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BEFORE THE PUBLIC UTILITIES COMMISSION OF THE

STATE OF CALIFORNIA

In the Matter of the Application of Pacific Gas and Electric Company for Approval of its 2018-2020 Electric Program Investment Charge Investment Plan. (U39E).	Application 17-04-028
And Related Matters.	Application 17-05-003 Application 17-05-005 Application 17-05-009

SOUTHERN CALIFORNIA EDISON COMPANY'S (U-338-E) ANNUAL REPORT ON THE STATUS OF THE ELECTRIC PROGRAM INVESTMENT CHARGE PROGRAM

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Dated: **February 28, 2019**

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In Ordering Paragraph 16 of Decision 12-05-037, the California Public Utilities Commission (Commission) ordered Southern California Edison Company (SCE), Pacific Gas and Electric Company (PG&E), San Diego Gas & Electric Company (SDG&E) and the California Energy Commission (CEC), collectively known as Electric Program Investment Charge (EPIC) Administrators, to file annual reports concerning the status of their respective EPIC programs. A copy of the annual report is also to be served on: (1) all parties in the most recent EPIC proceedings; (2) the service lists for the most recent general rate cases of PG&E, SCE and SDG&E; and (3) each successful and unsuccessful applicant for an EPIC funding award during the previous calendar year.

Subsequently, in D.13-11-025, Ordering Paragraph 22, the Commission required the EPIC Administrators to follow the outline contained in Attachment 5 when preparing the EPIC Annual Reports. In Ordering Paragraph 23 of the same Decision, the Commission required the EPIC Administrators to provide the project information contained in Attachment 6 as an electronic spreadsheet.

Finally, in D.15-04-020, Ordering Paragraph 6, the Commission required the EPIC Administrators to identify in their annual EPIC reports specific Commission proceedings addressing issues related to each EPIC project. In Ordering Paragraph 24 of the same decision, the Commission required that EPIC Administrators identify the CEC project title and amount of IOU funding used for joint projects.

In compliance with the Ordering Paragraphs of D.12-05-037, D.13-11-025 and D.15-04-020, SCE respectfully submits its annual report concerning the status of its EPIC activities for 2018. This is SCE's fifth annual report pertaining to its 2012-2014 EPIC Triennial Investment Plan (Application (A.) 12-11-004), after receiving Commission approval on November 14, 2013. Furthermore, this is SCE's third annual report pertaining to its 2015-2017 EPIC Triennial Investment Plan (Application (A.) 14-05-005), after receiving Commission approval on April 9, 2015. Lastly, this is SCE's first annual report pertaining to its 2018-2020 EPIC Triennial Investment Plan (Application (A.) 17-05-005), after receiving Commission approval on October 25, 2018.

Respectfully submitted,

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EPIC ADMINISTRATOR ANNUAL REPORT

EPIC Annual Report

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1. Executive Summary

a) Overview of Programs/Plan Highlights

2018 represented SCE's fifth full year of implementing program operations of its 2012 – 2014 Investment Plan Application[1] (EPIC I) after receiving Commission approval on November 19, 2013.[2] Furthermore, Year 2018 represented almost four full years of implementing program operations of SCE's 2015 – 2017 Investment Plan Application[3] (EPIC II) after receiving Commission approval on April 9, 2015.[4] Lastly, SCE received approval of its 2018-2020 Investment Plan Application (EPIC III) on October 25, 2018.

In this report, SCE separately presents the highlights from its 2012 – 2014 Investment Plan, 2015 – 2017 and 2018 – 2020 Investment Plan.

(1) 2012-2014 Investment Plan

For the period between January 1 and December 31, 2018, SCE expended a total of $1,756,989 toward project costs and $11,629 toward administrative costs for a grand total of $1,768,618. SCE's cumulative expenses over the lifespan of its 2012 – 2014 EPIC program amount to $36,273,453. SCE committed $2,488,282 toward projects and encumbered $28,475 through executed purchase orders during this period. SCE has no uncommitted EPIC funding for this period.

SCE executed 16 projects from its approved portfolio. Three projects were completed during calendar year 2015, 4 projects were completed in 2016, 4 projects were completed in 2017 and 2 projects were completed in 2018. A list of completed projects is included in the

Conclusion of this Report (section 4). In accordance with the Commission's directives,[5] SCE has completed final project reports for all projects and included them with the Annual Report according to the years completed. Reports completed in 2018 are included in the Appendix of this Annual Report. Two demonstrations remain in execution.

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1 (A.)12-11-001.
2 D.13-11-025, OP8.
3 (A.) 14-05-005.
4 D.15-04-020, OP1.
5 D.13-11-025, OP14.

(2) 2015-2017 Investment Plan

For the period between January 1 and December 31, 2018, SCE expended a total of $7,893,176 toward project costs and $890,975 toward administrative costs for a grand total of $8,784,151. SCE's cumulative expenses over the lifespan of its 2015 – 2017 EPIC program amount to $26,542,019. SCE committed $13,670,660 toward projects and encumbered $580,441 through executed purchase orders during this period. SCE has no uncommitted EPIC funding for this period.

SCE executed 13 projects from its approved portfolio. As of this report, 3 projects have been cancelled, for the reasons described in their respective project updates section.[6] Project execution activities continued on the remaining 10 projects. Of those 10 projects, the Advanced Metering Capabilities project was completed in 2017. The DC Fast Charging, Proactive Storm Demonstration and the Integration of Big Data for Advanced Automated Customer Load Management projects were completed in 2018 and final project reports are attached in the Appendix. Six demonstrations remain in execution.

(3) 2018-2020 Investment Plan

SCE received approval of its 2018-2020 Investment Plan Application (EPIC III) on October 25, 2018. SCE did not expend any project or administrative funds through December 31, 2018. SCE continued its project selection process in 2018 for EPIC III projects and thus did not commit or encumber any of its authorized budget.

b) Status of Programs

(1) 2012-2014 Investment Plan

As of December 31, 2018, SCE has expended $35,168,716[7] on program costs. Table 1 below summarizes the current funding status of SCE's EPIC projects:

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6 Starting at p. 37.

7 SCE's cumulative project expenses amounted to $30,114,188 based on the project spreadsheet in Appendix A. SCE's cumulative administration expenses amounted to $1,104,737. SCE's accounting system calculates in-house labor overheads separately which amounted to $5,054,528 for projects. As a result, SCE expended a total of $35,168,716 on program costs.

Table 1: 2012-2014 Triennial Investment Plan: 2018 Projects

1. Energy Resources Integration
• 4 Projects Funded ○ 1 Project Completed in 2016[8] ○ 2 Projects Completed in 2018[9]
2. Grid Modernization and Optimization
• 5 Projects Funded ○ 1 Project Cancelled in Q2, 2014[10] ○ 1 Project Completed in 2015[11] ○ 1 Project Completed in 2016[12] ○ 1 Project Completed in 2017[13]
3. Customer Focused Products and Services
• 3 Projects Funded ○ 1 Project Completed in 2015[14] ○ 1 Project Completed in 2016[15] ○ 1 Project Completed in 2017[16]
4. Cross-Cutting/Foundational Strategies and Technologies
• 4 Projects Funded ○ 1 Project Completed in 2015[17] ○ 1 Project Completed in 2016[18] ○ 2 Projects Completed in 2017[19]
Total Projects Funded: 16 Total Authorized Project Budget: $37,656,998[20] Total Project Spend: $35,168,716[21]

[8] Distribution Planning Tool.
[9] DOS Protection & Control Demonstration and Advanced Voltage and VAR Control of SCE Transmission.
[10] SCE cancelled the Superconducting Transformer project in 2014. Please refer to the project's status update in Section 4 for additional details.
[11] Portable End-to-End Test System.
[12] Dynamic Line Rating.
[13] Next Generation Distribution Automation, Phase 1.
[14] Outage Management & Customer Voltage Data Analytics.
[15] Submetering Enablement Demonstration.
[16] Beyond the Meter: Customer Device Communications Unification and Demonstration.
[17] Cyber-Intrusion Auto-Response and Policy Management System.
[18] Enhanced Infrastructure Technology Report.
[19] State Estimation Using Phasor Measurement Technologies and Deep Grid Coordination (otherwise known as the Integrated Grid Project).
[20] D.12-05-037, as updated by D.13-11-025. Includes $2,045,000 transfer from administrative funds to project funds.
[21] For additional details regarding SCE's Committed Funds, please see the attached spreadsheet.

Total Funding Committed: $2,488,282[22] Total Encumbered: $28,475[23] *Note: Due to intrinsic variability in TD&D /R&D projects, amounts shown are subject to change*

Table 2 below summarizes SCE's 2018 administrative expenses:

Table 2: 2012-2014 Triennial Investment Plan: 2018 Administration

• Program Administration	Total Authorized Budget: $1,855,002[24] Total Cumulative Cost: $1,104,737 Total 2018 Cost: $11,629

(2) 2015-2017 Investment Plan

As of December 31, 2018, SCE has expended $23,833,540[25] on program costs.

Table 3 below summarizes the current funding status of SCE's EPIC projects:

Table 3: 2015-2017 Triennial Investment Plan: 2018 Projects

1. Energy Resources Integration
• 3 Projects Funded 2 Projects canceled in 2016[26] 1 Project canceled in 2017[27]
2. Grid Modernization and Optimization
• 6 Projects Funded ○ 1 Project completed in 2017[28] ○ 1 Project completed in 2018[29]
3. Customer Focused Products and Services
• 3 Projects Funded

22 *Ibid.*
23 *Ibid.*
24 2012-2014 EPIC I Administrative Budget is $3,812,000, SCE Program Management transferred $1,956,998 from the Administrative to the Project Budget, reducing the Authorized Budget to $1,855,002.
25 SCE's cumulative project expenses amounted to $15,940,410 based on the project spreadsheet in Appendix A. SCE's cumulative administration expenses amounted to $1,817,504. SCE's accounting system calculates in-house labor overheads separately, which amounted to $256,942 for projects and $48,543 for program administration. As a result, SCE expended a total of $18,063,399 on program costs.
26 Bulk System Restoration under High Renewables Penetration and Series Compensation for Load Flow Control.
27 Optimized Control of Multiple Storage Systems.
28 Advanced Grid Capabilities Using Smart Meter Data.
29 Proactive Storm Impact Analysis Demonstration.

○ 2 Projects completed in 2018[30]
4. Cross-Cutting/Foundational Strategies and Technologies
• 1 Projects Funded
Total Projects Funded: 13 Total Authorized Project Budget: $37,504,200[31] Total Project Spend: $23,833,540[32] Total Funding Committed: $13,670,660[33] Total Encumbered: $580,441[34] *Note: Due to intrinsic variability in TD&D /R&D projects, amounts shown are subject to change*

Table 2 below summarizes SCE's 2018 administrative expenses:

Table 2: 2015-2017 Triennial Investment Plan: 2018 Administration

• Program Administration	Total Authorized Budget: $ 4,190,400[35] Total Cumulative Cost: $2,708,479 Total 2018 Cost: $890,975

(3) <u>2018-2020 Investment Plan</u>

As of December 31, 2018, SCE has expended $0 on program costs of its authorized project budget of $40,830,795[36] and its administration budget of $4,562,100.[37]

2. Introduction and Overview

a) <u>Background on EPIC (General Description of EPIC)</u>

The Commission established the EPIC Program to fund applied research and development, technology demonstration and deployment, and market facilitation programs to provide ratepayer benefits. Please refer to Decision (D.)12-05-037. This Decision further stipulates that the

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[30] DC Fast Charging and Integration of Big Data for Advanced Automated Customer Load Management.
[31] D.15-04-020, Ordering Paragraph 1 -- Appendix B, Table-5 p. 7.
[32] For additional details regarding SCE's Committed Funds, please see the attached spreadsheet.
[33] *Ibid.*
[34] *Ibid.*
[35] D.15-04-020, Ordering Paragraph 1 -- Appendix B, Table-5 p. 7
[36] D.18-01-008, at p. 38.
[37] *Ibid.*

EPIC Program will continue through 2020[38] with an annual budget of $162 million,[39] adjusted for inflation.[40] Approximately 80% of the EPIC budget is administered by the CEC, and 20% is administered by the investor-owned utilities (IOUs). Additionally, 0.5% of the total EPIC budget funds Commission oversight of the Program.[41] The IOUs were also limited to only the area of Technology Demonstration and Deployment (TD&D) activities.[42] SCE was allocated 41.1% of the IOU portion of the budget and administrative activities.[43]

The Commission approved SCE's 2012-2014 Investment Plan[44] in D.13-11-025 on November 19, 2013. SCE submitted its 2015-2017 Investment Plan Application[45] on May 1, 2014 and the Commission approved the Application in D.15-04-020 on April 9, 2015. SCE submitted its 2018-2020 Application on May 1, 2017 and the Commission approved the Application in D.18-10-052. SCE is currently executing its 2012-2014, 2015-2017 and 2018-2020 EPIC Investment Plans.

b) <u>EPIC Program Components</u>

The Commission limited SCE's triennial investment applications in this EPIC Program to TD&D projects, per D.12-05-037. The Commission defines TD&D projects as installing and operating pre-commercial technologies or strategies at a scale sufficiently large, and in conditions sufficiently reflective of anticipated actual operating environments, to enable appraisal of the operational and performance characteristics and the associated financial risks.[46]

In accordance with the Commission's requirement for TD&D projects, the IOUs continue to successfully utilize the joint IOU framework developed for the 2012-2014 cycle and enhanced for the 2015-2017 and 2018-2020 cycles with updated strategic initiatives to support the latest key drivers and policies. This includes the following four program categories: (1) energy resources integration, (2) grid

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38 D.12-05-037, OP1.
39 D.12-05-037, OP7.
40 Using the Consumer Price Index.
41 *Id*, OP5.
42 *Id*.
43 D.12-05-037, OP 7, as modified by D.12-07-001.
44 A.12-11-004.
45 A.14-05-005.
46 D.12-05-037, OP3.B.

modernization and optimization, (3) customer-focused products and services, and (4) cross-cutting/foundational strategies and technologies. SCE's 2012-2014, 2015-2017, 2018-2020 Investment Plans proposed projects for each of these four areas, focusing on the ultimate goals of promoting greater reliability, lowering costs, increasing safety, decreasing greenhouse gas emissions, and supporting low-emission vehicles and economic development for ratepayers.

c) EPIC Program Regulatory Process

The Commission approved SCE's 2012-2014 Application[47] in D.13-11-025 on November 19, 2013. SCE submitted its 2015-2017 Investment Plan Application[48] on May 1, 2014 and the Commission approved the Application in D.15-04-020 on April 9, 2015. The Commission opened a phase II of the proceeding to address projects proposed after Commission approval of an Investment Plan. The Commission issued its Phase II Decision,[49] requiring the IOUs to file a Tier 3 advice letter for any new or materially re-scoped project. This advice filing would need to justify why the project should receive Commission approval, rather than simply waiting for the next investment plan funding cycle. SCE submitted its 2018-2020 Investment Plan Application[50] on May 1, 2017 and the Commission approved the Application in D.18-10-52 on October 25, 2018. In compliance with the Commission's requirements for the EPIC Program,[51] SCE submits its 2018 Annual Report to update the Commission and stakeholders on SCE's program implementation.

d) Coordination

The EPIC Administrators have collaborated throughout 2018 on the execution of the 2012-2014 and 2015-2017 Investment Plans, as well as starting finalizing planning for the execution of the 2018-2020 Investment Plans. Specific examples of the IOUs coordinating with the CEC include:

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[47] A.12-11-004.
[48] A.14-05-005.
[49] D.15-09-005.
[50] A.17-05-005.
[51] D.12-05-037, Ordering Paragraph (OP) 16, as amended in D.13-11-025, at OPs 53-54 and D.15-04-020 at OP 6.

- Biweekly meetings to discuss stakeholder engagement planning (e.g., Symposium), as well as coordination and collaboration opportunities for the investment plan administrators;
- The EPIC Symposium in Sacramento on February 19th, 2018;
- Participation in technical advisory committees and working groups (e.g. Fire Safety Working Group);
- Project coordination on SCE's EPICII Integration of Big Data for Advanced Automated Customer Load Management project and the CEC's EPIC funded SunSpect Alliance project[52] to leverage resources and save costs; and
- Project coordination on the Electric Access System Enhancement (EASE) project.[53] EASE was funded ($4M) by the Department of Energy (DOE) under the Enabling Extreme Real-time Grid Integration of Solar Energy (ENERGISE) funding opportunity announcement (DE-FOA-0001495). SCE applied and was awarded CEC match funding ($2M).

As mentioned above in relation to CEC coordination, all the EPIC Administrators met on a near-weekly basis to discuss the items mentioned above, coordinate investment plan activities, and to plan and coordinate joint stakeholder workshops and the annual joint public symposium. Moreover, SCE had several collaborative meetings with the CEC to help further coordinate the respective investments plans.

e) <u>Transparent and Public Process/CEC Solicitation Activities</u>

On February 7, 2018, SCE supported the annual EPIC Symposium in Sacramento, CA. SCE gave an in-depth presentation on the Integrated Grid Project. Additionally, SCE participated in a public workshop hosted by PG&E in Fresno on November 9, 2018. SCE gave presentations on three potential EPIC III demonstrations:

- Next Generation Distribution Automation,

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52 CEC, PON 14-303.

53 Three-year project is enhancing DER interconnection to the grid, with the ability to help to provide services and optimization of resources by implementing an interoperable distributed control architecture.

- Phase 1, Cybersecurity for Industrial Control Systems and
- Distribution Centers of the Future.

SCE noted the Distribution Centers of the Future project is still undergoing project planning and selection, but has strong potential to be sited in a disadvantaged community.

SCE supported numerous parties applying for CEC EPIC funding in 2018. A total of 18 requests for Letters of Support (LOS) and Commitment (LOC) were received from a diverse array of parties including private vendors, universities and national laboratories, showing interest in partnering on their bids for CEC projects. These requests consisted of 15 LOSs and 3 LOCs. Of these requests, 6 LOSs[54] and 1 LOC were approved by the CEC. For SCE, a LOS typically supports the premise of a project. In some instances it will infer technical advisory support if (A) the project is awarded to the recipient and (B) the party and SCE come to a mutual understanding of what advisory support will be required.

A LOC includes the early financial and/or technical support in the event the project is awarded to the recipient. All public stakeholders continue to have the opportunity to participate in the execution of the Investment Plans by accessing SCE's EPIC website, where they can access SCE's Investment Plan Applications, request a LOS or LOC and directly contact SCE with questions pertaining to EPIC.

3. Budget

a) Authorized Budget

(1) 2012 – 2014 Investment Plan

Table 5: 2017 Authorized EPIC Budget

2017 (Jan 1 - Dec 31)	Administrative	Project Funding	Commission Regulatory Oversight Budget
SCE Program	$1.3M	$11.9M	$0.33M[55]
CEC Program	$5.3M	$47.7M	

[54] Three of these LOSs have not yet been confirmed for awarded funding.
[55] Advice Letter, 2747-E, p. 6.

(2) **2015 – 2017 Investment Plan**

Table 6: 2017 Authorized EPIC Budget

2017 (Jan 1 - Dec 31)	Administrative	Project Funding	Commission Regulatory Oversight Budget
SCE Program	$1.4M	$12.5M	$0.35M
CEC Program	$5.6M	$50M	

(3) **2018 – 2020 Investment Plan**

Table 7: 2018 Authorized EPIC Budget

2018 (Jan 1 - Dec 31)	Administrative	Project Funding	Commission Regulatory Oversight Budget
SCE Program	$1.5M	$13.6M	$0.02M
CEC Program	$6.0M	$54.4M	

b) **Commitments/ Encumbrances**

(1) **2012 – 2014 Investment Plan**

As of December 31, 2018, SCE has committed $2,488,282 and encumbered $28,475 of its authorized 2012-2014 program budget.

(2) **2015 – 2017 Investment Plan**

As of December 31, 2018, SCE has committed $13,670,660 and encumbered $580,441 of its authorized 2015-2017 program budget.

(3) **2018 – 2020 Investment Plan**

As of December 31, 2018, SCE has committed $0 and encumbered $0 of its authorized 2018-2020 program budget.

(4) **CEC & CPUC Remittances**

For CEC remittances, SCE remitted $3,317,890[56] for program administration, and $47,116,358 for encumbered projects during calendar year 2017.

For CPUC remittances, SCE remitted $152,070 in calendar year 2018.

c) **Dollars Spent on In-House Activities**

(1) **2012 – 2014 Investment Plan**

As of December 31, 2018, SCE has spent $5,054,528[57] on in-house activities.

(2) **2015 – 2017 Investment Plan**

As of December 31, 2018, SCE has spent $2,173,309[58] on in-house activities.

(3) **2018 – 2020 Investment Plan**

As of December 31, 2018, SCE has spent $0 on in-house activities.

d) **Fund Shifting Above 5% between Program Areas**

(1) **2012 – 2014 Investment Plan**

As of December 31, 2018, SCE does not have any pending fund shifting requests and/or approvals.

(2) **2015 – 2017 Investment Plan**

As of December 31, 2018, SCE does not have any pending fund shifting requests and/or approvals.

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56 SCE is in the process of remitting the third quarterly payment of $1,658,945 to the CEC. Due to the timing of the CPUC's Decision (D.)18-01-008, approving the EPIC III 2018-2020 budget in mid-January 2018 (Quarter 1). The Utilities are remitting the total CEC administrative budget over 11 quarters.

57 SCE expended a total of $5,054,528 on in-house activities through 2018 based on the project spreadsheet in Appendix A. SCE's accounting systems calculates in-house labor overheads separately, which amounted to $704,204. As a result, SCE expended a total of $6,320,356 on in-house costs.

58 SCE expended a total of $2,173,309 on in-house activities through 2018 based on the project spreadsheet in Appendix A. SCE's accounting systems calculates in-house labor overheads separately, which amounted to $408,691. As a result, SCE expended a total of $2582000 on in-house costs.

(3) 2018 – 2020 Investment Plan

As of December 31, 2018, SCE does not have any pending fund shifting requests and/or approvals.

e) Uncommitted/Unencumbered Funds

(1) 2012 – 2014 Investment Plan

As of December 31, 2018, SCE has $0 in uncommitted/unencumbered funds.

(2) 2015 – 2017 Investment Plan

As of December 31, 2018, SCE has $0 in uncommitted/unencumbered funds.

(3) 2018 – 2020 Investment Plan

As of December 31, 2018, SCE has $40,830,795[59] in uncommitted/unencumbered funds.

f) Joint CEC/SCE Projects

As of December 31, 2018, the only project with CEC participation is the DOE-funded EASE project described in section 2d of this Report. For this project, the CEC is providing match funding.

g) High-Level Summary

SCE provides a summary of project funding for both SCE's 2012-2014 and 2015-2017 Investment Plans, please refer to Table 1 and Table 3 in Section 1b. SCE does not provide a summary of project funding for its 2018-220 Investment Plan, because Commission approval occurred in late October and SCE didn't spend any project funds through December 31, 2018.

h) Project Status Report

Please refer to Appendix A of this Report for SCE's Project Status Report.

[59] D.18-01-008, at p. 38.

i) **Description of Projects:**

(i) **Investment Plan Period**

(ii) **Assignment to Value Chain**

(iii) **Objective**

(iv) **Scope**

(v) **Deliverables**

(vi) **Metrics**

(vii) **Schedule**

(viii) **EPIC Funds Encumbered**

(ix) **EPIC Funds Spent**

(x) **Partners (if applicable)**

(xi) **Match Funding (if applicable)**

(xii) **Match Funding Split (if applicable)**

(xiii) **Funding Mechanism (if applicable)**

(xiv) **Treatment of Intellectual Property (if applicable)**

j) **Status Update**

The following project descriptions for the objective and scope reflect the proposals filed in the EPIC Investment Plans[60], while the projects' status information show progress as of December 31, 2017.

60 The EPIC I Investment Plan Application (A.)12-11-004 was filed on November 1, 2012. The EPIC II Investment Plan A.14-05-005 was filed on May 1, 2014. The EPIC III Investment Plan A.17-05-005 on May 1, 2017.

(1) 2012 – 2014 Triennial Investment Plan Projects

1. Integrated Grid Project – Phase 1

Investment Plan Period:	**Assignment to value Chain:**
1st Triennial Plan (2012-2014)	Grid Operation/Market Design

Objective & Scope:

The project will demonstrate, evaluate, analyze and propose options that address the impacts of high distributed energy resources (DER) penetration and increased adoption of distributed generation (DG) owned by consumers directly connected to SCE's distribution grid and on the customer side of the meter. This demonstration project is in effect the next step following the ISGD project. Therefore, this project focuses on the effects of introducing emerging and innovative technology into the utility and consumer end of the grid to account for this increase in DER resources. This scenario introduces the need for the utility (SCE) to assess technologies and controls necessary to stabilize the grid with increased DG adoption, and more importantly, consider possible economic models that would help SCE adapt to the changing regulatory policy and GRC structures.

This value-oriented demonstration informs many key questions that have been asked:

- What is the value of distributed generation and where is it most valuable?
- What is the cost of intermittent resources?
- What is the value of storage and where is it most valuable?
- How are DER resources/devices co-optimized?
- What infrastructure is required to enable an optimized solution?
- What incentives/rate structure will enable an optimized solution?

Deliverables:

- An IGP cost/benefit analysis and business case
- A systems requirement specification
- An IGP demonstration architecture
- A distributed grid control architecture capable of supporting the use of market mechanism, price signals, direct control or distributed control to optimize reliability and economic factors on the distribution grid
- A data management and integration architecture supporting the overarching IGP architecture
- A supporting network and cybersecurity architecture for the IGP architecture
- Incentive structures that encourage technology adoption that provide benefits to overall system operations
- A volt/Var optimization strategy
- RFPs to secure control vendor solutions for the field demonstration phase of the IGP project
- IGP lab demonstration using a simulated environment
- Final project report (Phase 1)

Metrics:
1a. Number and total nameplate capacity of distributed generation facilities
1b. Total electricity deliveries from grid-connected distributed generation facilities
1c. Avoided procurement and generation costs
1d. Number and percentage of customers on time variant or dynamic pricing tariffs
1e. Peak load reduction (MW) from summer and winter programs
1f. Avoided customer energy use (kWh saved)
1g. Percentage of demand response enabled by automated demand response technology (e.g. Auto DR)
1h. Customer bill savings (dollars saved)
1i. Nameplate capacity (MW) of grid-connected energy storage
3a. Maintain / Reduce operations and maintenance costs
3b. Maintain / Reduce capital costs
3c. Reduction in electrical losses in the transmission and distribution system
3d. Number of operations of various existing equipment types (such as voltage regulation) before and after adoption of a new smart grid component, as an indicator of possible equipment life extensions from reduced wear and tear
3e. Non-energy economic benefits
3f. Improvements in system operation efficiencies stemming from increased utility dispatchability of customer demand side management
5a. Outage number, frequency and duration reductions
5b. Electric system power flow congestion reduction
5c. Forecast accuracy improvement
5f. Reduced flicker and other power quality differences
5i. Increase in the number of nodes in the power system at monitoring points
7b. Increased use of cost-effective digital information and control technology to improve reliability, security, and efficiency of the electric grid (PU Code § 8360)
7c. Dynamic optimization of grid operations and resources, including appropriate consideration for asset management and utilization of related grid operations and resources, with cost-effective full cyber security (PU Code § 8360)
7d. Deployment and integration of cost-effective distributed resources and generation, including renewable resources (PU Code § 8360)
7e. Development and incorporation of cost-effective demand response, demand-side resources, and energy-efficient resources (PU Code § 8360)
7f. Deployment of cost-effective smart technologies, including real time, automated, interactive technologies that optimize the physical operation of appliances and consumer devices for metering, communications concerning grid operations and status, and distribution automation (PU Code § 8360)
7h. Deployment and integration of cost-effective advanced electricity storage and peak-shaving technologies, including plug-in electric and hybrid electric vehicles, and thermal-storage air-conditioning (PU Code § 8360)
7j. Provide consumers with timely information and control options (PU Code § 8360)

7k. Develop standards for communication and interoperability of appliances and equipment connected to the electric grid, including the infrastructure serving the grid (PU Code § 8360) 7l. Identification and lowering of unreasonable or unnecessary barriers to adoption of smart grid technologies, practices, and services (PU Code § 8360) 8b. Number of reports and fact sheets published online 8d. Number of information sharing forums held 8f. Technology transfer 9b. Number of technologies eligible to participate in utility energy efficiency, demand response or distributed energy resource rebate programs 9c. EPIC project results referenced in regulatory proceedings and policy reports 9d. Successful project outcomes ready for use in California IOU grid (Path to market)
Schedule: IGP Phase 1: Q2 2014 – Q4 2017

EPIC Funds Encumbered: $0	**EPIC Funds Spent:** $17,425,533

Partners: None

Match Funding: N/A	**Match Funding split:** N/A	**Funding Mechanism:** N/A

Treatment of Intellectual Property SCE has no current patents or licensing agreements signed. Future Intellectual Property is to be determined.
Status Update The final project report is complete, was submitted with the 2017 Annual Report, and is available on SCE's public EPIC web site.

