OpFlex Pilot Report

SOUTHERN CALIFORNIA EDISON'S ANALYSIS, CONCLUSIONS, AND RECOMMENDATIONS ON ITS OPFLEX PILOT

Southern California Edison
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Contents

OPFLEX PILOT REPORT

1 Introduction

Southern California Edison (SCE) submits this report in accordance with California Public Utilities Commission (Commission or CPUC) Decision (D.) 21-06-002 Ordering Paragraph 18 and Resolution E-5260 Ordering Paragraph 2. This report outlines the results and suggestions from SCE's Electric Access System Enhancement (EASE) project,[1] which evaluated distributed energy resource (DER) operational alternatives that can be used to determine if they can address Operational Flexibility (OpFlex) constraints. This was done by implementing grid control systems in both laboratory and field demonstrations to support the streamlining of Distributed Energy Resource (DER) interconnections, improve access to grid assets and DERs, and to demonstrate the optimization of DERs for grid and market use cases. As approved in SCE's Advice Letters 4806-E, and 4806-E-A, and 4806-E-B, SCE's EASE project serves as its OpFlex Pilot to avoid duplicative efforts. The following sections discuss the specific metrics and objectives SCE was asked to address.

2 Operational Alternatives as Mitigants to OpFlex Constraints

What operational alternatives are a sufficient mitigant to OpFlex Constraints?[2] The Electric Access System Enhancement (EASE) project, prepared by Southern California Edison for the United State Department of Energy and California Energy Commission, addressed several use-cases that demonstrated scalable, interoperable, and cost-effective methods for integrating Distributed Energy Resources (DERs). EASE's use cases were critical in mitigating OpFlex

[1] Juan Castaneda and Andrew Loan. 2024. (EASE Final Report) *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.
[2] Resolution E-5260 Ordering Paragraph 2.

constraints by streamlining the DER interconnections, DER provisioning, optimizing DER usage, and enabling dynamic hosting capacity.

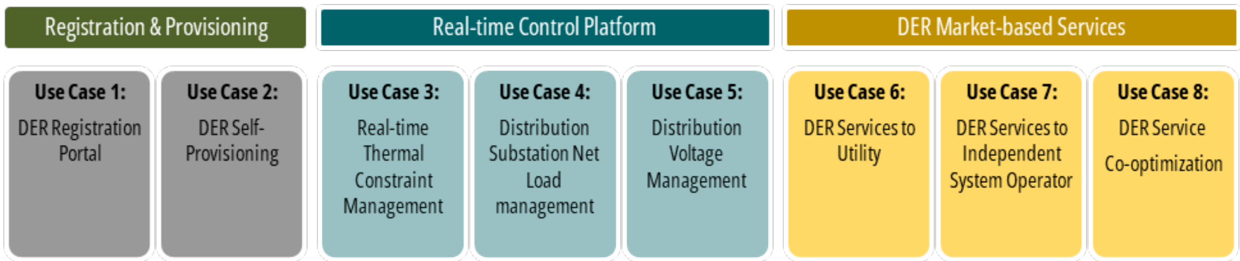

Figure 1: Overview of EASE Use Cases

2.1 DER Registration & Provisioning

- Use Case 1: DER Registration Portal
- Use Case 2: DER Self-Provisioning

These use-cases streamline the process of registering and provisioning DERs, reducing interconnection times, and ensuring better management of DER assets. This mitigation facilitates quicker integration of DERs into a DER management system (DERMS), thus minimizing operational delays associated with OpFlex constraints.[3]

2.2 Real-time Control Platform for Constraint Management

- Use Case 3: Real-time Thermal Constraint Management
- Use Case 4: Distribution Substation Net Load Management
- Use Case 5: Distribution Voltage Management

The real-time control platform enables the utility to manage thermal and voltage constraints dynamically. It optimizes the dispatch of DERs to balance demand and supply, ensuring that the grid operates within safe limits. This real-time management is crucial for addressing the unpredictability and variability of OpFlex constraints.[4]

