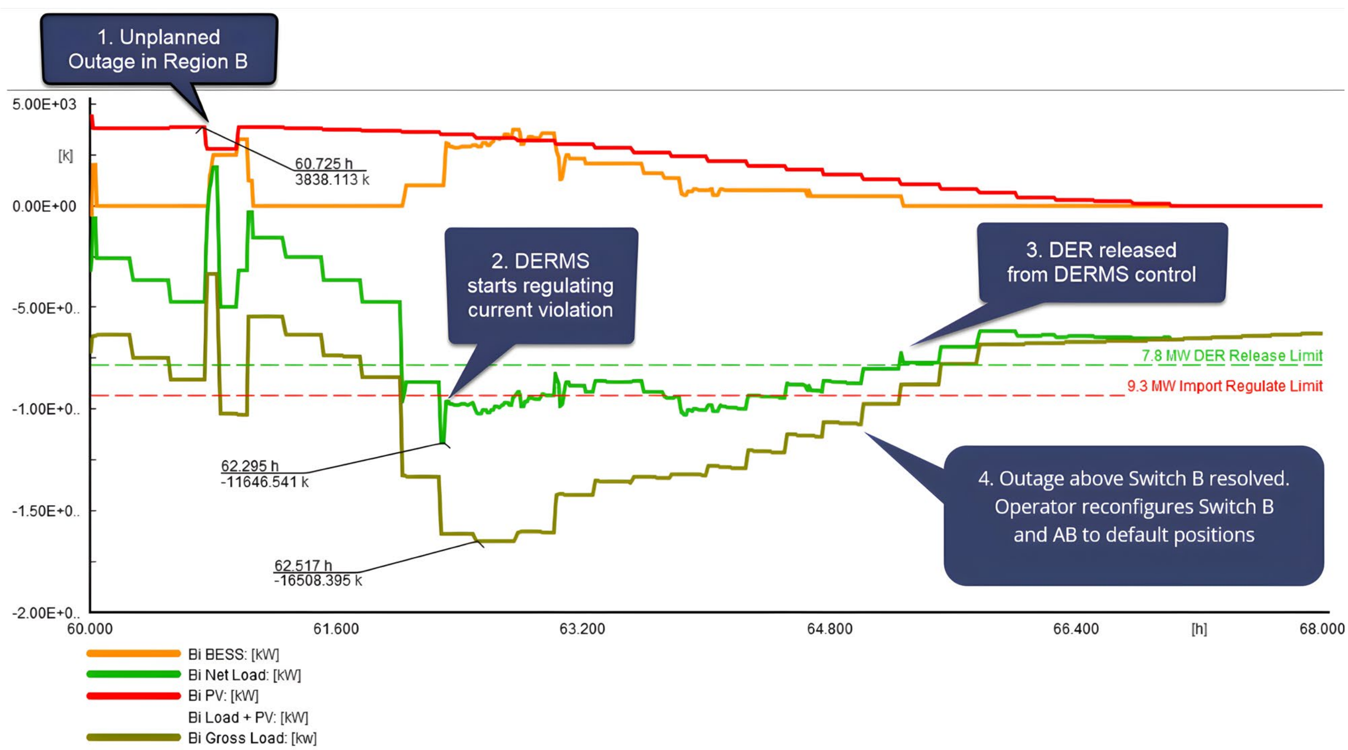
Source: Southern California Edison

Lab Validation

Constraint management was tested with a variety of voltage and current violations using a 10,000 DER model of Camden Substation throughout the course of the project. The most practical application demonstrated was during a real-time simulation of an unplanned outage, where the DERMS had to mitigate higher line loadings and voltage drops. A diagram of the simulation area is shown in Figure 14, where a fault on Switch B caused Region B (purple) to become de-energized. A simulated fault location, isolation, and service restoration (FLISR) scheme restored power through a tie-line on the Switch AB line segment, which restored power to Region B through Region A's supply. This eventually caused a high-loading event that exceeded the planned loading limit of Switch A due to the added load of supplying regions A and B. This caused the DERMS to go into constraint management mode to mitigate the high-loading event, using the DER best suited to alleviate the constraint, as determined by the sensitivity analysis. The loading event eventually subsided and the DERMS released control of the DER back to the DERs to resume the energy services they were instructed by the DSO to provide that day.

Overall, the DERMS system was able to work with the simulated FLISR system after power was restored to mitigate unplanned high loading and low voltage. The aggregate BESS and solar PV generation dispatches, gross feeder loading, and net loading of the Bismuth 12 kV circuit are shown in Figure 15, where positive values are generation and negative values are load. The DERMS prevented a current violation from deviating far from the 9.3 MW limit and released control of the DER once the overcurrent event subsided below its 7.8 MW DER release limit.

Figure 15: Summary of Bismuth Constraint Management Event



Source: Southern California Edison

As a result, all the success metrics listed in Table 3 were met. As shown in Figure 15, some DERs went offline in Region B due to the outage but reconnected to the DERMS once power was restored after the FLISR operation. The gross load in Region B peaked at 16.5 MW, which triggered a voltage violation within one of the circuit measurement points in Region B. At hour 64.8, Switch B was re-closed after the fault was repaired and Switch AB was opened. Loading continued to fall until it eventually dropped below the 7.8 MW DER release limit, where the net loading was low enough for the DERMS to safely release control back to the DER. The DERMS carried out the tasks listed in Table 3 in real time via software-in-the-loop simulation.

Table 3: Constraint Management Simulation Success Metrics

Pass/Fail	Description	Comments
Pass	**Prevent Overcurrent/Undervoltage:** The constraint management system prevents an overload from occurring at Switch A (measurement point ID MP_8_BI), or any of the other 14 circuit measurement locations, when switch A is supplying power to both Regions A and B after the fault event.	DERMS regulated constraint at MP_1_BI (Feeder head) and voltage constraints at MP_10_BI to MP_14_BI (all in Region B).
Pass	**Dispatch DER Efficiently:** DERMS commands BESS and PV to export at max to alleviate the overloading event.	BESS & PV exported when appropriate.
Pass	**Compatible with ADMS FLISR Operation:** The DERMS constraint management system does not disrupt the switching operations (or vice versa), cause any anomalies that can lead to another constraint, or dispatch a DER in an unproductive manner that worsens the constraint.	No unplanned switching or anomalies occurred during constraint management.

Note: ADMS = advanced distribution management system

Source: Southern California Edison

For more information on how the DERMS' constraint management system works, see Appendix B – DER Constraint Management. For a detailed map of the DERMS circuit measurement points and the DERs under its control, refer to Appendix E – DER in 9.2.1 Simulation.

Field Validation

For the field demonstration the DERMS' ability to mitigate the voltage and current constraint violations was validated according to the process in Appendix B – DER Constraint Management. More conservative violation limits were used to make constraint management more aggressive, since constraint violations were uncommon except for brief voltage drops. For reference, voltage never exceeded 5 percent of nominal voltage over the entire six-month test period, so constraint management would never have triggered if more typical, relaxed violation limits were used. Table 4 shows (right) the violation limit at which DERMS constraint management would kick in and (left) the DER release limit where the DERMS would gradually begin relaxing control over the DERs until the violation subsides.

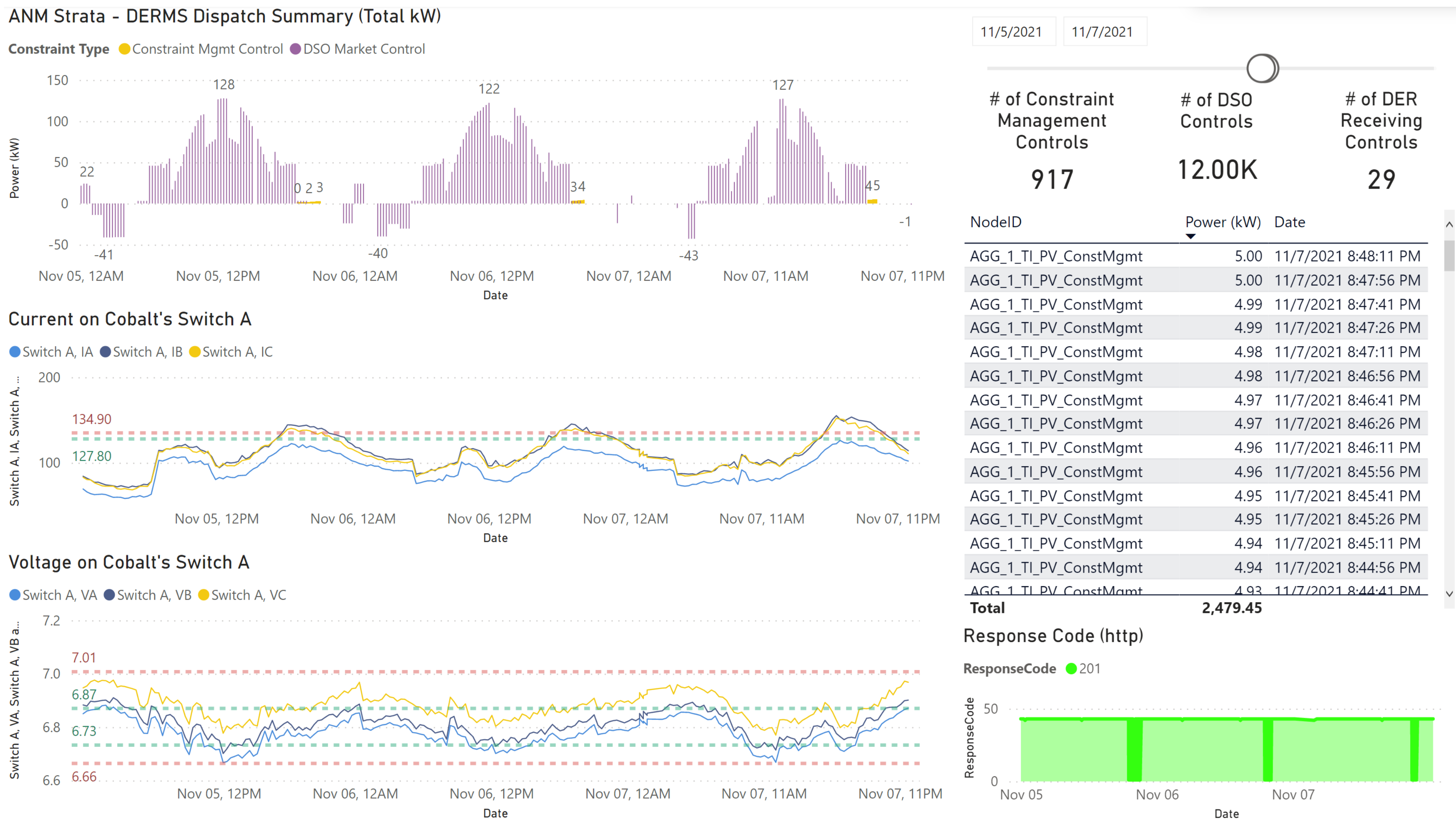
Table 4: Voltage and Current Violation Triggers, DERMS Constraint Management

DER Release Limit	Violation Limit
< 127.8 amps - or - 6.73 kV > voltage range > 6.87 kV ("nominal" voltage range)	> 134.9 amps - or - High Voltage Limit > 7.01 kV Low voltage Limit < 6.66 kV

Source: Southern California Edison

DERMS constraint management tests were validated using data from the energy management system (EMS) and the DERMS control dashboard, as shown in Figure 16. Controls are categorized as either DSO Market Controls or Constraint Management (or "Mgmt." for short) controls.

Figure 16: EMS and DERMS Control Dashboard



Source: Southern California Edison

EMS voltage and current data from the SCADA equipment on Switch A allowed the project team to detect when a violation was breached and verify that the DERMS responded properly. A series of health checks also confirmed that the DER aggregator received the DER control from the DERMS. Unfortunately, it was not possible to demonstrate constraint management operating at scale with all customer DERs during the field demonstration due to bugs and integration issues. Issues are discussed in greater detail in the following Lessons Learned section.

Lessons Learned

The following section lists the lessons learned and final takeaways from the validation of DERMS voltage and current constraint management. This section compares the practicality of the constraint management use cases while controlling real customer inverters distributed throughout a substation network. Throughout the course of the field demonstration, there were several issues:

- Interoperability issues between the DERMS and the distribution management system (DMS)
- Control transmission delays between the DERMS and the DERs
- Identification of the right number of measurements on the network
- Considerations for when constraint management is most effective

DER Constraint Management Requires High Concentrations of DER

It was no surprise that some of the project use cases were negatively impacted when only 31 DERs, rather than the target 100 DERs, were acquired for the demonstration. In total, these amounted to 167-kW generation capacity and 56 kilowatt-hours (kWh) of storage. This low concentration of DERs had a moderate impact on Use Cases 3, 4, and 5. Had 100 customers been acquired, and assuming the average customer had 5 kW of solar and 10 kWh of storage, there would have been roughly 500 kW of generation and 1 MWh of storage capacity distributed throughout the substation. This, of course, would have been the best-case scenario, but the project team was far from attaining that goal despite its one-year customer acquisition campaign. Naturally, this lower concentration of DERs was predicted to have a moderate impact on demonstrating the voltage and current constraint management use cases, since they require larger DER capacities. A summary of the impacts per use case is detailed in Table 5. The project team’s mitigation strategy was to use the DER’s behavior as an indicator as to whether the DERMS constraint management functionality was working for Use Cases 3 through 5. The DERMS’ voltage and current constraint violation limits were also reduced below a normal operating level to trigger constraint management more easily. This was done since voltage and loading are typically within nominal operating ranges. These mitigations allowed the project team to reduce the impact of having a low customer count from a severe to a moderate impact.

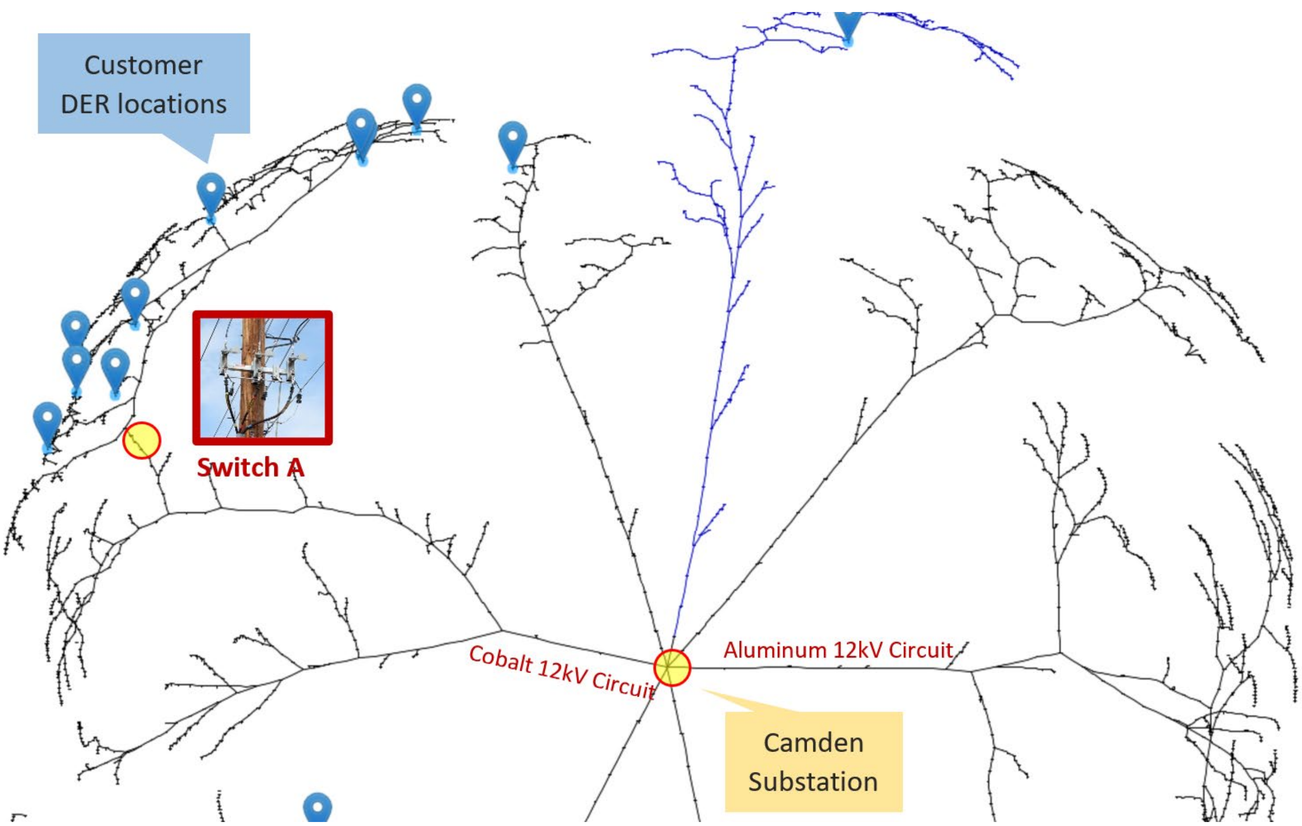
Table 5: Impact of DER Reduction to EASE Use Cases

EASE Use Case	Impact	Mitigation
1. DER Registration Portal	No impact	None
2. DER Self-Provisioning	No impact	None

EASE Use Case	Impact	Mitigation
3. Real-time Thermal Constraint Management	Moderate Impact	Use DER behavior as indicator for validating DERMS functionality. Artificially reduce DERMS constraint limits where possible to trigger DER behavior.
4. Distribution Substation Net Load Management		
5. Real-time Voltage Constraint Management		
6. DER Services to Utility	No Impact	None
7. DER Services to Independent System Operator	No Impact	None
8. DER Service Co-Optimization	No Impact	None

To estimate what the constraint violation limits should be, and to quantify the impact of the use cases, a sensitivity analysis estimated the voltage or current impact per number of DERs (assuming a 5.4 kW average/DER). The highest concentration of DERs was located under Switch A, as shown in Figure 17, which was estimated to have the most significant impact on influencing the network voltage or current.