2. Regulatory Mandates: Submetering Enablement Demonstration

Investment Plan Period: 1st Triennial Plan (2012-2014)	**Assignment to value Chain:** Demand-Side Management

Objective & Scope: On November 14, 2013, the Commission voted to approve the revised Proposed Decision (PD) Modifying the Requirements for the Development of a Plug-In Electric Vehicle Submetering Protocol set forth in D.11-07-029. The investor-owned utilities (IOUs) are to implement a two phased pilot beginning in May 2014, with funding for both phases provided by the EPIC. This project, Phase I of the pilot will (1) evaluate the demand for Single Customer of Record submetering, (2) estimate billing integration costs, (3) estimate communication costs, and (4) evaluate customer experience. IOUs and external stakeholders will finalize the temporary metering requirements, develop a template format used to report submetered, time-variant energy data, register Submeter Meter Data Management Agents and develop a Customer Enrollment Form, and finalize MDMA

Performance Requirements. The IOUs will also solicit a 3rd party evaluator to evaluate customer experience.
Deliverables: 1. Submetering Protocol Report 2. Manual Subtractive Billing Procedure 3. 3PE Final Report and Recommendation
Metrics: 6a. TOTAL number of SCE customer participants (Phase 1 & 2 each have 500 submeter limit) 6b. Number of SCE NEM customer participants (Phase 1 & 2 each have 100 submeter limit of 500 total) 6c. Submeter MDMA on-time delivery of customer submeter interval usage data 6d. Submeter MDMA accuracy of customer submeter interval usage data
Schedule: Q1 2014 – Q1 2017

EPIC Funds Encumbered: $823	**EPIC Funds Spent:** $1,138,359

Partners: N/A

Match Funding: N/A	**Match Funding split:** N/A	**Funding Mechanism:** N/A

Treatment of Intellectual Property SCE has no current patents or licensing agreements signed. Future Intellectual Property is to be determined.
Status Update The final project report is complete, was submitted with the 2016 Annual Report, and is available on SCE's public EPIC web site.

3. Distribution Planning Tool

Investment Plan Period: 1st Triennial Plan (2012-2014)	**Assignment to value Chain:** Distribution
Objective & Scope: This project involves the creation, validation, and functional demonstration of an SCE distribution system model that will address the future system architecture that accommodates distributed generation (primarily solar photovoltaic), plug-in electric vehicles, energy storage, customer programs (demand response, energy efficiency), etc. The modeling software to be used allows for implementation of advanced controls (smart charging, advanced inverters, etc.). These controls will enable interaction of a residential energy module and a power flow module. It also enables the evaluation of various technologies from an end-use customer perspective as well as a utility perspective, allowing full evaluation from substation bank to customer. This capability does not exist today. The completed model will help SCE demonstrate, communicate and better respond to technical, customer and market challenges as the distribution system architecture evolves.	

Deliverables: • Grid LAB-D user interface • SCE circuit model • Updated GridLAB-D to handle Cyme 7 database • Base cases & benchmark • Specifications for test cases from stakeholders • Created test cases • Periodic updates/meetings with stakeholders • Executed test cases • Final project report		
Metrics: 1d. Number and percentage of customers on time variant or dynamic pricing tariffs 1g. Percentage of demand response enabled by automated demand response technology (e.g. Auto DR) 5c. Forecast accuracy improvement 7b. Increased use of cost-effective digital information and control technology to improve reliability, security, and efficiency of the electric grid (PU Code § 8360) 7c. Dynamic optimization of grid operations and resources, including appropriate consideration for asset management and utilization of related grid operations and resources, with cost-effective full cyber security (PU Code § 8360) 7e. Development and incorporation of cost-effective demand response, demand-side resources, and energy-efficient resources (PU Code § 8360) 8c. Number of times reports are cited in scientific journals and trade publications for selected projects 8d. Number of information sharing forums held 8f. Technology transfer 9b. Number of technologies eligible to participate in utility energy efficiency, demand response or distributed energy resource rebate programs 9c. EPIC project results referenced in regulatory proceedings and policy reports 9d. Successful project outcomes ready for use in California IOU grid (Path to market)		
Schedule: Q1 2014 – Q1 2017		
EPIC Funds Encumbered: $0	**EPIC Funds Spent:** $1,071,118	
Partners: N/A		
Match Funding: N/A	**Match Funding split:** N/A	**Funding Mechanism:** N/A
Treatment of Intellectual Property SCE has no current patents or licensing agreements signed. Future Intellectual Property is to be determined.		

Status Update
The final project report is complete, was submitted with the 2016 Annual Report, and is available on SCE's public EPIC web site.

4. Beyond the Meter: Customer Device Communications, Unification and Demonstration (Phase II)

Investment Plan Period: 1st Triennial Plan (2012-2014)	**Assignment to value Chain:** Demand-Side Management
Objective & Scope: The Beyond the Meter (BTM) project will demonstrate the use of a DER management system to interface with and control DER based on customer and distribution grid use cases. It will also demonstrate the ability to communicate near-real time information on the customer's load management decisions and DER availability to SCE for grid management purposes. Three project objectives include: 1) develop a common set of requirements that support the needs of a variety of stakeholders including customers, distribution management, and customer program; 2) validate standardized interfaces, functionalities, and architectures required in new Rule 21 proceedings, IOU Implementation Guide, and UL 1741/IEEE 1547 standards; 3) collect and analyze measurement and cost/benefits data in order to inform the design of new tariffs, recommend the deployment of new technologies, and support the development of new programs.	
Deliverables: • "Enabling Communication Unification" status report • Written specifications for all three class of devices (EVSEs, solar inverters, and RESUs) • "Industry Harmonization and Closing Gaps" report • Receive devices for testing • Complete final report and recommendations	
Metrics: 1a. Number and total nameplate capacity of distributed generation facilities 1b. Total electricity deliveries from grid-connected distributed generation facilities 1c. Avoided procurement and generation costs 1e. Peak load reduction (MW) from summer and winter programs 1f. Avoided customer energy use (kWh saved) 1g. Percentage of demand response enabled by automated demand response technology (e.g. Auto DR) 3f. Improvements in system operation efficiencies stemming from increased utility dispatchability of customer demand side management 5b. Electric system power flow congestion reduction 5f. Reduced flicker and other power quality differences 5i. Increase in the number of nodes in the power system at monitoring points	

<table>
<tr><td colspan="3">7b. Increased use of cost-effective digital information and control technology to improve reliability, security, and efficiency of the electric grid (PU Code § 8360)
7c. Dynamic optimization of grid operations and resources, including appropriate consideration for asset management and utilization of related grid operations and resources, with cost-effective full cyber security (PU Code § 8360)
7d. Deployment and integration of cost-effective distributed resources and generation, including renewable resources (PU Code § 8360)
7e. Development and incorporation of cost-effective demand response, demand-side resources, and energy-efficient resources (PU Code § 8360)
7f. Deployment of cost-effective smart technologies, including real time, automated, interactive technologies that optimize the physical operation of appliances and consumer devices for metering, communications concerning grid operations and status, and distribution automation (PU Code § 8360)
7g. Integration of cost-effective smart appliances and consumer devices (PU Code § 8360)
7h. Deployment and integration of cost-effective advanced electricity storage and peak-shaving technologies, including plug-in electric and hybrid electric vehicles, and thermal-storage air-conditioning (PU Code § 8360)
7j. Provide consumers with timely information and control options (PU Code § 8360)
7k. Develop standards for communication and interoperability of appliances and equipment connected to the electric grid, including the infrastructure serving the grid (PU Code § 8360)
7l. Identification and lowering of unreasonable or unnecessary barriers to adoption of smart grid technologies, practices, and services (PU Code § 8360)
8b. Number of reports and fact sheets published online
8d. Number of information sharing forums held.
8f. Technology transfer
9a. Description/documentation of projects that progress deployment, such as Commission approval of utility proposals for widespread deployment or technologies included in adopted building standards
9b. Number of technologies eligible to participate in utility energy efficiency, demand response or distributed energy resource rebate programs
9c. EPIC project results referenced in regulatory proceedings and policy reports
9d. Successful project outcomes ready for use in California IOU grid (Path to market)</td></tr>
<tr><td colspan="3">Schedule:
Q3 2014 – Q4 2017</td></tr>
<tr><td colspan="2">EPIC Funds Encumbered:
$0</td><td>EPIC Funds Spent:
$1,48,149</td></tr>
<tr><td colspan="3">Partners:
N/A</td></tr>
<tr><td>Match Funding:
N/A</td><td>Match Funding split:
N/A</td><td>Funding Mechanism:
N/A</td></tr>
<tr><td colspan="3">Treatment of Intellectual Property</td></tr>
</table>

SCE has no current patents or licensing agreements signed. Future Intellectual Property is to be determined.
Status Update The EPIC I Final Report for the Beyond the Meter Project is complete, is being submitted with the 2017 Annual Report, and will be posted on SCE's public EPIC web site.

5. Portable End-to-End Test System

Investment Plan Period: 1st Triennial Plan (2012-2014)	**Assignment to value Chain:** Transmission
Objective & Scope: End-to-end transmission circuit relay testing has become essential for operations and safety. SCE technicians currently test relay protection equipment during commissioning and routing testing. Existing tools provide a limited number of scenarios (disturbances) for testing, and focus on testing protection elements; not testing system protection. This project will demonstrate a robust portable end-to-end toolset (PETS) that addresses: 1) relay protection equipment, 2) communications, and 3) provides a pass/fail grade based on the results of automated testing using numerous simulated disturbances. PETS will employ portable Real-Time Digital Simulators (RTDS's) in substations at each end of the transmission line being tested. Tests will be documented using a reporting procedure used in the Power Systems Lab today, which will help ensure that all test data is properly evaluated.	
Deliverables: • PETS portable RTDS test equipment • PETS operating instructions • PETS standard test report • Final project report	
Metrics: 3a. Maintain / reduce operations and maintenance costs 5a. Outage number, frequency and duration reductions 6a. Reduce testing cost 6b. Number of terminals tested on a line (more than 2 terminals/substations) 7b. Increased use of cost-effective digital information and control technology to improve reliability, security, and efficiency of the electric grid (PU Code § 8360) 8b. Number of reports and fact sheets published online 8d. Number of information sharing forums held 8f. Technology transfer 9c. EPIC project results referenced in regulatory proceedings and policy reports 9e. Technologies available for sale in the market place (when known)	
Schedule: Q1 2014 – Q4 2015	
EPIC Funds Encumbered: $0	**EPIC Funds Spent:** $39,563

Partners:		
N/A		
Match Funding: N/A	**Match Funding split:** N/A	**Funding Mechanism:** N/A
Treatment of Intellectual Property SCE has no current patents or licensing agreements signed. Future Intellectual Property is to be determined.		
Status Update The final project report is complete, was submitted with the 2015 Annual Report, and is available on SCE's public EPIC web site.		

6. Voltage and VAR Control of SCE Transmission System

Investment Plan Period: 1st Triennial Plan (2012-2014)	**Assignment to value Chain:** Transmission
Objective & Scope: This project involves demonstrating software and hardware products that will enable automated substation volt/var control. Southern California Edison (SCE) will demonstrate a Substation Level Voltage Control (SLVC) unit working with a transmission control center Supervisory Central Voltage Coordinator (SCVC) unit to monitor and control substation voltage. The scope of this project includes systems engineering, testing, and demonstration of the hardware and software that could be operationally employed to manage substation voltage.	
Deliverables: • Demonstration design specification • Construction documents: drawings, cable schedule, and bill of material • Monitoring console software and hardware • Advanced Volt/VAR Control (AVVC) testing • Field deployment • Controller operation monitoring and adjustment • AVVC final report and closeout	
Metrics: 3a. Maintain / reduce operations and maintenance costs 3c. Reduction in electrical losses in the transmission and distribution system 3d. Number of operations of various existing equipment types (such as voltage regulation) before and after adoption of a new smart grid component, as an indicator of possible equipment life extensions from reduced wear and tear 7b. Increased use of cost-effective digital information and control technology to improve reliability, security, and efficiency of the electric grid (PU Code § 8360) 7c. Dynamic optimization of grid operations and resources, including appropriate consideration for asset management and utilization of related grid operations and resources, with cost-effective full cyber security (PU Code § 8360) 8b. Number of reports and fact sheets published online	

8d. Number of information sharing forums held 8f. Technology transfer 9c. EPIC project results referenced in regulatory proceedings and policy reports 9d. Successful project outcomes ready for use in California IOU grid (Path to market)
Schedule: Q1 2014 – Q4 2018
EPIC Funds Encumbered: $0 | **EPIC Funds Spent:** $852,564
Partners: N/A
Match Funding: N/A | **Match Funding split:** N/A | **Funding Mechanism:** N/A
Treatment of Intellectual Property SCE has no current patents or licensing agreements signed. Future Intellectual Property is to be determined.
Status Update The Final Report for the Voltage and VAR Control of SCE Transmission System is complete, is being submitted with the 2018 Annual Report, and will be posted on SCE's public EPIC web site.

7. Superconducting Transformer (SCX) Demonstration

Investment Plan Period: 1st Triennial Plan (2012-2014)	**Assignment to value Chain:** Distribution
Objective & Scope: This project was cancelled in 2014. No further work is planned. *Original Project Objective and Scope:* SCE will support this $21M American Reinvestment and Recovery Act (ARRA) Superconducting Transformer (SCX) project by providing technical expertise and installing and operating the transformer at SCE's MacArthur substation. The SCX prime contractor is SuperPower Inc. (SPI), teamed with SPX Transformer Solutions (SPX) {formerly Waukesha Electric Systems}. SCE has provided two letters of commitment for SCX. The SCX project will develop a 28 MVA High Temperature Superconducting, Fault Current Limiting (HTS-FCL) transformer. The transformer is expected to be installed in 2015. SCE is supporting this project and is not an ARRA grant sub-recipient. SCE is being reimbursed for its effort by EPIC. SCE's participation in this project was previously approved under the now-defunct California Energy Commission's PIER program.	
Deliverables: N/A	
Metrics: N/A	

Schedule: Project was cancelled in Q2 2014.		
EPIC Funds Encumbered: $0	**EPIC Funds Spent:** $10,241	
Partners: N/A		
Match Funding: N/A	**Match Funding split:** N/A	**Funding Mechanism:** N/A
Treatment of Intellectual Property SCE has no current patents or licensing agreements signed.		
Status Update SCE formally cancelled this project in Q3 2014.		

8. State Estimation Using Phasor Measurement Technologies

Investment Plan Period: 1st Triennial Plan (2012-2014)	**Assignment to value Chain:** Grid Operation/Market Design
Objective & Scope: Accurate and timely power system state estimation data is essential for understanding system health and provides the basis for corrective action that could avoid failures and outages. This project will demonstrate the utility of improved static system state estimation using Phasor Measurement Unit (PMU) data in concert with existing systems. Enhancements to static state estimation will be investigated using two approaches: 1) by using GPS time to synchronize PMU data with Supervisory Control and Data Acquisition (SCADA) system data; 2) by augmenting SCE's existing conventional state estimator with a PMU based Linear State Estimator (LSE).	
Deliverables: • Demonstrated algorithm performance based on observations. • Report that addresses tests conducted and test results. • Final project report.	
Metrics: 6a. Enhanced grid monitoring and on-line analysis for resiliency 7b. Increased use of cost-effective digital information and control technology to improve reliability, security, and efficiency of the electric grid (PU Code § 8360) 8b. Number of reports and fact sheets published online 8d. Number of information sharing forums held 8f. Technology transfer 9d. Successful project outcomes ready for use in California IOU grid (Path to market) 9e. Technologies available for sale in the market place (when known)	
Schedule: Q2 2014 – Q4 2017	
EPIC Funds Encumbered: $0	**EPIC Funds Spent:** $822,179

Partners: N/A		
Match Funding: N/A	**Match Funding split:** N/A	**Funding Mechanism:** N/A
Treatment of Intellectual Property SCE has no current patents or licensing agreements signed. Future Intellectual Property is to be determined.		
Status Update The final project report is complete, was submitted with the 2017 Annual Report, and is available on SCE's public EPIC web site.		

9. Wide-Area Reliability Management & Control

Investment Plan Period: 1st Triennial Plan (2012-2014)	**Assignment to value Chain:** Grid Operation/Market Design
Objective & Scope: With the planned wind and solar portfolio of 33% penetration, a review of the integration strategy implemented in the SCE bulk system is needed. The basic premise for the integration strategy is that a failure in one area of the grid should not result in failures elsewhere. The approach is to minimize failures with well designed, maintained, operated and coordinated power grids. New technologies can provide coordinated wide-area monitoring, protection, and control systems with pattern recognition and advance warning capabilities. This project will demonstrate new technologies to manage transmission system control devices to prevent cascading outages and maintain system integrity.	
Deliverables: • Lab demonstration of control algorithms using real time simulations with Hardware in the loop • Develop recommendations based on the control system testing • Final project report	
Metrics: 6a. Enhanced contingency planning for minimizing cascading outages 8b. Number of reports and fact sheets published online 8d. Number of information sharing forums held 8f. Technology transfer	

Schedule: Q2 2014 – Q1 2019		
EPIC Funds Encumbered: $0	**EPIC Funds Spent:** $640,925	
Partners: N/A		
Match Funding: N/A	**Match Funding split:** N/A	**Funding Mechanism:** N/A
Treatment of Intellectual Property SCE has no current patents or licensing agreements signed. Future Intellectual Property is to be determined.		
Status Update In 2018, MHI assisted Siemens with the tuning evaluations and setting up cases for the SVC Power Oscillations Damping (POD) controller. A full dynamic and transient details models was utilized by Manitoba Hydro International (MHI) to represent the Devers Static VAr Compensator (SVC) with the updated control system. The objective of these models were used for the POD controller tuning studies. Different bulk system contingences were simulated inside SCE's system and surrounding systems for different seasons (e.g. summer, spring) and years. As part of the simulation, the year 2022 was used to reflect the system condition after once-through cooling (OTC) generation unit's retirement in 2020 (effecting up to 7GW of generation within SCE territory). The results were analyzed to extract the low frequency oscillations and their associated damping using Prony analysis. The critical bulk system contingences were identified and ranked and the parameters of the POD controller were tuned to damp these oscillations effectively and increase the system damping. Based on these simulations, the engineering teams worked with SCE's Grid Control center (GCC) and Substation Apparatus group to schedule the SVC outage, so Siemens engineers can update the Devers SVC firmware and GUI. In June of 2018, the update to the Devers SVC firmware and GUI was successfully completed allowing for the SVC to export the short circuit value measured by the SVC to the SCE EMS system and to allow the utilization of POD auxiliary control system to damp low frequency oscillations.		

10. Distributed Optimized Storage (DOS) Protection & Control Demonstration

Investment Plan Period: 1st Triennial Plan (2012-2014)	**Assignment to value Chain:** Distribution
Objective & Scope: The purpose of this demonstration is to provide end-to-end integration of multiple energy storage devices on a distribution circuit/feeder to provide a turn-key solution that can cost-effectively be considered for SCE's distribution system, where identified feeders can benefit from grid optimization and variable energy resources (VER) integration. To accomplish this, the project team will first identify distribution system circuits where multiple energy storage devices can be operated centrally. Once a feeder is selected, the energy storage devices will be integrated into the control system and tested to demonstrate central	

control and monitoring. At the end of the project, SCE will have established necessary standards-based hardware and control function requirements for grid optimization and renewables integration with distributed energy storage devices.
A second part of this project will investigate how energy storage devices located on distribution circuits can be used for reliability while also being bid into the CAISO markets to provide ancillary services. This is also known as dual-use energy storage. Initial use cases will be developed to determine the requirements for the control systems necessary to accomplish these goals.

Deliverables:

- Target circuit models
- Selected circuits for the project
- Requirement development for solution
- RFP for the control system
- Procurement of the control system
- Evaluation of centralized controller and representative energy storage devices
- Test platform readiness for protection evaluation
- Engagement of all expected SCE departments for deployment
- Procurement of M&V equipment
- Deployment of M&V equipment and centralized controller
- M&V complete and final report

Metrics:

1c. Avoided procurement and generation costs
1i. Nameplate capacity (MW) of grid-connected energy storage
3b. Maintain / Reduce capital costs
5f. Reduced flicker and other power quality differences
5i. Increase in the number of nodes in the power system at monitoring points
6a. Benefits in energy storage sizing through device operation optimization
6b. Benefits in distributed energy storage deployment vs. centralized energy storage deployment
7a. Description of the issues, project(s), and the results or outcomes
7b. Increased use of cost-effective digital information and control technology to improve reliability, security, and efficiency of the electric grid (PU Code § 8360)
7c. Dynamic optimization of grid operations and resources, including appropriate consideration for asset management and utilization of related grid operations and resources, with cost-effective full cyber security (PU Code § 8360)
7l. Identification and lowering of unreasonable or unnecessary barriers to adoption of smart grid technologies, practices, and services (PU Code § 8360)
8b. Number of reports and fact sheets published online
8d. Number of information sharing forums held
8f. Technology transfer
9c. EPIC project results referenced in regulatory proceedings and policy reports.

Schedule:

Q2 2014 – Q4 2017

EPIC Funds Encumbered:	EPIC Funds Spent:
$0	$74,436

Partners:
None

Match Funding:	**Match Funding split:**	**Funding Mechanism:**
N/A	N/A	N/A

Treatment of Intellectual Property
SCE has no current patents or licensing agreements signed. Future Intellectual Property is to be determined.

Status Update
The Final Report for the Voltage and VAR Control of SCE Transmission System is complete, is being submitted with the 2018 Annual Report, and will be posted on SCE's public EPIC web site.

11. Outage Management and Customer Voltage Data Analytics Demonstration

Investment Plan Period:	**Assignment to value Chain:**
1st Triennial Plan (2012-2014)	Grid Operation/Market Design

Objective & Scope:
Voltage data and customer energy usage data from the Smart Meter network can be collected and leveraged for a range of initiatives focused on achieving operational benefits for Transmission & Distribution. Before a full implementation of this new approach can be considered, a demonstration project will be conducted to understand how voltage and consumption data can be best collected, stored, and integrated with T&D applications to provide analytics and visualization capabilities. Further, Smart Meter outage and restoration event (time stamp) data can be leveraged to improve customer outage duration and frequency calculations. Various stakeholders in T&D have identified business needs to pursue more effective and efficient ways of calculating SAIDI (System Average Interruption Duration Index), SAIFI (System Average Interruption Frequency Index), and MAIFI (Momentary Average Interruption Frequency Index) for internal and external reporting. Before a full implementation of this new approach can be considered, a demonstration project will be conducted to understand the feasibility and value of providing smart meter data inputs and enhanced methodology for calculating the Indexes. The demonstration will focus on a limited geography (SCE District or Region) to obtain the Smart Meter inputs to calculate the Indexes and compare that number with the current methodologies to identify any anomalies. A hybrid approach using the Smart Meter-based input data combined with a better comprehensive electric connectivity model obtained from GIS may provide a more efficient and effective way of calculating the Indexes. Additionally, an effort to evaluate the accuracy of the Transformer Load Mapping data will be carried out.

Deliverables:
• Voltage Analytics for Power Quality Model • Simulated Circuit Condition Model

• Customer and Transformer Load Analysis Model • Enhanced Inputs and SAIDI/SAIFI Analysis • Final Project Report
Metrics: 3a. Maintain / reduce operations and maintenance costs 5c. Forecast accuracy improvement 5f. Reduced flicker and other power quality differences 6a. Enhance Outage Reporting Accuracy and SAIDI/SAIFI Calculation 8b. Number of reports and fact sheets published online 8f. Technology transfer 9c. EPIC project results referenced in regulatory proceedings and policy reports
Schedule: Q1 2014 – Q4 2015

EPIC Funds Encumbered: $0	**EPIC Funds Spent:** $1,018,697

Partners: N/A

Match Funding: N/A	**Match Funding split:** N/A	**Funding Mechanism:** N/A

Treatment of Intellectual Property SCE has no current patents or licensing agreements signed. Future Intellectual Property is to be determined.
Status Update The final project report is complete, was submitted with the 2015 Annual Report, and is available on SCE's public EPIC web site.