2.3 DER Market-based Services

- Use Case 6: DER Services to Utility

[3] See EASE Final Report (CEC-500-2024-064). page 12, DER Provisioning
[4] See EASE Report (CEC-500-2024-064). page 23, DER Constraint Management

- Use Case 7: DER Services to Independent System Operator
- Use Case 8: DER Service Co-optimization

These use-cases create a market-based framework for DERs to provide services to both the utility and the Independent System Operator (ISO). By leveraging market mechanisms, the utility incentivized DER owners to optimize their energy production and consumption. This economic approach ensured that DERs are utilized effectively, thereby mitigating planned operational constraints.[5]

Overall, the EASE project's use-cases provided a comprehensive approach to mitigating OpFlex constraints by enhancing the registration and provisioning process, optimizing real-time control, and creating market-based services. These operational alternatives grid's ability to support higher DER penetration while maintaining reliability and efficiency.

3 Challenges and Barriers to Implementing Operational Alternatives

What are the challenges and barriers to implementing operational alternatives?[6] The main challenges and barriers to implementing operational alternatives included:

- Scalable Architecture: Developing a scalable control architecture for managing Distributed Energy Resources (DER) territory-wide.[7]
- Secure Connections: Establishing secure connections to external DER aggregators.
- Integration with Production Systems: Integrating the control architecture with existing production systems while adhering to cybersecurity standards.[8]

[5] See EASE Report (CEC-500-2024-064). page 43, DSO Market Use Cases
[6] Resolution E-5260 Ordering Paragraph 2
[7] See EASE Report (CEC-500-2024-064). p 2, Enhanced Distributed Energy Resource Interconnection and Control
[8] Southern California Edison. (2024). Appendices, Publication Number: CEC-500-2024-064-AP, p A-1, APPENDIX A: EASE Architecture

- Customer Incentivization: Incentivizing customers to purchase solar or energy storage systems for field demonstrations.
- Customer Acquisition: Acquiring sufficient customer participation, particularly challenging during the COVID-19 pandemic.

4 Recommended Interconnection Rules to Support Operational Alternatives

What interconnection rules are recommended to facilitate and/or support operational alternatives?[9] Per the findings in the EASE Project, as well as recent developments related to DERMS, DER Aggregators, and interconnection rules, SCE suggests the following to facilitate operational alternatives:

- Streamlined Provisioning: Automating the provisioning process for DERs in SCE's DERMS, and a voltage sensitivity analysis performed per DER to evaluate its ability to influence voltage and thermal constraints.[10]
- Enhanced Interconnection Portals: Improving existing portals to support automated self-provisioning of DER assets into the DERMS.[11]
- DER Aggregator Requirements: To dispatch DER efficiently, SCE has developed requirements for how DER Aggregators should interface with its DERMS. The document outlines the technical processes for aggregators to connect their IEEE 2030.5 client with SCE's CSIP server and details the integration requirements for providing services through SCE's DERMS. [12]
- Compliance with Communication Protocols: Implementing IEEE 2030.5 and DNP3 communication protocols for interoperability among various customer inverter types.[13]

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[9] Resolution E-5260 Ordering Paragraph 2

[10] Southern California Edison. 2019. *DER Self-Provisioning Test Report*

[11] Southern California Edison. 2019. *DER Self-Provisioning Test Report*. p 12. E. Portal Design

[12] Southern California Edison. 2023. *DERMS IEEE 2030.5 Aggregator Requirements*. https://www.sce.com/sites/default/files/custom-files/PDF_Files/SCE%20DERMS%20IEEE%202030.5%20Aggregator%20Requirements%20FINAL_082023.pdf

[13] Southern California Edison. 2018. *Distributed Control Architecture Interoperability Test Report*. p 6, 2.0 Interoperability Test Summary

- Compliance with Common Smart Inverter Profile: SCE required that all participating inverters and DER aggregators are compliant with the Common Smart Inverter Profile (CSIP).[14] The CSIP serves as a common communication profile for inverter communications to ensure 'plug and play' interoperability between California IOUs and third-party smart inverters or their managing systems. It also ensures some level of predictability for how an inverter will act on DER controls.