Figure 17: Acquired DER Customers Downstream of Switch A on Camden Substation

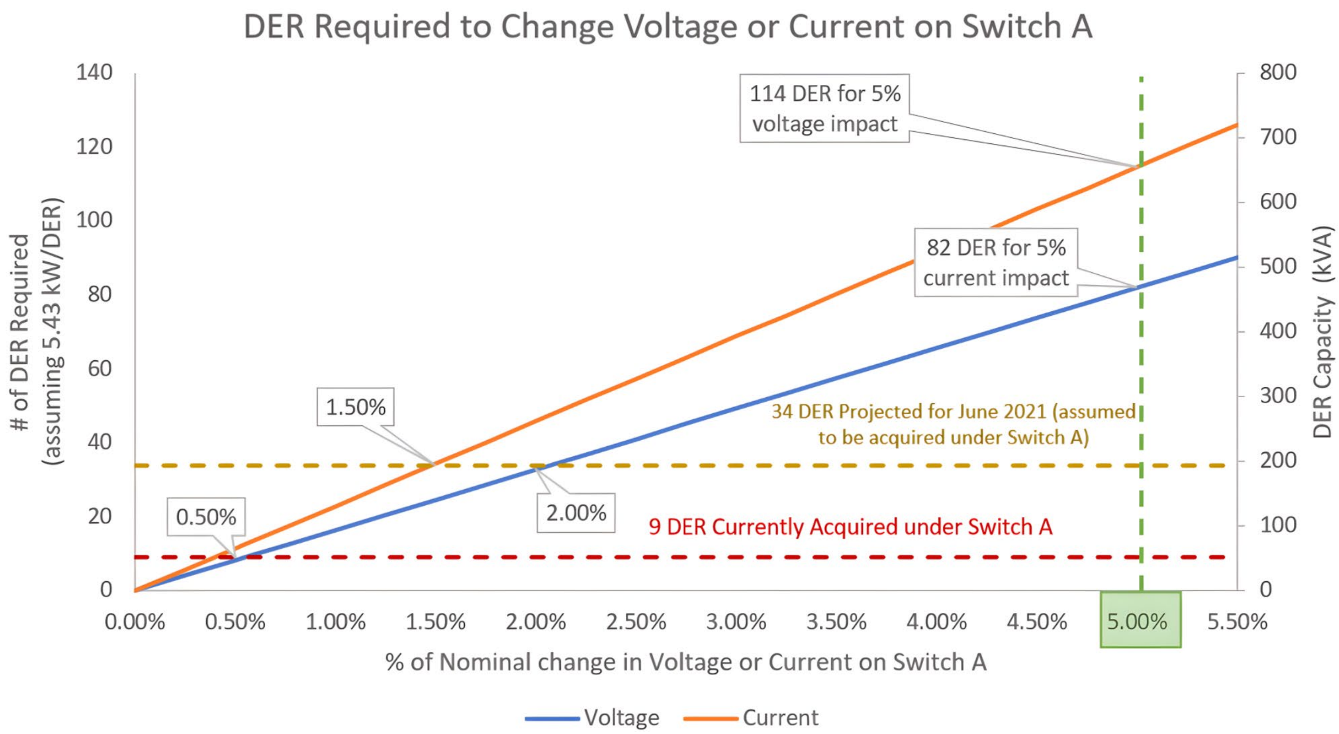


Source: Southern California Edison

As Figure 18 illustrates, roughly 82 DERs (445 kVA) would have been sufficient for a 5 percent reduction in current, and 114 DERs (619 kVA) would be required for a 5 percent boost to voltage at Switch A. If there had been sufficient storage capacity, then a reduction in voltage and current could also have been observed slightly below the magnitude listed in Figure 18.

These compromises in the DERMS' ability to noticeably manage network violations were an inevitable consequence of having a small concentration of DER.

Figure 18: DERs Required to Affect Change in Voltage/Current Under Switch A



Source: Southern California Edison

DERMS Interoperability Issues With EMS

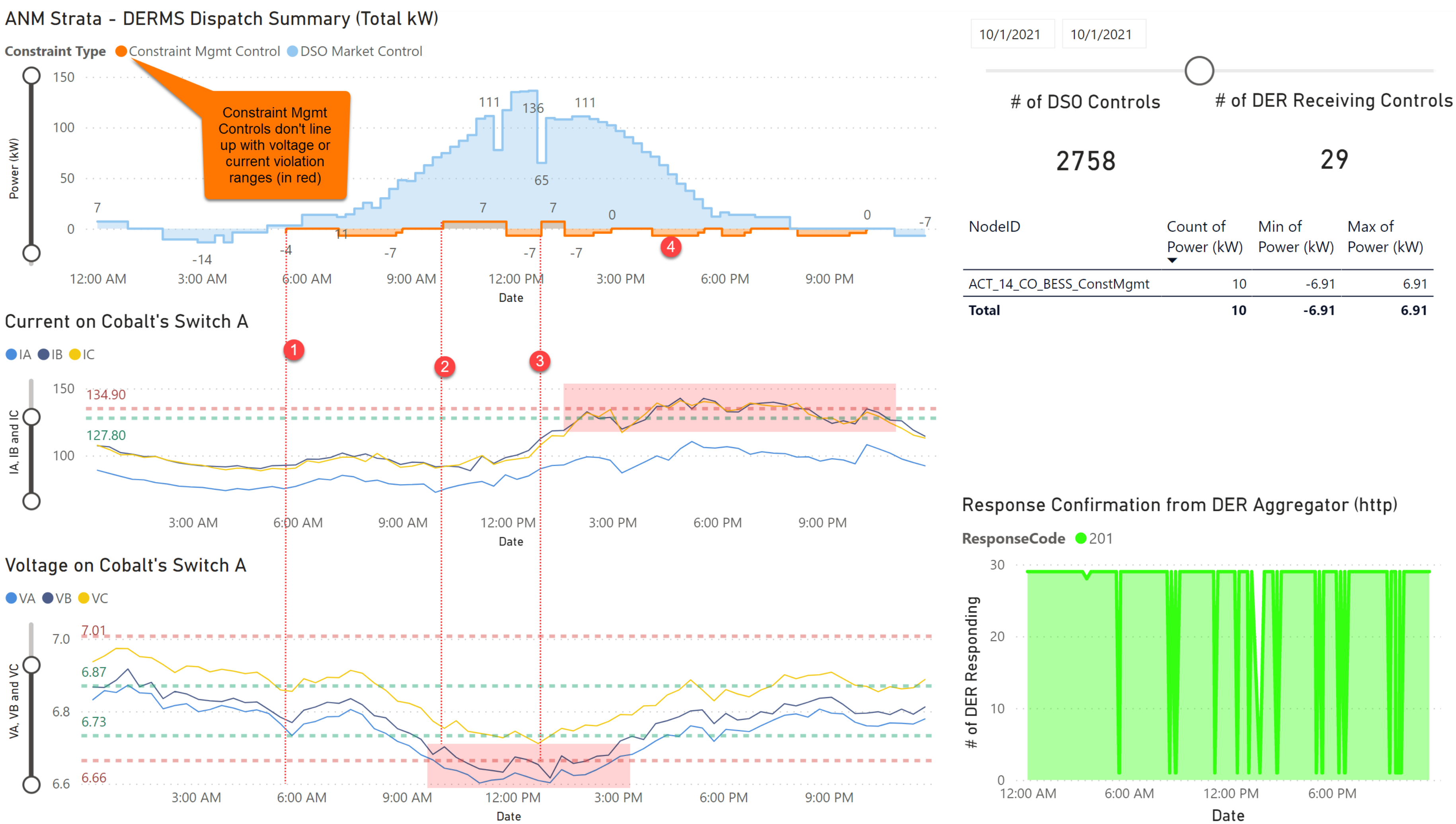
During the project's field demonstration phase, there were significant interoperability issues between the DERMS and the EMS. The DERMS and the EMS were connected via the UIB (see Figure 2), and the UIB was initially thought to be the source of the error because it was not reporting any measurements to the DERMS. A data historian on the DERMS was configured to store all measurements collected from the UIB, and this data collection verified that the UIB was not the source of the error. It was determined that 1) the DERMS had incorrect violation limits configured, and 2) the DERMS had lost the nameplate ratings of almost all DERs, preventing it from dispatching the DER when a violation was detected. The incorrect circuit measurement violation limits caused the DERMS to trigger constraint management at unexpected times. The lack of DER nameplate ratings then caused most DERs to be unresponsive even when violations occurred, since the DERMS assumed it had few DERs of sufficient capacity to manage the event. This can be seen in Figure 19, where the DERMS incorrectly dispatched just one BESS identified as ACT_14_CO_BESS on Cobalt from 6:00 a.m. to 9:00 p.m. on October 1, 2021. ACT_14_CO_BESS dispatches did not line up with when constraint violations were expected to occur, as shown in Figure 19. The violation limits in Figure 19 reflect the limits expected from Table 4 but not the actual limits programmed into the DERMS.

The following list summarizes the issues observed in the DERMS' response, as numbered in Figure 19.

1. DERMS incorrectly began dispatching only ACT_14_CO_BESS to charge at up to -7 kW at markers 1 through 4 when no voltage/current violations occurred.
2. DERMS may have correctly dispatched ACT_14_CO_BESS to export power at 7 kW when voltage dropped below the 6.66 kV regulate limit on markers 2 and 3, but no other DERs on Cobalt were used. For reference, there was a total of 3 battery/solar and 18 solar-only systems, as shown in Appendix F – DER Acquired for EASE.
3. At 12 p.m. the DERMS once again began to dispatch ACT_14-CO_BESS to charge at -7 kW for about an hour and then reverted to exporting at 7kW. This occurred as the phase B voltage (VB) oscillated above and below the 6.66 kV limit, but the DERMS should not have changed its dispatch strategy (at marker 3) to charge the BESS. Charging should have occurred only when voltage rose above the 7.01 kV upper regulate limit.
4. From 1 p.m. to 10 p.m. the DERMS only dispatched ACT_14_CO_BESS to charge up to -7 kW intermittently. This somewhat corresponded to the time the current exceeded the 134.9 ampere regulate limit on phases B and C (IB, IC), but the correct response would have been to dispatch all BESS and PV to export.

The takeaway from this was that all vendor systems should have adequate logging to identify interoperability and configuration issues. Similar issues occurred during lab testing but were more efficiently resolved and identified, since a data historian was set up from the start to log all DERMS activity. At the start of field deployment, the DERMS was not set up with a data historian due to timing constraints to commission the system. This prevented the project team from having sufficient logging information to understand why the DERMS was not responding correctly to voltage/current violations. By the time the data historian was set up and the issues were identified, there was not enough time to deploy fixes and validate that they were fully resolved. As a result, DER constraint management never fully demonstrated its capability to mitigate unexpected voltage and current violations on the network.

Figure 19: Constraint Management Testing During Field Test



NodeID	Count of Power (kW)	Min of Power (kW)	Max of Power (kW)
ACT_14_CO_BESS_ConstMgmt	10	-6.91	6.91
Total	**10**	**-6.91**	**6.91**

Source: Southern California Edison

Additional Communication Delays Between DERMS, DMS, and DER

During the project's field demonstration, several challenges occurred between the integration of the EASE project's DERMS and SCE's DMS. The first implementation challenge involved the DMS measurement post rate. The DMS published feeder voltage and current measurements every 20 minutes on average, which was far less frequently than the lab deployment's one-second post rate. The major downside to having a lower measurement post rate was that a voltage or current event may not be detected until 20 minutes later. Furthermore, the DERMS did not see the impact that its DER had on the voltage or current since it took an additional 20 minutes for the feeder measurement to update. This led to a 40-minute round-trip delay before the DERMS could verify that a violation was both detected and had started to be mitigated. This delay was too long for constraint management purposes, and capacitors would have reacted much more quickly to correct voltage. This is not to say that faster measurement post rates were not achievable with the existing SCADA interface to Switch A; rather, the read-only EMS interface did not allow for a more frequent measurement post rate at the time of testing without impacting production settings. Appendix B – DER Constraint Management provides a description of the timing constraints required for constraint management to work effectively.

In addition to DMS measurement post delays, there was, on average, a five-minute delay for field DERs to output a requested control by the DERMS. This delay was likely attributed to network latency from SCE's grid data center to the DER aggregator and finally to the customer DER via customer Wi-Fi hotspots. DER inverter clients also polled new controls from the DER aggregator every 30 seconds, which could have added an additional delay, depending on when the next control poll occurred. By comparison, simulated DERs were able to receive controls every minute, on average, in the lab deployment. This simulation did not accurately reflect real-world communication delays, since all servers sat on the same back-end network.

Another way to improve the DSO system is to make the DSO update the best DER dispatch for the rest of the day if a DERMS constraint management event happens. This would help because the battery state of charge of the BESS used in the event may have changed from the planned schedule, and the new battery state of charge needs to be considered for the rest of the operating day. Also, DERs do not get paid for participating in constraint management events, and they should get some rewards for their interrupted participation. They should at least get paid for the services they would have provided otherwise or get paid for the grid reliability services they did provide instead – whichever is higher.

Excessive Number of Circuit Measurement Points

There was a total of 69 measurement points throughout the Camden Substation network. These measurement points provided only a single measurement type, so all 69 measurements were unique. For example, capacitors only provided voltage; switches/breakers often only provided current; and more advanced switches provided voltage, current, and power measurements. During lab simulations, however, the DERMS had access to 96 points of measurements that provided voltage, current, and active and reactive power. This totaled 384 individual points of measurements sampled at 96 locations. Typically, to reduce costs, SCADA assets are equipped only with the sensors they need for operation. In the future, it is unlikely that SCADA assets will provide all measurement types. Based on lab simulations, a smaller number of points (such as the 69 points that exist today) would have provided sufficient coverage of a primary feeder to ensure that parameters remained in the nominal range.

Feeder Net Load Management

This section discusses the methods used in the DERMS feeder net load management process and the lab and field test results. Lessons learned from the lab and field tests are covered at the end.

Methods

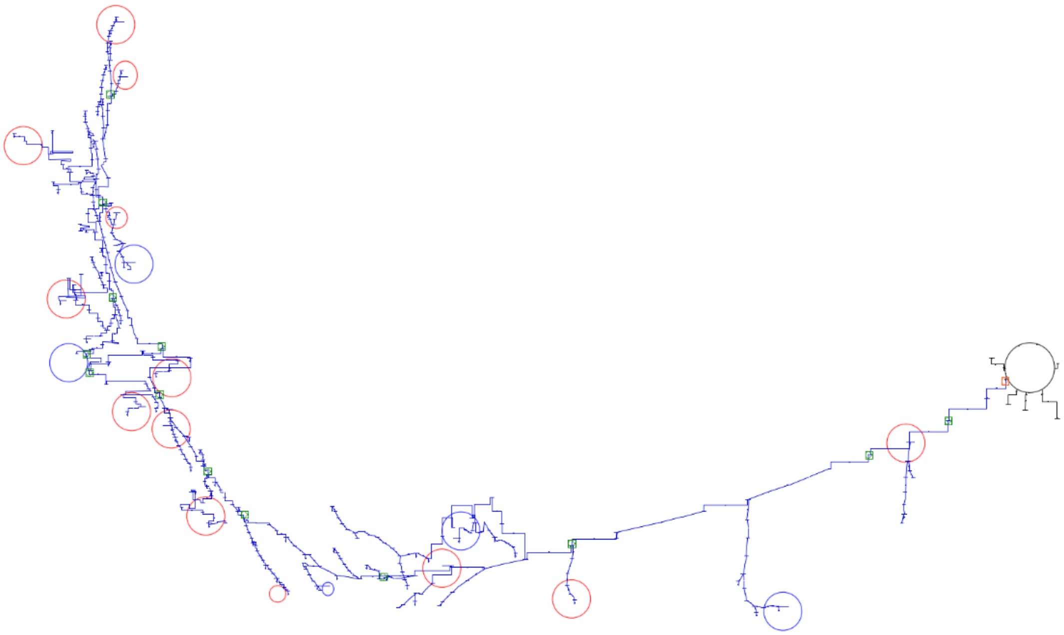
The benefits of load leveling included the mitigation of intermittency associated with PV generation, peak load shifting, improved power quality, reduction of generation ramp rate, and capacity requirements for generators. This could be beneficial on circuits with high or frequent ramps in current and could also stabilize voltage. A process was developed to determine the optimal energy storage schedules to level the circuit net load, considering different load ramp-up rate limitations. The optimization algorithm generated the day-ahead schedules for all the BESS connected to the circuit and worked in conjunction with the DERMS to manage circuit constraints. Optimal energy storage setpoints were communicated to the DERs in real time. The framework of the study consisted of the following steps:

1. Forecasting circuit load and PV generation
2. Determining circuit constraints using power flow
3. Calculating day-ahead optimal BESS schedules
4. Dispatching optimal BESS schedules in real time
5. Re-optimizing based on real-time measurements

Figure 20 shows the simulated circuit under study with high penetration of PV and BESS with the following characteristics:

- Circuit peak load of 6.5 MW
- Total BESS rating of 5.9 MW, where 3.25 MW capacity was from the behind-the-meter aggregated two-hour BESS on 13 different locations on the circuit (highlighted with red circles in the figure) and the remaining capacity was from an individual BESS (highlighted with blue circles) with ratings of either 250 kW, 1.4 MW, or 1 MW.
- Total PV capacity of 4.25 MW, where 3.25 MW capacity was from the behind-the-meter aggregated PVs on 13 different locations on the circuit (highlighted with red circles), and the remaining capacity was from two 500 kW PVs (highlighted with blue circles).