12. SA-3 Phase III Demonstration

Investment Plan Period: 1st Triennial Plan (2012-2014)	**Assignment to value Chain:** Transmission

Objective & Scope: This project is intended to apply the findings from the Substation Automation Three (SA-3) Phase II (Irvine Smart Grid Demonstration) project to demonstrate real solutions to automation problems faced by SCE today. The project will demonstrate two standards-based automation solutions (sub-projects) as follows: Subproject 1 (Bulk Electric System) will address issues unique to transmission substations including the integration of centrally managed critical cyber security (CCS) systems and NERC CIP compliance. When the project was proposed Subproject 2 (Hybrid) intended to address the integration of SA-3 capabilities with SAS and SA-2 legacy systems. In 2016 SA-3 Hybrid scope was completely dropped from the EPIC SA-3 phase III Demonstration. Furthermore, as part of the systems engineering the SA-3 technical team will demonstrate two automation tools as follows: Subproject 3 (Intelligent Alarming) will allow substation operators to pin-point root cause issues by analyzing the various scenarios and implement an intelligent alarming system that can identify the source of the problem and give operators only the relevant information needed to make informed decisions; and Subproject 4 (Real Time Digital Simulator (RTDS) Mobile Testing) will explore the benefits of an automated testing using a mobile RTDS unit, and propose test methodologies that can be implemented into the factory acceptance testing (FAT) and site acceptance testing (SAT) testing process.
Deliverables: • Bulk & Hybrid System Design Drawings & Diagrams • Hybrid System Deployment and Demonstration • BES System Deployment and Demonstration • Final Project Report
Metrics: 3a. Maintain / Reduce operations and maintenance costs 3b. Maintain / Reduce capital costs 5a. Outage number, frequency and duration reductions 5i. Increase in the number of nodes in the power system at monitoring points 6a. Increased cybersecurity 7b. Increased use of cost-effective digital information and control technology to improve reliability, security, and efficiency of the electric grid (PU Code § 8360) 7c. Dynamic optimization of grid operations and resources, including appropriate consideration for asset management and utilization of related grid operations and resources, with cost-effective full cyber security (PU Code § 8360) 7k. Develop standards for communication and interoperability of appliances and equipment connected to the electric grid, including the infrastructure serving the grid (PU Code § 8360) 8b. Number of reports and fact sheets published online 8d. Number of information sharing forums held 8f. Technology transfer 9c. EPIC project results referenced in regulatory proceedings and policy reports 9d. Successful project outcomes ready for use in California IOU grid (Path to market) 9e. Technologies available for sale in the market place (when known)

Schedule:		
Q1 2014 – Q3 2021		
EPIC Funds Encumbered: $27,265	**EPIC Funds Spent:** $4,224,989	
Partners: N/A		
Match Funding: N/A	**Match Funding split:** N/A	**Funding Mechanism:** N/A
Treatment of Intellectual Property: SCE has no current patents or licensing agreements signed. Future Intellectual Property is to be determined.		
Status Update: 2018 accomplishments: The project has added additional scope to address the SCE cybersecurity requirements and a configuration management for substation devices and automated configuration import for Substation Management Systems. With these change, the SA-3 Phase III project will be deployed at Viejo A-station for field demonstration and an in-service date of Oct 23, 2021. High level 2018 accomplishments: • Relays Automation setting and Goose messaging lab testing • SDN configuration and lab testing • PAC configuration and lab testing • FAT completion • Grid 2 Network telcom work completed		

13. Next-Generation Distribution Automation

Investment Plan Period:	**Assignment to value Chain:**
1st Triennial Plan (2012-2014)	Distribution
Objective & Scope: SCE's current distribution automation scheme often relies on human intervention that can take several minutes (or longer during storm conditions) to isolate faults, is only capable of automatically restoring power to half of the customers on the affected circuit, and needs to be replaced due to assets nearing the end of their lifecycle. In addition, the self-healing circuit being demonstrated as part of the Irvine Smart Grid Demonstration is unique to the two participating circuits and may not be easily applied elsewhere. As a result, the Next-Generation Distribution Automation project intends to demonstrate a cost-effective advanced automation solution that can be applied to the majority of SCE's distribution circuits. This solution will utilize automated switching devices combined with the latest protection and wireless communication technologies to enable detection and isolation of faults before the substation circuit breaker is opened, so that at least 2/3 of the circuit load can be restored quickly. This will improve reliability and reduce customer minutes of interruption. The system will also have directional power flow sensing to help SCE better manage distributed energy resources on the distribution system. At the end of the project,	

SCE will provide reports on the field demonstrations and recommend next steps for new standards for next-generation distribution automation.
Deliverables: • Remote Intelligent Switch demonstration and report • Overhead and Underground Remote Fault Indicators demonstration and report • Intelligent Fuses demonstration and report • Power Electronic Transformer demonstration and report • Secondary Network Monitoring demonstration and report • Final Project Report
Metrics: 3a. Maintain / Reduce operations and maintenance costs 3d. Number of operations of various existing equipment types (such as voltage regulation) before and after adoption of a new smart grid component, as an indicator of possible equipment life extensions from reduced wear and tear 5a. Outage number, frequency and duration reductions 5c. Forecast accuracy improvement 5d. Public safety improvement and hazard exposure reduction 5e. Utility worker safety improvement and hazard exposure reduction 5i. Increase in the number of nodes in the power system at monitoring points 6a. Improve data accuracy for distribution substation planning process 7b. Increased use of cost-effective digital information and control technology to improve reliability, security, and efficiency of the electric grid (PU Code § 8360) 7c. Dynamic optimization of grid operations and resources, including appropriate consideration for asset management and utilization of related grid operations and resources, with cost-effective full cyber security (PU Code § 8360) 7d. Deployment and integration of cost-effective distributed resources and generation, including renewable resources (PU Code § 8360) 7k. Develop standards for communication and interoperability of appliances and equipment connected to the electric grid, including the infrastructure serving the grid (PU Code § 8360) 8b. Number of reports and fact sheets published online 8d. Number of information sharing forums held 8f. Technology transfer 9c. EPIC project results referenced in regulatory proceedings and policy reports 9d. Successful project outcomes ready for use in California IOU grid (Path to market) 9e. Technologies available for sale in the market place (when known)
Schedule: Q1 2014 – Q4 2017

EPIC Funds Encumbered: $342	**EPIC Funds Spent:** $4,018,679

Partners: N/A

Match Funding:	**Match Funding split:**	**Funding Mechanism:**

N/A	N/A	N/A
Treatment of Intellectual Property: SCE has no current patents or licensing agreements signed. Future Intellectual Property is to be determined.		
Status Update: The final project reports were completed and submitted with the 2017 Annual Report, and is available on SCE's public EPIC web site. SCE has completed an Executive Summary Report that ties the subprojects together, which is being submitted with the 2018 Annual Report, and will be posted on SCE's public EPIC web site.		

14. Enhanced Infrastructure Technology Evaluation

Investment Plan Period:	**Assignment to value Chain:**
1st Triennial Plan (2012-2014)	Distribution
Objective & Scope: At the request of Distribution Apparatus Engineering (DAE) group's lead Civil Engineer, Advanced Technology (AT) will investigate, demonstrate, and evaluate recommendations for enhanced infrastructure technologies. The project will focus on evaluating advanced distribution sectional poles (hybrid, coatings, etc.), concealed communications on assets, vault monitoring systems (temperature, water, etc.), and vault ventilation systems. Funding is needed to investigate the problem, engineering, demonstrate alternatives, and come up with recommendations. SCE sees the need for poles that can withstand fires and have a better life cycle cost, and provide installation efficiencies when compared to existing wood pole replacements. Due to increased city restrictions, there is a need for more concealed communications on our assets such as streetlights (e.g., on the ISGD project, the City of Irvine wouldn't allow SCE to install repeaters on streetlights due to aesthetics). DAE also sees the need for technologies that may minimize premature vault change-outs (avg. replacement cost is ~$250K). At present, DAE does not have the necessary real-time vault data to sufficiently address the increasing vault deterioration issue nor do we utilize a hardened ventilation system that would help this issue by removing the excess heat out of the vaults (blowers last ~ 2 years, need better bearings for blower motors, etc.).	

Deliverables: • Vault Monitoring Technologies Demonstration Report • Vault Ventilation Field Demonstration Report • Hybrid Pole Demonstration Report • Concealed Communication Assets Demonstration Report • Final Project Report		
Metrics: 3a. Maintain / Reduce operations and maintenance costs 3b. Maintain / Reduce capital costs 4g. Wildlife fatality reductions (electrocutions, collisions) 5a. Outage number, frequency and duration reductions 6a. Operating performance of underground vault monitoring equipment 8b. Number of reports and fact sheets published online 8d. Number of information sharing forums held 8f. Technology transfer 9c. EPIC project results referenced in regulatory proceedings and policy reports		
Schedule: Q2 2014 – Q4 2016		
EPIC Funds Encumbered: $0	**EPIC Funds Spent:** $79,119	
Partners: N/A		
Match Funding: N/A	**Match Funding split:** N/A	**Funding Mechanism:** N/A
Treatment of Intellectual Property: SCE has no current patents or licensing agreements signed. Future Intellectual Property is to be determined.		
Status Update: The final project report is complete, was submitted with the 2016 Annual Report, and is available on SCE's public EPIC web site.		

15. Dynamic Line Rating Demonstration

Investment Plan Period: 1st Triennial Plan (2012-2014)	**Assignment to value Chain:** Transmission
Objective & Scope: Transmission line owners apply fixed thermal rating limits for power transmission lines. These limits are based on conservative assumptions of wind speed, ambient temperature and solar radiation. They are established to help ensure compliance with safety codes, maintain the integrity of line materials, and help secure network reliability. Monitored transmission lines can be more fully utilized to improve network efficiency. Line tension is directly related to average conductor temperature. The tension of a power line is directly related to the current rating of the line. This project will demonstrate the CAT-1 dynamic	

line rating solution. The CAT-1 system will monitor the tension of transmission lines in real-time to calculate a dynamic daily rating. If successful, this solution will allow SCE to perform real-time calculations in order to determine dynamic daily rating of transmission lines, thus increasing transmission line capacity.
Deliverables: • Installed Dynamic Line Rating System Prototypes • Final Project Report
Metrics: 3b. Maintain / Reduce capital costs 5b. Electric system power flow congestion reduction 6a. Increased power flow throughput 7b. Increased use of cost-effective digital information and control technology to improve reliability, security, and efficiency of the electric grid (PU Code § 8360) 7c. Dynamic optimization of grid operations and resources, including appropriate consideration for asset management and utilization of related grid operations and resources, with cost-effective full cyber security (PU Code § 8360) 8b. Number of reports and fact sheets published online 8d. Number of information sharing forums held 8f. Technology transfer 9c. EPIC project results referenced in regulatory proceedings and policy reports 9d. Successful project outcomes ready for use in California IOU grid (Path to market) 9e. Technologies available for sale in the market place (when known)
Schedule: Q2 2014 – Q1 2016

EPIC Funds Encumbered: $0	**EPIC Funds Spent:** $468,601

Partners: N/A

Match Funding: N/A	**Match Funding split:** N/A	**Funding Mechanism:** N/A

Treatment of Intellectual Property: SCE has no current patents or licensing agreements signed. Future Intellectual Property is to be determined.
Status Update: The final project report is complete, was submitted with the 2016 Annual Report, and is available on SCE's public EPIC web site.

16. Cyber-Intrusion Auto-Response and Policy Management System (CAPMS)

Investment Plan Period: 1st Triennial Plan (2012-2014)	**Assignment to value Chain:** Grid Operation/Market Design

Objective & Scope: Viasat in partnership with SCE and Duke Energy has been awarded a DOE contract (DE-0E0000675) to deploy a Cyber-intrusion Auto-response and Policy Management System (CAPMS) to provide real-time analysis of root cause, extent and consequence of an ongoing cyber intrusion using proactive security measures. CAPMS will be demonstrated in the SCE Advanced Technology labs at Westminster, CA. The DOE contract value is $6M with SCE & Duke Energy offering a cost share of $1.6M and $1.2M respectively.		
Deliverables: • System Requirements Artifact • Measurement and Validation Data • System Test Results • Final Project Report		
Metrics: 5a. Outage number, frequency and duration reductions 7b. Increased use of cost-effective digital information and control technology to improve reliability, security, and efficiency of the electric grid (PU Code § 8360) 7l. Identification and lowering of unreasonable or unnecessary barriers to adoption of smart grid technologies, practices, and services (PU Code § 8360) 8b. Number of reports and fact sheets published online 8d. Number of information sharing forums held 8f. Technology transfer 10a. Description or documentation of funding or contributions committed by others 10c. Dollar value of funding or contributions committed by others		
Schedule: Q3 2014 – Q3 2015		
EPIC Funds Encumbered: $0	**EPIC Funds Spent:** $1,809,323	
Partners: Viasat; Duke Energy		
Match Funding: N/A	**Match Funding split:** N/A	**Funding Mechanism:** N/A
Treatment of Intellectual Property: SCE has no current patents or licensing agreements signed. Future Intellectual Property is to be determined.		
Status Update: The final project report is complete, was submitted with the 2015 Annual Report, and is available on SCE's public EPIC web site.		

(2) 2015 – 2017 Triennial Investment Plan Projects

1. Integration of Big Data for Advanced Automated Customer Load Management

Investment Plan Period: 2nd Triennial Plan (2015-2017)	**Assignment to value Chain:** Demand-Side Management
Objective & Scope: This proposed project builds upon the "Beyond the Meter Advanced Device Communications" project from the first EPIC triennial investment plan, and proposes to demonstrate how the concept of "big data"[61] can be leveraged for automated load management. More specifically, this potential project would demonstrate the use of big data acquired from utility systems such as SCE's advanced metering infrastructure (AMI), distribution management system (DMS), and Advanced Load Control System (ALCS) and by communicating to centralized energy hubs at the customer level to determine the optimal load management scheme.	
Deliverables: • DERMS Functional Specification • Acceptance Test Plan and Report • Final Project Report	
Metrics: 7b. Increased use of cost-effective digital information and control technology to improve reliability, security, and efficiency of the electric grid (PU Code § 8360) 7c. Dynamic optimization of grid operations and resources, including appropriate consideration for asset management and utilization of related grid operations and resources, with cost-effective full cyber security (PU Code § 8360) 7d. Deployment and integration of cost-effective distributed resources and generation, including renewable resources (PU Code § 8360) 7f. Deployment of cost-effective smart technologies, including real time, automated, interactive technologies that optimize the physical operation of appliances and consumer devices for metering, communications concerning grid operations and status, and distribution automation (PU Code § 8360) 7k. Develop standards for communication and interoperability of appliances and equipment connected to the electric grid, including the infrastructure serving the grid (PU Code § 8360) 8e. Stakeholders attendance at workshops 8f. Technology transfer	
Schedule: Q1 2016-Q4 2018	
EPIC Funds Encumbered: $0	**EPIC Funds Spent:** $1,146,238
Partners: N/A	

[61] Big data refers to information available as a result from energy automation and adding sensors to the grid.

Match Funding:	Match Funding split:	Funding Mechanism:
N/A	N/A	N/A
Treatment of Intellectual Property: SCE has no current patents or licensing agreements signed. Future Intellectual Property is to be determined.		
Status Update: In 2018 the Big Data project successfully concluded. The accomplishments included: • Completed interoperability testing with the Big Data IEEE 2030.5 Aggregator client • In coordination with CEC PON 14-303 project, deployed and commissioned residential smart inverters using the project IEEE 2030.5 communication systems • Supported the development of cyber security requirements and architectures for the back office deployment of IEEE 2030.5 applications and the use of internet based communications • Demonstrated Common Smart Inverter Profile (CSIP) use cases with aggregated behind the meter photovoltaic and energy storage systems The resulting benefits from the project included: • Revisions to the IEEE 2030.5 standard, Rule 21 regulatory documents including the IOU aggregator agreement and deadlines, and a new version (v2.1) of the CSIP document • Support for the production Distributed Energy Management System (DERMS) procurement, back office cybersecurity requirements and control systems' architecture • Determined deficiencies related to aggregated smart inverter commissioning and support processes including setting up and troubleshooting customer communications, and lack of clearly defined roles and responsibilities where multiple stakeholders are involved. • Discovered and reported conflicts between existing UL 1741-SA requirements and new Rule 21 Smart Inverter control capability requirements • Developed requirements for the procurement of aggregators and smart inverter systems for other SCE EPIC, DOE and DRP demonstration projects. The Final Report for the Integration of Big Data for Advanced Automated Customer Load Management is complete, is being submitted with the 2018 Annual Report, and will be posted on SCE's public EPIC web site.		

2. Advanced Grid Capabilities Using Smart Meter Data

Investment Plan Period:	Assignment to value Chain:
2nd Triennial Plan (2015-2017)	Distribution
Objective & Scope: This project will examine the possibility of establishing the Phasing information for distribution circuits, by examining the voltage signature at the meter and transformer level, and by leveraging the connectivity model of the circuits. This project will also examine the possibility of establishing transformer to meter connectivity based on the voltage signature at the meter and at the transformer level.	

Deliverables: • Validated TLM algorithm • Validated Phase ID algorithm • Final project report
Metrics: 3a. Maintain / Reduce operations and maintenance costs 7b. Increased use of cost-effective digital information and control technology to improve reliability, security, and efficiency of the electric grid (PU Code § 8360) 8d. Number of information sharing forums held 8f. Technology transfer
Schedule: Q3 2015 – Q1 2017

EPIC Funds Encumbered: $	**EPIC Funds Spent:** $207,088	
Partners: N/A		
Match Funding: N/A	**Match Funding split:** N/A	**Funding Mechanism:** N/A
Treatment of Intellectual Property: SCE has no current patents or licensing agreements signed. Future Intellectual Property is to be determined.		
Status Update: The final project report is complete, was submitted with the 2017 Annual Report, and is available on SCE's public EPIC web site.		

3. Proactive Storm Impact Analysis Demonstration

Investment Plan Period: 2nd Triennial Plan (2015-2017)	**Assignment to value Chain:** Distribution
Objective & Scope: This project will demonstrate proactive storm analysis techniques prior to the storm's arrival and estimate its potential impact on utility operations. In this project, we will investigate certain technologies that can model a developing storm and its potential movement through the utility service territory based on weather projections. This information and model will then be integrated with the Geographic Information System (GIS) electrical connectivity model, Distribution Management System (DMS), and Outage Management System (OMS) capabilities, along with historical storm data, to predict the potential impact on the service to customers. In addition, this project will demonstrate the integration of near real-time meter voltage data with the GIS network to develop a simulated circuit model that can be effectively utilized to manage storm responses and activities, and deploy field crews.	
Deliverables: • RFP Package	

• Requirements / Use Cases • Measurement and Validation Plan • Supplier's Pilot Report • Technology Transfer Plan • Final project report
Metrics: 2a. Hours worked in California and money spent in California for each project 3a. Maintain / Reduce operations and maintenance costs 3b. Maintain / Reduce capital costs 5a. Outage number, frequency and duration reductions 5c. Forecast accuracy improvement 5d. Public safety improvement and hazard exposure reduction 8f. Technology transfer 9d. Successful project outcomes ready for use in California IOU grid (Path to market) 9e. Technologies available for sale in the market place (when known)
Schedule: Q3 2015 – Q4 2018

EPIC Funds Encumbered:	**EPIC Funds Spent:**
$0	$1,204,984

Partners:
N/A

Match Funding:	**Match Funding split:**	**Funding Mechanism:**
N/A	N/A	N/A

Treatment of Intellectual Property: SCE has no current patents or licensing agreements signed. Future Intellectual Property is to be determined.
Status Update: The Final Report for the Proactive Storm Impact Analysis Demonstration is complete, is being submitted with the 2018 Annual Report, and will be posted on SCE's public EPIC web site.

4. Next-Generation Distribution Equipment & Automation - Phase 2

Investment Plan Period:	**Assignment to value Chain:**
2nd Triennial Plan (2015-2017)	Distribution

Objective & Scope:
This project will leverage lessons learned from the Next Generation Distribution Automation – Phase 1 project performed in the first EPIC triennial investment plan period. This project will focus on integrating advanced control systems, modern wireless communication systems, and the latest breakthroughs in distribution equipment and sensing technology to develop a complete system design that would serve as a standard for distribution automation and advanced distribution equipment.

Deliverables: • **Hybrid Pole:** specification and report • **Underground Antenna:** functional specification, lab test report, demonstration summary and report • **Underground Remote Fault Indicator:** identification of viable products, publication of standard SCE-configured prototype Mobile Application and report • **Long Beach Network:** improved situational awareness and alarm approach, AT Laboratory SCADA network, DMS back-office recommended architecture and algorithm document, Software Requirements Document, Long Beach Distribution Network Contingency Analysis and Selection Algorithm Report, Standard, FAT & SAT Test Plan/Acceptance Criteria, FAT report, SAT report, training documents and report • **Remote Intelligence Switch:** Substation Radios, Field Radios, Support Software, Underground Interrupters, Documentation and report • **Intelligent Fuse:** delivery of single phase unit, single phase unit standard approval and publication, training of single phase unit, final report of single phase unit, delivery of three phase unit, three phase unit standard approval and publication, training of three phase unit and final report of three phase unit • **High Impedance:** Prototype 1, Prototype 2, Phase 2B Test Documentation and report
Metrics: 3a. Maintain/reduce operations and maintenance costs 3e. Non-energy economic benefits 5a. Outage number, frequency and duration reductions 5c. Forecast accuracy improvement 5d. Public safety improvement and hazard exposure reduction 5i. Increase in the number of nodes in the power system at monitoring points 7b. Increased use of cost-effective digital information and control technology to improve reliability, security, and efficiency of the electric grid (PU Code § 8360) 7c. Dynamic optimization of grid operations and resources, including appropriate consideration for asset management and utilization of related grid operations and resources, with cost-effective full cyber security (PU Code § 8360) 7f. Deployment of cost-effective smart technologies, including real time, automated, interactive technologies that optimize the physical operation of appliances and consumer devices for metering, communication concerning grid operations and status, and distribution automation (PU Code § 8360) 7k. Develop standards for communication and interoperability of appliances and equipment connected to the electric grid, including the infrastructure serving the grid (PU Code § 8360)
Schedule: Q3 2016 – Q4 2019

<table>
<tr><td colspan="2">EPIC Funds Encumbered:
$89,780</td><td colspan="2">EPIC Funds Spent:
$4,695,975</td></tr>
<tr><td colspan="4">Partners:
N/A</td></tr>
<tr><td>Match Funding:
N/A</td><td colspan="2">Match Funding split:
N/A</td><td>Funding Mechanism:
N/A</td></tr>
<tr><td colspan="4">Treatment of Intellectual Property:
SCE has no current patents or licensing agreements signed. Future Intellectual Property is to be determined.</td></tr>
<tr><td colspan="4">Status Update:
In 2018, the project team accomplished the following:
Underground Remote Fault Indicator – SCE conducted field demonstrations of underground remote fault indicators with capabilities to be installed without an outage, submersible, integrated radio, power harvesting, bi-directional power flow detection, real-time current monitoring. 50 UG RFIs for the first vendor have been installed for a field demonstration ending in 2019. Completed lab testing of UG RFI for a second vendor and several units will be installed for field evaluation in 2019.
Long Beach Secondary Network Situation Awareness- Complete the evaluation & lab demonstration phase for the LBNW Situation Awareness Project. The system demonstration use of real-time data together with load flow simulation to provide system operators with real-time situational awareness and contingency planning capability. SCE will be performing a field evaluation over the next six months in 2019 prior to transitioning to the production environment.
High Impedance Fault Detection - completed energized testing at SCE's Equipment Demonstration & Evaluation (12kV) Facility (EDEF) for High Impedance Fault Detection using Spread Spectrum Time Domain Reflectometry Technology. Field demonstration on several distribution circuits will be performed in 2019.
Remote Integrated Switch – Complete the assessment of the 2.5, 2.5 extended, 3.5, and 3.5 extended RIS circuit scheme and on track to implement additional RIS automation schemes at Johanna Substation in 2019.
Real-time Equipment Health Diagnostic – complete evaluations of two vendors through energized testing at SCE's Equipment Demonstration & Evaluation (12kV) Facility (EDEF). This project demonstrate technologies that can monitor and assess energized equipment (cable, splices, transformers, switches etc.) and indicate remaining life or existing condition. If their technology meets SCE requirements, one vendor will be chosen to perform field demonstration in 2019 on several circuits.</td></tr>
</table>

5. System Intelligence and Situational Awareness Capabilities

<table>
<tr><td colspan="2">Investment Plan Period:
2nd Triennial Plan (2015-2017)</td><td>Assignment to value Chain:
Distribution</td></tr>
<tr><td colspan="3">Objective & Scope:
This project will demonstrate system intelligence and situation awareness capabilities such as high impedance fault detection, intelligent alarming, predictive maintenance, and automated testing. This will be accomplished by integrating intelligent algorithms and advanced applications with the latest substation automation technologies, next generation control systems, latest breakthrough in substation equipment, sensing technology, and communications assisted protection schemes, This system will leverage the International Electrotechnical Commission (IEC) 61850 Automation Standard and will include cost saving technology such as process bus, peer to peer communications, and automated engineering and testing technology. This project will also inform complementary efforts at SCE aimed at meeting security and NERC CIP compliance requirements.</td></tr>
<tr><td colspan="3">Deliverables:
1- Intelligent Alarm processing stake-holders lab demonstration
2- Testing tools lab demonstration and hand over to production team
3- Process bus lab demonstration</td></tr>
<tr><td colspan="3">Metrics:
2a. Hours worked in California and money spent in California for each project
3a. Maintain / reduce operations and maintenance costs
3b. Maintain / reduce capital costs
3c. Reduction in electrical losses in the transmission and distribution system
3f. Improvements in system operation efficiencies stemming from increased utility dispatchability of customer demand side management
5a. Outage number, frequency and duration reductions
5e. Utility worker safety improvement and hazard exposure reduction
7b. Increased use of cost-effective digital information and control technology to improve reliability, security, and efficiency of the electric grid (PU Code § 8360)
8e. Stakeholders attendance at workshops
8f. Technology transfer</td></tr>
<tr><td colspan="3">Schedule:
Q1 2016- Q4 2020</td></tr>
<tr><td colspan="2">EPIC Funds Encumbered:
$31,209</td><td>EPIC Funds Spent:
$1,853,840</td></tr>
<tr><td colspan="3">Partners:
N/A</td></tr>
<tr><td>Match Funding:
N/A</td><td>Match Funding split:
N/A</td><td>Funding Mechanism:
N/A</td></tr>
</table>

Treatment of Intellectual Property: SCE has no current patents or licensing agreements signed. Future Intellectual Property is to be determined.
Status Update: 2018 Achievements Process Bus lab demonstration: • Process Bus Evaluation Final report complete • Process Bus Fiber Optics CT Demonstration started project planning • Process Bus Fiber Optics CT Demonstration received SSRT approval • Process Bus Fiber Optics CT Demonstration completed Engineering Design Substation Testing Tools: DTM (Distributed Test Manager) • Successfully created DTM workspaces using SCE's Substation Engineering Modeling Tool (SEMT) standard generated files to simulate an array of IEC61850 devices – SEMT files are primarily used for HMI generation and can now be used for DTM test beds. • Within these workspaces we successfully tested the IEC 61850 communication capabilities with our existing tools and software - Proved interoperability with the SA-3 HMI. • Used DTM to act as a server in a proof-of-concept test between AT's QA network and the outside eDNA server (test environment). • Working with the vendor we facilitated the testing of Modbus protocol communication between the DTM software and the physical PLC located in Fenwick Labs. • Proved DTM can run multiple automated scripts for testing of the SA-3 HMI and PLC schemes without the need of any physical relay or IED – the script testing proves to be reliable and consistent throughout our various runs.

6. Regulatory Mandates: Submetering Enablement Demonstration - Phase 2

Investment Plan Period: 2nd Triennial Plan (2015-2017)	**Assignment to value Chain:** Demand-Side Management
Objective & Scope: This project expands on the submetering project from the first EPIC triennial investment plan cycle to demonstrate plug-in electric vehicle (PEV) submetering at multi-dwelling and commercial facilities. Specifically, the project will leverage third party metering to conduct subtractive billing for various sites, including those with multiple customers of record.	
Deliverables: • Manual subtractive billing procedure for multiple customers of record • 3PE final report • PEV submetering protocol • Final project report	
Metrics: 1d. Number and percentage of customers on time variant or dynamic pricing tariffs	

1h. Customer bill savings (dollars saved) 3e. Non-energy economic benefits 4a. GHG emissions reductions (MMTCO2e) 6a. The 3rd Party Evaluator, Nexant, in collaboration with the Energy Division and IOUs, will develop a set of metrics for Phase 2 to be included in the final report 7h. Deployment and integration of cost-effective advanced electricity storage and peak-shaving technologies, including plug-in electric and hybrid electric vehicles, and thermal-storage air-conditioning (PU Code § 8360) 7j. Provide consumers with timely information and control options (PU Code § 8360) 7k. Develop standards for communication and interoperability of appliances and equipment connected to the electric grid, including the infrastructure serving the grid (PU Code § 8360) 7l. Identification and lowering of unreasonable or unnecessary barriers to adoption of smart grid technologies, practices, and services (PU Code § 8360) 8e. Stakeholders attendance at workshops 8f. Technology transfer 9c. EPIC project results referenced in regulatory proceedings and policy reports 9d. Successful project outcomes ready for use in California IOU grid (Path to market) 9e. Technologies available for sale in the market place (when known)		
Schedule: Q4 2015 – Q3 2018		
EPIC Funds Encumbered: $0	**EPIC Funds Spent:** $1,189,603	
Partners: N/A		
Match Funding: N/A	**Match Funding split:** N/A	**Funding Mechanism:** N/A
Treatment of Intellectual Property: SCE has no current patents or licensing agreements signed. Future Intellectual Property is to be determined.		

Status Update:
2018 Achievements include: 1) Completed Phase 2 Submetering Pilot on April 30, 2018 2) 151 submeters enrolled , 33 were NEM accounts 3) 144 completed maximum of 12 billing cycles; seven customers terminated early 4) Nexant final report submitted to ED on December 4, 2018

7. Bulk System Restoration Under High Renewables Penetration

Investment Plan Period:	**Assignment to value Chain:**
2nd Triennial Plan (2015-2017)	Transmission
Objective & Scope: The Bulk System Restoration under High Renewable Penetration Project will evaluate system restoration plans following a blackout event under high penetration of wind and solar generation resources. Typically, the entire restoration plan consists of three main stages; Black Start, System Stabilization, and load pick-up. The Project will be divided into two phases: * Phase I of the project will address the feasibility of new approaches to system restoration by reviewing the existing system restoration plans and it's suitability for higher penetration of renewable generation. It will include a suitable RTDS Bulk Power system to be used in the first stage of system restoration, black start, and it will also include the modeling of wind and solar renewable resources. * Phase II of the project will focus on on-line evaluation of restoration plans using scenarios created using (RTDS) with hardware in the loop such as generation, transformer and transmission line protective relays. The RTDS is a well-known tool to assess and evaluate performance of protection and control equipment. This project intends to utilize the RTDS capabilities to evaluate and demonstrate system restoration strategies with variable renewable resources focusing on system stabilization and cold load pick-up. Furthermore, alternate restoration scenarios will be investigated. After the restoration process is evaluated, tested, and demonstrated in the RTDS Lab environment, we will provide a recommendation to system operations and transmission planning for their inputs to further develop this approach into an actual operational tool.	
Deliverables: N/A	
Metrics: N/A	
Schedule: N/A	
EPIC Funds Encumbered: $0	**EPIC Funds Spent:** $42,193

Partners: N/A		
Match Funding: N/A	**Match Funding split:** N/A	**Funding Mechanism:** N/A
Treatment of Intellectual Property: SCE has no current patents or licensing agreements signed. Future Intellectual Property is to be determined.		
Status Update: In December 2016, this project was cancelled by SCE Senior Leadership as a result of internal organizational change that focused the organization on Distribution System strategic objectives. This was reported in the 2016 EPIC Annual Report.		