5 Feasible Timelines for Implementing Interconnection Rules

What timelines are feasible for implementing the interconnection rules to facilitate and/or support operational alternatives?[15] Based on the progress made in the different areas highlighted in section 4, Recommended Interconnection Rules to Support Operational Alternatives, SCE feels it is feasible to implement the interconnection rules to facilitate DER control management (a DER Operational Alternative) by late 2026 within a field demonstration (see section 10 for more information on the recommendation). Insights gained from the EASE project have been fed into the development of SCE's production DERMS system, which is expected to be completed by late 2026. Within SCE's DERMS product, SCE will provide the capability to streamline DER provisioning and interoperability with DER aggregators and CSIP compatible inverters.

6 Analysis of the availability and or capability of equipment to implement OpFlex solutions

See SCE's responses to questions in Appendix B of Resolution E-5260 in Section 11 below for a breakdown of the availability and capabilities of SCE's piloted equipment.

[14] Common Smart Inverter Profile Working Group. 2018. *Common Smart Inverter Profile V2.11*. https://sunspec.org/common-smart-inverter-profile-csip/

[15] Resolution E-5260 Ordering Paragraph 2

7 Scalability of OpFlex DER Operational Alternatives

Analysis of the scalability of the OpFlex DER Operational Alternatives studied in the pilot;[16] The scalability of the OpFlex DER control operational alternatives studied in the pilot was extensively analyzed in the EASE Final Report. It was concluded that the DERMS and Distribution System Operator (DSO) platform, when integrated with the Utility Integration Bus (UIB), can provision, and manage up to 10,000 DER on a single substation through optimal power flow simulations. The scaling methodology was validated using a digital twin of Camden Substation, which indicated that DER could be grouped into topology nodes to simplify computational resources required for optimization while still maintaining control granularity.[17] The DSO platform scales per substation using container microservices to add compute resources as new substations or DERs join the network. This ensures the day-ahead optimization process runs reliably and within the required timeframes for energy market.

8 Economic Viability of OpFlex DER Operational Alternatives

Commentary on the economic viability of the OpFlex DER operational alternatives studied in the pilot;[18] According to Proposal F-1[19], the concept of operational flexibility within the ICA7 context is that utilities need the flexibility to reconfigure circuits during maintenance or unplanned outages.[20] The EASE Project's applications may extend beyond simply easing operational constraints, enhancing the number of DERs and allowing revenue generation through a DER marketplace. This compensation enabled the utility to use DERs for distribution deferrals as a

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[16] Resolution E-5260 Ordering Paragraph 2

[17] Southern California Edison. (2024). Appendices, Publication Number: CEC-500-2024-064-AP, p A-1, APPENDIX A: EASE Architecture

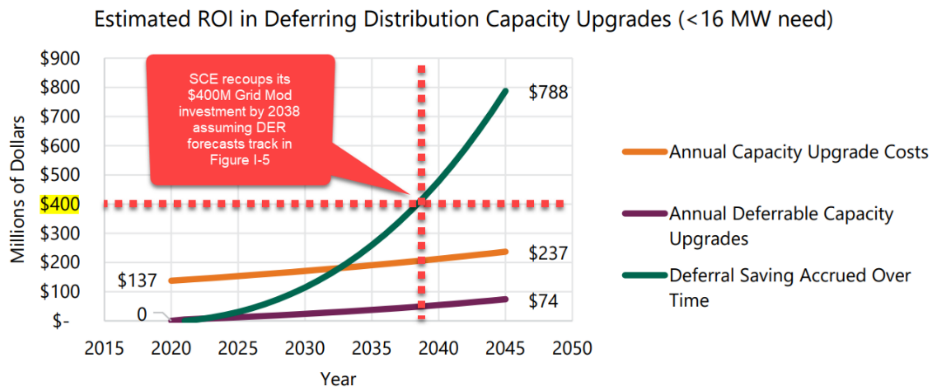
[18] Resolution E-5260 Ordering Paragraph 2