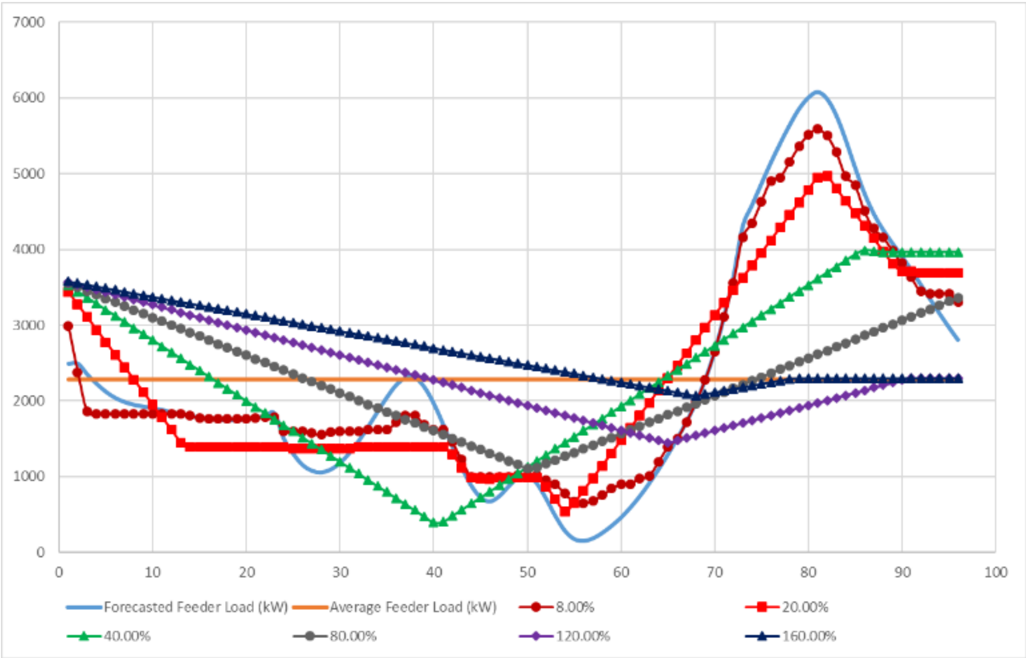
Figure 20: Case Study Distribution Circuit



Source: Southern California Edison

The impact of the minimization of load ramp-rate was also investigated, with different BESS capacities used in the optimization algorithm. The BESS were assumed to start at 25 percent initial state-of-charge (SOC) at the beginning of each day. The results are shown in Figure 21, showing the sum of all BESS kW ratings as a percentage of the peak load. On average, BESS reached 100% SOC in 3.25 hours in this study.

Figure 21: BESS Capacity Impact on Load Leveling



Source: Southern California Edison

Table 6 provides further details on the impact of BESS capacity, listing minimum to maximum power variation and minimized ramp-rate of the resulting feeder head net load profile. As captured in Table 6, higher capacities of BESS were better equipped to reduce both the variations in feeder loading, along with the maximum change in load ramp-rate. Daily min-to-max load variation of the circuit decreased almost linearly with higher BESS capacities. On the other hand, the load ramp-rate decreased significantly when the total BESS capacity was rated 20 percent above the peak load, dropping from 2438 kW per hour to 661 kW per hour. Factors such as the cost of BESS, the avoided cost of load leveling, and peak load reduction may be compared to determine the appropriate size of the energy storage for achieving the desired load leveling capabilities.

Table 6: Impact of BESS Capacity on Load-leveling Metrics

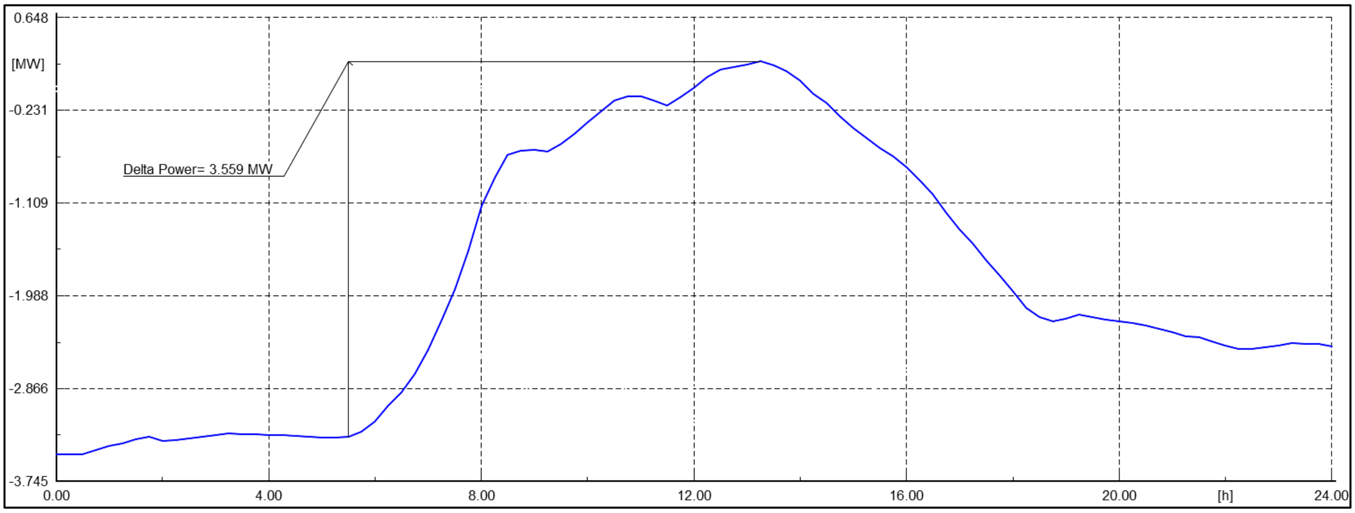
BESS Rating % of Peak Load	Min-to-Max Daily Variation (kW)	Load Ramp- Rate (kW/hr.)
1%	5830	2676
8%	4938	2438
20%	4430	661
40%	3591	320
60%	3169	250
80%	2442	199
100%	2261	159
120%	2122	133
140%	1831	111
160%	1510	90

Source: Southern California Edison

Lab Validation

A lab validation of feeder net load management was performed on the Titanium 12 kV circuit connected to the Camden Substation, where the circuit and DER asset details were previously discussed in Figure 20. This simulation was performed in real time using PowerFactory as the digital twin of the network with which the DERMS interacted. The feeder net load algorithm forecasted the demand and generation for the 24-hour period and used that information to determine when to charge and discharge BESS to maintain a steady net load. With a high penetration of the PV in this specific circuit, the net load on this feeder could drop to nearly zero demand on the feeder during peak PV generation, as shown Figure 22, if left unmanaged.

Figure 22: Circuit Net Load With Unmanaged PV



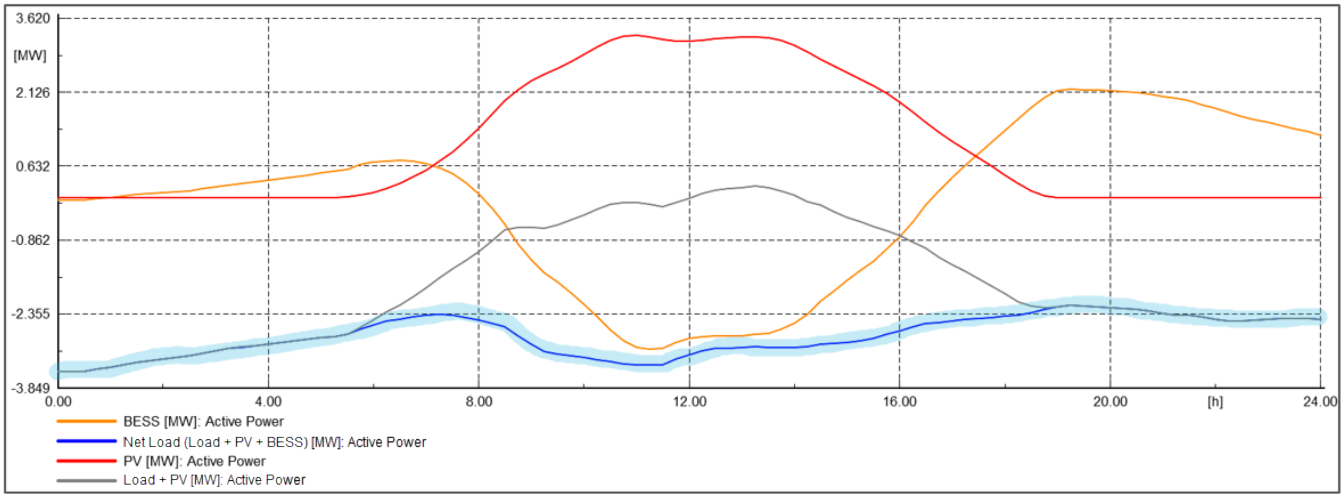
Source: Southern California Edison

Another challenge was managing the intermittency of PV generation. There is always a deviation between the forecasted and the actual PV generation. If the change in weather conditions is significant, the day-ahead energy storage schedule may not be optimum for the actual day. In this case, the intraday rescheduling of the energy storage set points may have compensated for weather forecast inaccuracies. However, the BESS may have ended up having a different end-of-the-day SOC from what was originally planned. The upcoming test cases of this section investigated the impact of significant weather forecast inaccuracies on the feeder net load management and the SOC of the energy storage systems.

Lab Results

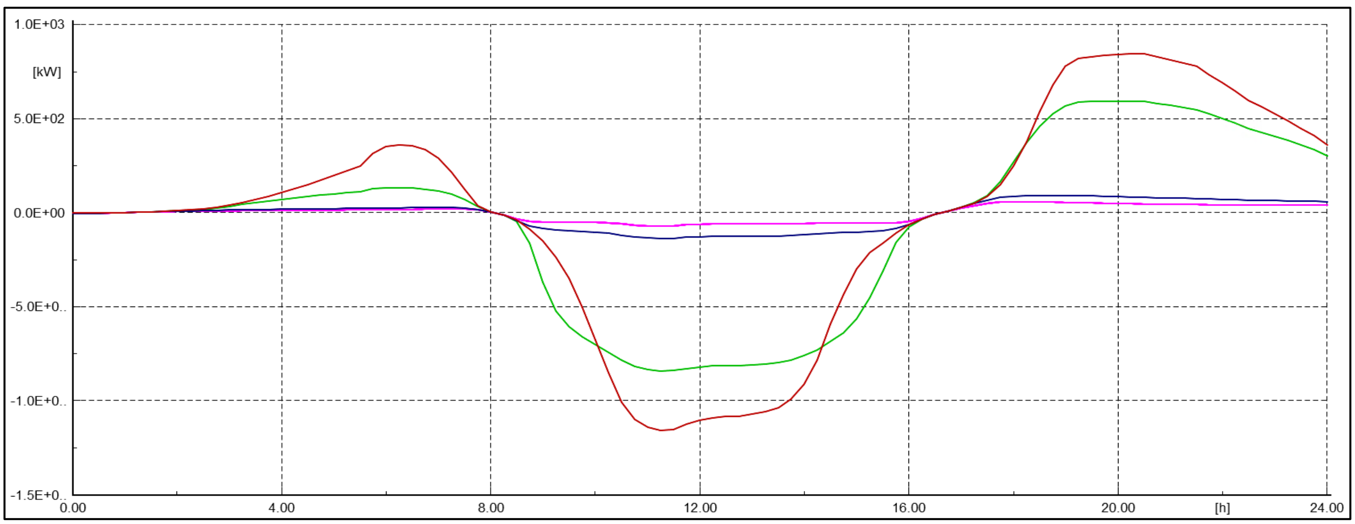
Figure 23 depicts a summary of system load (including PV generation), PV and BESS contribution, and the resulting net load of the feeder. Figure 24 shows the charge/discharge schedule of the aggregated and individually controlled BESS. Energy storage systems were mainly charging during the daytime and discharging during the evening or early morning, to support a flattened net load at the feeder head. Note that this was also tested at scale with 10,000 DERs in the 10-day provisioning test in Figure 4 and Figure 5. The blue line in Figure 23 shows that the net load remained flatter overall, with the PV energy generated during the day going into the batteries. That stored energy was then exported in the evening to support a flatter net load.

Figure 23: Circuit Total Load



Source: Southern California Edison

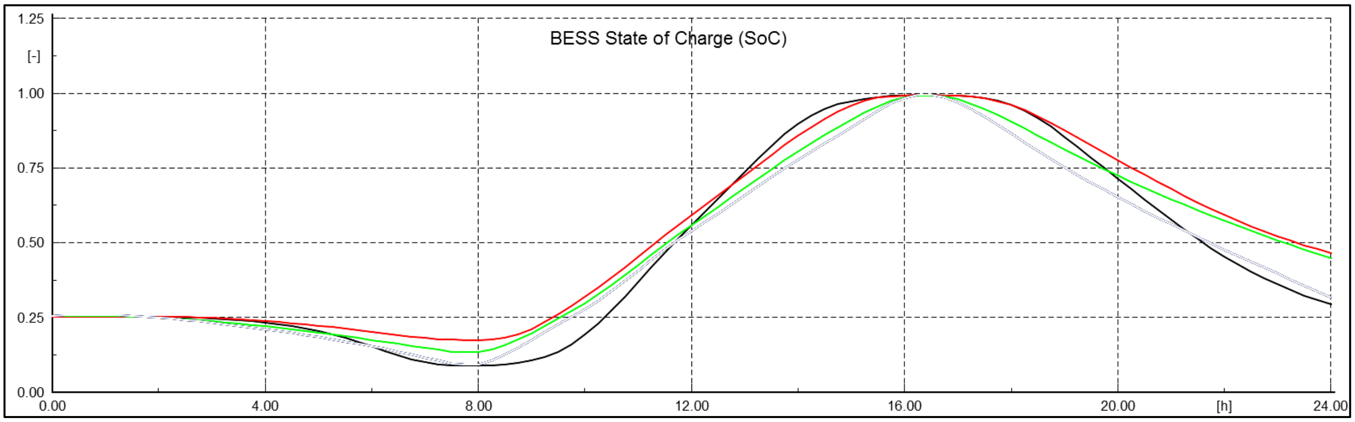
Figure 24: BESS Charge/Discharge Schedule



Source: Southern California Edison

Figure 25 illustrates the SOC of individual and aggregated BESS during the day. The initial SOC for all the BESS was assumed to be 25 percent at the beginning of the day. The net load management algorithm calculated the schedules for the end-of-the-day SOC to be close to the initial SOC at the beginning of the day.

Figure 25: BESS SOC Throughout 24-hour Test



Note: 1 being equal to 100% SOC

Source: Southern California Edison

Field Testing Results

Feeder net load management was tested using the five available customer battery systems shown in Table 7. The Cobalt 12 kV circuit contained the highest concentration of batteries at 11 kW/28 kWh of capacity, which worked with the PV throughout the Cobalt 12 kV to minimize the net load at the substation. See Appendix F – DER Acquired for EASE for the full list of DER customers for the field demonstration. Due to the low concentration of energy storage and PV systems discussed in Table 5, feeder net load management was not expected to be effective at noticeably flattening the feeder load.