8. Series Compensation for Load Flow Control

Investment Plan Period: 2nd Triennial Plan (2015-2017)	**Assignment to value Chain:** Transmission
Objective & Scope: The intent of this project is to demonstrate and deploy the use of Thyristor Controlled Series Capacitors (TCSC) for load flow control on series compensated transmission lines. On SCE's 500 kV system in particular, several long transmission lines are series-compensated using fixed capacitor segments that do not support active control of power flow. The existing fixed series capacitors use solid state devices as a protection method and are called Thyristor Protected Series Capacitors (TPSC).	
Deliverables: N/A	

Metrics: N/A		
Schedule: N/A		
EPIC Funds Encumbered: $0	**EPIC Funds Spent:** $367,344	
Partners: N/A		
Match Funding: N/A	**Match Funding split:** N/A	**Funding Mechanism:** N/A
Treatment of Intellectual Property: SCE has no current patents or licensing agreements signed. Future Intellectual Property is to be determined.		
Status Update: In 2016, it was determined that the deliverables for this project could easily be done via another project that was already in progress. Therefore, we ultimately determined that the project should be cancelled. This was reported in the 2016 Annual Report.		

9. Versatile Plug-in Auxiliary Power System (VAPS)

Investment Plan Period: 2nd Triennial Plan (2015-2017)	**Assignment to value Chain:** Distribution
Objective & Scope: This project demonstrates the electrification of transportation and vocational loads that previously used internal combustion engines powered by petroleum fuels in the SCE fleet. The VAPS system uses automotive grade lithium ion battery technology (Chevrolet Volt and Ford Focus EV) which is also used in notable stationary energy storage projects (Tehachapi 32 MWh Storage).	
Deliverables: **Light Duty VAPS Platform – PHEV Pickup Truck:** Purchase Order for PHEV Truck, Test Result Report, Final Report **Class 8 PHEV/BEV:** Purchase Order for Class 8 PHEV/BEV, Test Result Report, Final Report **Medium Duty VAPS Platform – Class 5 PHEV 9ft. Flatbed:** A Plug-in Hybrid Ford F550 Flatbed, Test Result Report, Final Report Small, Medium and Large VAPS Systems: Purchase Order for Small VAPS, Year-end Report, Purchase Order for Medium/Large VAPS, Test Result Report, Final Project Report, New Fleet VAPS System Report	
Metrics: 3a. Maintain/Reduce operations and maintenance costs 3e. Non-energy economic benefits 4a. GHG emissions reductions (MMTCO2e) 4b. Criteria air pollution emission reductions 5d. Public safety improvement and hazard exposure reduction 5e. Utility worker safety improvement and hazard exposure reduction	

7h. Deployment and integration of cost-effective advanced electricity storage and peak-shaving technologies, including plug-in electric and hybrid electric vehicles, and thermal-storage air-conditioning (PU Code § 8360) 8f. Technology transfer	
Schedule: Q3 2015 – Q1 2019	
EPIC Funds Encumbered: $0	**EPIC Funds Spent:** $615,340
Partners: N/A	

Match Funding: N/A	**Match Funding split:** N/A	**Funding Mechanism:** N/A
Treatment of Intellectual Property: SCE has no current patents or licensing agreements signed. Future Intellectual Property is to be determined.		
Status Update: 2018 Accomplishments 1. Class 8 EV Project (Heavy Duty Truck): Project was cancelled in 2017 2. Class 5 PHEV Project (Medium Duty Truck): Testing completed on upfitted vehicle October 2018 with findings captured. Final report in process with plan for completion in early 2019. 3. Light Duty PHEV Truck Project: Vehicle received from Efficient Drivertrain Inc. (EDI) with the completed upfit late February 2018 and testing began. Performance testing was impacted by numerous operational and reliability issues. EDI is continuing to troubleshoot remaining issues related to the upfit to allow for performance testing to be completed in 2019. 4. Large VAPS Project: The trailer mounted portable energy system (MobiGen) was received mid-2018 and lab testing began. Battery tests have been coordinated with Freewire and will continue into 2019. 5. Medium VAPS Project: Envoltz underground electric cable puller report in process with plan to be completed Q1 2019. The Envoltz overhead electric cable puller is planned to be received in Q1 2019 with functionality testing to be performed immediately after. 6. Small VAPS Project: JEMS 4A base system was removed from the vehicle in April 2018. Monitoring data collected on 22 Altec JEMS trucks through October 2018. Plan to update reports with findings in 2019.		

10. Dynamic Power Conditioner

Investment Plan Period: 2nd Triennial Plan (2015-2017)	**Assignment to value Chain:** Distribution
Objective & Scope: This project will demonstrate the use of the latest advances in power electronics and energy storage devices and controls to provide dynamic phase balancing. The project will	

also provide voltage control, harmonics cancellation, sag mitigation, and power factor control while fostering steady state operations such as injection and absorption of real and reactive power under scheduled duty cycles or external triggers. This project aims to mitigate the cause of high neutral currents and provide several power quality benefits by using actively controlled real and reactive power injection and absorption.
Deliverables: • Complete Specification documents for hardware • Use Cases • Lab Test Report of the Dynamic Power Conditioner • Final Project Report Presentation of project detailed findings and results. Final Report on effectiveness of device in the lab including a summary of all data collected and how the data may be accessed.
Metrics: 1a. Number and total nameplate capacity of distributed generation facilities 1b. Total electricity deliveries from grid-connected distributed generation facilities 1i. Nameplate capacity (MW) of grid-connected energy storage 2. Job creation 3a. Maintain / Reduce operations and maintenance costs 3b. Maintain / Reduce capital costs 3c. Reduction in electrical losses in the transmission and distribution system 5a. Outage number, frequency and duration reductions 5b. Electric system power flow congestion reduction 5f. Reduced flicker and other power quality differences 7a. Description of the issues, project(s), and the results or outcomes 9. Adoption of EPIC technology, strategy, and research data/results by others
Schedule: Q3 2016 – Q4 2019

EPIC Funds Encumbered: $415,200	**EPIC Funds Spent:** $335,122

Partners: N/A

Match Funding: N/A	**Match Funding split:** N/A	**Funding Mechanism:** N/A

Treatment of Intellectual Property: SCE has no current patents or licensing agreements signed. Future Intellectual Property is to be determined.
Status Update: In 2018, The DER Demonstrations Group partnered with Siemens Industry to complete the design of the Dynamic Power Conditioner. However, the inverter manufacturing that was originally scheduled to be completed in July 2018 was not finalized due to Siemens not being able to meet SCE's project specifications. The project was then suspended until other options were identified. With the assistance of Siemens, a new inverter vendor (EPC) was selected and will provide the inverter for the DPC. To assure that this inverter meets the

needs of the SCE project, the project engineers conducted an EPC site visit on Nov 29 to inspect inverter and verify that it meets our specs and requirements. Based on the addition testing and validating of the new inverter, this projects schedule will move into 2019.

11. Optimized Control of Multiple Storage Systems

Investment Plan Period: 2nd Triennial Plan (2015-2017)		**Assignment to value Chain:** Distribution
Objective & Scope: This project aims to demonstrate the ability of multiple energy storage controllers to integrate with SCE's Distribution Management System (DMS) and other decision-making engines to realize optimum dispatch of real and reactive power based on grid needs.		
Deliverables: N/A		
Metrics: N/A		
Schedule: N/A		
EPIC Funds Encumbered: $0	**EPIC Funds Spent:** $140,482	
Partners: N/A		
Match Funding: N/A	**Match Funding split:** N/A	**Funding Mechanism:** N/A
Treatment of Intellectual Property: SCE has no current patents or licensing agreements signed. Future Intellectual Property is to be determined.		
Status Update: In 2017, the goals of this project were found to overlap significantly with those of the EPIC II Regional Grid Optimization Demo Phase 2 project (otherwise known as Integrated Grid Project (IGP) Phase 2). This project was then cancelled and the proposed benefits will be realized through IGP Phase 2 project.		

12. DC Fast Charging Demonstration

Investment Plan Period: 2nd Triennial Plan (2015-2017)	**Assignment to value Chain:** Demand-Side Management
Objective & Scope: The goal of this project is to demonstrate public DC fast charging stations at SCE facilities near freeways in optimal locations to benefit electric vehicle miles traveled (eVMT) by plug-in electric vehicles (PEVs) while implementing smart grid equipment and techniques to minimize system impact. The Transportation Electrification (TE) Organization is actively pursuing several strategic objectives, including optimizing TE fueling from the grid to improve asset utilization. Deploying a limited number of fast charging stations at selected	

SCE facilities that are already equipped to deliver power at this level (without additional infrastructure upgrade) will support this objective. The project will leverage SCE's vast service territory and its facilities to help PEV reach destinations that would otherwise be out-of-range.
Deliverables: Final Report
Metrics: 3a. Maintain/Reduce operations and maintenance costs 5b. Electric system power flow congestion reduction 5h. Reduction in system harmonics 8d. Number of information sharing forums held 8e. Stakeholders attendance at workshops 8f. Technology transfer
Schedule: Q1 2016 – Q1 2018

EPIC Funds Encumbered: $0	**EPIC Funds Spent:** $21,945

Partners: N/A

Match Funding: N/A	**Match Funding split:** N/A	**Funding Mechanism:** N/A

Treatment of Intellectual Property: SCE has no current patents or licensing agreements signed. Future Intellectual Property is to be determined.
Status Update: The Final Report for the DC Fast Charging Demonstration is complete, is being submitted with the 2018 Annual Report, and will be posted on SCE's public EPIC web site.

13. Integrated Grid Project II

Investment Plan Period: 2nd Triennial Plan (2015-2017)	**Assignment to value Chain:** Cross-Cutting/Foundational Strategies & Technologies

Objective & Scope: The project will deploy, field test and measure innovative technologies that emerge from the design phase of the Integrated Grid Project (IGP) that address the impacts of DER (distributed energy resources) owned by both 3rd parties and the utility. The objectives are to demonstrate the next generation grid infrastructure that manages, operates, and optimizes the distributed energy resources on SCE's system. The results will help determine the controls and protocols needed to manage DER, how to optimally manage an integrated distribution system to provide safe, reliable, affordable service and also how to validate locational value of DERs and understand impacts to future utility investments.

Deliverables: • Evaluation of system performance and field operations performance • Report on market maturity of technologies demonstrated • Final project report (Phase 2)
Metrics: 1a. Number and total nameplate capacity of distributed generation facilities 1b. Total electricity deliveries from grid-connected distributed generation facilities 1c. Avoided procurement and generation costs 1d. Number and percentage of customers on time variant or dynamic pricing tariffs 1e. Peak load reduction (MW) from summer and winter programs 1f. Avoided customer energy use (kWh saved) 1g. Percentage of demand response enabled by automated demand response technology (e.g. Auto DR) 1h. Customer bill savings (dollars saved) 1i. Nameplate capacity (MW) of grid-connected energy storage 3a. Maintain / Reduce operations and maintenance costs 3b. Maintain / Reduce capital costs 3c. Reduction in electrical losses in the transmission and distribution system 3d. Number of operations of various existing equipment types (such as voltage regulation) before and after adoption of a new smart grid component, as an indicator of possible equipment life extensions from reduced wear and tear 3e. Non-energy economic benefits 3f. Improvements in system operation efficiencies stemming from increased utility dispatchability of customer demand side management 5a. Outage number, frequency and duration reductions 5b. Electric system power flow congestion reduction 5c. Forecast accuracy improvement 5f. Reduced flicker and other power quality differences 5i. Increase in the number of nodes in the power system at monitoring points 7b. Increased use of cost-effective digital information and control technology to improve reliability, security, and efficiency of the electric grid (PU Code § 8360) 7c. Dynamic optimization of grid operations and resources, including appropriate consideration for asset management and utilization of related grid operations and resources, with cost-effective full cyber security (PU Code § 8360) 7d. Deployment and integration of cost-effective distributed resources and generation, including renewable resources (PU Code § 8360) 7e. Development and incorporation of cost-effective demand response, demand-side resources, and energy-efficient resources (PU Code § 8360) 7f. Deployment of cost-effective smart technologies, including real time, automated, interactive technologies that optimize the physical operation of appliances and consumer devices for metering, communications concerning grid operations and status, and distribution automation (PU Code § 8360)

7h. Deployment and integration of cost-effective advanced electricity storage and peak-shaving technologies, including plug-in electric and hybrid electric vehicles, and thermal-storage air-conditioning (PU Code § 8360)
7j. Provide consumers with timely information and control options (PU Code § 8360);
7k. Develop standards for communication and interoperability of appliances and equipment connected to the electric grid, including the infrastructure serving the grid (PU Code § 8360)
7l. Identification and lowering of unreasonable or unnecessary barriers to adoption of smart grid technologies, practices, and services (PU Code § 8360)
8b. Number of reports and fact sheets published online
8d. Number of information sharing forums held
8f. Technology transfer
9b. Number of technologies eligible to participate in utility energy efficiency, demand response or distributed energy resource rebate programs
9c. EPIC project results referenced in regulatory proceedings and policy reports
9d. Successful project outcomes ready for use in California IOU grid (Path to market)

Schedule:
Q3 2016 – Q3 2020

EPIC Funds Encumbered:	**EPIC Funds Spent:**
$44,252	$12,283,386

Partners:
The CEC and DOE on the EASE ENERGISE project (part of the DOE Sunshot program).

Match Funding:	**Match Funding split:**	**Funding Mechanism:**
$2.3M Cost Share	N/A	Pay-for-Performance Contracts

Treatment of Intellectual Property:
SCE has no current patents or licensing agreements signed. Future Intellectual Property is to be determined.

Status Update:
Accomplishments in 2018 include:

1. IGP Controllers
   1a.Completed additional FAT testing in the AT Lab (April 2018)
   1b. Completed phase out of BeagleBones and Replaced with FAN Radios for Pre-SAT testing in the QAS Environment (April 2018)
   1c. Completed Hardware and Software transition from AT Lab to QAS Environment for SAT Testing (August 2018)
      1c. (1) Completed SGS testing with FAN radio in AT Lab
      1c. (2) Completed FAN radios integration into AT lab PCCs
      1c. (3) Completed detailed Network Diagram for QAS
      1c. (4) Completed integration of PowerFactory, Triangle MicroWorks, and CodeMeter in QAS

1c. (5) Completed integration of controllers with DMS (including completion of DMS screens)

1c. (6) Completed integration of controllers with Lab PCCs

1c. (7) Completed communication path of SGS Comms Hub with SGS Connect

1d. Began SAT Integration Testing (August 2018)

2. CEC SunSpec (2030.5)

2a. Completed FAT testing with controllers in AT Lab (January 2018)

2b. Completed Kitu Interop Testing (May 2018)

2c. Completed Cyber / Application Testing in AT Lab (September 2018)

2d. Completed Testing / Communication with field inverters from AT Lab (December 2018)

3. DOE NODES / NREL

3.a Completed HIL test evaluation and report (June 2018)

3.b Completed deliverable tasks for 4.8.1 (detailed testing, analysis, and reporting) (November 2018)

4. DOE Prosumer Grid ARPA-E

4.a Completed project and delivered final report (November 2018)

5. DOE NODES

5.a. Completed HIL test evaluation and report (June 2018)

6. Integrated Grid Analytics

6a. Completed numerous milestones regarding developing sample data types and developing requirements engineering tasks

7. Adaptive Protection System

7a. Completed Phase 1 (Model Accuracy) (June 2018)

7b. Completed Phase 2 (Protection System Modeling) (April 2018)

8. DOE EASE

8a. Summary of EASE accomplishments in 2018:

• Completion of EASE Use Cases and publish them to the industry for comments

o DER Registration System

o DER Self-Provisioning

o Real-time Thermal Constraint Management

o Distribution Substation Net Load Management

o Distribution Voltage Management

o DER Services to Utility

o DER Services to ISO

o DER Co-optimization

• Completion of a draft Commercialization Plan

• Successful demonstration of a streamlined DER registration portal

• Completion of DER control system interoperability in the lab environment

• Successful demonstration of DER self-provisioning into the lab DER control system

8b. Summary of EASE conference presentations/publications in 2018:

• Presentation: “Southern California Edison’s EASE Project: Use Cases and IoT Framework” at DistribuTECH 2018.

• Presentation: "Electric Access System Enhancement (EASE)" DOE SETO Portfolio Review meeting, 2018.
• Presentation: 2018 IEEE PES T&D Conference & Exposition
• Presentation: 2018 Emerging Technologies Review by University of California – Santa Barbara
• Presentation: "DER Services to the Utility Electric Access System Enhancement Project Use Cases"2018 CEATI Smart Grid Conference
• Publication: "Enhancing Distribution System Hosting Capacity Through Active Network Management", 2018 IEEE Conference on Technologies for Sustainability, SusTech 2018

4. Conclusion

a) Key Results for the Year for SCE's EPIC Program

(1) 2012-2014 Investment Plan

For the period between January 1 and December 31, 2018, SCE expended a total of $1,756,989 toward project costs and $11,629 toward administrative costs for a grand total of $1,768,618. SCE's cumulative expenses over the lifespan of its 2012 – 2014 EPIC program amount to $36,273,453. SCE committed $2,488,282 toward projects and encumbered $28,475 through executed purchase orders during this period.

SCE continued executing projects from its approved portfolio. SCE's EPIC I Portfolio consists of 16 projects; 3 of these projects were completed during the calendar year 2015, 4 projects were completed in 2016, 4 projects were completed in 2017 and 2 projects were completed in 2018.

The list of completed 2012-2014 Investment Plan projects is shown below:

1. Enhanced Infrastructure Technology Report;
2. Submetering Enablement Demonstration;
3. Dynamic Line Rating;
4. Distribution Planning Tool;
5. Beyond the Meter: Customer Device Communications Unification and Demonstration;
6. Portable End-to-End Test System

7. State Estimation Using Phasor Measurement Technologies;
8. Deep Grid Coordination (otherwise known as the Integrated Grid Project)
9. DOS Protection & Control Demonstration
10. Advanced Voltage and VAR Control of SCE Transmission
11. Outage Management and Customer Voltage Data Analytics Demonstration
12. Cyber-Intrusion Auto-Response and Policy Management System (CAPMS)
13. Next Generation Distribution Automation, Phase 1

Final project reports for projects 12-13 are included in the Appendix of this annual report.

(2) __2015-2017 Investment Plan__

For the period between January 1 and December 31, 2018, SCE expended a total of $7,893,176 toward project costs and $890,975 toward administrative costs for a grand total of $8,784,151. SCE's cumulative expenses over the lifespan of its 2015 – 2017 EPIC program amount to $26,542,019. SCE committed $13,670,660 toward projects and encumbered $580,441 through executed purchase orders during this period.

SCE continued executing projects from its approved portfolio. SCE's EPIC II Portfolio consists of 13 projects; 3 projects have been cancelled for reasons described in their respective project updates in section 0 above, 1 project was completed during the calendar 2017 and 3 projects were completed in 2018.

The list of completed 2015-2017 Investment Plan projects is shown below:

1. Advanced Grid Capabilities Using Smart Meter Data
2. DC Fast Charging
3. Proactive Storm Impact Analysis Demonstration
4. Integration of Big Data for Advanced Automated Customer Load Management

5. Next Steps for EPIC Investment Plan (stakeholder workshops etc.)

During the calendar year 2018, SCE will continue to focus on successfully executing its remaining 3 approved projects as part of its 2012 – 2014 Investment Plan, and 9 approved projects as part of its 2015 – 2017 Investment Plan. Key program implementation activities will include finalizing demonstration plans and requirement specifications, initiating new procurements, continuing technology deployments in SCE's field and lab environments, and executing rigorous testing, measurement, and verification processes.

Furthermore, SCE will continue its open dialogue with stakeholders through workshops in 2018. In these workshops and annual symposium, SCE and the other EPIC Administrators will provide stakeholders with an update on key accomplishments and learnings obtained from their respective EPIC programs. In addition, SCE looks forward to receiving CPUC approval and guidance on the EPIC III Portfolio and beginning more rigorous internal project vetting and detailed planning on the 22 potential projects.

a) Issues That May Have Major Impact on Progress in Projects

During the calendar year 2019, SCE will focus on successfully executing and closing out its remaining 2 approved projects as part of its EPIC I Investment Plan. SCE also continue to focus on successfully executing its 7 approved projects as part of its EPIC II Investment Plan. Furthermore, SCE will finish its rigorous internal project vetting and begin execution of its 22 potential projects. Key program implementation activities will include finalizing demonstration plans and requirement specifications, initiating new procurements, continuing technology deployments in SCE's lab and field environments, and executing rigorous testing, measurement, and verification processes.

Furthermore, SCE will continue its open dialogue with stakeholders through workshops in 2019. In these workshops and annual symposium, SCE and the other EPIC Administrators will provide stakeholders, including DACs with an update on key accomplishments and learnings obtained from their respective EPIC programs. SCE and the other EPIC Administrators also plan to engage stakeholders, especially DACs earlier in the process through more frequent, focused workshops.

Appendix A

SCE EPIC Project Status Report Spreadsheet

Investment Program Period	Program Administrator	Project Name	Project Type	A brief description of the project	Date of the award	Was this project awarded in the immediately prior calendar year?	Assignment to Value Chain	Encumbered Funding Amount ($)	Committed Funding Amount ($)	Funds Expended to date: Contract/Grant Amount ($)	Funds Expended to date: In house expenditures ($)	Funds Expended to date: Total Spent to date ($)	Administrative and overhead costs incurred for each project
Select from: 1st triennial (2012-2014); 2nd triennial (2015-2017); 3rd triennial (2018-2020)	Select from: CEC, PG&E, SCE, SDG&E	Enter project title.	Describe the type of project th.	General description (objective, scope, deliverables, schedule)	The date the award/grant was made. (Format: XX/XX/XXXX)	Yes/No	Select from: Generation, Transmission, Distribution, Grid Operation/Market Design, Demand-Side Management	($)	($)	($)	($)	($)	($)Does not include EPIC administration costs. Includes only project specific administrative and overhead costs.
1st triennial (2012-2014)	SCE	**Integrated Grid Project** *Note: Previously referred to as Regional Grid Optimization*	Cross-Cutting/Foundational Strategies & Technologies	The project will demonstrate, evaluate, analyze and propose options that address the impacts of DER (Distributed Energy Resources) penetration and increased adoption of DG (Distributed Generation) owned by consumers on all segments/aspects of SCE's grid – transmission, distribution and overall "reliable" power delivery cost to SCE customers (all tiers). This demonstration project is in effect the next step to the ISGD project. Therefore, this analysis will focus on the effects of introducing emerging and innovative technology into the utility and consumer end of the grid, predominantly the commercial and industrial customers with the ability to generate power with self-owned and operated renewable energy sources, but connected to the grid for "reliability" and "stability" operational reasons. This scenario introduces the need for the utility (SCE) to assess discriminative technology necessary for stabilizing the grid with increased DG adoption, and more importantly, consider possible economic models that would help SCE adopt to the changing regulatory policy and GRC structures.	8/15/2012	No	Grid Operation/Market Design	$ -	$ -	$ 15,679,990	$ 1,745,543	$ 17,425,533	N/A
1st triennial (2012-2014)	SCE	**Regulatory Mandates: Submetering Enablement Demonstration**	Customer Focused Products and Services	On 11/14/13, the California Public Utilities Commission (CPUC) voted to approve the revised Proposed Decision (PD) Modifying the Requirements for the Development of a Plug-In Electric Vehicle Submetering Protocol set forth in D.11-07-029. The investor-owned utilities (IOUs) are to implement a two phased pilot beginning in May 2014, with funding for both phases provided by the Electric Program Investment Charge (EPIC). This project, Phase I of the pilot will (1) evaluate the demand for Single Customer of Record submetering, (2) estimate billing integration costs, (3) estimate communication costs, and (4) evaluate customer experience. IOU's and external stakeholders will finalize the temporary metering requirements, develop a template format used to report submetered, time-variant energy data, register Submeter Meter Data Management Agents and develop a Customer Enrollment Form, and finalize MDMA Performance Requirements. The IOUs will also solicit a 3rd party evaluator to evaluate customer experience.	8/15/2012	No	Demand-Side Management	$ 823		$ 985,986	$ 148,614	$ 1,134,600	N/A
1st triennial (2012-2014)	SCE	**Distribution Planning Tool**	Energy Resources Integration	This project involves the creation, validation, and functional demonstration of an SCE distribution system model that will address the future system architecture that accommodates distributed generation (primarily solar photovoltaic), plug-in electric vehicles, energy storage, customer programs (demand response, energy efficiency), etc. The modeling software to be used allows for implementation of advanced controls (smart charging, advanced inverters, etc.). These controls will enable interaction of a residential energy module and a power flow module. It also enables the evaluation of various technologies from an end-use customer perspective as well as a utility perspective, allowing full evaluation from substation bank to customer. This capability does not exist today. The completed model will help SCE demonstrate, communicate and better respond to technical, customer and market challenges as the distribution system architecture evolves.	8/15/2012	No	Distribution	$ -	$ -	$ 850,911	$ 220,207	$ 1,071,118	N/A

Investment Program Period	Program Administrator	Project Name	Project Type	Leveraged Funds	Partners	Match Funding	Match Funding Split	Funding Mechanism	Intellectual Property	Identification of the method used to grant awards.	If competitively selected, provide the number of bidders passing the initial pass/fail screening for project	If competitively selected, provide the name of selected bidder.	If competitively selected, provide the rank of the selected bidder in the selection process.	If competitively selected, explain why the bidder was not the highest scoring bidder, explain why a lower scoring bidder was selected.
Select from: 1st triennial (2012-2014); 2nd triennial (2015-2017); 3rd triennial (2018-2020)	Select from: CEC, PG&E, SCE, SDG&E	Enter project title.	Describe the type of project th.	($) Specify amount of leveraged funds (if applicable).	Identify the name of any partners to this project (if applicable).	Specify the match funding amount for this project (if applicable)	If the match funding is split, specify the amount.	Identify pay-for performance contracts or grants	Describe any Intellectual Property (ies) for this project (if applicable).	For example: competitive bid, interagency agreement, sole source.	Provide the number of successful bids in the competitive solicitation.	Name of the successful bidder for this award.	(1st, 2nd, etc.)	Only applicable if competitively selected and not the highest ranking bidder.
1st triennial (2012-2014)	SCE	**Integrated Grid Project** *Note: Previously referred to as Regional Grid Optimization*	Cross-Cutting/Foundational Strategies & Technologies	N/A	N/A	N/A	N/A	Pay-for-Performance Contracts	SCE has no current patents or licensing agreements signed. Future Intellectual Property is to be determined.	Competitive Bid (Request for Proposals): Enbala Power Networks; Integral Analytics, LLC; Directed Awards Issued to the Following Vendor(s): Corepoint 1, Inc; Pacific Coast Engineering; Optiv Security, Inc; Ramsey Electronics:	9	Integral Analytics Enbala	1st 2nd	Does not apply; Highest scoring bidders were selected for award.
1st triennial (2012-2014)	SCE	**Regulatory Mandates: Submetering Enablement Demonstration**	Customer Focused Products and Services	N/A	N/A	N/A	N/A	Pay-for-Performance Contracts	SCE has no current patents or licensing agreements signed. Future Intellectual Property is to be determined.	This was a “quasi-competitive” bid process conducted by the Energy Division (ED) of the CPUC	The ED opened the Phase 1 Pilot Submetering MDMA participation to all companies. Four companies applied: Electric Motor Werks, KnGrid, NRG and Ohmconnect. All four passed the initial pass/fail ED screening.	All four companies were approved by the ED to participate in the Phase 1 Submetering Pilot. Electric Motor Werks, KnGrid, NRG and Ohmconnect	There was no ranking provided by the ED. The four companies were free to choose which of the three IOU territories it wanted to participate in. Three companies, Electric Motor Werks, NRG and Ohmconnect selected to participate in SCE's territory. Note: PO process is not yet complete for Electric Motor Werks.	ED did not provide any scoring of the applicants.
1st triennial (2012-2014)	SCE	**Distribution Planning Tool**	Energy Resources Integration	N/A	N/A	N/A	N/A	Pay-for-Performance Contracts	SCE has no current patents or licensing agreements signed. Future Intellectual Property is to be determined.	Directed Awards Issued to the Following Vendor(s): Battelle Memorial Institute CYME International T&D Inc. INFOSYS Limited Nexant Inc Siemenes Industry Siements Indsustry, Inc.	N/A	N/A	N/A	N/A