[19] Final Report Rule 21 Working Group Four, at 82

[20] Integration Capacity Analysis (ICA) is a tool developed in the Distribution Resources Plans (R.14-08-013) proceeding to inform developers of the DER hosting capacity on a circuit (how much capacity is available before a grid upgrade is required). ICA values vary over time and location depending on grid conditions.

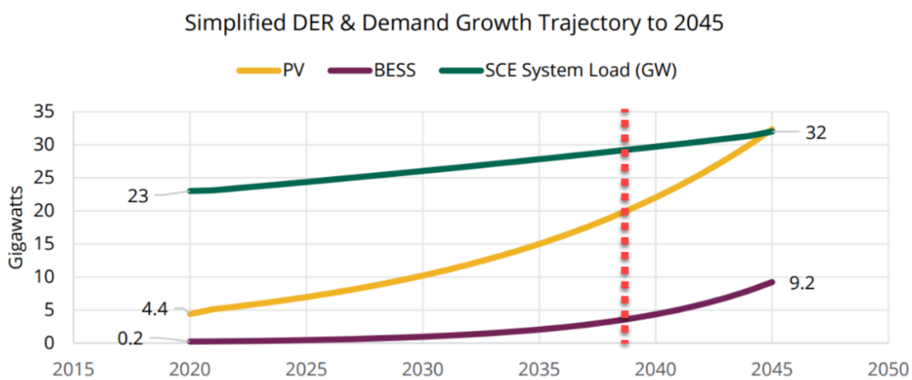
means of providing economic viability for the OpFlex DER control operational alternatives. [21]

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



Source: Southern California Edison

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



Source: Southern California Edison

Figure 2: Figure I-6 and I-5 in Appendix i of EASE Final Project Appendices

The main caveat is that economic viability depends on the cost-effectiveness of DER deferrals compared to traditional solutions at specific locations, and this case study had to broadly assume an even distribution of DER throughout SCE's service territory. Offering customer incentives could still boost DER adoption in SCE's service area among all customers. In EASE's pilot, the 31 customer DERs might have earned up to $4,600 over a decade by participating in the DSO Day-ahead market. Enabling value-stacking grid services could enhance DER cost competitiveness in

[21] EASE Final Report Appendices (CEC-500-2024-064-AP), APPENDIX I: Case Study on Dynamic Hosting Capacity

net benefits calculations. Future studies should explore how aggregated DERs affect energy costs and reduce customer expenses as installation costs decline.

9 Analysis of Pilot Metrics of Success

Analysis of the pilots against the Joint IOU Pilot Metrics of Success given in Appendix B;[22] The analysis of the pilot is provided in more detail in section 11. Metrics Evaluation, which provides a breakdown of the availability and capabilities of SCE's piloted equipment. A summary of compliance with these metrics are shown in the table below.