Table 7: Customer Battery Systems Participating in Feeder Net Load Management

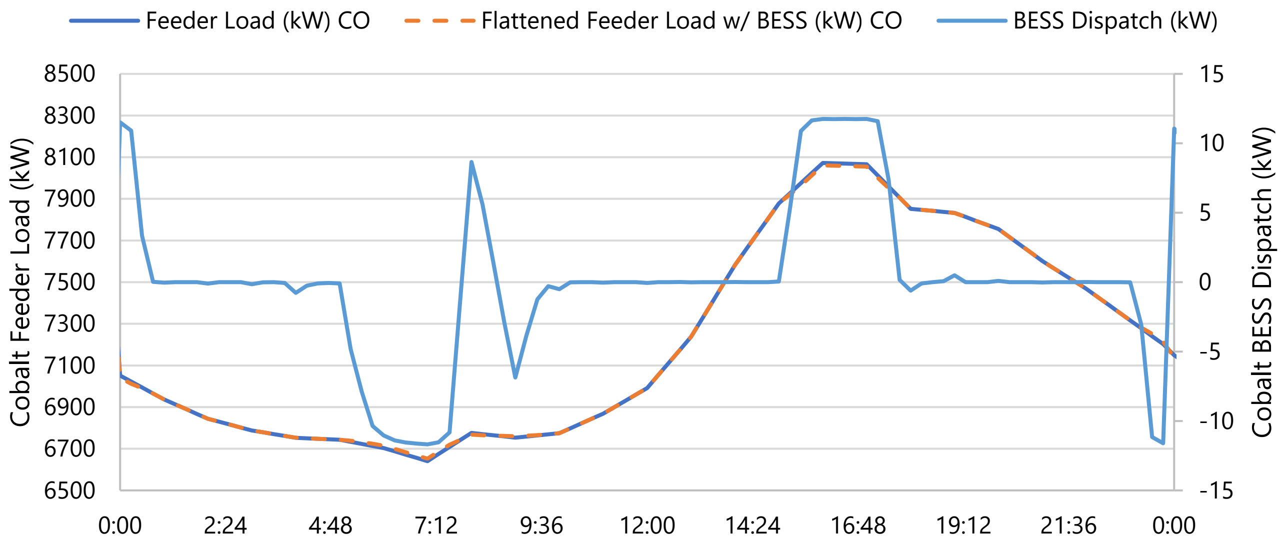
Inverter No.	EASE DER Name	Manufac-turer	Inverter Model	Type	Individual CEC AC Size kW	kWh	Circuit
1	ACT_1_AY_BESS	Generac	x7602	PV & BESS	6.26	17.1	ALLOY
22	ACT_14_CO_BESS	Generac	x7602	PV & BESS	6.909	17	COBALT
23	ACT_15_CO_BESS	Generac	x7602	PV & BESS	4.299	11.115	COBALT
26	ACT_1_TI_BESS	Generac	x7602	PV & BESS	6.8	11.4	TITANIUM

Source: Southern California Edison

The same methodology outlined in the lab validation of feeder net load management was performed on the batteries listed in Table 7, and a sample of the results is shown for Cobalt 12 kV in Figure 26. The aggregate BESS dispatch is shown over time with the gross feeder load and the flattened feeder load. The results do not show any significant difference in magnitude, considering that the demand on Cobalt 12 kV was between 6.5 MW and 8 MW during this test day, which dwarfs the 10 kW of aggregate battery capacity under the control of the DERMS.

Similar test results were achieved for the energy storage systems on the Alloy and Titanium 12 kV circuits, which showed no significant impact to flatten the load. Overall, this form of energy storage optimization was not effective and would be better suited for circuits with higher DER concentrations that have high loading.

Figure 26: Cobalt 12 kV Feeder Net Load Management Results — Forecasted vs Flattened Load



Source: Southern California Edison

Lessons Learned

The following takeaways were captured after demonstrating feeder net load management at a lab and a field capacity.

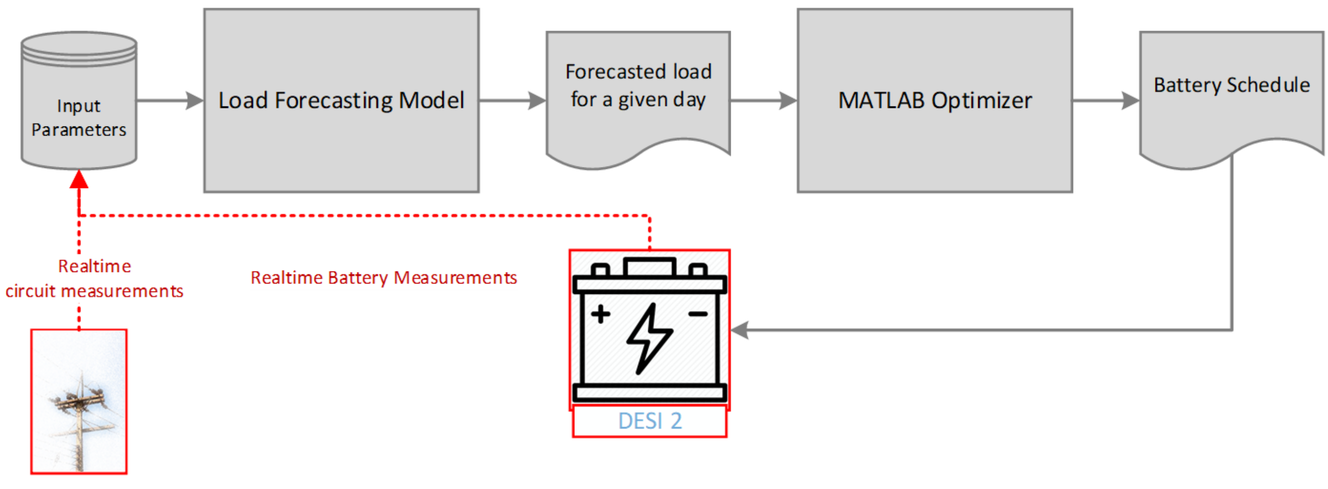
Factoring in the Cost of Electricity

Feeder net load management would provide more value to DER owners and the utility if the optimization were to consider the day-ahead cost of electricity as one of its inputs. The weight of the cost of electricity would have to be adjusted based on the grid need for peak load reduction on that feeder, but it would likely be more cost-effective for DER owners as well and somewhat better aligned with system needs. Ideally, this would be a derived cost of electricity for the feeder itself (not the 66 kV locational marginal price node) to reflect the value of energy for that feeder's demand profile. This use case may be better suited as a DSO optimization objective, since the DSO already has a process for calculating a cost-optimized dispatch. The DSO also has a price framework developed for extrapolating a feeder, or even a transformer, nodal electricity price, which is referred to as the "distribution locational marginal price" methodology. Feeder net load management was also very similar to the DSO's loss-optimized objective function, which was targeted at reducing network losses, and in turn had a similar peak-shaving effect. However, the DSO's loss-optimized dispatch also did not factor in the price of electricity in the optimized DER dispatch; this is discussed in the DSO Market Use Cases section of this chapter.

Designing a Feedback Loop Into the Optimization

Designing a feedback loop for the feeder net load management algorithm, as shown in Figure 27, would have improved the DERMS' ability to adapt to forecast deviations at the circuit measurement point. It could also better gauge the battery's real-world output and energy storage capacity performance over time. This information was already accessible to the DERMS, but additional development would have been required to incorporate these measurements into the optimization. This also would have required the optimization to re-run during the day on a regular interval, or when the real time loading conditions significantly deviated from the forecasted loading conditions.

Figure 27: Feedback Loop for Feeder Net Load Management Algorithm



Source: Southern California Edison

DSO Market Use Cases

This section discusses the methodology used in the DSO's market-based use cases and the lab and field test results. Lessons learned from the lab and the field tests are discussed at the end.

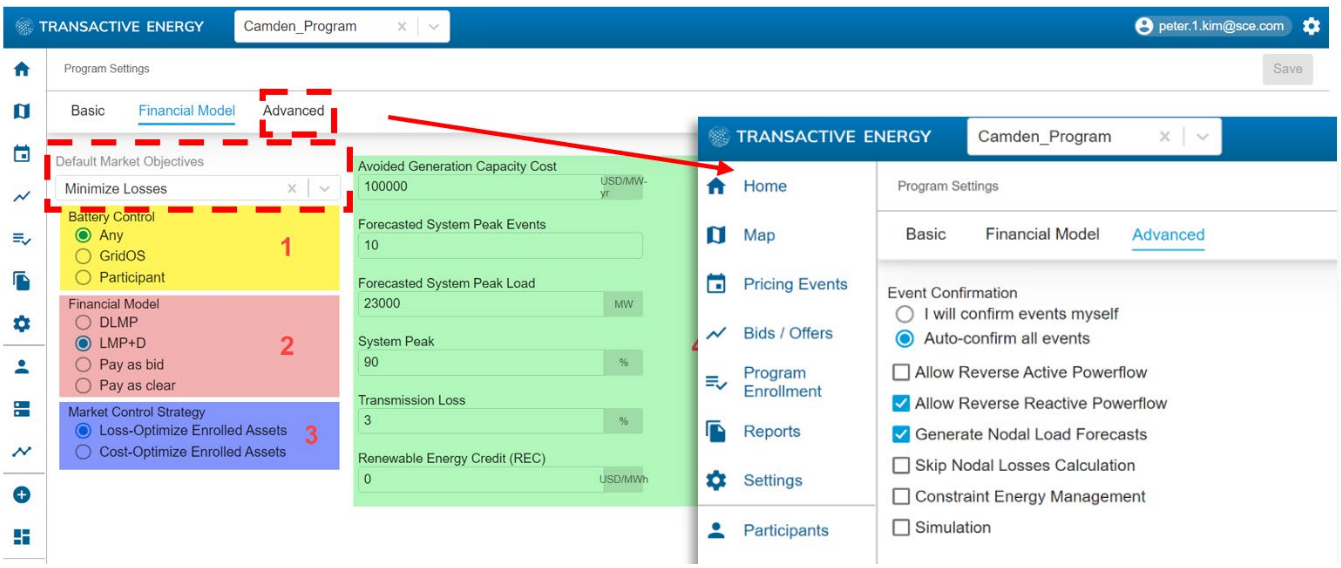
Method

The DSO platform provides a transactive energy management system (TEMS) to the utility and the consumer with separate interfaces to manage system and resource operation, respectively. The utility uses the DSO's distributed system platform to manage DERs and its optimization objectives. Under this project, SCE used Opus One's GridOS platform to coordinate operation of enrolled DERs. A DER market participant used the TEMS GridOS-Market Participant Interface to configure preferences in how their DER was managed by the DSO and, if desired, manually placed bids or offers on behalf of their DER to meet their individual needs. Alternatively, DER market participants could opt to have the DSO automatically optimize their DER based on the forecasted network load, weather, and electricity prices during the market operating day. Depending on the exact market strategy configured in GridOS, the DSO could automatically optimize DER in several ways. For lab and field testing, the following objective functions were tested:

- Locational marginal price cost optimized dispatch
- Distribution locational marginal price cost optimized dispatch
- Loss optimized dispatch, where locational marginal price was not considered

These market functions would apply to all DERs within a B-Bank substation, and changes in the objective function would take effect on the next market day. Figure 28 illustrates what the DSO operator could configure. The operator could select between various preconfigured objective functions in GridOS or could fine-tune battery control, the financial model, and the market control strategy as they see fit.

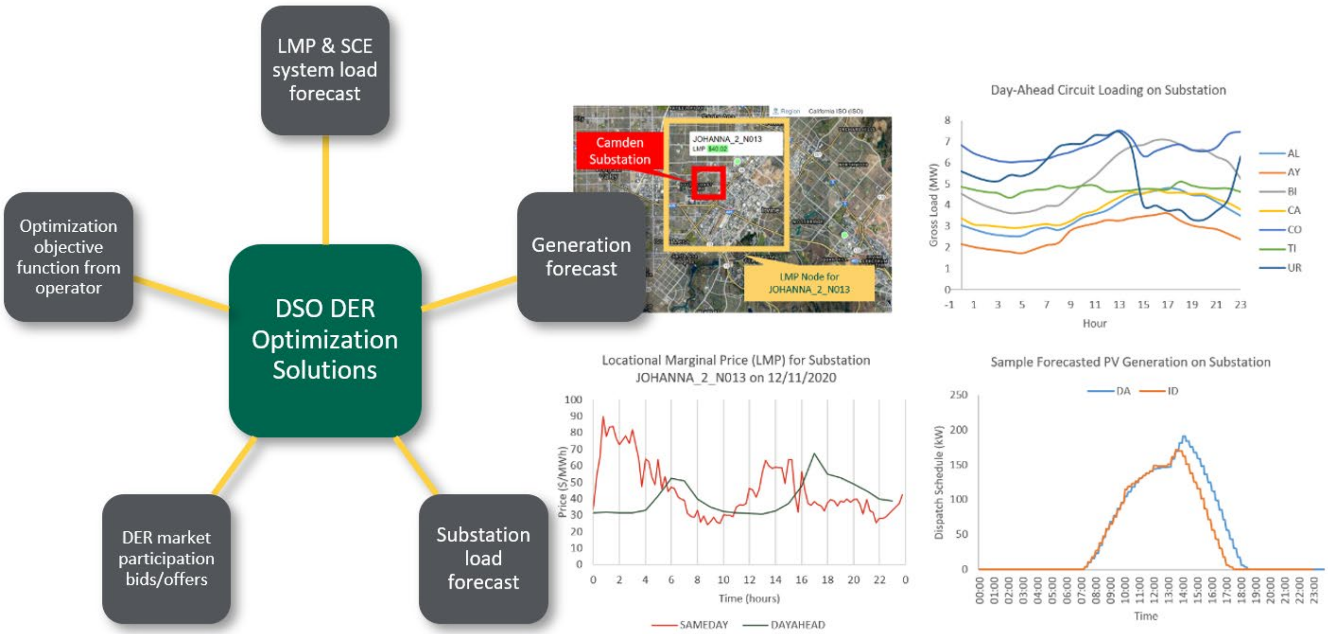
Figure 28: TEMS Market Strategy Configuration Page



Source: Southern California Edison

The DSO required the day-ahead forecasted inputs shown in Figure 29 to calculate the optimized DER dispatches for the next day. On the day of the scheduled dispatch, the DSO received updated real-time information and, if needed, made corrections to the dispatch schedule. This occurred if the SCE system load exceeded the preset limit (indicating that the SCE system was under significant demand) or if the locational marginal price became negative in value (indicating too much generation on the distribution network).

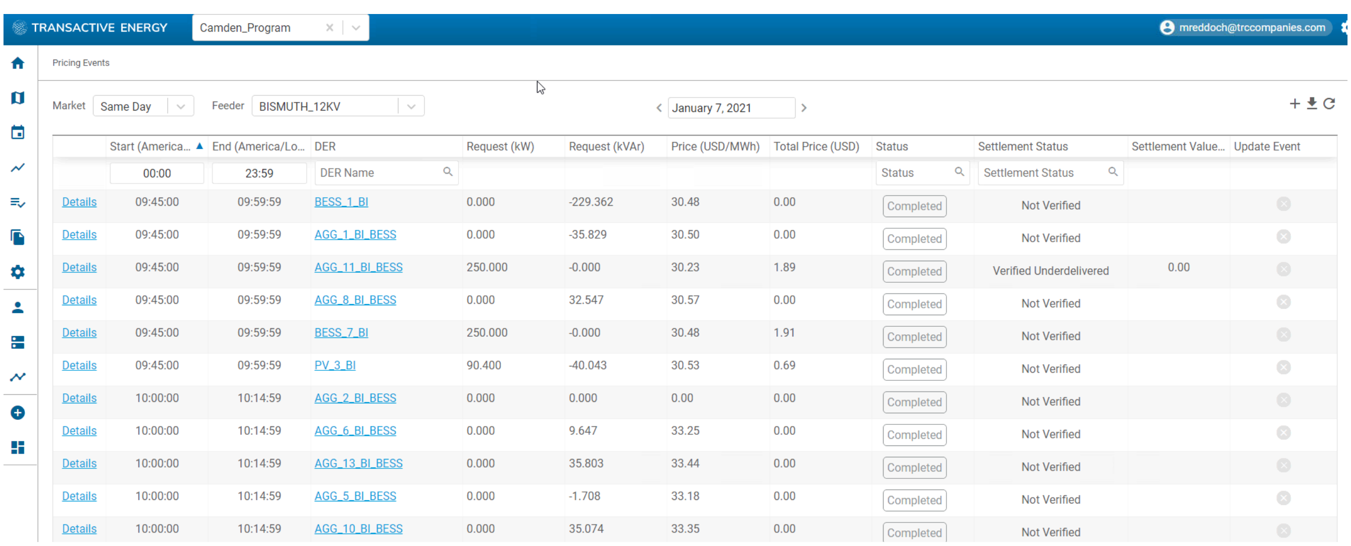
Figure 29: DSO Required Forecasted Inputs: Locational Marginal Price, SCE System Demand, Feeder Demand, and PV Generation



Source: Southern California Edison

Once DER dispatches were calculated, they could be viewed in the GridOS pricing events page (Figure 30), where a DSO operator could see the dispatched controls (known as pricing events) committed by each participating DER. The resolution of day-ahead pricing events was hourly, and the resolution of same-day pricing events was in 15-minute increments. All pricing events showed the settlement status and the value the DERs were awarded for delivering their committed bid/offer. A summary of settlements was later compiled into a market settlements report at the end of each day for all DERs.