Investment Program Period	Program Administrator	Project Name	Project Type	If interagency or sole source agreement, specify date of notification to the Joint Legislative Budget Committee (JLBC) was notified and date of JLBC authorization.	Does the recipient for this award identify as a California-based entity, small business, or businesses owned by women, minorities, or disabled veterans?	How the project leads to technological advancement or breakthroughs to overcome barriers to achieving the state's statutory energy goals	Applicable metrics
Select from: 1st triennial (2012-2014); 2nd triennial (2015-2017); 3rd triennial (2018-2020)	Select from: CEC, PG&E, SCE, SDG&E	Enter project title.	Describe the type of project th.	See Public Resources Code § 25711.5(e)(5). Applicable to CEC, only.	Enter "Yes" or "No". See General Order 156; Public Resources Code§ 25711.5(e)(4)	See Public Resources Code § 25711.5(e)(1). Applicable to CEC, only.	Describe qualitative and quantitative metrics applicable to project.
1st triennial (2012-2014)	SCE	**Integrated Grid Project** *Note: Previously referred to as Regional Grid Optimization*	Cross-Cutting/Foundational Strategies & Technologies	N/A; Applicable to CEC only.	@ Business, Inc.: California-based entity Bridgewater Consulting Group, Inc: California-based entity; Small Business; DBE Corepoint 1, Inc: California-based entity Pacific Coast Engineering: California-based entity; Small Business	N/A; Applicable to CEC only.	1a. Number and total nameplate capacity of distributed generation facilities 1b. Total electricity deliveries from grid-connected distributed generation facilities 1c. Avoided procurement and generation costs 1d. Number and percentage of customers on time variant or dynamic pricing tariffs 1e. Peak load reduction (MW) from summer and winter programs 1f. Avoided customer energy use (kWh saved) 1g. Percentage of demand response enabled by automated demand response technology (e.g. Auto DR) 1h. Customer bill savings (dollars saved) 1i. Nameplate capacity (MW) of grid-connected energy storage 3a. Maintain / Reduce operations and maintenance costs 3b. Maintain / Reduce capital costs 3c. Reduction in electrical losses in the transmission and distribution system 3d. Number of operations of various existing equipment types (such as voltage regulation) before and after adoption of a new smart grid component, as an indicator of possible equipment life extensions from reduced wear and tear 3e. Non-energy economic benefits 3f. Improvements in system operation efficiencies stemming from increased utility dispatchability of customer demand side management 5a. Outage number, frequency and duration reductions 5b. Electric system power flow congestion reduction 5c. Forecast accuracy improvement 5f. Reduced flicker and other power quality differences 5i. Increase in the number of nodes in the power system at monitoring points 7b. Increased use of cost-effective digital information and control technology to improve reliability, security, and efficiency of the electric grid (PU Code § 8360); 7c. Dynamic optimization of grid operations and resources, including appropriate consideration for asset management and utilization of related grid operations and resources, with cost-effective full cyber security (PU Code § 8360); 7d. Deployment and integration of cost-effective distributed resources and generation, including renewable resources (PU Code § 8360); 7e. Development and incorporation of cost-effective demand response, demand-side resources, and energy-efficient resources (PU Code § 8360); 7f. Deployment of cost-effective smart technologies, including real time, automated, interactive technologies that optimize the physical operation of appliances and consumer devices for metering, communications concerning grid operations and
1st triennial (2012-2014)	SCE	**Regulatory Mandates: Submetering Enablement Demonstration**	Customer Focused Products and Services	N/A; Applicable to CEC only.	NRG: N/A Ohmconnect: California-based entity Electric Motor Werks: California-based entity	N/A; Applicable to CEC only.	6a. TOTAL number of SCE customer participants (Phase 1 & 2 each have 500 submeter limit) 6b. Number of SCE NEM customer participants (Phase 1 & 2 each have 100 submeter limit of 500 total) 6c. Submeter MDMA on-time delivery of customer submeter interval usage data 6d. Submeter MDMA accuracy of customer submeter interval usage data
1st triennial (2012-2014)	SCE	**Distribution Planning Tool**	Energy Resources Integration	N/A; Applicable to CEC only.	Battelle Memorial Institute: N/A CYME International T&D Inc. - N/A INFOSYS Limited - Yes (CA entitiy) Nexant Inc - Yes (CA entitiy) Siemenes Industry - Yes (CA entitiy) Siements Indsustry, Inc. - Yes (CA entitiy)	N/A; Applicable to CEC only.	1d. Number and percentage of customers on time variant or dynamic pricing tariffs 1g. Percentage of demand response enabled by automated demand response technology (e.g. Auto DR) 5c. Forecast accuracy improvement 7b. Increased use of cost-effective digital information and control technology to improve reliability, security, and efficiency of the electric grid (PU Code § 8360) 7c. Dynamic optimization of grid operations and resources, including appropriate consideration for asset management and utilization of related grid operations and resources, with cost-effective full cyber security (PU Code § 8360) 7e. Development and incorporation of cost-effective demand response, demand-side resources, and energy-efficient resources (PU Code § 8360); 8c. Number of times reports are cited in scientific journals and trade publications for selected projects. 8d. Number of information sharing forums held. 8f. Technology transfer 9b. Number of technologies eligible to participate in utility energy efficiency, demand response or distributed energy resource rebate programs 9c. EPIC project results referenced in regulatory proceedings and policy reports. 9d. Successful project outcomes ready for use in California IOU grid (Path to market).

Investment Program Period	Program Administrator	Project Name	Project Type	2018 Update	Coordination with CPUC Proceedings or Legislation
Select from: 1st triennial (2012-2014); 2nd triennial (2015-2017); 3rd triennial (2018-2020)	Select from: CEC, PG&E, SCE, SDG&E	Enter project title.	Describe the type of project th.		
1st triennial (2012-2014)	SCE	**Integrated Grid Project** *Note: Previously referred to as Regional Grid Optimization*	Cross-Cutting/Foundational Strategies & Technologies	The final project report is complete, was submitted with the 2017 Annual Report, and is available on SCE's public EPIC web site.	Distribution Resources Plan, R.14-08-013; A.15-07-003 Integrated Demand-side Resource Program, R.14-10-003
1st triennial (2012-2014)	SCE	**Regulatory Mandates: Submetering Enablement Demonstration**	Customer Focused Products and Services	The final project report is complete, was submitted with the 2016 Annual Report, and is available on SCE's public EPIC web site.	
1st triennial (2012-2014)	SCE	**Distribution Planning Tool**	Energy Resources Integration	The final project report is complete, was submitted with the 2016 Annual Report, and is available on SCE's public EPIC web site.	Distribution Resources Plan, R.14-08-013; A.15-07-003

Investment Program Period	Program Administrator	Project Name	Project Type	A brief description of the project	Date of the award	Was this project awarded in the immediately prior calendar year?	Assignment to Value Chain	Encumbered Funding Amount ($)	Committed Funding Amount ($)	Funds Expended to date: Contract/Grant Amount ($)	Funds Expended to date: In house expenditures ($)	Funds Expended to date: Total Spent to date ($)	Administrative and overhead costs incurred for each project
1st triennial (2012-2014)	SCE	**Beyond the Meter: Customer Device Communications, Unification and Demonstration (Phase II)**	Customer Focused Products and Services	The Beyond the Meter (BTM) project will demonstrate the use of a DER management system to interface with and control DER based on customer and distribution grid use cases. It will also demonstrate the ability to communicate near-real time information on the customer's load management decisions and DER availability to SCE for grid management purposes. Three project objectives include: 1) development of a common set of requirements that support the needs of a variety of stakeholders including customers, distribution management, and customer program; 2) validation of standardized interfaces, functionalities, and architectures required in new Rule 21 proceedings, IOU Implementation Guide, and UL 1741/IEEE 1547 standards; 3) collection and analysis measurement and cost/benefits data in order to inform the design of new tariffs, recommend the deployment of new technologies, and support the development of new programs.	8/15/2012	No	Demand-Side Management	$ 45	$ -	$ 1,307,752	$ 170,397	$ 1,478,149	N/A
1st triennial (2012-2014)	SCE	**Portable End-to-End Test System**	Grid Modernization and Optimization	End-to-end transmission circuit relay testing has become essential for operations and safety. SCE technicians currently test relay protection equipment during commissioning and routing testing. Existing tools provide a limited number of scenarios (disturbances) for testing, and focus on testing protection elements; not testing system protection. This project will demonstrate a robust portable end-to-end toolset (PETS) that addresses: 1) relay protection equipment, 2) communications, and 3) provides a pass/fail grade based on the results of automated testing using numerous simulated disturbances. PETS will employ portable Real-Time Digital Simulators (RTDS's) in substations at each end of the transmission line being tested. Tests will be documented using a reporting procedure used in the Power Systems Lab today, which will ensure that all test data is properly evaluated.	8/15/2012	No	Transmission	$ -	$ -	$ 33,167	$ 6,396	$ 39,563	N/A
1st triennial (2012-2014)	SCE	**Voltage and VAR Control of SCE Transmission System**	Energy Resources Integration	This project involves the demonstration of software and hardware products that will enable automated substation volt/var control. Southern California Edison (SCE) will demonstrate a Substation Level Voltage Control (SLVC) unit working with a transmission control center Supervisory Central Voltage Coordinator (SCVC) unit to monitor and control substation voltage. The scope of this project includes systems engineering, testing, and demonstration of the hardware and software that could be operationally employed to manage substation voltage.	8/15/2012	No	Transmission	$ -	$ -	$ 595,576	$ 256,988	$ 852,564	N/A

Investment Program Period	Program Administrator	Project Name	Project Type	Leveraged Funds	Partners	Match Funding	Match Funding Split	Funding Mechanism	Intellectual Property	Identification of the method used to grant awards.	If competitively selected, provide the number of bidders passing the initial pass/fail screening for project	If competitively selected, provide the name of selected bidder.	If competitively selected, provide the rank of the selected bidder in the selection process.	If competitively selected, explain why the bidder was not the highest scoring bidder, explain why a lower scoring bidder was selected.
1st triennial (2012-2014)	SCE	**Beyond the Meter: Customer Device Communications, Unification and Demonstration (Phase II)**	Customer Focused Products and Services	N/A	N/A	N/A	N/A	Pay-for-Performance Contracts	SCE has no current patents or licensing agreements signed. Future Intellectual Property is to be determined.	Competitive Bid (Request for Proposals) & Directed Awards Directed Awards Issued to the Following Vendor(s): Autogrid Systems, Inc.; Qualitylogic, Inc.	2	Saker Systems, LLC	1	Does not apply; Highest scoring bidder was selected for award.
1st triennial (2012-2014)	SCE	**Portable End-to-End Test System**	Grid Modernization and Optimization	N/A	N/A	N/A	N/A	Pay-for-Performance Contracts	SCE has no current patents or licensing agreements signed. Future Intellectual Property is to be determined.	Directed Awards Issued to the Following Vendor(s): Doble Engineering Company; General Electric Company: RTDS Technologies Inc.; Schweitzer Engineering Labs Inc.	N/A	N/A	N/A	N/A
1st triennial (2012-2014)	SCE	**Voltage and VAR Control of SCE Transmission System**	Energy Resources Integration	N/A	N/A	N/A	N/A	Pay-for-Performance Contracts	SCE has no current patents or licensing agreements signed. Future Intellectual Property is to be determined.	Directed Awards Issued to the Following Vendor(s): Siemens Industry, Inc; The Mathworks, Inc Nexant Inc	TBD	TBD	TBD	TBD

Investment Program Period	Program Administrator	Project Name	Project Type	If interagency or sole source agreement, specify date of notification to the Joint Legislative Budget Committee (JLBC) was notified and date of JLBC authorization.	Does the recipient for this award identify as a California-based entity, small business, or businesses owned by women, minorities, or disabled veterans?	How the project leads to technological advancement or breakthroughs to overcome barriers to achieving the state's statutory energy goals	Applicable metrics
1st triennial (2012-2014)	SCE	**Beyond the Meter: Customer Device Communications, Unification and Demonstration (Phase II)**	Customer Focused Products and Services	N/A; Applicable to CEC only.	Saker Systems LLC: California-base entity; DBE Autogrid Systems, Inc: California-base entity Qualitylogic, Inc.: California-base entity	N/A; Applicable to CEC only.	1a. Number and total nameplate capacity of distributed generation facilities 1b. Total electricity deliveries from grid-connected distributed generation facilities 1c. Avoided procurement and generation costs 1e. Peak load reduction (MW) from summer and winter programs 1f. Avoided customer energy use (kWh saved) 1g. Percentage of demand response enabled by automated demand response technology (e.g. Auto DR) 3f. Improvements in system operation efficiencies stemming from increased utility dispatchability of customer demand side management 5b. Electric system power flow congestion reduction 5f. Reduced flicker and other power quality differences 5i. Increase in the number of nodes in the power system at monitoring points 7b. Increased use of cost-effective digital information and control technology to improve reliability, security, and efficiency of the electric grid (PU Code § 8360); 7c. Dynamic optimization of grid operations and resources, including appropriate consideration for asset management and utilization of related grid operations and resources, with cost-effective full cyber security (PU Code § 8360); 7d. Deployment and integration of cost-effective distributed resources and generation, including renewable resources (PU Code § 8360); 7e. Development and incorporation of cost-effective demand response, demand-side resources, and energy-efficient resources (PU Code § 8360); 7f. Deployment of cost-effective smart technologies, including real time, automated, interactive technologies that optimize the physical operation of appliances and consumer devices for metering, communications concerning grid operations and status, and distribution automation (PU Code § 8360); 7g. Integration of cost-effective smart appliances and consumer devices (PU Code § 8360); 7h. Deployment and integration of cost-effective advanced electricity storage and peak-shaving technologies, including plug-in electric and hybrid electric vehicles, and thermal-storage air-conditioning (PU Code § 8360); 7j. Provide consumers with timely information and control options (PU Code § 8360); 7k. Develop standards for communication and interoperability of appliances and equipment connected to the electric grid, including the infrastructure serving the grid (PU Code § 8360); 7l. Identification and lowering of unreasonable or unnecessary barriers to adoption of smart grid technologies, practices, and services (PU Code § 8360) 8b. Number of reports and fact sheets published online 8d. Number of information sharing forums held. 8f. Technology transfer
1st triennial (2012-2014)	SCE	**Portable End-to-End Test System**	Grid Modernization and Optimization	N/A; Applicable to CEC only.	Doble Engineering Company: N/A General Electric Company: N/A RTDS Technologies Inc.: N/A Schweitzer Engineering Labs Inc: California-based entity	N/A; Applicable to CEC only.	3a. Maintain / Reduce operations and maintenance costs 5a. Outage number, frequency and duration reductions 6a. Reduction in testing cost 6b. Number of terminals tested on a line (more than 2 terminals/substations) 7b. Increased use of cost-effective digital information and control technology to improve reliability, security, and efficiency of the electric grid (PU Code § 8360); 8b. Number of reports and fact sheets published online 8d. Number of information sharing forums held. 8f. Technology transfer 9c. EPIC project results referenced in regulatory proceedings and policy reports. 9e. Technologies available for sale in the market place (when known).
1st triennial (2012-2014)	SCE	**Voltage and VAR Control of SCE Transmission System**	Energy Resources Integration	N/A; Applicable to CEC only.	Siemens Industry, Inc: California-based entity The Mathworks, Inc: N/A Nextant Inc - California- based entity	N/A; Applicable to CEC only.	3a. Maintain / Reduce operations and maintenance costs 3c. Reduction in electrical losses in the transmission and distribution system 3d. Number of operations of various existing equipment types (such as voltage regulation) before and after adoption of a new smart grid component, as an indicator of possible equipment life extensions from reduced wear and tear 7b. Increased use of cost-effective digital information and control technology to improve reliability, security, and efficiency of the electric grid (PU Code § 8360) 7c. Dynamic optimization of grid operations and resources, including appropriate consideration for asset management and utilization of related grid operations and resources, with cost-effective full cyber security (PU Code § 8360) 8b. Number of reports and fact sheets published online 8d. Number of information sharing forums held. 8f. Technology transfer 9c. EPIC project results referenced in regulatory proceedings and policy reports. 9d. Successful project outcomes ready for use in California IOU grid (Path to market).

Investment Program Period	Program Administrator	Project Name	Project Type	2018 Update	Coordination with CPUC Proceedings or Legislation
1st triennial (2012-2014)	SCE	**Beyond the Meter: Customer Device Communications, Unification and Demonstration (Phase II)**	Customer Focused Products and Services	The final project report is complete, was submitted with the 2017 Annual Report, and is available on SCE's public EPIC web site.	
1st triennial (2012-2014)	SCE	**Portable End-to-End Test System**	Grid Modernization and Optimization	The final project report is complete, was submitted with the 2015 Annual Report, and is available on SCE's public EPIC web site.	
1st triennial (2012-2014)	SCE	**Voltage and VAR Control of SCE Transmission System**	Energy Resources Integration	In 2018 the project accoplishments include: In April, the project team, along with key stakeholders, approved the reduction in scope and finish the remaining activites to complete the remaining scope. The EPIC I Final Report for the Voltage and VAR Control of SCE's Transmission System Project is complete, is being submitted with the 2018 Annual Report, and will be posted on SCE's public EPIC web site.	

Investment Program Period	Program Administrator	Project Name	Project Type	A brief description of the project	Date of the award	Was this project awarded in the immediately prior calendar year?	Assignment to Value Chain	Encumbered Funding Amount ($)	Committed Funding Amount ($)	Funds Expended to date: Contract/Grant Amount ($)	Funds Expended to date: In house expenditures ($)	Funds Expended to date: Total Spent to date ($)	Administrative and overhead costs incurred for each project
1st triennial (2012-2014)	SCE	Superconducting Transformer (SCX) Demo	Grid Modernization and Optimization	SCE will support this $21M American Reinvestment and Recovery Act (ARRA) Superconducting Transformer (SCX) project by providing technical expertise and installing and operating the transformer at SCE's MacArthur substation. The SCX prime contractor is SuperPower Inc. (SPI), teamed with SPX Transformer Solutions (SPX) {formerly Waukesha Electric Systems}. SCE has provided two letters of commitment for SCX. The SCX project will develop a 28 MVA High Temperature Superconducting, Fault Current Limiting (HTS-FCL) transformer. The transformer is expected to be installed in 2015. SCE is supporting this project and is not an ARRA grant sub-recipient. SCE is being reimbursed for its effort by EPIC. SCE's participation in this project was previously approved under the now defunct California Energy Commission's PIER program.	8/15/2012	No	Distribution	$ -	$ -	$ 4,022	$ 6,219	$ 10,241	N/A
1st triennial (2012-2014)	SCE	**State Estimation Using Phasor Measurement Technologies**	Cross-Cutting/Foundational Strategies & Technologies	Accurate and timely power system state estimation data is essential for understanding system health and provides the basis for corrective action that could avoid failures and outages. This project will demonstrate the utility of improved static system state estimation using Phasor Measurement Unit (PMU) data in concert with existing systems. Enhancements to static state estimation will be investigated using two approaches: 1) by using GPS time to synchronize PMU data with Supervisory Control and Data Acquisition (SCADA) system data; 2) by augmenting SCE's existing conventional state estimator with a PMU based Linear State Estimator (LSE).	8/15/2012	No	Grid Operation/Market Design	$ -	$ -	$ 739,331	$ 82,848	$ 822,179	N/A
1st triennial (2012-2014)	SCE	Wide-Area Reliability Management & Control	Energy Resources Integration	With the planned wind and solar portfolio of 33% penetration, a review of the integration strategy implemented in the SCE bulk system is needed. The basic premise for the integration strategy is that a failure in one area of the grid should not result in failures elsewhere. The approach is to minimize failures with well designed, maintained, operated, and coordinated power grids. New technologies can provide coordinated wide-area monitoring, protection, and control systems with pattern recognition and advance warning capabilities. This project will demonstrate new technologies to manage transmission system control devices to prevent cascading outages and maintain system integrity.	8/15/2012	No	Grid Operation/Market Design	$ -	$ 767,343	$ 518,679	$ 122,246	$ 640,925	N/A

Investment Program Period	Program Administrator	Project Name	Project Type	Leveraged Funds	Partners	Match Funding	Match Funding Split	Funding Mechanism	Intellectual Property	Identification of the method used to grant awards.	If competitively selected, provide the number of bidders passing the initial pass/fail screening for project	If competitively selected, provide the name of selected bidder.	If competitively selected, provide the rank of the selected bidder in the selection process.	If competitively selected, explain why the bidder was not the highest scoring bidder, explain why a lower scoring bidder was selected.
1st triennial (2012-2014)	SCE	Superconducting Transformer (SCX) Demo	Grid Modernization and Optimization	N/A	SuperPower Inc.; SPX Transformer Solutions	TBD	TBD	Pay-for-Performance Contracts	SCE has no current patents or licensing agreements signed. Future Intellectual Property is to be determined.	N/A	N/A	N/A	N/A	N/A
1st triennial (2012-2014)	SCE	**State Estimation Using Phasor Measurement Technologies**	Cross-Cutting/Foundational Strategies & Technologies	N/A	N/A	N/A	N/A	Pay-for-Performance Contracts	SCE has no current patents or licensing agreements signed. Future Intellectual Property is to be determined.	Directed Awards Issued to the Following Vendor(s): Power World Corporation Electric Power Group, LLC	TBD	TBD	TBD	TBD
1st triennial (2012-2014)	SCE	Wide-Area Reliability Management & Control	Energy Resources Integration	N/A	N/A	N/A	N/A	Pay-for-Performance Contracts	SCE has no current patents or licensing agreements signed. Future Intellectual Property is to be determined.	Directed Awards Issued to the Following Vendor(s): V&R Energy Systems Research, Inc.; Siemens Industry, Inc	N/A	N/A	N/A	N/A

Investment Program Period	Program Administrator	Project Name	Project Type	If interagency or sole source agreement, specify date of notification to the Joint Legislative Budget Committee (JLBC) was notified and date of JLBC authorization.	Does the recipient for this award identify as a California-based entity, small business, or businesses owned by women, minorities, or disabled veterans?	How the project leads to technological advancement or breakthroughs to overcome barriers to achieving the state's statutory energy goals	Applicable metrics
1st triennial (2012-2014)	SCE	Superconducting Transformer (SCX) Demo	Grid Modernization and Optimization	N/A; Applicable to CEC only.	N/A; Project is cancelled.	N/A; Applicable to CEC only.	N/A; Project is cancelled
1st triennial (2012-2014)	SCE	**State Estimation Using Phasor Measurement Technologies**	Cross-Cutting/Foundational Strategies & Technologies	N/A; Applicable to CEC only.	Power World Corporation: California-based entity Electric Power Group, LLC: California-based entity; Small Business; MBE	N/A; Applicable to CEC only.	6a. Enhanced grid monitoring and on-line analysis for resiliency 7b. Increased use of cost-effective digital information and control technology to improve reliability, security, and efficiency of the electric grid (PU Code § 8360); 8b. Number of reports and fact sheets published online 8d. Number of information sharing forums held. 8f. Technology transfer 9d. Successful project outcomes ready for use in California IOU grid (Path to market). 9e. Technologies available for sale in the market place (when known).
1st triennial (2012-2014)	SCE	Wide-Area Reliability Management & Control	Energy Resources Integration	N/A; Applicable to CEC only.	V&R Energy Systems Research, Inc.: California-based entity Siemens Industry, Inc.: California-based entity	N/A; Applicable to CEC only.	6a. Enhanced contingency planning for minimizing cascading outages 8b. Number of reports and fact sheets published online 8d. Number of information sharing forums held. 8f. Technology transfer

Investment Program Period	Program Administrator	Project Name	Project Type	2018 Update	Coordination with CPUC Proceedings or Legislation
1st triennial (2012-2014)	SCE	Superconducting Transformer (SCX) Demo	Grid Modernization and Optimization	SCE formally cancelled this project in Q3 2014.	N/A - Cancelled.
1st triennial (2012-2014)	SCE	**State Estimation Using Phasor Measurement Technologies**	Cross-Cutting/Foundational Strategies & Technologies	The final project report is complete, was submitted with the 2017 Annual Report, and is available on SCE's public EPIC web site.	
1st triennial (2012-2014)	SCE	Wide-Area Reliability Management & Control	Energy Resources Integration	In 2018, MHI assisted Siemens with the tuning evaluations and setting up cases for the SVC Power Oscillations Damping (POD) controller. A full dynamic and transient details models was utilized by Manitoba Hydro International (MHI) to represent the Devers Static VAr Compensator (SVC) with the updated control system. The objective of these models were used for the POD controller tuning studies. Different Bulk system Contingences were simulated inside SCE system and surrounding systems for different seasons (e.g. summer, spring) and years. As part of the simulation, the year 2022 was used to reflect the system condition after once -through cooling (OTC) generation unit's retirement in 2020 (effecting up to 7GW of generation within SCE territory). The result were analyzed to extract the low frequency oscillations and their associated damping using Prony analysis. The critical bulk system Contingences were identified and ranked and the parameters of the POD controller were tuned to damp these oscillations effectively and increase the system damping. Based on these simulations, the engineering teams worked with SCE's Grid Control center (GCC) and Substation Apparatus group to schedule the SVC outage, so Siemens engineers can update the Devers SVC firmware and GUI. In June of 2018, the update to the Devers SVC firmware and GUI was successfully completed allowing for the SVC to export the short circuit value measured by the SVC to the SCE EMS system and to allow the utilization of POD auxiliary control system to damp low frequency oscillations.	