Metric #	Description	Success/Failure
1-3	Over-Arching Metrics	Success
4-8	Demonstrate the Ability to Integrate Participating Generating Facilities into IOU Control Systems:	Success
9-18	Demonstrate the Ability to Control Participating Generating Facilities	Success
19-22	Identifying and forecasting scenarios	Success
23-27	Calculating and allocating DER actions	Success
28-30	Engineering tools and processes	Success
31-32	Monitoring and reporting	Success
33-37	Evaluation metrics: Proposal F-1	Success

10 Recommendations for Scaling the Use of DER Operational Alternatives

Recommendations as to whether and how to scale the use of DER operational alternatives as a mitigation for operational flexibility constraints, including the constraints and timing of ADMS and DERMS development.[22] As recommended in Section 4 of this report, SCE supports using DER control management (a DER Operational Alternative) to handle abnormal grid conditions by dispatching DER to import or export power and address voltage/current violations caused by an OpFlex Event. The EASE pilot evaluated DER alternatives for abnormal grid conditions through Shadow Testing, which used production system data

[22] Resolution E-5260 Ordering Paragraph 2

without risking DER customers. SCE's ADMS and DERMS will be able to recalculate DER dispatches in real time in response to unplanned switching events to avoid voltage or current issues, but this capability and failsafe responses will need to be field tested.

This response to unplanned or planned switching events is achieved through the ADMS' Load and Volt-VAR Management system, which responds in tens of seconds, and the DERMS' day-ahead and intra-day optimization process, which considers topology changes due to OpFlex events using the ADMS' network load flow engine, responding in minutes. When an OpFlex event occurs (planned or unplanned switching), DER dispatches are recalculated to optimize active power and prevent violations, either in minutes using the full circuit model or in seconds with a heuristic method. The ADMS' Load and Volt-VAR Management system will manage the DER in real-time to prevent voltage problems using capacitors and tap-changing transformers. This validation should occur in a pilot after the DERMS deployment, expected to start by late 2026. See metric 35 for scalability recommendations.

11 Metrics Evaluation

Over-Arching Matters

1. Pilot adequately tests systems and scenarios

The EASE project started with grid control systems in a lab to validate use cases before moving to field demonstrations. These use cases included testing DER operational alternatives.[23]

2. Value engineering opportunities:

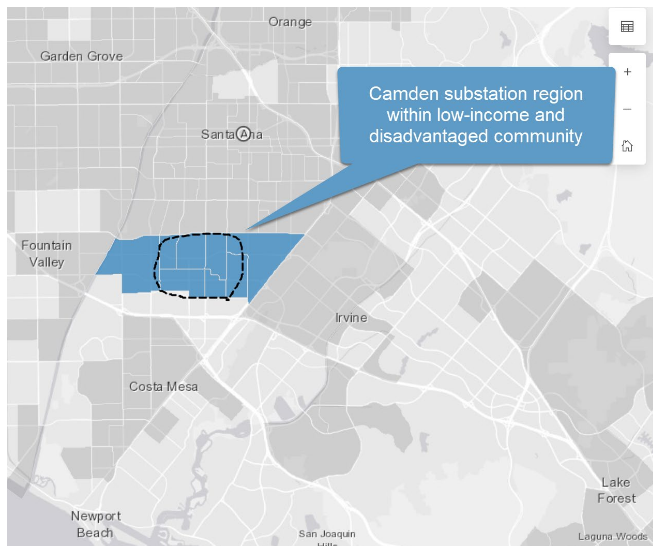
The main value engineering opportunity is presented in its Case Study on Dynamic Hosting Capacity.[24]

3. Diversity, Equity, and Inclusion:

[23] EASE Final Report (CEC-500-2024-064). Page 9 to 11, Chapter 2: Project Approach

[24] EASE Final Report Appendices (CEC-500-2024-064-AP), APPENDIX I: Case Study on Dynamic Hosting Capacity

The project did not explicitly address DEI, but it ensured that DER deployment was and did not favor specific communities.[25] The EASE project was designed with an inclusive approach to customer acquisition, particularly the Camden Substation in the City of Santa Ana, which is identified as a low-income and disadvantaged and vulnerable community. Targeting a disadvantaged and vulnerable community aligned with the goals of the Department of Energy to ensure that the benefits of such projects reach underserved and vulnerable populations. The project team incentivized customers to participate through significant rebates and incentives. This strategy not only promoted greater equity in the adoption of renewable energy solutions but also provided valuable insights into the practical challenges and opportunities of managing distributed energy resources and understanding some of the near-term barriers in adoption of DER in such communities.