Figure 30: GridOS Distribution System Platform DER Pricing Events Page



	Start (America...	End (America/Lo...	DER	Request (kW)	Request (kVAr)	Price (USD/MWh)	Total Price (USD)	Status	Settlement Status	Settlement Value...	Update Event
	00:00	23:59	DER Name					Status	Settlement Status		
Details	09:45:00	09:59:59	BESS_1_BI	0.000	-229.362	30.48	0.00	Completed	Not Verified		
Details	09:45:00	09:59:59	AGG_1_BI_BESS	0.000	-35.829	30.50	0.00	Completed	Not Verified		
Details	09:45:00	09:59:59	AGG_11_BI_BESS	250.000	-0.000	30.23	1.89	Completed	Verified Underdelivered	0.00	
Details	09:45:00	09:59:59	AGG_8_BI_BESS	0.000	32.547	30.57	0.00	Completed	Not Verified		
Details	09:45:00	09:59:59	BESS_7_BI	250.000	-0.000	30.48	1.91	Completed	Not Verified		
Details	09:45:00	09:59:59	PV_3_BI	90.400	-40.043	30.53	0.69	Completed	Not Verified		
Details	10:00:00	10:14:59	AGG_2_BI_BESS	0.000	0.000	0.00	0.00	Completed	Not Verified		
Details	10:00:00	10:14:59	AGG_6_BI_BESS	0.000	9.647	33.25	0.00	Completed	Not Verified		
Details	10:00:00	10:14:59	AGG_13_BI_BESS	0.000	35.803	33.44	0.00	Completed	Not Verified		
Details	10:00:00	10:14:59	AGG_5_BI_BESS	0.000	-1.708	33.18	0.00	Completed	Not Verified		
Details	10:00:00	10:14:59	AGG_10_BI_BESS	0.000	35.074	33.35	0.00	Completed	Not Verified		

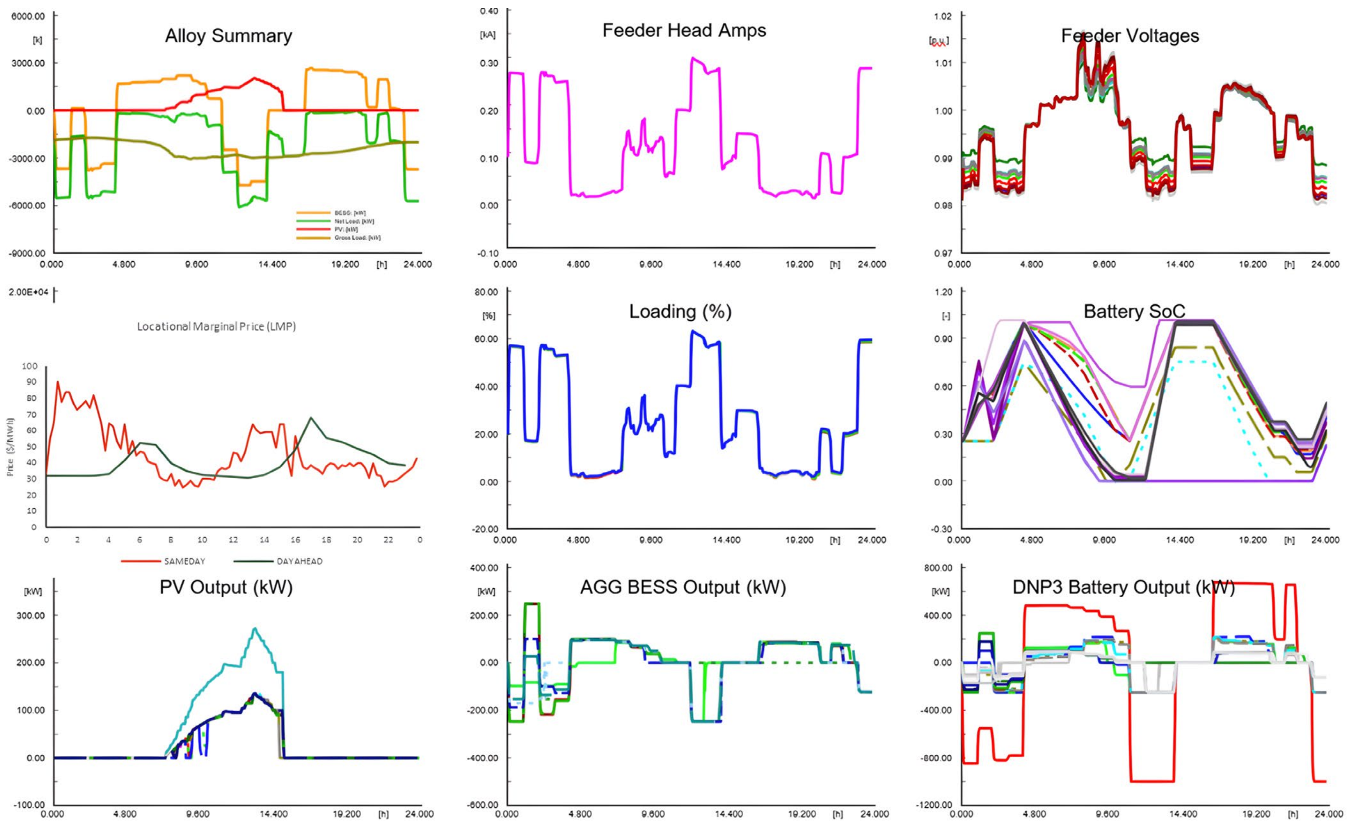
Source: Southern California Edison

Lab Validation

The DSO optimized the dispatch of the 10,000 DERs in the lab environment, comprised of 30 MW of photovoltaics and 40 MW/117 MWh of battery energy storage. DERs within Camden Substation's 12 kV network were optimized to provide the lowest cost, or losses, while maintaining nominal voltage and current levels throughout the network. DER optimizations were performed daily through AC optimal power flow simulations that solved every 15-minutes during the day, known as the intraday. The next day's hourly dispatches were calculated after 3 p.m., when day-ahead electricity prices are made available by the California ISO. Overall, test results showed that loss-optimized dispatches were better suited for managing circuits with high demand, since the DSO minimized the amount of current imported from the substation. Cost-optimized dispatches were better suited for circuits that had lower demand, since DERs were more likely to export or import power from the grid at maximum nameplate capacity during short periods of high or low electricity price fluctuations.

Within the PowerFactory digital twin, the DSO's DER dispatches, and the grid impact could be seen over a 24-hour period on a particular feeder, as shown in Figure 31 for the Alloy 12 kV circuit. These simulations allowed the DSO to connect to a digital twin of the grid and demonstrate that it could manage the very high concentrations of DER forecasted for the coming decades. Grid impacts on the voltage and current throughout the network were captured to ensure that the DSO was able to successfully balance DER generation and demand in a cost- or loss-optimized manner. The DSO managed five times more photovoltaic capacity and 14 times more energy storage capacity than what is interconnected today. Today, DERs are interconnected based on the static hosting capacity of the network, and capacity upgrades could be required to host more DERs. These simulations proved that a dynamic hosting capacity is achievable to significantly increase the number of DERs hosted while providing DER owners a means to earn revenue for their energy services in a DER marketplace. In the future, the DSO may be able to determine the amount of distributed generation able to interconnect safely to the grid based on the local demand available to consume that generation rather than relying solely on the static capacity of the distribution network. The value of dynamically managing hosting capacity to meet local electricity demand may become even greater as the adoption of electric vehicles and all-electric appliances connecting to the grid continues to grow.

Figure 31: DSO Software-in-the-loop 24-hour Lab Simulation Using 10,000 DERs on Camden Substation



Source: Southern California Edison

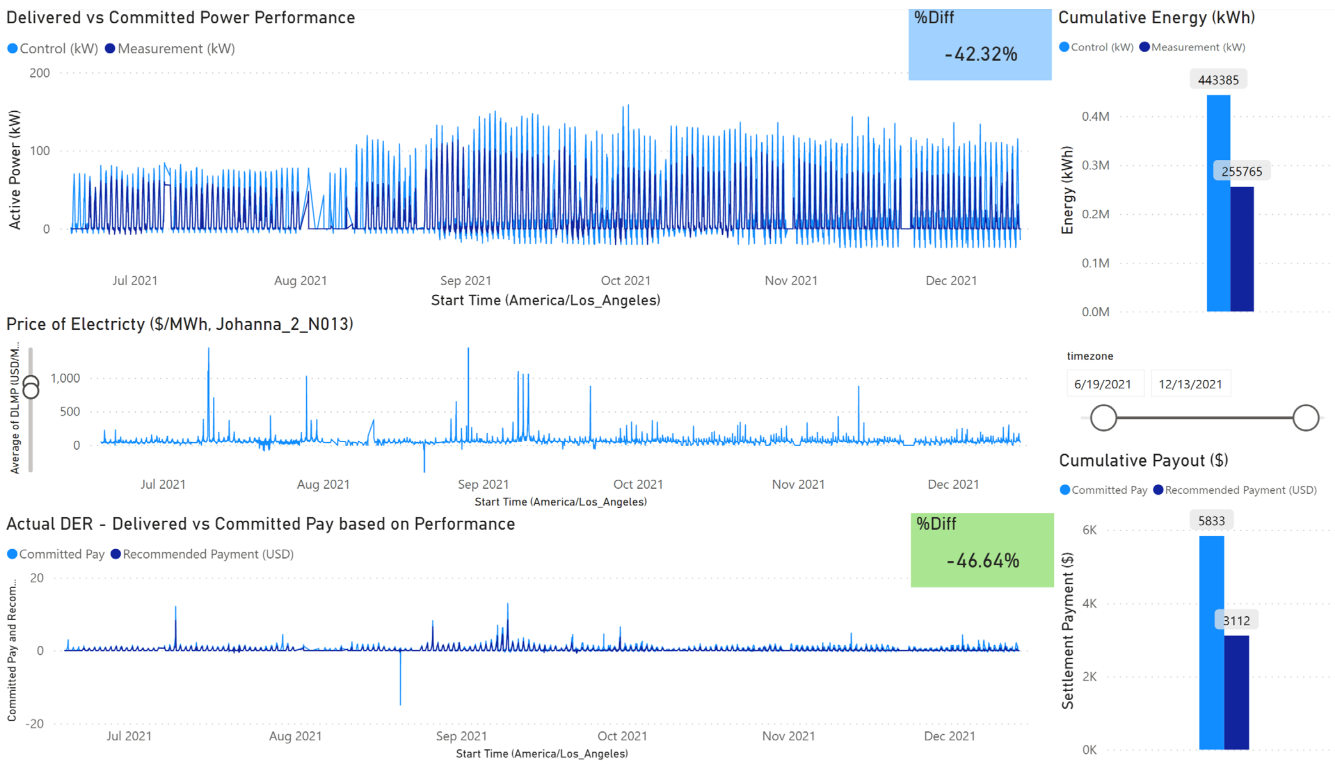
Enabling Dynamic Hosting Capacity Territory-wide to Supply Demand Growth

The DSO enabled the utility to have a dynamic hosting capacity for each feeder since it was able to balance DER generation and customer demand. This capability would allow the grid to host more DERs and demand than traditionally possible with wires alone. Hosting more DERs has the added benefit of supplying increased demand growth, sometimes beyond the capacity limits of the distribution grid assets. Enabling a dynamic hosting capacity could help utilities manage the forecasted growth in electricity as California shifts to carbon-free generation sources on the distribution network. This capability is discussed in greater detail in Appendix H – Case Study on Dynamic Hosting Capacity, where a case study is performed to show how the DSO could defer a capacity upgrade by using sufficient DER concentrations.

Field Validation

The project team performed DSO use case testing from June to December 2021. Throughout this period, the performance of all 31 DERs on the Camden Substation was tracked to show the aggregate delivered and committed power of all DERs, the price of electricity, and the settlement pay, as shown in Figure 32.

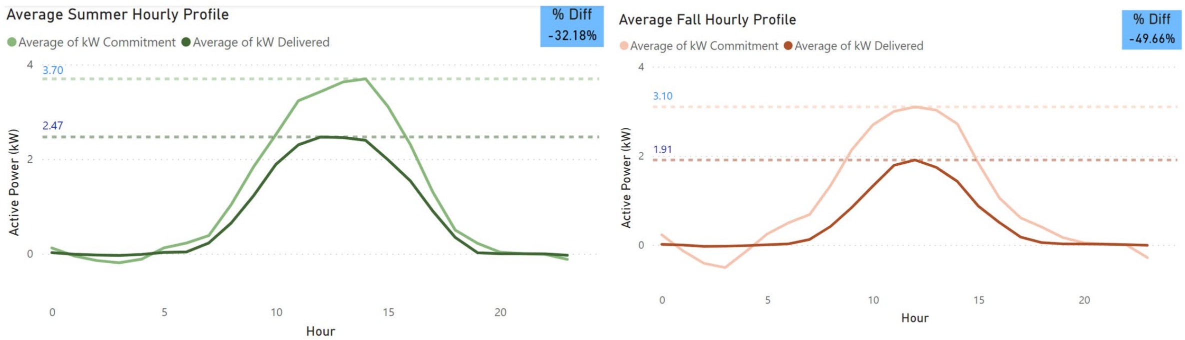
Figure 32: DSO Use Case Testing of Aggregate DER Activity, June – December 2021



Source: Southern California Edison

The majority of DERs were provisioned by the end by September 2021, which was when the DSO had all 167 kW of DER generation capacity and 56 kW of BESS import/export capacity. The total system output of the DERs never quite reached the forecasted control dispatches set by the DSO. This was likely due to forecasting inaccuracies, the actual PV system output per customer location based on panel orientation, and customer DER system losses. On average, there was a 1 kW difference in the forecasted (committed) and the delivered peak output of PV, as shown in Figure 33. Since each individual PV was forecasted using the same methodology, this 33 percent difference in production would likely scale proportionally as more PVs interconnect. Also, there was a 600-watt difference between the summer and fall seasons in peak PV production due to the shorter days and rainier weather conditions.

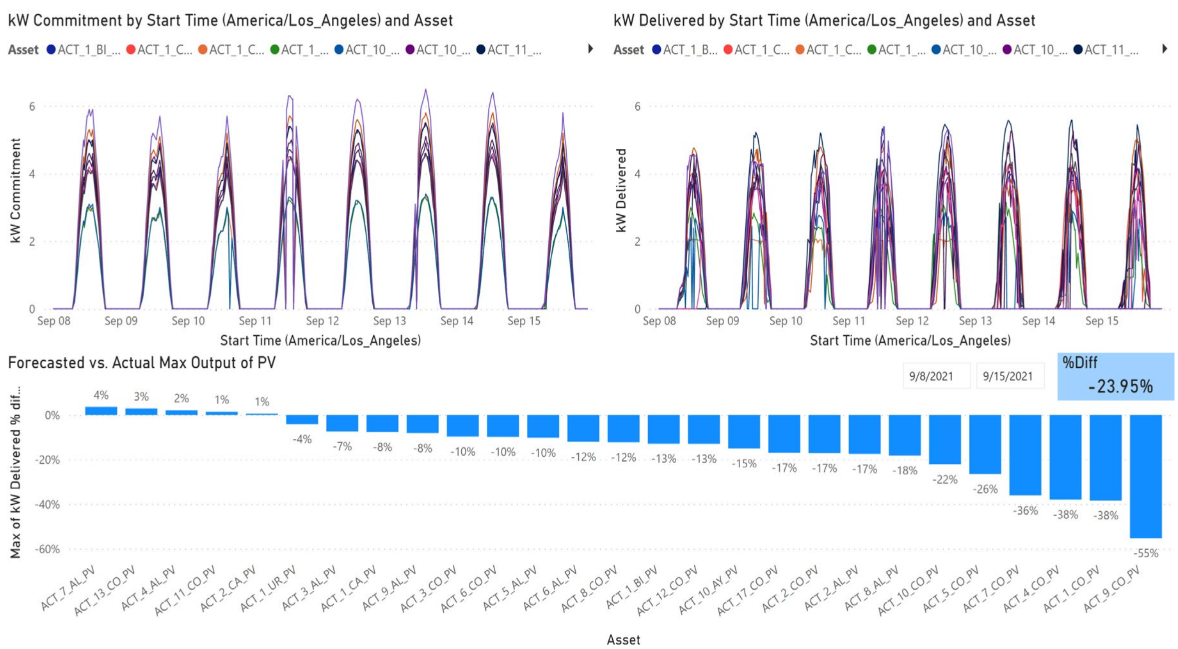
Figure 33: Comparison of Summer and Fall Average Hourly DER Output (BESS and PV)



Source: Southern California Edison

Overall, there was a 23 percent difference between committed versus actual output of PV, as shown in Figure 34. As a best-case scenario, weather forecasts were most accurate on clear-sky days, when there was only a 10 percent difference between the forecasted and the observed solar irradiance. Actual PV generation profiles were much more complex than what the solar irradiance profile suggested. Small variations in solar irradiance due to cloud coverage could have a significant impact on solar output, depending on the panel configuration on each customer's rooftop. Aside from cloud coverage, occasional dips in PV output were sometimes caused by the DSO's failure to calculate DER dispatches for that interval. This occurred when the optimal power flow engine failed to solve for the most optimal DER dispatch to meet the objective function. It was not always apparent why load flow failed to solve at times, but it was often attributed to rapid changes in local network conditions or general program errors not related to the state of the network.