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1st triennial (2012-2014)	SCE	**Distributed Optimized Storage (DOS) Protection & Control Demonstration**	Energy Resources Integration	This field demonstration will test end-to-end integration of multiple energy storage devices on a distribution circuit/feeder to provide a turn-key solution that can cost-effectively be considered for SCE's distribution system, where identified feeders can benefit from grid optimization and variable energy resources (VER) integration. To accomplish this, the project team will first identify distribution system feeders where multiple energy storage devices can be operated centrally. Once a feeder is selected, the energy storage devices will be deployed and tested to demonstrate seamless utility integration, control, and operation of these devices using a single centralized controller. At the end of the project, SCE will have established clear methodologies for identifying feeders that can benefit from distributed energy storage devices and will have established necessary standards-based hardware and control function requirements for grid optimization and renewables integration with distributed energy storage devices.	8/15/2012	No	Distribution	$ -	$ -	$ 7,208	$ 67,228	$ 74,436	N/A
1st triennial (2012-2014)	SCE	**Outage Management and Customer Voltage Data Analytics Demonstration**	Customer Focused Products and Services	Voltage data and customer energy usage data from the Smart Meter network can be collected and leveraged for a range of initiatives focused on achieving operational benefits for Transmission & Distribution. Before a full implementation of this new approach can be considered, a demonstration project will be conducted to understand how voltage and consumption data can be best collected, stored, and integrated with T&D applications to provide analytics and visualization capabilities. Further, Smart Meter outage and restoration event (time stamp) data can be leveraged to improve customer outage duration and frequency calculations. Various stakeholders in T&D have identified business needs to pursue more effective and efficient ways of calculating SAIDI (System Average Interruption Duration Index), SAIFI (System Average Interruption Frequency Index), and MAIFI (Momentary Average Interruption Frequency Index) for internal and external reporting. Before a full implementation of this new approach can be considered, a demonstration project will be conducted to understand the feasibility and value of providing smart meter data inputs and enhanced methodology for calculating the Indexes. The demonstration will focus on a limited geography (SCE District or Region) to obtain the Smart Meter inputs to calculate the Indexes and compare that number with the current methodologies to identify any anomalies. A hybrid approach using the Smart Meter-based input data combined with a better comprehensive electric connectivity model obtained from GIS may provide a more efficient and effective way of calculating the Indexes. Additionally, an effort to evaluate the accuracy of the Transformer Load Mapping data will be carried out.	11/1/2012	No	Grid Operation/Market Design	$ -	$ -	$ 713,145	$ 305,552	$ 1,018,697	N/A
1st triennial (2012-2014)	SCE	**Dynamic Line Rating**	Grid Modernization and Optimization	Transmission line owners apply fixed thermal rating limits for power transmission lines. These limits are based on conservative assumptions of wind speed, ambient temperature and solar radiation. They are established to help ensure compliance with safety codes, maintain the integrity of line materials, and help secure network reliability. Monitored transmission lines can be more fully utilized to improve network efficiency. Line tension is directly related to average conductor temperature. The tension of a power line is directly related to the current rating of the line. This project will demonstrate the CAT-1 dynamic line rating solution. The CAT-1 system will monitor the tension of transmission lines in real-time to calculate a dynamic daily rating. If successful, this solution will allow SCE to perform real-time calculations in order to determine dynamic daily rating of transmission lines, thus increasing transmission line capacity.		No	Distribution	$ -	$ -	$ 399,045	$ 69,556	$ 468,601	N/A

Investment Program Period	Program Administrator	Project Name	Project Type	Leveraged Funds	Partners	Match Funding	Match Funding Split	Funding Mechanism	Intellectual Property	Identification of the method used to grant awards.	If competitively selected, provide the number of bidders passing the initial pass/fail screening for project	If competitively selected, provide the name of selected bidder.	If competitively selected, provide the rank of the selected bidder in the selection process.	If competitively selected, explain why the bidder was not the highest scoring bidder, explain why a lower scoring bidder was selected.
1st triennial (2012-2014)	SCE	**Distributed Optimized Storage (DOS) Protection & Control Demonstration**	Energy Resources Integration	TBD	TBD	TBD	TBD	Pay-for-Performance Contracts	SCE has no current patents or licensing agreements signed. Future Intellectual Property is to be determined.	TBD	TBD	TBD	TBD	TBD
1st triennial (2012-2014)	SCE	**Outage Management and Customer Voltage Data Analytics Demonstration**	Customer Focused Products and Services	N/A	N/A	N/A	N/A	Pay-for-Performance Contracts	SCE has no current patents or licensing agreements signed. Future Intellectual Property is to be determined.	Directed Awards Issued to the Following Vendor(s): Cyient, Inc.; Nexant Inc	N/A	N/A	N/A	N/A
1st triennial (2012-2014)	SCE	**Dynamic Line Rating**	Grid Modernization and Optimization	N/A	N/A	N/A	N/A	Pay-for-Performance Contracts	SCE has no current patents or licensing agreements signed. Future Intellectual Property is to be determined.	Competitive Bid ((Request for Proposal) to the Following Vendor(s): 1- .... (Direct award) to the Following Vendor(s): 2-	N/A	N/A	N/A	N/A

Investment Program Period	Program Administrator	Project Name	Project Type	If interagency or sole source agreement, specify date of notification to the Joint Legislative Budget Committee (JLBC) was notified and date of JLBC authorization.	Does the recipient for this award identify as a California-based entity, small business, or businesses owned by women, minorities, or disabled veterans?	How the project leads to technological advancement or breakthroughs to overcome barriers to achieving the state's statutory energy goals	Applicable metrics
1st triennial (2012-2014)	SCE	**Distributed Optimized Storage (DOS) Protection & Control Demonstration**	Energy Resources Integration	N/A; Applicable to CEC only.	TBD	N/A; Applicable to CEC only.	1c. Avoided procurement and generation costs 1i. Nameplate capacity (MW) of grid-connected energy storage 3b. Maintain / Reduce capital costs 5f. Reduced flicker and other power quality differences 5i. Increase in the number of nodes in the power system at monitoring points 6a. Benefits in energy storage sizing through device operation optimization 6b. Benefits in distributed energy storage deployment vs. centralized energy storage deployment 7a. Description of the issues, project(s), and the results or outcomes 7b. Increased use of cost-effective digital information and control technology to improve reliability, security, and efficiency of the electric grid (PU Code § 8360) 7c. Dynamic optimization of grid operations and resources, including appropriate consideration for asset management and utilization of related grid operations and resources, with cost-effective full cyber security (PU Code § 8360) 7l. Identification and lowering of unreasonable or unnecessary barriers to adoption of smart grid technologies, practices, and services (PU Code § 8360) 8b. Number of reports and fact sheets published online 8d. Number of information sharing forums held. 8f. Technology transfer 9c. EPIC project results referenced in regulatory proceedings and policy reports.
1st triennial (2012-2014)	SCE	**Outage Management and Customer Voltage Data Analytics Demonstration**	Customer Focused Products and Services	N/A; Applicable to CEC only.	Cyient, Inc.: N/A Nexant Inc: California-based entity	N/A; Applicable to CEC only.	3a. Maintain / Reduce operations and maintenance costs 5c. Forecast accuracy improvement 5f. Reduced flicker and other power quality differences 6a. Enhance Outage Reporting Accurary and SAIDI/SAIFI Calculation 8b. Number of reports and fact sheets published online 8f. Technology transfer 9c. EPIC project results referenced in regulatory proceedings and policy reports.
1st triennial (2012-2014)	SCE	**Dynamic Line Rating**	Grid Modernization and Optimization	N/A; Applicable to CEC only.		N/A; Applicable to CEC only.	3b. Maintain / Reduce capital costs 5b. Electric system power flow congestion reduction 6a. Increased power flow throughput 7b. Increased use of cost-effective digital information and control technology to improve reliability, security, and efficiency of the electric grid (PU Code § 8360) 7c. Dynamic optimization of grid operations and resources, including appropriate consideration for asset management and utilization of related grid operations and resources, with cost-effective full cyber security (PU Code § 8360) 8b. Number of reports and fact sheets published online 8d. Number of information sharing forums held 8f. Technology transfer 9c. EPIC project results referenced in regulatory proceedings and policy reports 9d. Successful project outcomes ready for use in California IOU grid (Path to market) 9e. Technologies available for sale in the market place (when known)

Investment Program Period	Program Administrator	Project Name	Project Type	2018 Update	Coordination with CPUC Proceedings or Legislation
1st triennial (2012-2014)	SCE	**Distributed Optimized Storage (DOS) Protection & Control Demonstration**	Energy Resources Integration	The EPIC I DOS Protection and Controls Project is complete, is being submitted with the 2018 Annual Report, and will be posted on SCE's public EPIC web site.	Energy Storage R,.15-03-011; D.14-10-040 & D.14-10-045 Resource Adequacy OIR, R.14-10-010
1st triennial (2012-2014)	SCE	**Outage Management and Customer Voltage Data Analytics Demonstration**	Customer Focused Products and Services	The final project report is complete, was submitted with the 2015 Annual Report, and is available on SCE's public EPIC web site.	
1st triennial (2012-2014)	SCE	**Dynamic Line Rating**	Grid Modernization and Optimization	The final project report is complete, was submitted with the 2017 Annual Report, and is available on SCE's public EPIC web site.	

Investment Program Period	Program Administrator	Project Name	Project Type	A brief description of the project	Date of the award	Was this project awarded in the immediately prior calendar year?	Assignment to Value Chain	Encumbered Funding Amount ($)	Committed Funding Amount ($)	Funds Expended to date: Contract/Grant Amount ($)	Funds Expended to date: In house expenditures ($)	Funds Expended to date: Total Spent to date ($)	Administrative and overhead costs incurred for each project
1st triennial (2012-2014)	SCE	SA-3 Phase III Demonstration	Grid Modernization and Optimization	This project is intended to apply the findings from the Substation Automation Three (SA-3) Phase II (Irvine Smart Grid Demonstration) project to demonstrate real solutions to automation problems faced by SCE today. The project will demonstrate two standards-based automation solutions (sub-projects) as follows: Subproject 1 (Bulk Electric System) will address issues unique to transmission substations including the integration of centrally managed critical cyber security (CCS) systems and NERC CIP compliance; Subproject 2 (Hybrid) will address the integration of SA-3 capabilities with SAS and SA-2 legacy systems. Furthermore, as part of the systems engineering the SA-3 technical team will demonstrate two automation tools as follows: Subproject 3 (Intelligent Alarming) will allow substation operators to pin-point root cause issues by analyzing the various scenarios and implement an intelligent alarming system that can identify the source of the problem and give operators only the relevant information needed to make informed decisions; and Subproject 4 (Real Time Digital Simulator (RTDS) Mobile Testing) will explore the benefits of an automated testing using a mobile RTDS unit, and propose test methodologies that can be implemented into the factory acceptance testing (FAT) and site acceptance testing (SAT) testing process.	8/15/2012	No	Transmission	$ 27,265	$ 1,720,939	$ 3,444,614	$ 780,375	$ 4,224,989	N/A
1st triennial (2012-2014)	SCE	**Next-Generation Distribution Automation**	Grid Modernization and Optimization	SCE's current distribution automation scheme often relies on human intervention that can take several minutes (or longer during storm conditions) to isolate faults, is only capable of automatically restoring power to half of the customers on the affected circuit, and needs to be replaced due to assets nearing the end of their lifecycle. In addition, the self-healing circuit being demonstrated as part of the Irvine Smart Grid Demonstration is unique to the two participating circuits and may not be easily applied elsewhere. As a result, the Next-Generation Distribution Automation project intends to demonstrate a cost-effective advanced automation solution that can be applied to the majority of SCE's distribution circuits. This solution will utilize automated switching devices combined with the latest protection and wireless communication technologies to enable detection and isolation of faults before the substation circuit breaker is opened, so that at least 2/3 of the circuit load can be restored quickly. This will improve reliability and reduce customer minutes of interruption. The system will also have directional power flow sensing to help SCE better manage distributed energy resources on the distribution system. At the end of the project, SCE will provide reports on the field demonstrations and recommend next steps for new standards for next-generation distribution automation.	8/15/2012	No	Distribution	$ 342	$ -	$ 3,096,838	$ 921,841	$ 4,018,679	N/A
1st triennial (2012-2014)	SCE	**Enhanced Infrastructure Technology Evaluation**	Grid Modernization and Optimization	At the request of Distribution Apparatus Engineering (DAE) group's lead Civil Engineer, Advanced Technology (AT) will investigate, demonstrate, and come up with recommendations for enhanced infrastructure technologies. The project will focus on evaluating advanced: distribution sectional poles (hybrid, coatings, etc.), concealed communications on assets, vault monitoring systems (temperature, water, etc.), and vault ventilation systems. Funding is required to investigate the problem, engineering, demonstrate alternatives, and come up with recommendations. DAE sees the need for poles that can withstand fires and have a better life cycle cost, and provide installation efficiencies when compared to existing wood pole replacements. Due to increased city restrictions, there is a need for more concealed communications on our assets such as streetlights (e.g., on the ISGD project, the City of Irvine wouldn't allow us to install repeaters on streetlights due to aesthetics). DAE also sees the need for technologies that may minimize premature vault change-outs (avg. replacement cost is ~$250K). At present, DAE does not have the necessary real-time vault data to sufficiently address the increasing vault deterioration issue nor do we utilize a hardened ventilation system that would help this issue by removing the excess heat out of the vaults (blowers last ~ 2 years, need better bearings for blower motors, etc.).	12/17/2013	No	Distribution	$ -	$ -	$ 33,972	$ 45,147	$ 79,119	N/A

Investment Program Period	Program Administrator	Project Name	Project Type	Leveraged Funds	Partners	Match Funding	Match Funding Split	Funding Mechanism	Intellectual Property	Identification of the method used to grant awards.	If competitively selected, provide the number of bidders passing the initial pass/fail screening for project	If competitively selected, provide the name of selected bidder.	If competitively selected, provide the rank of the selected bidder in the selection process.	If competitively selected, explain why the bidder was not the highest scoring bidder, explain why a lower scoring bidder was selected.
1st triennial (2012-2014)	SCE	SA-3 Phase III Demonstration	Grid Modernization and Optimization	N/A	N/A	N/A	N/A	Pay-for-Performance Contracts	SCE has no current patents or licensing agreements signed. Future Intellectual Property is to be determined.	Competitive Bid ((Request for Proposal) to the Following Vendor(s): 1- .... (Direct award) to the Following Vendor(s): 2-	N/A	N/A	N/A	N/A
1st triennial (2012-2014)	SCE	**Next-Generation Distribution Automation**	Grid Modernization and Optimization	N/A	N/A	N/A	N/A	Pay-for-Performance Contracts	SCE has no current patents or licensing agreements signed. Future Intellectual Property is to be determined.	Competitive Bid Directed Awards Issued to the Following Vendor(s): Cleaveland Price Inc.; Doble Engineering Company; GE MDS LLC.; One Source Supply Solutions LLC.	2	G&W Electric Company; Par Electrical Contractors Inc.	G&W Electric Company; Par Electrical Contractors Inc.	
1st triennial (2012-2014)	SCE	**Enhanced Infrastructure Technology Evaluation**	Grid Modernization and Optimization	N/A	N/A	N/A	TBD	Pay-for-Performance Contracts	SCE has no current patents or licensing agreements signed. Future Intellectual Property is to be determined.	Directed Awards Issued to the Following Vendor(s): American Restore, Inc.; Rivcomm, Inc.; California Turbo Inc	N/A	N/A	N/A	N/A

Investment Program Period	Program Administrator	Project Name	Project Type	If interagency or sole source agreement, specify date of notification to the Joint Legislative Budget Committee (JLBC) was notified and date of JLBC authorization.	Does the recipient for this award identify as a California-based entity, small business, or businesses owned by women, minorities, or disabled veterans?	How the project leads to technological advancement or breakthroughs to overcome barriers to achieving the state's statutory energy goals	Applicable metrics
1st triennial (2012-2014)	SCE	SA-3 Phase III Demonstration	Grid Modernization and Optimization	N/A; Applicable to CEC only.		N/A; Applicable to CEC only.	3a. Maintain / Reduce operations and maintenance costs 3b. Maintain / Reduce capital costs 5a. Outage number, frequency and duration reductions 5i. Increase in the number of nodes in the power system at monitoring points 6a. Increased cybersecurity 7b. Increased use of cost-effective digital information and control technology to improve reliability, security, and efficiency of the electric grid (PU Code § 8360); 7c. Dynamic optimization of grid operations and resources, including appropriate consideration for asset management and utilization of related grid operations and resources, with cost-effective full cyber security (PU Code § 8360); 7k. Develop standards for communication and interoperability of appliances and equipment connected to the electric grid, including the infrastructure serving the grid (PU Code § 8360); 8b. Number of reports and fact sheets published online 8d. Number of information sharing forums held. 8f. Technology transfer 9c. EPIC project results referenced in regulatory proceedings and policy reports. 9d. Successful project outcomes ready for use in California IOU grid (Path to market). 9e. Technologies available for sale in the market place (when known).
1st triennial (2012-2014)	SCE	**Next-Generation Distribution Automation**	Grid Modernization and Optimization	N/A; Applicable to CEC only.	G&W Electric Company: California-based entity; Small Business Par Electrical Contractors Inc.: California-based entity	N/A; Applicable to CEC only.	3a. Maintain / Reduce operations and maintenance costs 3d. Number of operations of various existing equipment types (such as voltage regulation) before and after adoption of a new smart grid component, as an indicator of possible equipment life extensions from reduced wear and tear 5a. Outage number, frequency and duration reductions 5c. Forecast accuracy improvement 5d. Public safety improvement and hazard exposure reduction 5e. Utility worker safety improvement and hazard exposure reduction 5i. Increase in the number of nodes in the power system at monitoring points 6a. Improve data accuracy for distribution substation planning process 7b. Increased use of cost-effective digital information and control technology to improve reliability, security, and efficiency of the electric grid (PU Code § 8360); 7c. Dynamic optimization of grid operations and resources, including appropriate consideration for asset management and utilization of related grid operations and resources, with cost-effective full cyber security (PU Code § 8360); 7d. Deployment and integration of cost-effective distributed resources and generation, including renewable resources (PU Code § 8360); 7k. Develop standards for communication and interoperability of appliances and equipment connected to the electric grid, including the infrastructure serving the grid (PU Code § 8360); 8b. Number of reports and fact sheets published online 8d. Number of information sharing forums held. 8f. Technology transfer 9c. EPIC project results referenced in regulatory proceedings and policy reports. 9d. Successful project outcomes ready for use in California IOU grid (Path to market). 9e. Technologies available for sale in the market place (when known).
1st triennial (2012-2014)	SCE	**Enhanced Infrastructure Technology Evaluation**	Grid Modernization and Optimization	N/A; Applicable to CEC only.	American Restore, Inc.: California-based entity Rivcomm, Inc.: California-based entity; Small Business California Turbo Inc: California-based entity	N/A; Applicable to CEC only.	3a. Maintain / Reduce operations and maintenance costs 3b. Maintain / Reduce capital costs 4g. Wildlife fatality reductions (electrocutions, collisions) 5a. Outage number, frequency and duration reductions 6a. Operating performance of underground vault monitoring equipment 8b. Number of reports and fact sheets published online 8d. Number of information sharing forums held. 8f. Technology transfer 9c. EPIC project results referenced in regulatory proceedings and policy reports.

Investment Program Period	Program Administrator	Project Name	Project Type	2018 Update	Coordination with CPUC Proceedings or Legislation
1st triennial (2012-2014)	SCE	SA-3 Phase III Demonstration	Grid Modernization and Optimization	2018 accomplishments: The project has added additional scope to address the SCE cybersecurity requirements and a configuration management for substation devices and automated configuration import for Substation Management Systems. With these change, the SA-3 Phase III project will be deployed at Viejo A-station for field demonstration and an in-service date of Oct 23, 2020. High level 2018 accomplishments: • Relays Automation setting and Goose messaging lab testing • SDN configuration and lab testing • PAC configuration and lab testing • FAT completion • Grid 2 Network telcom work completed	
1st triennial (2012-2014)	SCE	**Next-Generation Distribution Automation**	Grid Modernization and Optimization	EPIC 1 Next-Generation Distribution Automation Executive Summary report completed and included with 2018 EPIC annual report which combines all final report goals and will be posted on SCE's public EPIC site.	
1st triennial (2012-2014)	SCE	**Enhanced Infrastructure Technology Evaluation**	Grid Modernization and Optimization	The final project report is complete, was submitted with the 2016 Annual Report, and is available on SCE's public EPIC web site.	

Investment Program Period	Program Administrator	Project Name	Project Type	A brief description of the project	Date of the award	Was this project awarded in the immediately prior calendar year?	Assignment to Value Chain	Encumbered Funding Amount ($)	Committed Funding Amount ($)	Funds Expended to date: Contract/Grant Amount ($)	Funds Expended to date: In house expenditures ($)	Funds Expended to date: Total Spent to date ($)	Administrative and overhead costs incurred for each project
1st triennial (2012-2014)	SCE	**Cyber-Intrusion Auto-Response and Policy Management System (CAPMS)**	Cross-Cutting/Foundational Strategies & Technologies	Viasat in partnership with SCE and Duke Energy has been awarded a DOE contract (DE-0E0000675) to deploy a Cyber-intrusion Auto-response and Policy Management System (CAPMS) to provide real-time analysis of root cause, extent and consequence of an ongoing cyber intrusion using proactive security measures. CAPMS will be demonstrated in the SCE Advanced Technology labs at Westminster, CA. The DOE contract value is $6M with SCE & Duke Energy offering a cost share of $1.6M and $1.2M respectively.	7/16/2014	Yes	Grid Operation/Market Design	$ -	$ -	$ 1,703,952	$ 105,371	$ 1,809,323	N/A
2nd triennial (2015-2017)	SCE	**Integration of Big Data for Advanced Automated Customer Load Management**	Customer Focused Products and Services	This proposed project will demonstrate the use of an IEEE 2030.5 compliant Distributed Energy Resources Management System (DERMS) in order to: 1.Demonstrate the IEEE 2030.5 Common Smart Inverter Profile (CSIP) use cases (grouping, monitoring, controls, and registration) being developed by the IOUs, with results being used to inform development of the profile 2.Evaluate the use of the IEEE 2030.5 Distributed Energy Resources (DER) Function Set for effectiveness and completeness, with results being used to inform future revisions of the standard 3.Demonstrate a standardized interface between SCE's back office systems (e.g., the utility integration bus or UIB) and the DERMS.	11/17/2014	Yes	Demand-Side Management	$ -	$ -	$ 1,126,036	$ 20,202	$ 1,146,238	$ 5,113

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1st triennial (2012-2014)	SCE	**Cyber-Intrusion Auto-Response and Policy Management System (CAPMS)**	Cross-Cutting/Foundational Strategies & Technologies	DOE & Duke Energy Contributions: $4,486,430	Viasat; Duke Energy	N/A	N/A	Pay-for-Performance Contracts	SCE has no current patents or licensing agreements signed. Future Intellectual Property is to be determined.	Directed Awards Issued to the Following Vendor(s): @ Business Inc; Magnetic Instrumentation Inc; Saker Systems, LLC; World Wide Technology Inc; Zones, Inc.; Accuvant Inc; Electric Power Group, LLC; Schweitzer Engineering Labs Inc	N/A	N/A	N/A	N/A
2nd triennial (2015-2017)	SCE	**Integration of Big Data for Advanced Automated Customer Load Management**	Customer Focused Products and Services	TBD	TBD	TBD	TBD	Pay-for-Performance Contracts	SCE has no current patents or licensing agreements signed. Future Intellectual Property is to be determined.	Competitive	1	Kitu, Inc	TBD	TBD

Investment Program Period	Program Administrator	Project Name	Project Type	If interagency or sole source agreement, specify date of notification to the Joint Legislative Budget Committee (JLBC) was notified and date of JLBC authorization.	Does the recipient for this award identify as a California-based entity, small business, or businesses owned by women, minorities, or disabled veterans?	How the project leads to technological advancement or breakthroughs to overcome barriers to achieving the state's statutory energy goals	Applicable metrics
1st triennial (2012-2014)	SCE	**Cyber-Intrusion Auto-Response and Policy Management System (CAPMS)**	Cross-Cutting/Foundational Strategies & Technologies	N/A; Applicable to CEC only.	@ Business Inc: DBE Magnetic Instrumentation Inc: N/A Saker Systems, LLC: California-base entity; Small Business; DBE World Wide Technology Inc: DBE Zones, Inc.: DBE Accuvant Inc: California-based entity Electric Power Group, LLC: California-based entity Schweitzer Engineering Labs Inc: California-based entity	N/A; Applicable to CEC only.	5a. Outage number, frequency and duration reductions 7b. Increased use of cost-effective digital information and control technology to improve reliability, security, and efficiency of the electric grid (PU Code § 8360); 7l. Identification and lowering of unreasonable or unnecessary barriers to adoption of smart grid technologies, practices, and services (PU Code § 8360) 8b. Number of reports and fact sheets published online 8d. Number of information sharing forums held. 8f. Technology transfer 10a. Description or documentation of funding or contributions committed by others 10c. Dollar value of funding or contributions committed by others.
2nd triennial (2015-2017)	SCE	**Integration of Big Data for Advanced Automated Customer Load Management**	Customer Focused Products and Services	N/A; Applicable to CEC only.	Small Business	N/A; Applicable to CEC only.	Metrics plan TBD

Investment Program Period	Program Administrator	Project Name	Project Type	2018 Update	Coordination with CPUC Proceedings or Legislation
1st triennial (2012-2014)	SCE	**Cyber-Intrusion Auto-Response and Policy Management System (CAPMS)**	Cross-Cutting/Foundational Strategies & Technologies	The final project report is complete, was submitted with the 2015 Annual Report, and is available on SCE's public EPIC web site.	California Energy Solutions for the 21st Century (CES-21), D.14-03-029
2nd triennial (2015-2017)	SCE	**Integration of Big Data for Advanced Automated Customer Load Management**	Customer Focused Products and Services	In 2018 the Big Data project successfully concluded. The accomplishments included: • Completed interoperability testing with the Big Data IEEE 2030.5 Aggregator client • In coordination with CEC PON 14-303 project, deployed and commissioned residential smart inverters using the project IEEE 2030.5 communication systems • Supported the development of cyber security requirements and architectures for the back office deployment of IEEE 2030.5 applications and the use of internet based communications • Demonstrated Common Smart Inverter Profile (CSIP) use cases with aggregated behind the meter photovoltaic and energy storage systems The resulting benefits from the project included: • Revisions to the IEEE 2030.5 standard, Rule 21 regulatory documents including the IOU aggregator agreement and deadlines, and a new version (v2.1) of the CSIP document • Support for the production Distributed Energy Management System (DERMS) procurement, back office cybersecurity requirements and control systems' architecture • Determined deficiencies related to aggregated smart inverter commissioning and support processes including setting up and troubleshooting customer communications, and lack of clearly defined roles and responsibilities where multiple stakeholders are involved. • Discovered and reported conflicts between existing UL 1741-SA requirements and new Rule 21 Smart Inverter control capability requirements • Developed requirements for the procurement of aggregators and smart inverter systems for other SCE EPIC, DOE and DRP demonstration projects. The Final Report for the Integration of Big Data for Advanced Automated Customer Load Management is complete, is being submitted with the 2018 Annual Report, and will be posted on SCE's public EPIC web site.	