The customer acquisition strategy included:

- Targeted Outreach: Marketing efforts were expanded by increasing the number of approved installers from 4 to 7, and using various channels such as door hangers, yard signs, social media marketing on LinkedIn and the Nextdoor App, and additional mailers to the Camden circuit customer base.
- Incentives and Rebates: Customers were offered significant rebates, ensuring that even those from lower-income households could

[25] EASE Final Report (CEC-500-2024-064). Page 2 to 5, Executive Summary: Project Results

participate. For instance, small solar systems received a baseline rebate of $4,800 or 80% of the total system cost, whichever was lower. This structure ensured affordability and encouraged participation from diverse economic backgrounds.

- Community Engagement: Virtual meetings with city officials and local public affairs were pursued to engage the community actively and ensure transparency and inclusivity in the project's implementation.

These efforts are detailed in the EASE Customer Acquisition Meeting presentation (EASE DoE Customer Outreach), which outlines the demographics of Santa Ana and the targeted approach to customer acquisition.

Integration of Participating Generating Facilities

4. DER locations and capabilities modeled:

The Camden substation network model included detailed DER locations and capabilities. This network model was leveraged by the DCA for all DER dispatch use cases.[26, 27]

5. DER systems provisioning:

The DER provisioning process was automated to deliver accurate customer DER nameplate data and assess each DER's impact on voltage and current in the distribution network through a sensitivity analysis.[28, 29]

6. Status and telemetry to IOU systems:

DER systems reported real-time status and telemetry data every 30 seconds. See Distributed Control Architecture Interoperability Test Report, Page 19, Appendix B – Interpreting the Log Files

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[26] EASE Final Report (CEC-500-2024-064). Page 9 to 11, Page A-3, Network Model, AMI Load Data, and DER Registration

[27] Distributed System Operator (DSO) Test Report, Page 7, DCA Environment Overview

[28] See Task 4.0: Self-Provisioning Test Report for an overview of the provisioning process

[29] EASE Final Report (CEC-500-2024-064). Page 12, DER Provisioning

7. Interoperability with IOU systems:

The project successfully demonstrated interoperability using IEEE 2030.5 and DNP3 communication protocols for dispatching DER.[30, 31]

8. Real-time visibility:

The DERMS offered almost real-time insight into the grid and DER status. SCE's DMS system usually sets measurements to report data upon significant changes in value.[32] The threshold for these changes varies per data point and could not be adjusted for this demo.[33]

Facilities

9-13. Control signals and schedules:

The DERMS successfully sent control signals and schedules to DER systems and managed real-time responses. On average, 78 to 85% of the controls dispatched were delivered by the DER devices. This was in part due to the inability to implement control queuing, but also partially due to efficiency losses and possibly panel orientation & layout on customer homes.[34, 35]

14. Failsafes for communication loss:

The DERMS included failsafes to manage communication and hardware failures.

1. The DERMS could leverage other DER to provide DER constraint management if communication loss to some DER creates a voltage or current violation.[36]

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[30] EASE Final Report (CEC-500-2024-064)., Page 13 to 18, Interoperability Testing, Page 19 to 23, Lessons Learned
[31] DCA Interoperability Test Report
[32] EASE Final Report (CEC-500-2024-064). Page 23 DER Constraint Management to understand the circuit measurement points available to the DERMS, Page 43 to 48, DSO Market Use Cases for day-ahead forecasting & optimization processes
[33] Distribution System Operator (DSO) Test Report Milestone 6.3.1 Part 2, Page 11 to 14, Use-Case 7 | DER Services to the Independent System Operator (ISO)
[34] EASE Final Report (CEC-500-2024-064)., Page 13 to 18, Interoperability Testing, Page 46 to 55, DSO Market Use Cases
[35] Distribution System Operator (DSO) Test Report Milestone 6.3.1 Part 2, a. Page 15 to 23, Simulation Results for Use-Case 7, Page 24 to 28, Control Dispatch and Settlement Validation, Page 29 to 30, Improvements to Reduce Control Delays using Control Queuing
[36] EASE Final Report (CEC-500-2024-064), Page 23 to 25, DER Constraint Management