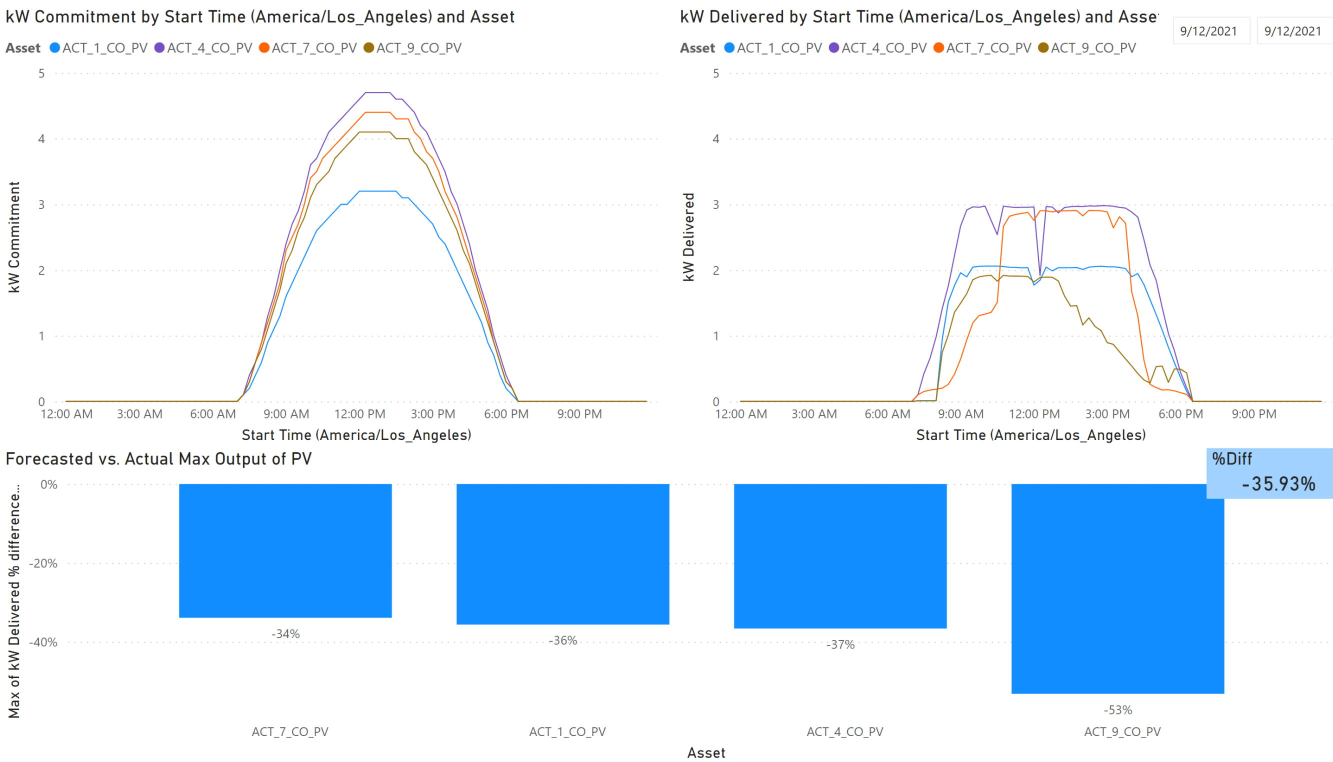
Figure 34: Photovoltaic Performance



Source: Southern California Edison

The lowest performing inverters were filtered out, as shown in Figure 35. These four inverters were one of two inverters installed on their respective properties, known as dual-inverter systems. The output of these inverters appeared to have been clipped toward the top of their expected peak output. Typically, this was an indication that the inverters were undersized by the installer while installing more solar panels to compensate for the lower-than-expected average output. However, it was not clear that these panels were, in fact, undersized, since the size of the inverter (in kW) provided by the installer exceeded the clipped inverter output shown in Figure 35. Refer to Appendix F – DER Acquired for EASE for a full list of DER assets information per DER ID number shown in Figure 35.

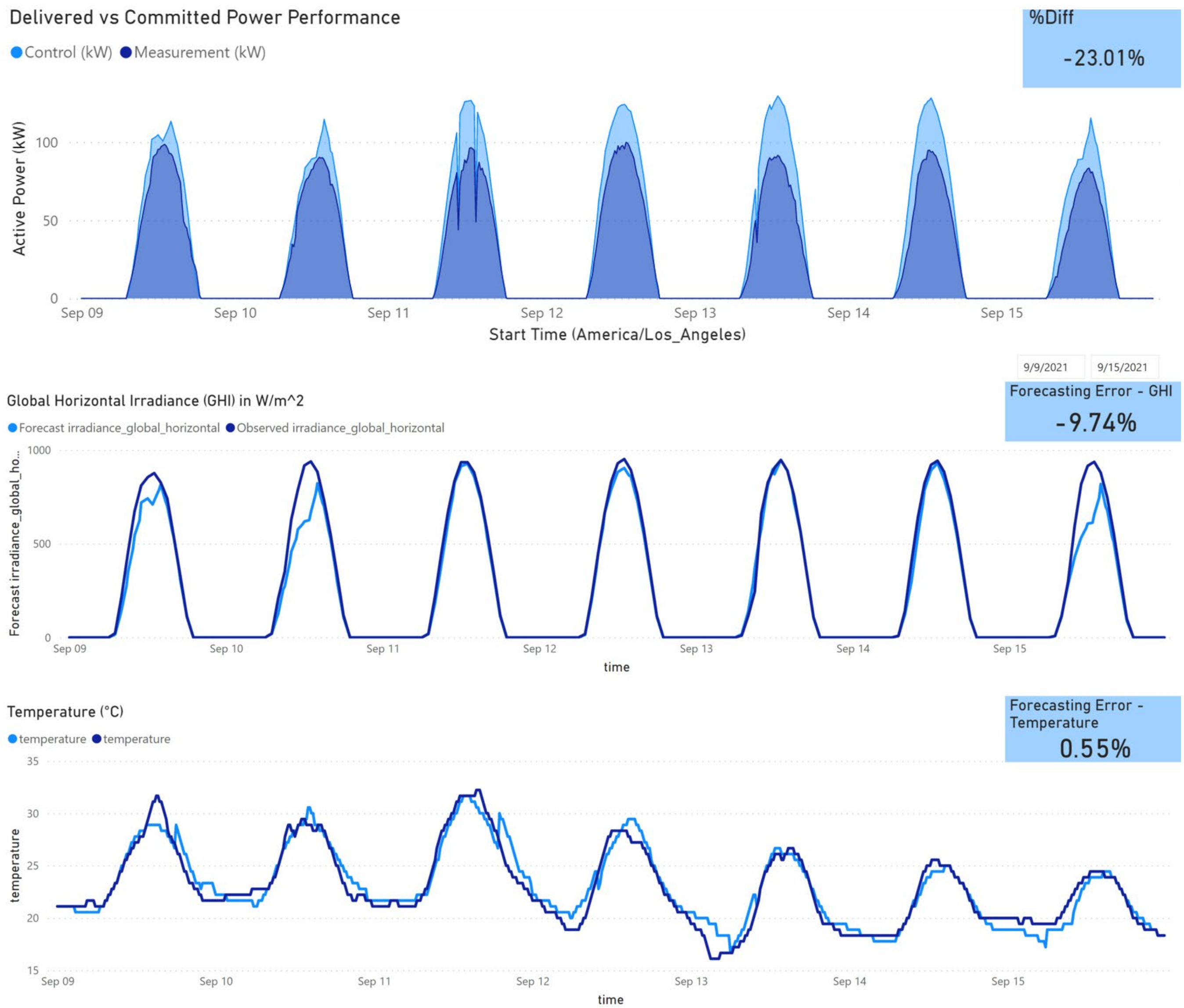
Figure 35: Clipping on Four Dual-inverter Solar Systems



Source: Southern California Edison

PV forecasts were most accurate on clear-sky days. Throughout the six-month period, the best-case irradiance and temperature forecasts were studied to observe maximum aggregate PV generation performance, as shown in Figure 36. Overall, the lowest forecasting error was 9.74 percent for irradiance and 0.55 percent for temperature, which yielded a 23 percent difference between the forecasted and the observed aggregate PV output. Ideally, the forecasting model could be re-trained to adjust DER dispatches to what is more realistically observed over time, but this feature was not available during testing.

Figure 36: Forecasted Vs Observed Solar Irradiance and Temperature

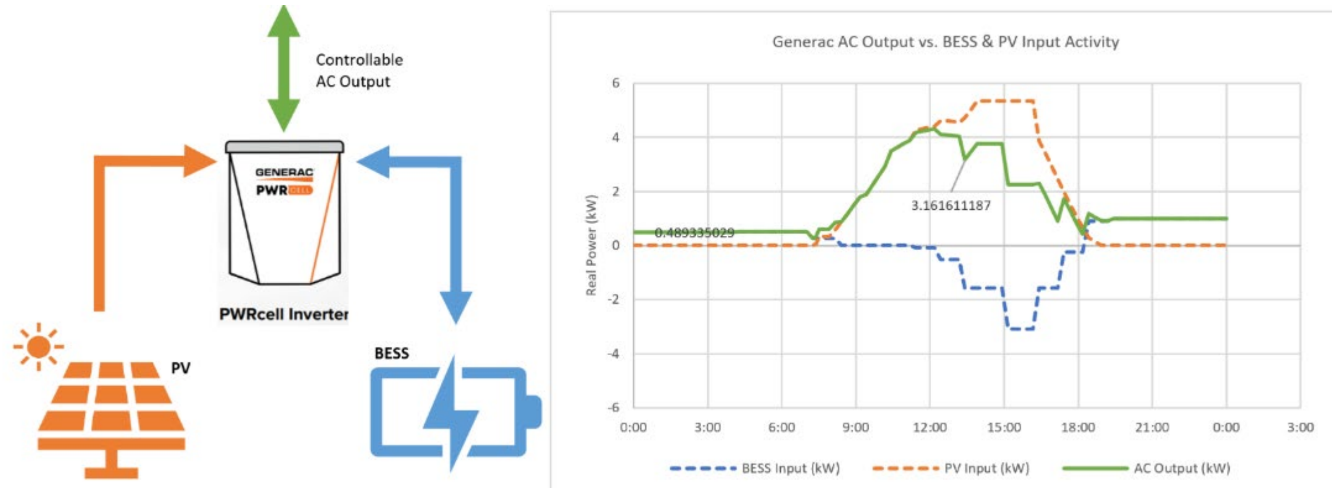


Source: Southern California Edison

DC-Coupled PV and BESS Systems

Next, the project team evaluated the performance of the integrated smart inverters, which were supplied by Generac Power Systems. The Generac inverters coupled the PV and BESS to the same DC input bus and provided a single AC output to the grid, as shown in Figure 37. For this inverter type, the charging/discharging of the BESS and the curtailment of PV was managed only by the smart inverter, while a DERMS was allowed to control the AC output provided the DER was able to support it. PV and BESS were modeled independently in the GridOS DSO software to calculate the BESS and PV schedules for the next day and these calculations were summed together to determine the net AC output. For simplicity, the DC-coupled PV and BESS systems are referred to as "Generac inverters."

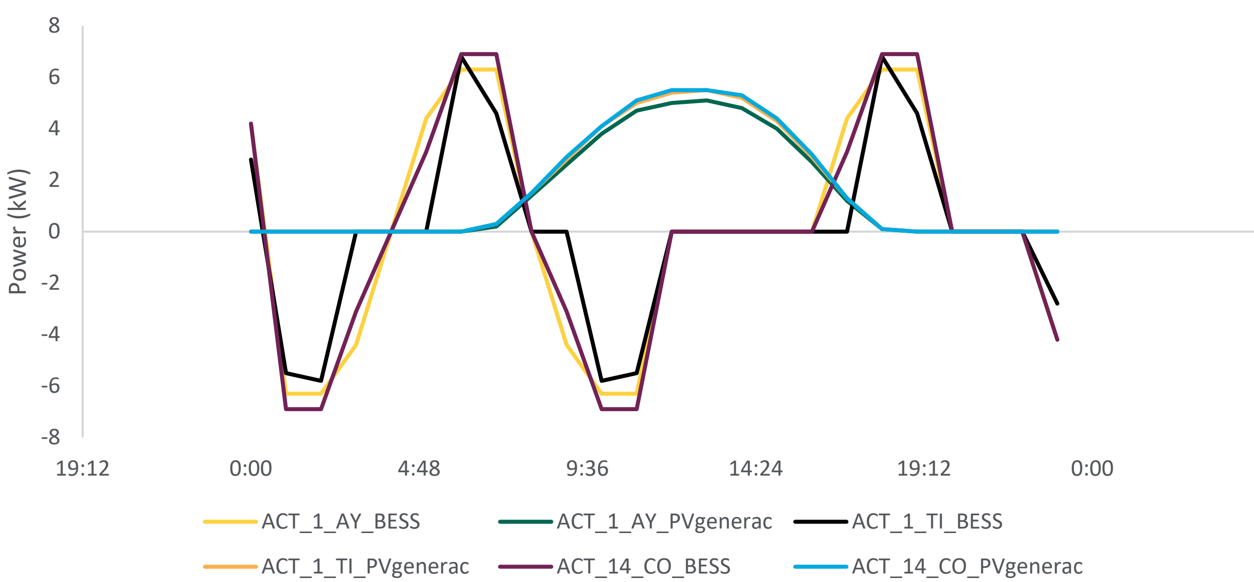
Figure 37: Generac Inverter Connection With AC Output vs BESS and PV Input Active Over Time



Source: Southern California Edison

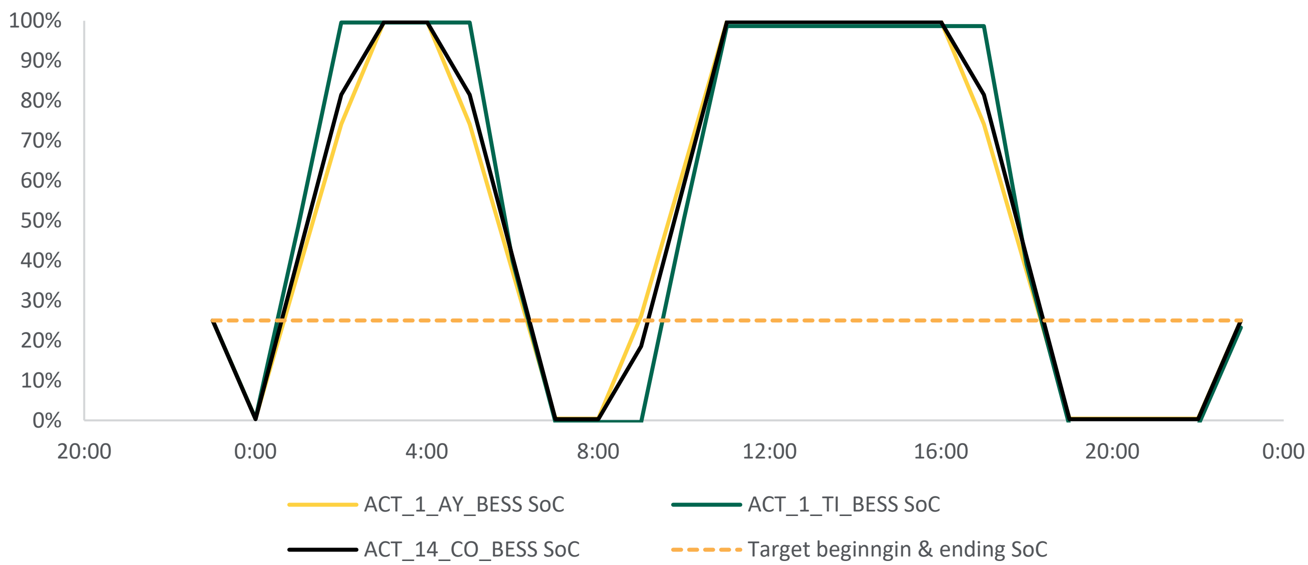
The Generac inverters were more difficult to control reliably compared to a dedicated PV or BESS inverter. The optimal BESS and PV schedules were calculated for September 20, 2021, by GridOS, as shown in Figure 38, the day prior to using forecasted weather, loading, and pricing information. The batteries went through two full cycles of charging and discharging throughout the day; the state of charge of the batteries over time is shown in Figure 39.