Investment Program Period	Program Administrator	Project Name	Project Type	A brief description of the project	Date of the award	Was this project awarded in the immediately prior calendar year?	Assignment to Value Chain	Encumbered Funding Amount ($)	Committed Funding Amount ($)	Funds Expended to date: Contract/Grant Amount ($)	Funds Expended to date: In house expenditures ($)	Funds Expended to date: Total Spent to date ($)	Administrative and overhead costs incurred for each project
2nd triennial (2015-2017)	SCE	**Advanced Grid Capabilities Using Smart Meter Data**	Grid Modernization and Optimization	This project will examine the possibility of establishing the Phasing information for distribution circuits, by examining the voltage signature at the meter and transformer level, and by leveraging the connectivity model of the circuits. This project will also examine the possibility of establishing transformer to meter connectivity based on the voltage signature at the meter and at the transformer level.	11/17/2014	Yes	Distribution	$ -	$ -	$ 10,775	$ 196,313	$ 207,088	$ 6,871
2nd triennial (2015-2017)	SCE	**Proactive Storm Impact Analysis Demonstration**	Grid Modernization and Optimization	This project will demonstrate proactive storm analysis techniques prior to its arrival and estimate its potential impact on utility operations. In this project, we will investigate some technologies that can model a developing storm and its potential movement through the utility service territory based on weather projections. This information and model will then be integrated with the Geographic Information System (GIS) electrical connectivity model, Distribution Management System (DMS), and Outage Management System (OMS) functionalities, along with historical storm data to predict the potential impact on the service to customers. In addition, this project will demonstration the integration of near real time meter voltage data with the GIS network to develop a simulated circuit model that can be effectively utilized fo rstorm management an dfield crew deployment.	11/17/2014	Yes	Distribution	$ -	$ -	$ 1,075,169	$ 129,815	$ 1,204,984	$ 12,464
2nd triennial (2015-2017)	SCE	**Next-Generation Distribution Equipment & Automation - Phase 2**	Grid Modernization and Optimization	This project will leverage lessons learned from the Next Generation Distribution Automation – Phase 1 project performed in the first EPIC triennial investment plan period. This project will focus on integrating advanced control systems, modern wireless communication systems, and the latest breakthroughs in distribution equipment and sensing technology to develop a complete system design that would be a standard for distribution automation and advanced distribution equipment	11/16/2015	Yes	Distribution	$ 89,780	$ 2,088,505	$ 4,029,043	$ 666,932	$ 4,695,975	$ 30,067
2nd triennial (2015-2017)	SCE	**System Intelligence and Situational Awareness Capabilities**	Grid Modernization and Optimization	This project will demonstrate system intelligence and situation awareness capabilities such as high impedance fault detection, intelligent alarming, predictive maintenance, and automated testing. This will be accomplished by integrating intelligent algorithms and advanced applications with the latest substation automation technologies, next generation control systems, latest breakthrough in substation equipment, sensing technology, and communications assisted protection schemes, This system will leverage the IEC 61850 Automation Standard and will include cost saving technology such as process bus, peer to peer communications, and automated engineering and testing technology. This project will also inform complementary efforts at SCE aimed at meeting security and NERC CIP compliance requirements	11/16/2015	No	Distribution	$ 31,209	$ 1,028,666	$ 1,482,184	$ 101,656	$ 1,583,840	$ 17,269

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2nd triennial (2015-2017)	SCE	**Advanced Grid Capabilities Using Smart Meter Data**	Grid Modernization and Optimization	TBD	TBD	TBD	TBD	Pay-for-Performance Contracts	SCE has no current patents or licensing agreements signed. Future Intellectual Property is to be determined.	TBD	TBD	TBD	N/A - This technology is very new	There are almost no vendors offering technologies in this area
2nd triennial (2015-2017)	SCE	**Proactive Storm Impact Analysis Demonstration**	Grid Modernization and Optimization	N/A	N/A	N/A	N/A	Pay-for-Performance Contracts	SCE has no current patents or licensing agreements signed. Future Intellectual Property is to be determined.	Competitive	9	IBM, First Quartile Consulting	TBD	TBD
2nd triennial (2015-2017)	SCE	**Next-Generation Distribution Equipment & Automation - Phase 2**	Grid Modernization and Optimization	TBD	TBD	TBD	TBD	Pay-for-Performance Contracts	SCE has no current patents or licensing agreements signed. Future Intellectual Property is to be determined.	Competitive Bid Directed Awards Issued to the Following Vendor(s): Athena Power, Inc.; G&W Electric Company; Southwest Research Institute	4	Cleaveland Price Inc.; Schneider Electric; Sentient Energy, Inc.; Wesco Distribution Inc.	Cleaveland Price Inc.; Schneider Electric; Sentient Energy, Inc.; Wesco Distribution Inc.	Multiple prototypes were required for testing purposes
2nd triennial (2015-2017)	SCE	**System Intelligence and Situational Awareness Capabilities**	Grid Modernization and Optimization	TBD	TBD	TBD	TBD	Pay-for-Performance Contracts	SCE has no current patents or licensing agreements signed. Future Intellectual Property is to be determined.	Competitive Bid Directed Awards Issued to the Following Vendor(s): GENERAL NETWORKS, TESCO AUTOMATION LTD, MORRIS & WILLNER PARTNERS,	N/A	N/A	N/A	N/A

Investment Program Period	Program Administrator	Project Name	Project Type	If interagency or sole source agreement, specify date of notification to the Joint Legislative Budget Committee (JLBC) was notified and date of JLBC authorization.	Does the recipient for this award identify as a California-based entity, small business, or businesses owned by women, minorities, or disabled veterans?	How the project leads to technological advancement or breakthroughs to overcome barriers to achieving the state's statutory energy goals	Applicable metrics
2nd triennial (2015-2017)	SCE	**Advanced Grid Capabilities Using Smart Meter Data**	Grid Modernization and Optimization	N/A; Applicable to CEC only.	TBD	N/A; Applicable to CEC only.	3a. Maintain / Reduce operations and maintenance costs 7b. Increased use of cost-effective digital information and control technology to improve reliability, security, and efficiency of the electric grid (PU Code § 8360) 8d. Number of information sharing forums held 8f. Technology transfer
2nd triennial (2015-2017)	SCE	**Proactive Storm Impact Analysis Demonstration**	Grid Modernization and Optimization	N/A; Applicable to CEC only.	First Quartile: Small Business	N/A; Applicable to CEC only.	2a. Hours worked in California and money spent in California for each project 3a. Maintain / Reduce operations and maintenance costs 3b. Maintain / Reduce capital costs 5a. Outage number, frequency and duration reductions 5c. Forecast accuracy improvement 5d. Public safety improvement and hazard exposure reduction 8f. Technology transfer 9d. Successful project outcomes ready for use in California IOU grid (Path to market) 9e. Technologies available for sale in the market place (when known)
2nd triennial (2015-2017)	SCE	**Next-Generation Distribution Equipment & Automation - Phase 2**	Grid Modernization and Optimization	N/A; Applicable to CEC only.	Sentient Energy, Inc.: California-based entity Wesco Distribution Inc.: California-based entity; Business owned by women, minorities, or disabled veterans	N/A; Applicable to CEC only.	3a. Maintain/reduce operations and maintenance costs 3e. Non-energy economic benefits 5a. Outage number, frequency and duration reductions 5c. Forecast accuracy improvement 5d. Public safety improvement and hazard exposure reduction 5i. Increase in the number of nodes in the power system at monitoring points 7b. Increased use of cost-effective digital information and control technology to improve reliability, security, and efficiency of the electric grid (PU Code § 8360) 7c. Dynamic optimization of grid operations and resources, including appropriate consideration for asset management and utilization of related grid operations and resources, with cost-effective full cyber security (PU Code § 8360) 7f. Deployment of cost-effective smart technologies, including real time, automated, interactive technologies that optimize the physical operation of appliances and consumer devices for metering, communication concerning grid operations and status, and distribution automation (PU Code § 8360) 7k. Develop standards for communication and interoperability of appliances and equipment connected to the electric grid, including the infrastructure serving the grid (PU Code § 8360)
2nd triennial (2015-2017)	SCE	**System Intelligence and Situational Awareness Capabilities**	Grid Modernization and Optimization	N/A; Applicable to CEC only.	GENERAL NETWORKS: California-based entity MORRIS & WILLNER PARTNERS: California-based entity	N/A; Applicable to CEC only.	2a. Hours worked in California and money spent in California for each project 3a. Maintain / Reduce operations and maintenance costs 3b. Maintain / Reduce capital costs 3c. Reduction in electrical losses in the transmission and distribution system 3f. Improvements in system operation efficiencies stemming from increased utility dispatchability of customer demand side management 5a. Outage number, frequency and duration reductions 5e. Utility worker safety improvement and hazard exposure reduction 7b. Increased use of cost-effective digital information and control technology to improve reliability, security, and efficiency of the electric grid (PU Code § 8360); 8e. Stakeholders attendance at workshops 8f. Technology transfer

Investment Program Period	Program Administrator	Project Name	Project Type	2018 Update	Coordination with CPUC Proceedings or Legislation
2nd triennial (2015-2017)	SCE	**Advanced Grid Capabilities Using Smart Meter Data**	Grid Modernization and Optimization	The final project report is complete, was submitted with the 2017 Annual Report, and is available on SCE's public EPIC web site.	
2nd triennial (2015-2017)	SCE	**Proactive Storm Impact Analysis Demonstration**	Grid Modernization and Optimization	The EPIC II Final Report for the Proactive Storm Impact Analysis Demonstration Project is complete, is being submitted with the 2018 Annual Report, and will be posted on SCE's public EPIC web site.	Distribution Resources Plan, R.14-08-013; A.15-07-003 Integrated Demand-side Resource Program, R.14-10-003
2nd triennial (2015-2017)	SCE	**Next-Generation Distribution Equipment & Automation - Phase 2**	Grid Modernization and Optimization	In 2018, the project team accomplished the following: **Underground Remote Fault Indicator** – SCE conducted field demonstrations of underground remote fault indicators with capabilities to be installed without an outage, submersible, integrated radio, power harvesting, bi-directional power flow detection, real-time current monitoring. 50 UG RFIs for the first vendor have been installed for a field demonstration ending in 2019. Completed lab testing of UG RFI for a second vendor and several units will be installed for field evaluation in 2019. **Long Beach Secondary Network Situation Awareness**- Complete the development & lab demonstration phase for the LBNW Situation Awareness Project. The system demonstration use of real-time data together with load flow simulation to provide system operators with real-time situational awareness and contingency planning capability. SCE will be performing a field evaluation over the next six months in 2019 prior to transitioning to the production environment. **High Impedance Fault Detection** - complete energized testing at SCE's Equipment Demonstration & Evaluation (12kV) Facility (EDEF) for High Impedance Fault Detection using Spread Spectrum Time Domain Reflectometry Technology. Field demonstration on several distribution circuits will be performed in 2019. **Remote Integrated Switch** – Complete the development of the 2.5, 2.5 extended, 3.5, and 3.5 extended RIS circuit scheme and on track to implement additional RIS automation schemes at Johanna Substation in 2019. **Real-time Equipment Health Diagnostic** – complete evaluations of two vendors through energized testing at SCE's Equipment Demonstration & Evaluation (12kV) Facility (EDEF). This project demonstrate technologies that can monitor and assess energized equipment (cable, splices, transformers, switches etc.) and indicate remaining life or existing condition. If their technology meets SCE requiremetns, one vendor will be chosen to perform field demonstration in 2019 on several circuits.	Distribution Resources Plan, R.14-08-013; A.15-07-003 Integrated Demand-side Resource Program, R.14-10-003
2nd triennial (2015-2017)	SCE	**System Intelligence and Situational Awareness Capabilities**	Grid Modernization and Optimization	2018 Achievements Process Bus lab demonstration: • Process Bus Evaluation Final report complete • Process Bus Fiber Optics CT Demonstration started project planning • Process Bus Fiber Optics CT Demonstration received SSRT approval • Process Bus Fiber Optics CT Demonstration completed Engineering Design Substation Testing Tools: DTM (Distributed Test Manager) • Successfully created DTM workspaces using SCE's Substation Engineering Modeling Tool (SEMT) standard generated files to simulate an array of IEC61850 devices – SEMT files are primarily used for HMI generation and can now be used for DTM test beds. • Within these workspaces we successfully tested the IEC 61850 communication capabilities with our existing tools and software - Proved interoperability with the SA-3 HMI. • Used DTM to act as a server in a proof-of-concept test between AT's QA network and the outside eDNA server (test environment). • Working with the vendor we facilitated the testing of Modbus protocol communication between the DTM software and the physical PLC located in Fenwick Labs. • Proved DTM can run multiple automated scripts for testing of the SA-3 HMI and PLC schemes without the need of any physical relay or IED – the script testing proves to be reliable and consistent throughout our various runs.	

Investment Program Period	Program Administrator	Project Name	Project Type	A brief description of the project	Date of the award	Was this project awarded in the immediately prior calendar year?	Assignment to Value Chain	Encumbered Funding Amount ($)	Committed Funding Amount ($)	Funds Expended to date: Contract/Grant Amount ($)	Funds Expended to date: In house expenditures ($)	Funds Expended to date: Total Spent to date ($)	Administrative and overhead costs incurred for each project
2nd triennial (2015-2017)	SCE	**Regulatory Mandates: Submetering Enablement Demonstration - Phase 2**	Customer Focused Products and Services	This project expands on the submetering project from the first EPIC triennial investment plan cycle to demonstrate plug-in electric vehicle (PEV) submetering at multi-dwelling and commercial facilities. Specifically, the project will leverage 3rd party metering to conduct subtractive billing for various sites including those with multiple customers of record	11/17/2014	Yes	Demand-Side Management	$ -	$ -	$ 1,061,771	$ 127,832	$ 1,189,603	$ 8,122
2nd triennial (2015-2017)	SCE	Bulk System Restoration Under High Renewables Penetration	Renewables/DER Resource Integration	The Bulk System Restoration under High Renewable Penetration Project will evaluate system restoration plans following a blackout event under high penetration of wind and solar generation resources. Typically the entire restoration plan consists of three main stages; Black Start, System Stabilization, and load pick-up. The Project will be divided into two phases: * Phase I of the project will address the feasibility of new approaches to system restoration by reviewing the existing system restoration plans and it's suitability for higher penetration of renewable generation. It will include a suitable RTDS Bulk Power system to be used in the first stage of system restoration, black start and it will also include the modeling of wind and solar renewable resources. * Phase II of the project will focus on on-line evaluation of restoration plans using scenarios created using (RTDS) with hardware in the loop such as generation, transformer and transmission line protective relays. The RTDS is a well-known tool to assess and evaluate performance of protection and control equipment. This project intends to utilize the RTDS capabilities to evaluate and demonstrate system restoration strategies with variable renewable resources focusing on system stabilization and cold load pick-up. Furthermore alternate restoration scenarios will be investigated. After the restoration process is evaluated, tested, and demonstrated in the RTDS Lab environment, a recommendation will be provided to system operations and transmission planning for their inputs for further developing this approach into an actual operational tool.	11/17/2014	Yes	Transmission	$ -	$ -	$ 8,326	$ 33,867	$ 42,193	$ 4,355
2nd triennial (2015-2017)	SCE	Series Compensation for Load Flow Control	Renewables/DER Resource Integration	The intent of this project is to demonstrate and deploy the use of Thyristor Controlled Series Capacitors (TCSC) for load flow control on series compensated transmission lines. On SCE's 500 kV system in particular, several long transmission lines are series compensated using fixed capacitor segments that do not support active control of power flow. The existing fixed series capacitors use solid state devices as a protection method and are called Thyristor Protected Series Capacitors (TPSC)	11/16/2015	No	Transmission	$ -	$ -	$ 351,534	$ 15,810	$ 367,344	$ 2,548
2nd triennial (2015-2017)	SCE	**Versatile Plug-in Auxiliary Power System (VAPS)**	Grid Modernization and Optimization	This project demonstrates the electrification of transportation and vocational loads that previously used internal combustion engines powered by petroleum fuels in the SCE fleet. The VAPS system uses automotive grade lithium ion battery technology (Chevrolet Volt and Ford Focus EV) which is also used in notable stationary energy storage projects (Tehachapi 32 MWh Storage)	11/17/2014	Yes	Distribution	$ -	$ 3,028,364	$ 532,407	$ 82,933	$ 615,340	$ 5,638

Investment Program Period	Program Administrator	Project Name	Project Type	Leveraged Funds	Partners	Match Funding	Match Funding Split	Funding Mechanism	Intellectual Property	Identification of the method used to grant awards.	If competitively selected, provide the number of bidders passing the initial pass/fail screening for project	If competitively selected, provide the name of selected bidder.	If competitively selected, provide the rank of the selected bidder in the selection process.	If competitively selected, explain why the bidder was not the highest scoring bidder, explain why a lower scoring bidder was selected.
2nd triennial (2015-2017)	SCE	**Regulatory Mandates: Submetering Enablement Demonstration - Phase 2**	Customer Focused Products and Services	TBD	TBD	TBD	TBD	Pay-for-Performance Contracts	SCE has no current patents or licensing agreements signed. Future Intellectual Property is to be determined.	TBD	TBD	TBD	TBD	TBD
2nd triennial (2015-2017)	SCE	Bulk System Restoration Under High Renewables Penetration	Renewables/DER Resource Integration	TBD	TBD	TBD	TBD	Pay-for-Performance Contracts	SCE has no current patents or licensing agreements signed. Future Intellectual Property is to be determined.	Non-Competitive Nayak Corporation Inc	NA	NA	NA	NA
2nd triennial (2015-2017)	SCE	Series Compensation for Load Flow Control	Renewables/DER Resource Integration	TBD	TBD	TBD	TBD	Pay-for-Performance Contracts	SCE has no current patents or licensing agreements signed. Future Intellectual Property is to be determined.	TBD	TBD	TBD	TBD	TBD
2nd triennial (2015-2017)	SCE	**Versatile Plug-in Auxiliary Power System (VAPS)**	Grid Modernization and Optimization	N/A	N/A	N/A	N/A	Pay-for-Performance Contracts	SCE has no current patents or licensing agreements signed. Future Intellectual Property is to be determined.	Competitive Bid Directed Awards Issued to the Following Vendor(s): FleetCarma	1	Altec Industries Inc.	1	N/A

Investment Program Period	Program Administrator	Project Name	Project Type	If interagency or sole source agreement, specify date of notification to the Joint Legislative Budget Committee (JLBC) was notified and date of JLBC authorization.	Does the recipient for this award identify as a California-based entity, small business, or businesses owned by women, minorities, or disabled veterans?	How the project leads to technological advancement or breakthroughs to overcome barriers to achieving the state's statutory energy goals	Applicable metrics
2nd triennial (2015-2017)	SCE	**Regulatory Mandates: Submetering Enablement Demonstration - Phase 2**	Customer Focused Products and Services	N/A; Applicable to CEC only.	TBD	N/A; Applicable to CEC only.	1d. Number and percentage of customers on time variant or dynamic pricing tariffs 1h. Customer bill savings (dollars saved) 3e. Non-energy economic benefits 4a. GHG emissions reductions (MMTCO2e) 6a. The 3rd Party Evaluator, Nexant, in collaboration with the Energy Division and IOUs, will develop a set of metrics for Phase 2 to be included in the final report. 7h. Deployment and integration of cost-effective advanced electricity storage and peak-shaving technologies, including plug-in electric and hybrid electric vehicles, and thermal-storage air-conditioning (PU Code § 8360) 7j. Provide consumers with timely information and control options (PU Code § 8360): 7k. Develop standards for communication and interoperability of appliances and equipment connected to the electric grid, including the infrastructure serving the grid (PU Code § 8360) 7l. Identification and lowering of unreasonable or unnecessary barriers to adoption of smart grid technologies, practices, and services (PU Code § 8360) 8e. Stakeholders attendance at workshops 8f. Technology transfer 9c. EPIC project results referenced in regulatory proceedings and policy reports 9d. Successful project outcomes ready for use in California IOU grid (Path to market) 9e. Technologies available for sale in the market place (when known)
2nd triennial (2015-2017)	SCE	Bulk System Restoration Under High Renewables Penetration	Renewables/DER Resource Integration	N/A; Applicable to CEC only.	Nayak Corporation - NA	N/A; Applicable to CEC only.	Metrics plan TBD
2nd triennial (2015-2017)	SCE	Series Compensation for Load Flow Control	Renewables/DER Resource Integration	N/A; Applicable to CEC only.	TBD	N/A; Applicable to CEC only.	Metrics plan TBD
2nd triennial (2015-2017)	SCE	**Versatile Plug-in Auxiliary Power System (VAPS)**	Grid Modernization and Optimization	N/A; Applicable to CEC only.	No	N/A; Applicable to CEC only.	3a. Maintain/Reduce operations and maintenance costs 3e. Non-energy economic benefits 4a. GHG emissions reductions (MMTCO2e) 4b. Criteria air pollution emission reductions 5d. Public safety improvement and hazard exposure reduction 5e. Utility worker safety improvement and hazard exposure reduction 7h. Deployment and integration of cost-effective advanced electricity storage and peak-shaving technologies, including plug-in electric and hybrid electric vehicles, and thermal-storage air-conditioning (PU Code § 8360) 8f. Technology transfer

Investment Program Period	Program Administrator	Project Name	Project Type	2018 Update	Coordination with CPUC Proceedings or Legislation
2nd triennial (2015-2017)	SCE	**Regulatory Mandates: Submetering Enablement Demonstration - Phase 2**	Customer Focused Products and Services	1) Completed Phase 2 Submetering Pilot on April 30, 2018 2) 151 submeters enrolled , 33 were NEM accounts 3) 144 completed maximum of 12 billing cycles; seven customers terminated early 4) Nexant final report submitted to ED on December 4, 2018 Nexant Report needs to be approved by the CPUC, prior to writing the project final report	
2nd triennial (2015-2017)	SCE	Bulk System Restoration Under High Renewables Penetration	Renewables/DER Resource Integration	In Dec. 2016, this project was cancelled by SCE Senior Leadership as a result of internal organizational change that focused the organization on Distribution System strategic objectives. This was reported in the 2016 EPIC Annual Report.	Process Bus lab demonstration:
2nd triennial (2015-2017)	SCE	Series Compensation for Load Flow Control	Renewables/DER Resource Integration	In 2016, it was determined that the deliverables for this project could easily be done via another project that was already in flight. So a determination was made to cancel this project. This was reported in the 2016 Annual Report.	Intelligent Alarms processing
2nd triennial (2015-2017)	SCE	**Versatile Plug-in Auxiliary Power System (VAPS)**	Grid Modernization and Optimization	2018 Accomplishments **1. Class 8 EV Project (Heavy Duty Truck):** Project was cancelled in 2017 **2. Class 5 PHEV Project (Medium Duty Truck):** Testing completed on upfitted vehicle October 2018 with findings captured. Final report in process with plan for completion in early 2019. **3. Light Duty PHEV Truck Project:** Vehicle received from Efficient Drivertrain Inc. (EDI) with the completed upfit late February 2018 and testing began. Performance testing was impacted by numerous operational and reliability issues. EDI is continuing to troubleshoot remaining issues related to the upfit to allow for performance testing to be completed in 2019. **4. Large VAPS Project:** The trailer mounted portable energy system (MobiGen) was received mid-2018 and lab testing began. Battery tests have been coordinated with Freewire and will continue into 2019. **5. Medium VAPS Project:** Envoltz underground electric cable puller report in process with plan to be completed Q1 2019. The Envoltz overhead electric cable puller is planned to be received in Q1 2019 with functionality testing to be performed immediately after. **6. Small VAPS Project:** JEMS 4A base system was removed from the vehicle in April 2018. Monitoring data collected on 22 Altec JEMS trucks through October 2018. Plan to update reports with findings in 2019.	Substation Testing Tools

Investment Program Period	Program Administrator	Project Name	Project Type	A brief description of the project	Date of the award	Was this project awarded in the immediately prior calendar year?	Assignment to Value Chain	Encumbered Funding Amount ($)	Committed Funding Amount ($)	Funds Expended to date: Contract/Grant Amount ($)	Funds Expended to date: In house expenditures ($)	Funds Expended to date: Total Spent to date ($)	Administrative and overhead costs incurred for each project
2nd triennial (2015-2017)	SCE	**Dynamic Power Conditioner**	Grid Modernization and Optimization	This project will demonstrate the use of the latest advances in power electronics and energy storage devices and controls to provide dynamic phase balancing as well as providing voltage control, harmonics cancellation, sag mitigation, and power factor control while providing steady state operations such as injection and absorption of real and reactive power under scheduled duty cycles or external triggers. This project aims to mitigate the cause of high neutral currents and provide several power quality benefits through the use of actively controlled real and reactive power injection and absorption	11/17/2014	Yes	Distribution	$ 415,200	$ 2,000,125	$ 310,800	$ 24,322	$ 335,122	$ 1,197
2nd triennial (2015-2017)	SCE	Optimized Control of Multiple Storage Systems	Renewables/DER Resource Integration	This project aims to demonstrate the ability of multiple energy storage controllers to integrate with SCE's Distribution Management System (DMS) and other decision making engines to realize optimum dispatch of real and reactive power based on grid needs	11/17/2014	Yes	Distribution	$ -	$ -	$ 138,289	$ 2,193	$ 140,482	$ -
2nd triennial (2015-2017)	SCE	**DC Fast Charging Demonstration**	Customer Focused Products and Services	The goal of this project is to demonstrate public DC fast charging stations at SCE facilities near freeways in optimal locations to benefit electric vehicle miles traveled (eVMT) by plug-in electric vehicles (PEVs) while implementing smart grid equipment and techniques to minimize system impact. The Transportation Electrification (TE) Organization is actively pursuing several strategic objectives, including optimizing TE fueling from the grid to improve asset utilization. Deploying a limited number of fast charging stations at selected SCE facilities that are already equipped to deliver power at this level (without additional infrastructure upgrade) will support this objective. The project will leverage SCE's vast service territory and its facilities to help PEV reach destinations that would otherwise be out-of-range	11/16/2015	No	Demand-Side Management	$ -	$ -	$ 11,637	$ 10,308	$ 21,945	$ 1,172
2nd triennial (2015-2017)	SCE	**Integrated Grid Project II (filed as Regional Grid Optimization Demo)**	Cross-Cutting/Foundational Strategies & Technologies	The project will deploy, field test and measure innovative technologies that emerge from the design phase of the Integrated Grid Project (IGP) that address the impacts of DER (Distributed Energy Resources) owned by both 3rd parties and the utility. The objectives are to demonstrate the next generation grid infrastructure that manages, operates, and optimizes the distributed energy resources on SCE's system. The results will help determine the controls and protocols needed to manage DER, how to optimally manage an integrated distribution system to provide safe, reliable, affordable service and also how to validate locational value of DERs and understand impacts to future utility investments.	4/21/2016	No	Grid Operation/Market Design	$ 44,252	$ 5,525,000	$ 11,522,260	$ 761,126	$ 12,283,386	$ -

Projects	1st triennial (2012-2014)	28,475	2,488,282	30,114,188	5,054,528	35,168,716
Projects	2nd triennial (2015-2017)	580,441	13,670,660	21,660,231	2,173,309	23,833,540
EPIC I Admin	1st triennial (2012-2014)					1,104,737
EPIC II Admin	2nd triennial (2015-2017)					2,708,479
Total	1st triennial (2012-2014)					36,273,453
Total	2nd triennial (2015-2017)					26,542,019

Investment Program Period	Program Administrator	Project Name	Project Type	Leveraged Funds	Partners	Match Funding	Match Funding Split	Funding Mechanism	Intellectual Property	Identification of the method used to grant awards.	If competitively selected, provide the number of bidders passing the initial pass/fail screening for project	If competitively selected, provide the name of selected bidder.	If competitively selected, provide the rank of the selected bidder in the selection process.	If competitively selected, explain why the bidder was not the highest scoring bidder, explain why a lower scoring bidder was selected.
2nd triennial (2015-2017)	SCE	**Dynamic Power Conditioner**	Grid Modernization and Optimization	TBD	TBD	TBD	TBD	Pay-for-Performance Contracts	SCE has no current patents or licensing agreements signed. Future Intellectual Property is to be determined.	TBD	TBD	TBD	TBD	TBD
2nd triennial (2015-2017)	SCE	Optimized Control of Multiple Storage Systems	Renewables/DER Resource Integration	TBD	TBD	TBD	TBD	Pay-for-Performance Contracts	SCE has no current patents or licensing agreements signed. Future Intellectual Property is to be determined.	TBD	TBD	TBD	TBD	TBD
2nd triennial (2015-2017)	SCE	**DC Fast Charging Demonstration**	Customer Focused Products and Services	TBD	TBD	TBD	TBD	Pay-for-Performance Contracts	SCE has no current patents or licensing agreements signed. Future Intellectual Property is to be determined.	TBD	TBD	TBD	TBD	TBD
2nd triennial (2015-2017)	SCE	**Integrated Grid Project II (filed as Regional Grid Optimization Demo)**	Cross-Cutting/Foundational Strategies & Technologies	N/A	N/A	N/A	N/A	Pay-for-Performance Contracts	SCE has no current patents or licensing agreements signed. Future Intellectual Property is to be determined.	Competitive Bid (Request for Proposals): Enbala Power Networks; Integral Analytics, LLC; Directed Awards Issued to the Following Vendor(s): DigSilent Americas LLC: Morris & Willner Partners; GE Management Services, LLC; World Wide Technology, Inc; Zones, Inc	9	Integral Analytics Enbala	1st 2nd	Does not apply; Highest scoring bidders were selected for award.