2. The DSO portion highlighted a gap in the existing system, which did not consider demand response assets or other DER or generation asset types as failsafes.[37]

15. Control system uptime:

The final deployed system had a relatively high system up-time during testing, but the system availability, uptime, and mean time to repair wasn't tracked during the pilot. Upon revisiting some of the test data the following metrics are approximations:

- Field Deployment Timeframe: [191 days] June 9th, 2021 to December 17th, 2021
- Availability: 89%
- Average Downtime: 2 hours per occurrence
- Mean Time Between Failures: 14 days
- Mean time to Repair: 2 days

The most vulnerable point of failure was the Utility Integration Bus's message broker, which served as the enterprise service bus for exchanging all information among the various systems within the DCA.[38] SCE's production DERMS will provide a much higher level of uptime thanks to a much more robust and scalable compute and microservice architecture.

16. Contractual obligations:

All DER were assumed to be enrolled in providing DER market services and could be taken over as needed for constraint management. This was configured in the Transactive Energy Management market strategy configuration page.[39]

17. DER management scenarios:

See metric 16 above.

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[37] EASE Final Report (CEC-500-2024-064), Page 18 to 19, Issues of Scaling and Validating Provisioning Interoperability, Page 56 to 58
[38] EASE Final Report (CEC-500-2024-064), Page 48, Figure 32
[39] EASE Final Report (CEC-500-2024-064), Page 44, Figure 28

18. Reverting DER operations:

DERMS reverted DER operations to default after abnormal conditions during constraint management scenarios.[40, 41, 42]

Identifying Triggers for DER Operational Alternatives

19-22. Identifying and forecasting scenarios:

The DERMS did not have any direct integration with the ADMS' switching scenarios, but SCE did test the DERMS to evaluate whether it would still mitigate any grid constraint violations. The DERMS successfully prevented overloads, efficiently dispatched DER, and operated compatibly with ADMS without causing anomalies.[43] Future integrations with SCE's production DERMS will involve considering planned switching in the day-ahead optimization. The DERMS will retrieve the planned switching information from ADMS and incorporate the appropriate dynamics in the network initialization process for each time step for the day-ahead DER dispatches.

Develop Methodology for DER Management Scenarios

23-27. Calculating and allocating DER actions:

The project developed methodologies to calculate and allocate DER actions during OpFlex events. See references in metric 18. The EASE project's real-time current and voltage constraint management system use cases also provide details into the methodology behind which DER are utilized.[44]

Develop Operational Processes for OpFlex DER Alternatives

28-30. Engineering tools and processes:

The main goal of the EASE project was to improve dispatching for DER systems, but it also investigated how the DERMS would react in switching scenarios (metric 28) during the 9.2.1 Software-in-the-Loop Simulation in EASE's DCA Integration with an

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[40] EASE Final Report (CEC-500-2024-064), Page 26 to 27, Lab Validation
[41] EASE Final Report Appendices (CEC-500-2024-064-AP), Appendix B: DER Constraint Management
[42] 9.2.1 Software-in-the-Loop Simulation of EASE's DCA Integration with an ADMS, Page 6, Simulation Results for detailed step-by-step process for how DER
[43] 9.2.1 Software-in-the-Loop Simulation of EASE's DCA Integration with an ADMS,
[44] Use Case 3: Real-Time Current Constraint Management section 4.1, Use Case 5: Real-Time Voltage Constraint Management section 4.1

ADMS test report. Switching outcomes could be assessed in PowerFactory before or after a planned or unplanned event. However, no processes were developed for operators and engineers to update facility settings (metric 29), as these changes were made only in the simulation. The simulation was repeated to confirm successful mitigation (metric 29). If facilities did not respond correctly, the event was re-assessed, adjusted in PowerFactory, and retested until the correct outcome was achieved (metric 30). Despite lacking a formal process in metric 30, the project team effectively executed, analyzed, and improved its OpFlex DER control operations during switching events.