Figure 38: Step 1, Calculate Optimal BESS and PV Schedules, September 20, 2021



Source: Southern California Edison

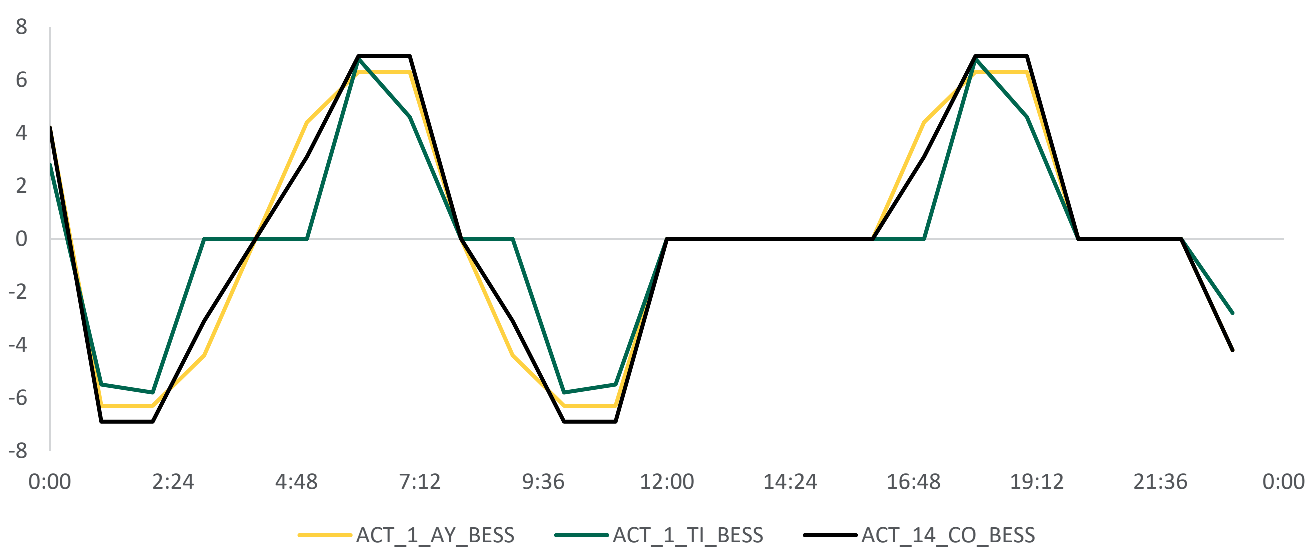
Figure 39: Step 1, Estimated Generac BESS SOC, September 20, 2021



Source: Southern California Edison

The resulting summed PV and BESS Generac inverter schedules are shown in Figure 40, which shows the net AC output for the three inverters for September 20, 2021.

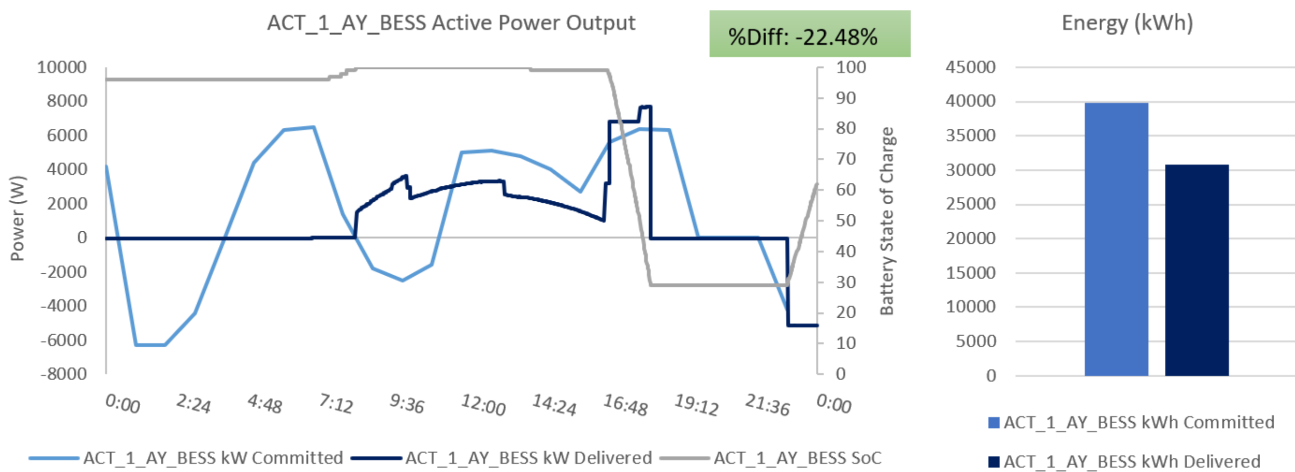
Figure 40: Step 2, Summed PV and BESS Outputs for Generac Inverters



Source: Southern California Edison

The results of the latest interoperability tests on the Generac inverters are shown in Figure 41, using the Generac inverter identified as "ACT_1_AY_BESS" as an example. In the figure, the active power output, battery state of charge, and cumulative energy output were tracked for all systems. Overall, these Generac inverters had a much higher difference between the forecasted and the delivered output of the inverter, which ranged from a 22 percent to a 38 percent difference from the control dispatched. One issue uncovered during testing was that all Generac inverters were configured by the installers to have a 30 percent minimum reserve SOC limit. This would allow customers to always reserve 30 percent of the battery's energy capacity for backup power in the event of an outage. The DSO system did not have the capability to set a minimum or a maximum reserve SOC in the operator interface for the demonstration period; instead, Generac Power Systems temporarily disabled the minimum reserve state of charge for a handful of tests to prove this was the main issue.

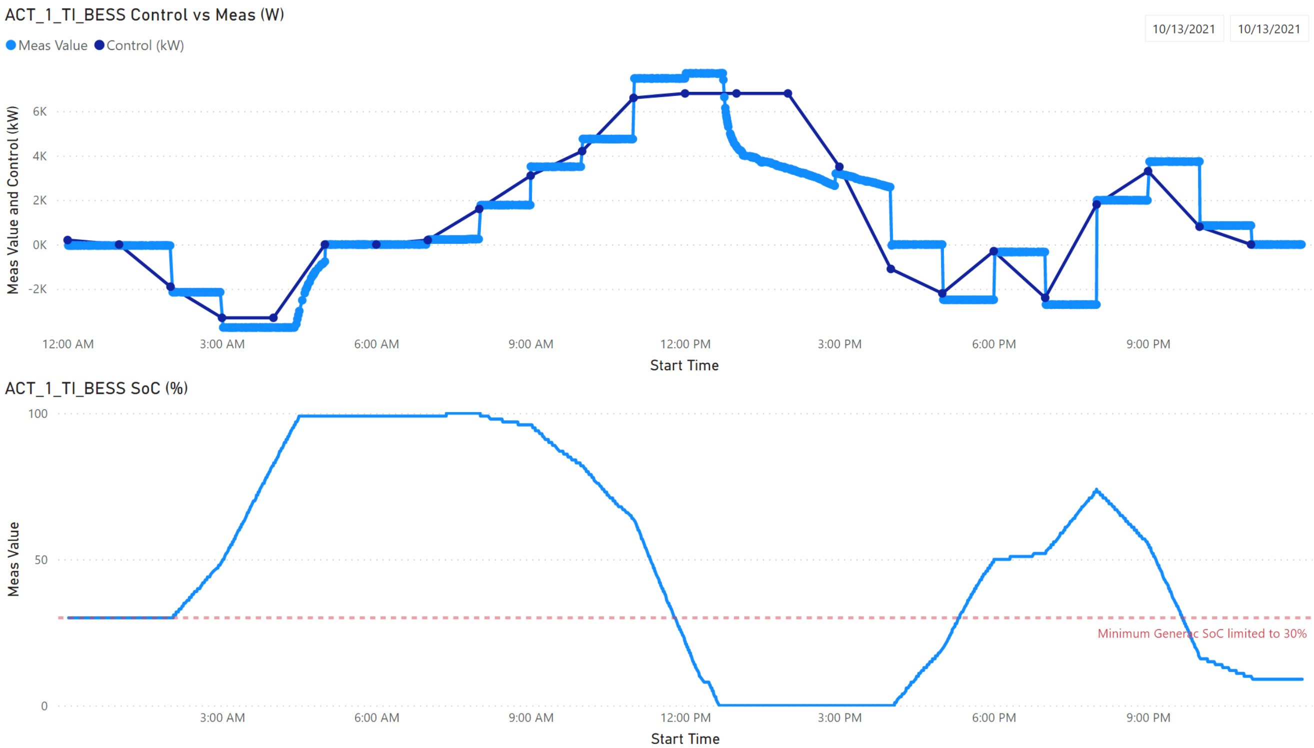
Figure 41: ACT_1_AY_BESS Performance



Source: Southern California Edison

Once the minimum reserve state of charge was disabled, there was no more than a 15 percent difference between the forecasted versus the actual output of the Generac inverters. This 15 percent difference was largely attributed to the Generac inverters often reaching their minimum or maximum state of charge sooner than anticipated, as shown at 12 p.m. in Figure 42. This was probably caused by the DSO's forecasting error for PV generation, since PV production was likely lower than forecasted in the morning, which caused the battery to discharge more to meet the target AC output from the DSO. In the future, this could be improved by designing DC-coupled systems to enable DER aggregators to individually control the PV or BESS.

Figure 42: Generac Performance After Lifting Minimum State of Charge Limits



Source: Southern California Edison

Lessons Learned

Several improvements could be made to the DSO system that would improve resource adequacy, reliability, and the ability to effectively defer wires-only capital investments on the grid.

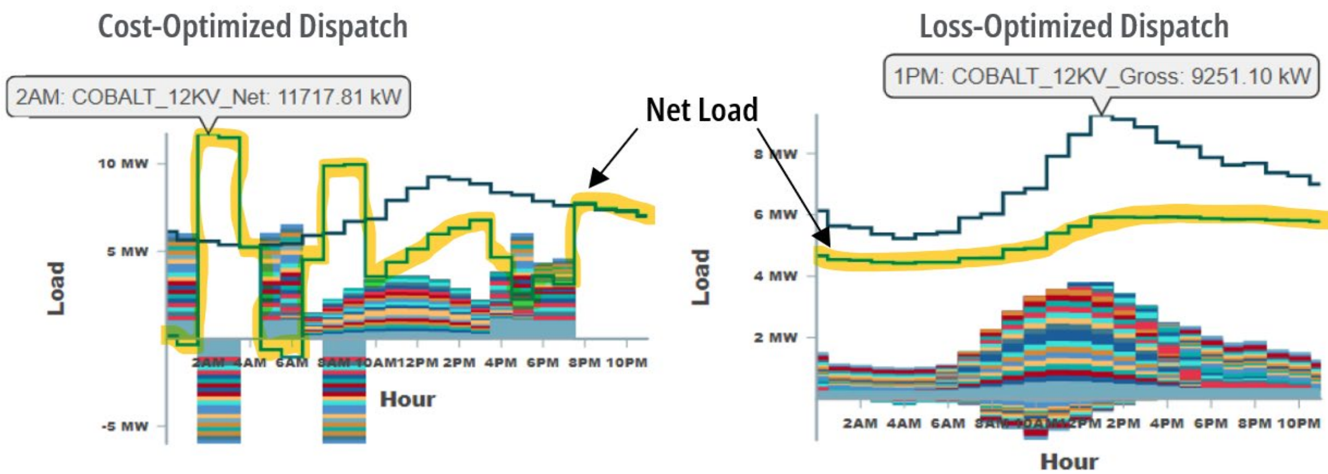
Consideration of the Entire Substation Planned Loading Limit

The DSO's optimization needs to consider the entire substation planned loading limit, not just the circuit's planned loading limit. Often, the planned loading limit of a substation is less than the planned loading limits of all circuits combined. Without this taken into consideration, the DSO could assume that all circuits can operate at their planned loading limit simultaneously, which would overload substation equipment.

Automatic Selection of the Network's Appropriate Objective Function

The DSO should automatically select the appropriate objective function for a given network. A cost-optimized DER dispatch (left chart in Figure 43) prioritizes dispatching DER at the lowest cost of electricity. Cost-optimized dispatches may be less desirable when a circuit is approaching its planned loading limit. In that case, it would be more important to prioritize service reliability over cost. A loss-optimized DER dispatch (right chart in Figure 43) prioritizes reducing losses, which minimizes peaks. This objective would be more ideal for a circuit where demand is approaching the planned loading limit but less ideal for circuits with more available capacity. This results in a lower peak net load for a loss-optimized dispatch versus the cost-optimized dispatch. For this objective, the DSO did not consider the California ISO nodal price of electricity in how it dispatched DERs, but in the future the DSO could establish a feeder or transformer level price of electricity to reflect the grid value in dispatching DERs to meet local, or hyperlocal, grid needs.

Figure 43: Cost-Optimized DER vs a Loss-Optimized DER Dispatch From DSO



Source: Southern California Edison

Inclusion of Demand Response Assets With Resources Managed by DSO Optimization

Demand response assets should be included as part of the resources managed by the DSO's optimization. Demand response and load flexibility with other non-DER appliances were not considered as part of the EASE project. Shedding customers' electricity usage should be a last resort, but demand response provides a means to shift load throughout the day or reduce consumption if the DSO is unable to mitigate high demand with the DERs are available. This would be advantageous on days when rolling blackouts would otherwise be needed if the forecasted electricity supply cannot meet demand. Targeted load shed events would also serve as a safety net should DERs not meet their forecasted generation.

Inclusion of Other DER Asset Types Critical for Intermittency Planning

Including other DER asset types is critical to ensuring that intermittency of any given DER can be planned for in the future. EASE's DSO system optimized only for PV and BESS DER types as part of this project, but it could incorporate utility-owned wind turbine assets for large commercial and industrial customers, vehicle-to-grid enabled electric vehicle charging stations, or small-scale distributed bioenergy (such as food waste anaerobic digesters near restaurants or grocery stores).

Consideration of Minimum and Maximum Net-load Scenarios

SCE's distribution system planning process looked only at peak demand over a 10-year outlook. In the future, minimum and maximum net-load scenarios should be considered in this 10-year planning outlook. This would, for example, determine whether intermittent generation sources, like solar, will still supply capacity needs as daylight hours shorten in the winter. Also, as more customers electrify their appliances, there will be higher demand in the winter from electric heat pumps warming homes and businesses.

The Importance of DER Aggregators for Reaching Scale

The EASE computing system was limited in the number of individual DERs the DSO, DERMS, and DER aggregator could control directly within its lab simulation modeling 10,000 DERs on the Camden B-Bank Substation. The DSO system heavily relied on the DER aggregator to manage 99 percent of the 10,000 DERs on just one substation (seven circuits), as shown in Figure 44.

Figure 44: Camden Substation Area

Source: Southern California Edison

Those roughly 9,900 DERs were managed by the DSO and DERMS by assigning them to 178 directly controllable topology area nodes that were each assumed to host 56 DERs, rated at roughly 250 kW/500 kWh per node. This dramatically simplified the optimization problem by optimizing 178 topology node areas on the B-bank substation. The DERMS directly controlled the larger 71 commercial- and industrial-size DERs. The EASE computing architecture was never designed to directly control all DERs within the substation due to the significantly high computation overhead that would be required to optimize all DERs within a single substation area. Other advances in computing may allow the DSO to control and optimize more individual DERs, such as advances in parallelizing load flow and optimization solver algorithms, but these were out of scope for this demonstration. EASE's computation architecture was, however, sufficient to test the DSO use cases and concepts enabling a dynamic hosting capacity on the distribution network.

Future DER aggregators, like bulk system generation plants today, could be incentivized to compete with bulk-system energy supplied through substations and play a critical role in managing most of the DER customers on the network. The DSO would act as the balancing authority for the distribution network, with each substation/feeder as its area of balancing requirement. This would create a hybrid between a centralized DSO system managing the overall distribution network demand and generation flow and the decentralized DER aggregators operating under the guidance of the DSO to manage their DER assets. This system could more easily be scaled territory-wide and is being developed under SCE’s Grid Management System production design with a little fewer than 4,500 circuits. Those use cases will be carried over to production in SCE’s Grid Management System, which is discussed later in the Technology Transfer and Commercialization section of the following chapter.

Chapter 4: Technology/Knowledge/Market Transfer Activities

Technology Transfer and Commercialization

The insights demonstrated in the EASE projects will be leveraged in a variety of areas throughout SCE. SCE is working to develop the foundational capabilities required to decarbonize its electric power supply to customers. The thought process and roadmap for this strategy are explained in SCE's whitepaper, *Reimagining the Grid (SCE, 2020)*.

Insights and process improvements gained from the EASE project will be put into production in SCE's Grid Modernization efforts; specifically, the development of its Grid Management System DERMS Optimization Engine and Short-term Forecasting Engine (Johnson, 2021). The SCE's DERMS Optimization Engine will follow a very similar process of calculating the next day's DER dispatches in the day-ahead market using locational marginal price, load, and weather data as inputs. These forecast inputs will be provided to the Optimization Engine through the Short-term Forecasting Engine, which will forecast the day-ahead weather, load, and generation from PV and wind assets for the next day. The Optimization Engine will also optimize DER dispatch for various market and grid reliability goals and coordinate with other grid devices (capacitors, tap changes, regulators) that regulate voltage and load in advance. This would help maintain the voltage within five percent of the nominal value despite the possible fluctuations of PV or wind generation.

The project team expects other aspects of EASE technology to be included in the second release of SCE's Advanced Distribution Management System (ADMS) and base DERMS to enable the situational capabilities needed to address the specific needs of various regions in SCE's service area. These include:

- Enabling behind-the-meter and front-of-the-meter DERs to participate in the energy market that can be guided by the DSO by meeting the following objectives:
    - Improve forecasting capabilities for DERs (Short-term Forecasting Engine)
    - Optimize the energy dispatch of DERs and demand response assets on the grid on a feeder-by-feeder basis (Optimization Engine)
    - Optimize traditional grid voltage and load regulating assets (capacitors, tap changers, regulators, switches)
- Using standardized communication protocols and computing architecture that were leveraged in EASE:
    - IEEE 2030.5 Common Smart Inverter Profile to communicate with behind-the-meter DERs
    - DNP V3.0 SA v5 protocol to communicate with large front-of-the-meter DERs

Knowledge Transfer Activities

The EASE project team presented at a variety of conferences and forums and published one technical paper with IEEE. The industry presentations and publications are listed in Appendix C – Industry Presentations & Publications. Some of the noteworthy presentations are listed below:

- IEEE Conference on Technologies for Sustainability (SusTech)
- CAISO T&D Interface Coordination Working Group
- DOE SETO Colloquium – SCE's Customer Acquisition Strategy for EASE

At the IEEE Conference on Technologies for Sustainability (SusTech) the project team presented its feeder net load management methodology for flattening the load at the feeder head using the aggregate DERs on a feeder. This capability allowed the DERMS to perform a day-ahead load forecasting process that was used to optimally dispatch the DERs for the next day, such that the load at the feeder head was flattened and less variable. It was the project teams' first step at attempting to coordinate all DERs throughout the substation to achieve an objective function and was a precursor to the DSO's day-ahead energy market process, which incentivized DERs to provide services based on the locational marginal price for the next day.

The project team also showcased its working DSO energy market at CAISO's T&D Interface Coordination Working Group, which aimed to define how a DSO retail market would interact with the ISO wholesale market. The project team illustrated how DER could respond to locational marginal prices at wholesale nodes and provide grid services on the distribution network. CAISO is currently developing a more detailed framework and interface between utilities and ISOs. That framework will use some of the insights from the EASE project to inform capabilities and potentially define future pilot demonstrations to demonstrate the value of integrating smaller and aggregate DERs into the energy market.

Finally, the project team disseminated the results of its customer acquisition strategy in its pilot field demonstration. The team shared its process for developing its strategy to acquire customers; this consisted of the following elements

- Substation customer demographics analysis
- Solar and storage customer propensity analysis
- System rebate incentive structure depending on the purchased system size
- Marketing campaign
- Key performance metrics for tracking customer adoption

The project team shared which strategies worked, where the strategy fell short, and other considerations for future pilot projects. The customer acquisition campaign was a valuable knowledge-sharing activity that demonstrated the feasibility and benefits of the DSO system to customers and stakeholders. The campaign also provided insights and lessons learned for future customer acquisition efforts for similar projects. Following are some of the key takeaways from the campaign:

- Perform customer propensity analysis prior to selection of the field pilot location.

- Tailor messaging and outreach strategies to the needs and preferences of different customer segments.
- Use multiple channels and methods to reach out to customers and increase their awareness and interest.
- Engage with community partners to build trust and credibility with customers and facilitate their enrollment and participation.
- Provide clear and consistent information and communication to customers throughout the project lifecycle.
- Offer incentives and rewards to customers for enrolling their DERs in the DSO market and providing grid services.

The EASE project has demonstrated the value of sharing project information with various groups, such as internal stakeholders, external partners, and the public. By sharing data and information openly, the project team has been able to foster new collaborations, accelerate research, increase visibility, and create transparency. Sharing project information helped to demonstrate the benefits of the DSO system and identify potential risks and future opportunities from the pilot technology. The company will continue to share learnings from this project with others through any other opportunities that may present themselves.

Chapter 5: Conclusions/Recommendations

These simulations proved that a dynamic hosting capacity is achievable to significantly increase the number of DERs hosted while providing DER owners a means to earn revenue for their energy services in a DER marketplace. The EASE project demonstrated a control architecture that can be used to develop an operator-type distribution system to work with DER aggregators to provide energy services to the grid. This control architecture can be scaled territory-wide, with the utility acting as a centralized distribution system operator managing optimization of all DERs and DER aggregators on the distribution network. In turn, DER aggregators would manage and optimize DERs in their assigned area. Such a system would enable the utility to improve grid reliability and incentivize DER owners to provide market-based services and receive compensation. It could be used not only to host more DERs but also to supply more demand growth on the existing network. Further, this capacity has the potential to defer distribution upgrades, save ratepayers money, and accelerate the downward cost trend of installing residential and commercial DERs.

This capability to supplement capacity requires sufficiently high DER concentration levels, and SCE estimates that, by 2045, it will have acquired a total of 30 GW of PV and 10 GW of storage on its distribution networks. Peak demand in SCE territory is expected to increase by 40 percent by 2045, from 23 GW to 32 GW. 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, when SCE reaches carbon neutrality. This assumes SCE could continue to defer projects using the necessary combination of controllable DERs with a DSO, which would result in ratepayer benefits such as reduced electrical bills due to the utility's savings from deferred capacity upgrade projects and improved cost recovery.

Even with today's DER prices per kW, a DSO market could improve a customer's return on investment in DERs. On average, customers participating in the EASE project's DSO market were estimated to earn $4,600 over 10 years for bidding their resource in the DSO market. Further work is required from an economic and policy perspective to better define how this system could work with DERs. Additionally, more work would be needed to better simulate this marketplace. The EASE project demonstrated that the price of energy could influence how DERs are optimized to benefit the grid, but the analysis did not include how the DSO energy market could impact the levelized cost of energy capacity in SCE's Grid Needs Assessment once this system is implemented in the future. Future research demonstrations could incorporate value-stacking DER benefits, such as voltage and reactive power control, to broaden the versatility of grid services that aggregated DERs can provide. Currently, levelized costs of energy for DERs tend to exclusively include energy savings accrued over time without optimizing their usage in the context of an integrated energy market. Enabling DERs to provide value-stacking grid services would provide additional value streams in the locational net benefit calculation for DERs and make them more cost competitive when comparing potential capacity upgrade projects. Future studies should examine how aggregate DERs influence the levelized cost of energy and their ability to reduce customer energy costs.

In addition to SCE's investments in renewables on the bulk system, this system would contribute, by 2045, to a 339-million-metric-ton reduction in the carbon dioxide equivalent (MMT CO_2e) of greenhouse gases throughout California. Most importantly, through this transition, all California residents will benefit from reduced greenhouse gas emissions and new economic opportunities. Based on these estimates, SCE's investments in grid modernization will begin to pay off before it reaches its goals of carbon neutrality by 2045.

Chapter 6: Benefits to Ratepayers

The Electric Access System Enhancement (EASE) project demonstrated a scalable, interoperable, and cost-effective means of integrating high penetrations of DERs. The control architecture leveraged a DER management system, a distribution system operator for transacting energy, and a third-party DER aggregator platform. The project identified ways to enhance the customer interconnection process to the grid, improve access to information from DERs, and optimize the use of DERs to provide energy services in a simulated day-ahead shadow market while maintaining grid reliability. By integrating these capabilities into a scalable system of systems, the DSO can effectively balance DER generation and customer demand on the distribution network.

This integrated capability would allow the grid to host more DERs than traditionally possible on wires alone. Hosting more DERs has the added benefit of supplying increased demand growth, sometimes beyond the capacity limits of the distribution network itself.

Besides supplying increased demand growth, an increase in circuit hosting capacity and the integrated nature of the control architecture offers the following additional ratepayer potential benefits:

- Deferred capacity upgrades
- Significant reduction in greenhouse gas emissions as those sectors of the economy powered by fossil fuels are electrified
- Increased local generation on the grid to power electricity demand
- New avenues of compensation for DER owners
- Improved economics of DER adoption
- Facilitation of effective DER management
- Optimized generation of controllable DERs to reduce net demand during peak hours
- Extended life of distribution equipment by optimizing control of DERs
- Incentives for customers to adopt DER by enrolling their DER in a DSO market via their aggregator
- Greater participation in the energy market to help reduce the levelized cost of electricity

In addition, the clean energy and grid investments required to meet 2045 goals present a tremendous economic development opportunity for California. Utility-scale generation and storage and the supporting grid represent as much as $250 billion of clean energy and grid investments and include thousands of sustaining craft and skilled jobs (SCE, 2019).

Reduction in greenhouse gas emissions

The integration of DERs into the distribution network will reduce greenhouse gas emissions by increasing the share of renewable energy in the electricity mix and reducing reliance on fossil fuels. 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 the reduction in greenhouse gases are consequences of customers adopting more DERs, 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. This also provides new avenues for DER owners to be compensated for additional value-stacking grid services, improving economics of DER adoption for value provided and facilitating effective DER management.

Figure 45: SCE's Greenhouse Gas Reduction Goals for 2045

Source: Southern California Edison

Combined with its investments in renewables on the bulk system, SCE expects to see, by 2045, a 339 MMT CO_2e reduction in greenhouse gases, as shown in Figure 45. This assumes that the targets of interconnecting clean sources of energy and shifting to electricity as the primary energy source for transportation, buildings, industrial plants, and agriculture are met. Another 108 MMT CO_2e will need to be sequestered for SCE to meet its goal of carbon neutrality by 2045. EASE's DSO system more efficiently integrates and utilizes aggregate and individual DERs. With sufficient DER adoption on the grid, EASE computing architecture would help SCE achieve its greenhouse gas reduction target of decarbonizing its electric supply by 2045.

Improved Economics of DER Adoption and Integration

Energy markets are a fair way to incentivize low-cost generation of electricity because they allow different types of generators to compete on a level playing field and receive compensation for the services they provide to the grid. Energy markets also reflect the changing costs and values of different resources over time and location, which can encourage innovation and efficiency. The DSO system can become the interface that coordinates and communicates between DER owners, utilities, and market operators to enable broader DER participation in the energy markets.

DER owners can provide the same services as larger generators in aggregate through a DSO system. When DERs are allowed to participate in the wholesale markets and provide grid services, DER owners and aggregators can earn additional income from their investments and reduce their payback period. This can improve the economics for DER adoption and incentivize more customers to install and operate DERs. Greater participation in the energy market can also help reduce the levelized cost of electricity by increasing competition and reducing the market power of individual suppliers. This can lead to lower energy generation costs for suppliers, which are typically passed directly to consumers in their bills.

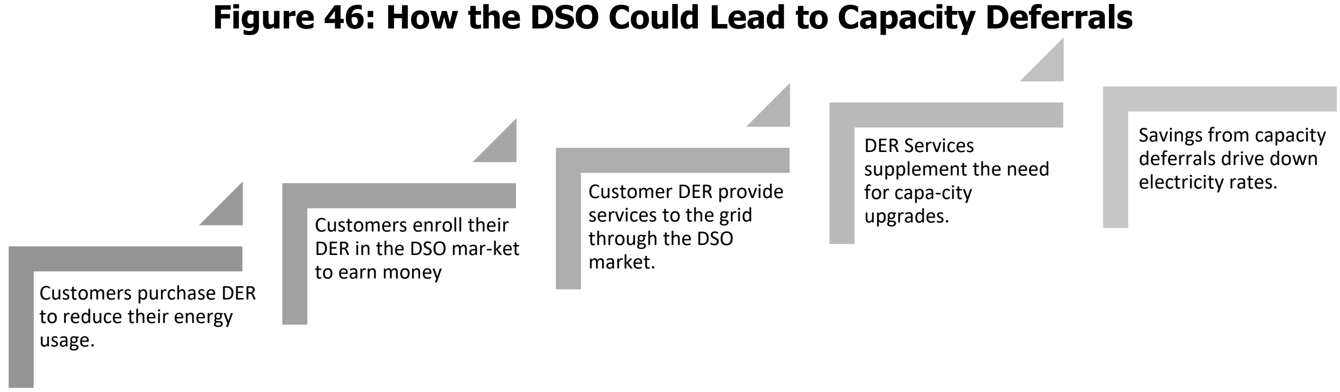
Aggregate DERs participating in a DSO market have the potential to provide new avenues of compensation for DER owners. Like the wholesale markets, customer DERs will provide various services such as energy, capacity, ancillary services, and demand response and be compensated for their services. This market opportunity will create new revenue streams for DER owners and aggregators and reduce the total cost of ownership of their DER assets. During the EASE project's field demonstration, residential customers in Santa Ana, California, were estimated to earn a maximum of $462 for a 5-kW PV and 2-hour BESS system in 2021 by participating in the simulated DSO market. Over a 10-year period this could yield around $4,600 for the customer, which could significantly impact their return on investment. The DSO system would also promote local generation on the grid lead, providing a more efficient means to supply customer demand through aggregate DERs. At scale, this could have a significant impact on reducing the losses for transmitting power from large, centralized generation plants to customers.

This shows that, even with today's DER prices per kW, a DSO market could improve a customer's return on investment in a DER. More work needs to be done from an economic and policy standpoint to better define how this type of system could work with DERs.

Deferred Capacity Upgrades and Efficient Supply

SCE can use the DSO's DER optimization capabilities to host more gross customer demand than is traditionally possible today. A DSO has the benefit of situational awareness and load forecasts to optimize the generation of controllable DERs 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. As more customers electrify their homes, buildings, and vehicles, demand for electricity will be higher, but a DSO market could help incentivize low-cost generation.

Figure 46: How the DSO Could Lead to Capacity Deferrals



SCE calculated the deferral savings accrued over time and estimated that it could recover over $400 million of its investments in the Grid Modernization plan by around the year 2040 through distribution deferrals (SCE, 2020). An additional $300 million in savings could be accumulated between 2040 and 2045, when SCE reaches carbon neutrality. 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 requires further study.

The clean energy and grid investments required to meet 2045 goals present a tremendous economic development opportunity for California. 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. The DSO system is a promising solution to address the challenges and opportunities of integrating high penetrations of DERs on the distribution network. By creating a platform for DERs to offer their services to the grid and the market, the DSO system can unlock the full potential of clean energy resources and enable a more efficient and resilient grid. The DSO system can also support the transition to a carbon-neutral economy by facilitating the electrification of various sectors and reducing reliance on fossil fuels. The DSO system is aligned with SCE's vision to provide reliable, affordable, and clean energy to its customers by 2045. Future work could investigate how the DSO system can enhance customer engagement and satisfaction, improve grid reliability and security, and foster innovation and collaboration among different stakeholders in the energy sector.

GLOSSARY AND LIST OF ACRONYMS

Term	Definition
AC	Alternating current
ADMS	Advanced distribution management systems are computer systems used by distribution system operators to monitor the status of all devices on the electric distribution grid and to control these devices in a well-coordinated manner for optimal performance, reliability, and efficiency. The ADMS includes distribution supervisory control and data acquisition capabilities plus outage management software and advanced distribution system software applications, such as optimal power flow, volt-var optimization, fault line location service and restoration technologies, and, in some cases, hardware and software platforms to monitor and control distributed energy resources.
BESS	Battery energy storage systems may include small-scale storage devices such as home energy storage units and plug-in electric vehicles. Large-scale energy storage units include battery energy storage systems, flywheels, superconducting magnetic energy storage, ultra-capacitors, and pumped storage and aggregated plug-in electric vehicles.
California ISO	California independent system operator
DC	Direct current
DERs	Distributed energy resources are generators, energy storage devices, or controllable loads connected at the secondary (low) voltage level or the primary (medium) voltage distribution level.
DERMS	A hardware and software platform to monitor and control distributed energy resources to maintain or improve the reliability and overall performance of the electric distribution system.
Distribution Substation	A distribution substation transfers power from the transmission system to the distribution system of an area. The distribution substation reduces voltage to a level suitable for local (e.g., City, suburban area) distribution.
DMS	A distribution management system is a computer system that includes distribution supervisory control and data acquisition facilities plus elementary support functions for monitoring and control, such as alarming and user interface. The distribution management system typically does not include advanced applications, such as optimal power flow, outage management, volt-var optimization, and fault line location service and restoration.
DSO	A distribution service operator is an entity envisioned to manage distribution system demand, generation, and other distributed energy resources by optimizing resource allocation to grid reliability services and the wholesale energy market. A distribution system operator would operate and maintain each local distribution area, separate from the transmission operator, and would be responsible for providing reliable real-time distribution service.

Term	Definition
EMS	An energy management system is responsible for capturing and historizing power flow and voltage information on distribution network assets.
FLISR	Fault location, isolation and service restoration technologies and systems involve automated feeder switches and reclosers, line monitors, communication networks, distribution management systems, outage management systems, supervisory control and data acquisition systems, grid analytics, models, and data processing tools. These technologies work in tandem to automate power restoration, reducing both the impact and length of power interruptions.
Grid Management System	Southern California Edison's envisioned Grid Management System, which will be a system of systems that includes advanced distribution management system and distributed energy resource management system capabilities.
Grid Needs Assessment	Grid needs assessment presents the needs identified throughout Southern California Edison's distribution and subtransmission system that fall under the category of one or more of the four distribution services adopted by D.16-12-036.
GW	Gigawatt
IEEE	Institute of Electrical and Electronics Engineers, a professional association that develops electrical engineering standards
kVA	Kilovolt-amperes
kWh	Kilowatt-hours
MMT	Million metric tons
MW	Megawatt
Permission to Operate	Permission to operate is a completion status signaling that a utility customer is ready to operate their interconnected asset.
PV	Shorthand for a solar photovoltaic (PV) system, which is a collection of multiple solar panels that generate electricity.
SCADA	Supervisory control and data acquisition
SCE	Southern California Edison
SOC	Battery state of charge as a percentage
TEMS	Transactive energy management system
UIB	The utility integration bus is a type of enterprise service bus that allows the utility to integrate various systems to enable the management of distributed energy resources using utility system telemetry.

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This material is based upon work supported by the U.S. Department of Energy's Office of Energy Efficiency and Renewable Energy (EERE) under the Solar Energy Technology Office Award Number DE-0008004.

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