Monitoring and Reporting on OpFlex Success

31-32. Monitoring and reporting:

The DERMS monitored and reported on DER management scenarios, recording data on operational alternatives. See metrics 9 to 13 and the project's M&V midpoint analysis for a view of how DERMS and DMS results were reported to users.[45]

Evaluation Metrics: Proposal F-1

33. Lessons Learned:

Lessons learned can be found in the following sections of the Lessons Learned sections of the EASE Final Report.[46]

34. Stakeholder Feedback:

SCE's industry presentations (EASE Final Report Appendices, Appendix C) allowed SCE to collect stakeholder feedback on the project.[47] These perspectives were captured prior to publishing the final project report and are incorporated in the Lessons Learned sections (see metric 33).

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[45] 10.2.1 Field Testing Mid-Point Analysis

[46] EASE Final Report (CEC-500-2024-064), Page 19, 30, 42, and 55

[47] EASE Final Report Appendices (CEC-500-2024-064-AP), Appendix C Industry Presentations & Publications

35: Scalability:

With SCE's production DERMS optimization engine and short-term forecasting engines being ready in late 2026, SCE is searching for pilot opportunities for DER aggregators to take advantage of these new capabilities for managing DER at scale with DER operators. See section Recommended Interconnection Rules to Support Operational Alternatives for a list of standards and activities SCE has implemented to prepare for future pilots. As mentioned in section 3, Challenges and Barriers to Implementing Operational Alternatives, and metric 3, customers may require incentives to participate in these pilot projects. It may be necessary to leverage EPIC funds to:

- Incentivize DER aggregators to integrate with SCE's DERMS for executing advanced DER dispatch functions.
- Incentivizing DER customers to participate in these services even though the market may not compensate them for their participation.

36: Additional DER Operational Alternatives:

The primary operational alternative outside of the OpFlex pilot's scope involves the usage of a transactive energy platform to encourage customers to bid their DER resources into an energy market, ensuring they are rewarded for the services their DERs provide.[48] Market-based services comprising dispatch schedules and prices were calculated through a system integrated with SCE's Utility Integration Bus (UIB). The DERMS had the ability to temporarily override the Distribution System Operator's (DSO) market-based dispatch objective to use DER to alleviate thermal or voltage violations.

Moreover, optimizing DERs to offer energy services in a simulated day-ahead shadow market can give grid operators and forecasting analysts important insights into the operation of DER and grid assets under different conditions, without risking grid volatility or misoperations.[49]

[48] EASE Final Report (CEC-500-2024-064), Page 43, DSO Market Use Cases
[49] 10.2.1 Field Testing Mid-Point Analysis, Page 11, 5 Constraint Management Validation

37. Documentation & Dissemination:

See EASE Final Report Appendices, Page C-1, Appendix C: Industry Presentations & Publications.[50] Some of the noteworthy meetings were:

- CAISO's T&D Interface Coordination Working Group, where the project's transactive energy platform was presented to the working group and Elliot Mainzer (President & CEO).[51]
- DOE SETO Colloquium – SCE's Customer Acquisition Strategy for EASE, which discussed the challenges in incentivizing customers to participate in the pilot project despite offering significant customer rebates.[52]

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[50] EASE Final Report Appendices, Page C-1, Appendix C: Industry Presentations & Publications
[51] EASE DSO Use-Cases CAISO.pdf
[52] EASE DoE Customer Outreach.pdf