Investment Program Period	Program Administrator	Project Name	Project Type	If interagency or sole source agreement, specify date of notification to the Joint Legislative Budget Committee (JLBC) was notified and date of JLBC authorization.	Does the recipient for this award identify as a California-based entity, small business, or businesses owned by women, minorities, or disabled veterans?	How the project leads to technological advancement or breakthroughs to overcome barriers to achieving the state's statutory energy goals	Applicable metrics
2nd triennial (2015-2017)	SCE	**Dynamic Power Conditioner**	Grid Modernization and Optimization	N/A; Applicable to CEC only.	TBD	N/A; Applicable to CEC only.	Metrics plan TBD
2nd triennial (2015-2017)	SCE	Optimized Control of Multiple Storage Systems	Renewables/DER Resource Integration	N/A; Applicable to CEC only.	TBD	N/A; Applicable to CEC only.	Metrics plan TBD
2nd triennial (2015-2017)	SCE	**DC Fast Charging Demonstration**	Customer Focused Products and Services	N/A; Applicable to CEC only.	TBD	N/A; Applicable to CEC only.	3a. Maintain/Reduce operations and maintenance costs 5b. Electric system power flow congestion reduction 5h. Reduction in system harmonics 8d. Number of information sharing forums held 8e. Stakeholders attendance at workshops 8f. Technology transfer
2nd triennial (2015-2017)	SCE	**Integrated Grid Project II (filed as Regional Grid Optimization Demo)**	Cross-Cutting/Foundational Strategies & Technologies	N/A; Applicable to CEC only.	Morris & Willner Partners: Business owned my women, minorities or disabled veterans. World Wide Technology, Inc: Business owned my women, minorities or disabled veterans. Zones, Inc: Business owned my women, minorities or disabled veterans.	N/A; Applicable to CEC only.	1a. Number and total nameplate capacity of distributed generation facilities 1b. Total electricity deliveries from grid-connected distributed generation facilities 1c. Avoided procurement and generation costs 1d. Number and percentage of customers on time variant or dynamic pricing tariffs 1e. Peak load reduction (MW) from summer and winter programs 1f. Avoided customer energy use (kWh saved) 1g. Percentage of demand response enabled by automated demand response technology (e.g. Auto DR) 1h. Customer bill savings (dollars saved) 1i. Nameplate capacity (MW) of grid-connected energy storage 3a. Maintain / Reduce operations and maintenance costs 3b. Maintain / Reduce capital costs 3c. Reduction in electrical losses in the transmission and distribution system 3d. Number of operations of various existing equipment types (such as voltage regulation) before and after adoption of a new smart grid component, as an indicator of possible equipment life extensions from reduced wear and tear 3e. Non-energy economic benefits 3f. Improvements in system operation efficiencies stemming from increased utility dispatchability of customer demand side management 5a. Outage number, frequency and duration reductions 5b. Electric system power flow congestion reduction 5c. Forecast accuracy improvement 5f. Reduced flicker and other power quality differences 5i. Increase in the number of nodes in the power system at monitoring points 7b. Increased use of cost-effective digital information and control technology to improve reliability, security, and efficiency of the electric grid (PU Code § 8360); 7c. Dynamic optimization of grid operations and resources, including appropriate consideration for asset management and utilization of related grid operations and resources, with cost-effective full cyber security (PU Code § 8360); 7d. Deployment and integration of cost-effective distributed resources and generation, including renewable resources (PU Code § 8360); 7e. Development and incorporation of cost-effective demand response, demand-side resources, and energy-efficient resources (PU Code § 8360); 7f. Deployment of cost-effective smart technologies, including real time, automated, interactive technologies that optimize the physical operation of appliances and consumer devices for metering, communications concerning grid operations and

Investment Program Period	Program Administrator	Project Name	Project Type	2018 Update	Coordination with CPUC Proceedings or Legislation
2nd triennial (2015-2017)	SCE	**Dynamic Power Conditioner**	Grid Modernization and Optimization	In 2018, The DER Demonstrations Group partnered with Siemens Industry to complete the design of the Dynamic Power Conditioner. However, the inverter manufacturing that was originally scheduled to be completed in July 2018 was not finalized due to Siemens not being able to meet SCE's project specifications. The project was then suspended until other options were identified. With the assistance of Siemens, a new inverter vendor (EPC) was selected and will provide the inverter for the DPC. To assure that this inverter meets the needs of the SCE project, the project engineers conducted an EPC site visit on Nov 29 to inspect inverter and verify that it meets our specs and requirements. Based on the addition testing and validating of the new inverter, this projects schedule will move into 2019.	
2nd triennial (2015-2017)	SCE	Optimized Control of Multiple Storage Systems	Renewables/DER Resource Integration	In 2017, the goals of this project were found to overlap significantly with those of the EPIC II Regional Grid Optimization Demo Phase 2 project (otherwise known as Integrated Grid Project phase 2). This project was then cancelled and the proposed benefits will be realized through the Regional Grid Optimization Demo Phase 2 project.	
2nd triennial (2015-2017)	SCE	**DC Fast Charging Demonstration**	Customer Focused Products and Services	The EPIC II Final Report for the DC Fast Charging Demonstration Project is complete, is being submitted with the 2018 Annual Report, and will be posted on SCE's public EPIC web site.	
2nd triennial (2015-2017)	SCE	**Integrated Grid Project II (filed as Regional Grid Optimization Demo)**	Cross-Cutting/Foundational Strategies & Technologies	Accomplishements in 2018 include: 1. IGP Controllers 1a.Completed additional FAT testing in the AT Lab (April 2018) 1b. Completed phase out of BeagleBones and Replaced with FAN Radios for Pre-SAT testing in the QAS Environment (April 2018) 1c. Completed Hardware and Software transition from AT Lab to QAS Environment for SAT Testing (August 2018) 1c. (1) Completed SGS testing with FAN radio in AT Lab 1c. (2) Completed FAN radios integration into AT lab PCCs 1c. (3) Completed detailed Network Diagram for QAS 1c. (4) Completed integration of PowerFactory, Triangle MicroWorks, and CodeMeter in QAS 1c. (5) Completed integration of controllers with DMS (including completion of DMS screens) 1c. (6) Completed integration of controllers with Lab PCCs 1c. (7) Completed communication path of SGS Comms Hub with SGS Connect 1d. Began SAT Integration Testing (August 2018) 2. CEC SunSpec (2030.5) 2a. Completed FAT testing with controllers in AT Lab (January 2018) 2b. Completed Kitu Interop Testing (May 2018) 2c. Completed Cyber / Application Testing in AT Lab (September 2018) 2d. Completed Testing / Communication with field inverters from AT Lab (December 2018) 3. DOE NODES / NREL 3.a Completed HIL test evaluation and report (June 2018) 3.b Completed deliverable tasks for 4.8.1 (detailed testing, analysis, and reporting) (November 2018) 4. DOE Prosumer Grid ARPA-E 4.a Completed project and delivered final report (November 2018) 5. DOE NODES 5.a. Completed HIL test evaluation and report (June 2018) 6. Integrated Grid Analytics 6a. Completed numerous milestones regarding developing sample data types and developing requirements engineering tasks 7. Adaptive Protection System 7a. Completed Phase 1 (Model Accuracy) (June 2018)	

Appendix B

DC Fast Charging Final Project Report

DC Fast Charging
Final Project Report

Created by

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Disclaimer

Acknowledgments

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1 Executive Summary

Electric vehicle load growth is expected to increase rapidly to support California's ambitious climate change goals, and electric vehicles are targeted to make up a significant portion of Southern California Edison's (SCE's) served customer load. Currently SCE and other utilities do not have a comprehensive understanding for how DC (direct current) fast chargers impact the grid in terms of power quality. Also, there is no plan on how to best manage the high demand of these stations while assessing the most effective method to minimize the cost to operate the site from the utilities' perspective.

The project reviewed the impacts that DC fast chargers have on the electrical grid in terms of power quality and demand, then proposes that the data collected be used to perform an optimal power flow analysis to assess the most cost-effective solution to construct and manage these sites as they become larger and more powerful.

2 Project Summary

The purpose of this project is to study the impacts that DC (direct current) fast chargers have on the electrical grid. In addition, SCE provided high resolution demand usage data to evaluate how demand at these sites might be managed. This project started in its planning phase in 2016, data collection phase in 2017, and analysis and reporting phase in 2018. The major stakeholders involved in this project were SCE's Distribution Engineering and Power Quality organizations, and were informed of the findings, demand data and power quality data of the grid impact analysis.

Under the EPIC Investment Framework for Utilities shown in Figure 1, this project falls under the Grid Modernization and Optimization strategic initiative since it seeks to prepare for emerging technologies by understanding the grid impact of DC fast chargers on the utility system. If plug-in electric vehicles (PEVs) become very popular, there may be a demand to install large numbers of fast chargers. Because DC fast charging loads can require a high energy demand from the electrical distribution system this could pose a challenge for SCE and its ability to serve high customer loads in densely populated and rural areas where capacity can be limited. This project will collect high resolution demand data, to evaluate how DC fast charging sites may be managed for high demand, thus optimizing SCE's existing distribution system assets to reduce cost.

Figure 1, EPIC Investment Framework for Utilities

There are several key state policies that point to a future where more DC fast charging stations may be needed to support California's transportation electrification effort. The state's greenhouse gas (GHG) goals call for a 40 percent reduction in GHG emissions from 1990 levels by 2030 and an 80 percent reduction by 2050. Air quality goals include a 90 percent reduction in emissions of nitrogen oxides from 2010 levels in some of the state's most polluted areas by 2032. The transportation sector (including fuel refining) and fossil fuels used in space and water heating now produce almost three times as many GHG emissions as the electric sector and more than 80 percent of the air pollution in California. These goals have set the industry into motion as more auto manufacturers are producing PEVs for the mass-market. As battery technology improves, the medium and heavy-duty vehicle sector will become a key driver for increasing demand of DC fast charging to charge heavier and more powerful vehicles with larger batteries.

2.1 Problem Statement

The number of EVs in California is expected to grow to support California's ambitious GHG reduction goals. Electric vehicle load growth is expected to increase rapidly as a result and is targeted to make up a significant portion of SCE's served customer load, as shown in Figure 2. DC fast chargers are a significant challenge that the utility will eventually face due to the high demand they require to serve their customers. Currently, SCE does not have detailed incremental data on how DC fast chargers impact their grid in terms of power quality, and SCE does not have a plan for how to manage the high demand of these stations. This project will help to prepare SCE for the increased demand of DC fast charging stations by providing detailed data on how a fast charging station impacts the grid from a power quality and demand perspective. This data will then be used to evaluate how demand at these sites could be managed.

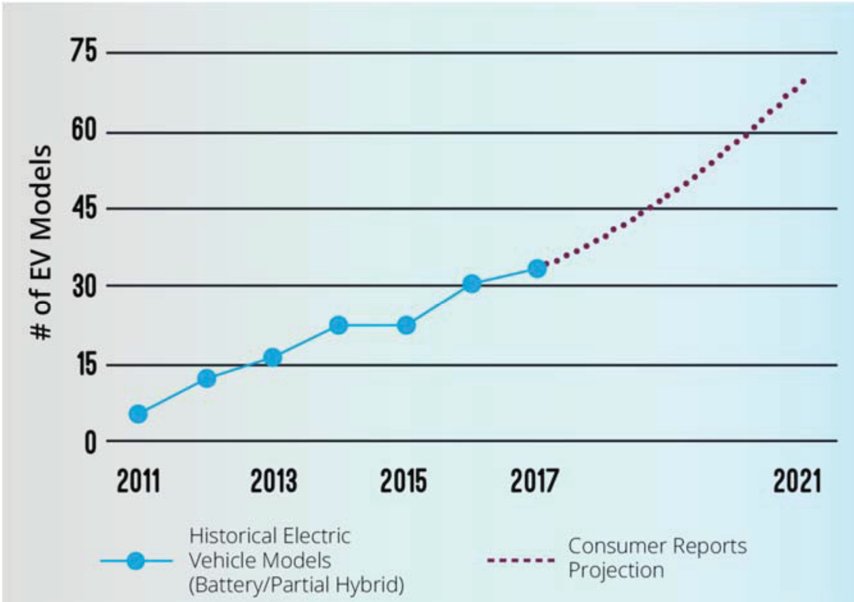

Figure 2 - Battery/Partial Hybrid Electric Vehicle Models (Sources: U.S. Department of Energy/Consumer Reports)

2.2 Project Scope

To assess the grid impact of DC fast chargers, power quality analyzers were installed at 13 DC fast charging stations across SCE's territory. These Power analyzers captured demand and power quality at each DC fast charging site at the interface point where the utility provides electrical service to the customer (generally the point where the utility billing meter is installed). Figure 3 shows an example installation where a power analyzer was installed at the customer's main point of service inside their switchgear.

SCE's distribution engineering group then provided circuit demand data for each DC fast charger site. This demand data was used to evaluate the demand impact each DC fast charger site had on its connected circuit. In addition, the data allowed us to assess the DC fast charger site's demand impact, impact to the planned loading limit (PLL) of the circuit.

To further understand how DC fast charging loads can be managed, SCE procured a DC fast charging station at their electric vehicle technical center. This DC fast charging station was used to evaluate the effectiveness of demand management techniques that were realized through analyzing the collected DC fast charger site data.

Note that for this report SCE is obligated to ensure that all customer data was kept confidential, this was done by anonymizing and aggregating data where appropriate to protect each customer's identity.

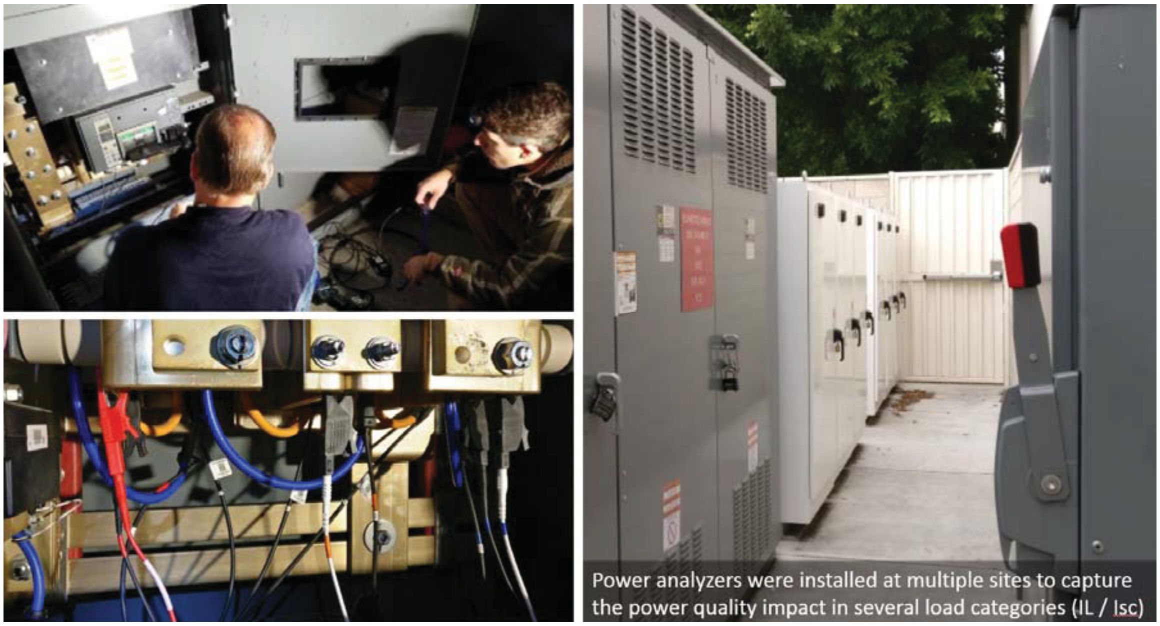

Figure 3 - Power Analyzer installation

2.3 Schedule

The project started in 2016, however data collection did not start until May 2017. This delay was caused in part due to cybersecurity concerns. The telemetry for this procured data solution took longer than expected to receive internal IT department approval, which occurred in March 2017.

Since most of SCE's efforts were focused toward procuring the power analyzer hardware, the procurement of the DC fast charger installation at SCE's electric vehicle technical center was installed and commissioned in April 2017.

In addition to installation issues, additional research was done to ensure that the power quality data collected, accurately represented the impact to the DC fast charger sites according to power quality industry standards. Through stakeholder recommendations from SCE's power quality group, additional training for IEEE 519-2014[1] (see section 3.5.1 for technical lessons learned) was needed to safely evaluate sites. Once training was completed, the final report was completed in December 2018. See Table 1 below for project schedule milestones.

[1] IEEE 519-2014 - IEEE Recommended Practice and Requirements for Harmonic Control in Electric Power Systems.

Milestones	Date Completed
Project Planning Complete	16-Jan
Project Kickoff Meeting	16-Feb
Hardware Procurement Complete - Power Analyzers & DC Fast Charger	17-Apr
Installation Planning of Power Analyzers Begins	17-May
Installation Planning of Power Analyzers Complete	18-Jan
DC Fast Charger Installation Complete	17-Jun
Data Collection & Analysis Complete	18-June
Final Report Complete	18-Dec

Table 1 - Milestone Schedule

3 Project Results

A grid impact assessment was performed on the DC Fast Chargers. The metrics for assessing the grid impact of the DC fast chargers was to identify whether sites are compliant with IEEE 519. In addition, the site demand was compared to circuit demand and aggregated to summarize the overall contribution to total circuit demand from the 13 evaluated sites. In addition to IEEE 519 compliance, we identified an overvoltage sensitivity and a lack of neutral-to-ground bonding issues with some of the evaluated chargers. SCE was able to work with the charger manufacturers to resolve these issues. In addition to the field evaluations, SCE performed a baseline power quality evaluation on the installed DC fast charger at its Electric Vehicle Technical Center in Pomona.

3.1.1 IEEE 519 Compliance

Compliance with IEEE 519 was evaluated by comparing the magnitude for harmonics 1 through 50, along with the total demand distortion, for each current phase. Note that IEEE 519 only provides recommended limits for up to the 50th harmonic. These magnitudes were compared with respect to the limit defined by the ratio between the maximum demand load current and the maximum short circuit current at the point of common coupling (PCC), as indicated in section 5.2 of the IEEE 519 standard. Also, the voltage total harmonic distortion was evaluated in accordance to the limits defined in section 5.1 of the standard. To conduct a fair comparison, sites were averaged based on the ratio between their maximum demand load current (I_L) and the maximum short circuit current (I_{SC}) at the PCC. This ratio is a comparison between the size of the customer's load and the amount of demand the grid is capable of supplying. The DC fast charging stations that were monitored fell into the following 3 categories for I_L / I_{SC}, which are:

- $50 < I_L / I_{SC} < 100$
- $100 < I_L / I_{SC} < 1000$
- $I_L / I_{SC} > 1000$

Voltage total harmonic distortion (vTHD) was also evaluated during the monitoring period for all sites, and none were found to be above the recommended 5 percent limit.

For confidentiality, the sites monitored, the exact demand current (IL), and the short-circuit duty current are all kept confidential as they are customer data.

Instead this comparison focuses on the results of what was monitored in this load category rather than the DC fast charger manufacturer. Also, all sites were averaged together, but the maximum and minimum results were also displayed for each harmonic to show the range of results recorded from the grid impact study.

3.1.1.1 Sites with 50 < I_L / I_{SC} < 100

The following figures show the I_L / I_{SC} averaged across all monitored sites where <u>50 < I_L / I_{SC} < 100</u>. All sites that were assessed in this category were IEEE 519 compliant and did not produce harmonic currents that would be harmful to neighboring customers. Compliance is validated by ensuring that the current for each harmonic as a percentage of I_L, and current total demand distortion (iTDD) were below their defined limits as shown in Figure 4 and Figure 5. No electrical anomalies were discovered during the 1 month evaluating period of these sites.

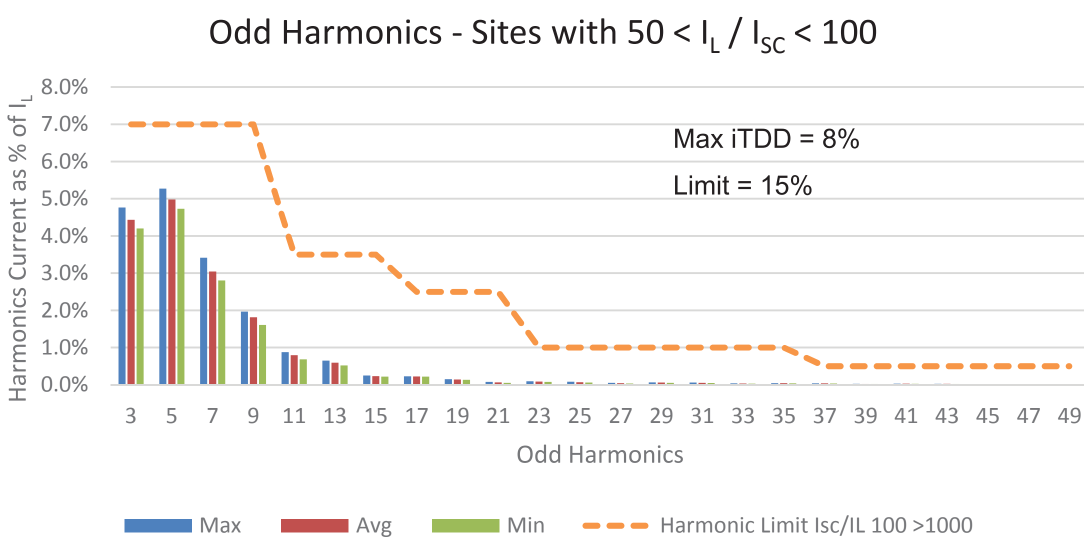

Figure 4 - Odd Harmonics for sites with I_L/I_{sc} 50 to 100

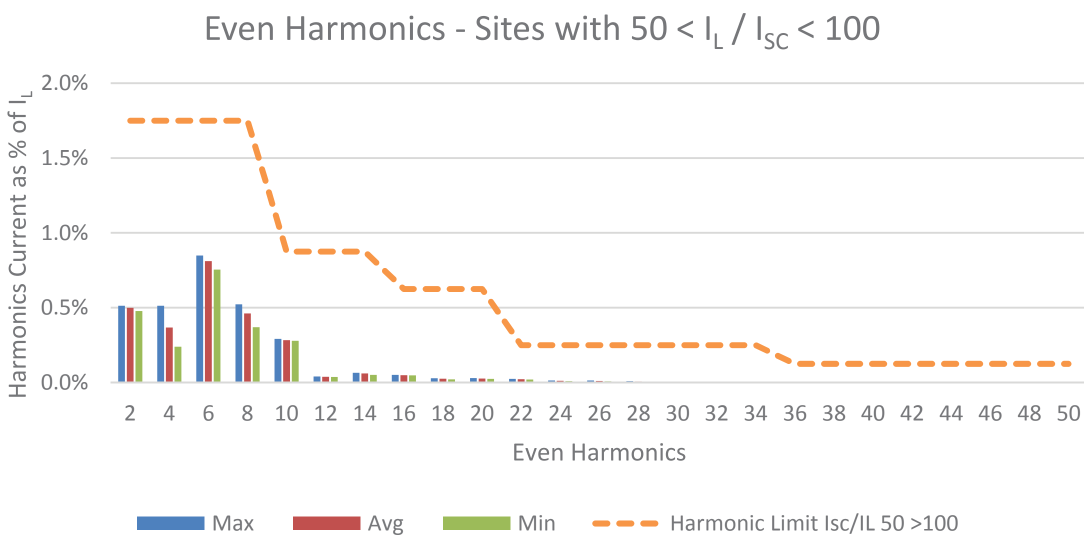

Figure 5 - Even Harmonics for sites with I_L/I_{sc} 50 to 100

Sites with 100 < I_L / I_{SC} < 1000

The following figures show the I_L / I_{SC} averaged across all monitored sites where 100 < I_L / I_{SC} < 1000. All sites that were assessed in this category were IEEE 519 compliant and did not produce harmonic currents that would be harmful to neighboring customers. Compliance is validated by ensuring that the current for each harmonic as a percentage of I_L, and current total demand distortion (iTDD) were below their defined limits as shown in Figure 6 and Figure 7. No electrical anomalies were discovered during the 1 month evaluating period of these sites.

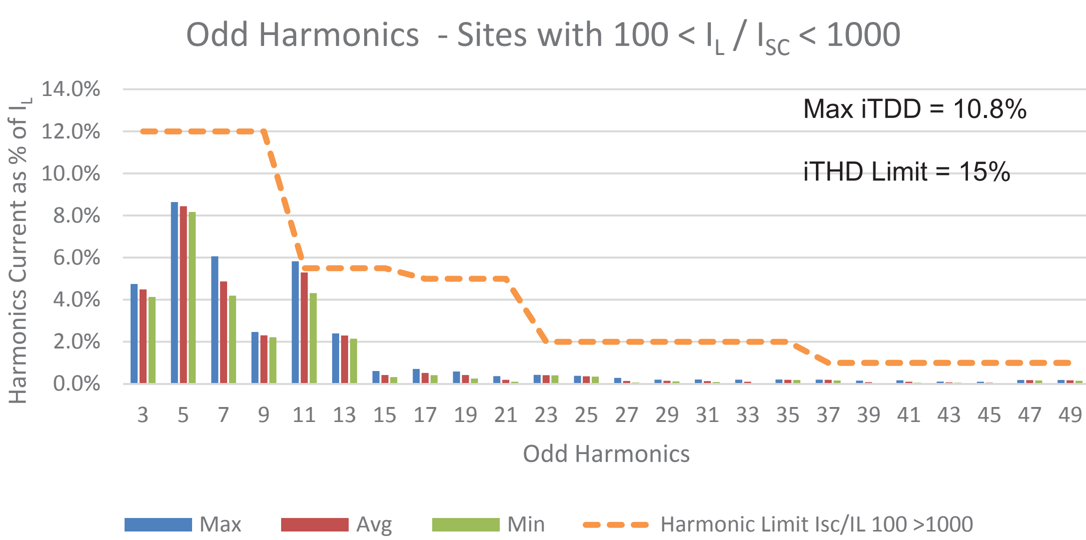

Figure 6 - Odd Harmonics for sites with 100 < I_L/I_{sc} < 1000

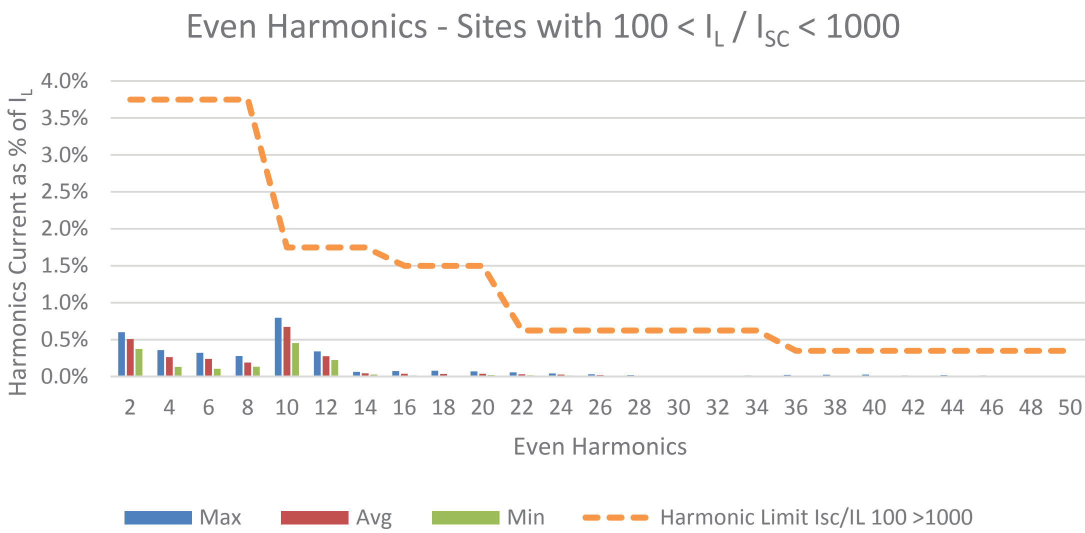

Figure 7 - Even Harmonics for sites with 100 < I_L/I_{sc} < 1000

Sites with I_L / I_{SC} > 1000

The following figures show the I_L / I_{SC} averaged across all monitored sites where I_L / I_{SC} > 1000. All sites that were assessed in this category were IEEE 519 compliant and did not produce harmonic currents that would be harmful to neighboring customers. Compliance is validated by ensuring that the current for each harmonic as a percentage of I_L, and current total demand distortion (iTDD) were below their defined limits as shown in Figure 8 and Figure 9. vTHD remained below the recommended limit of 5% throughout the monitoring period. No electrical anomalies were discovered during the 1 month evaluating period of these sites.

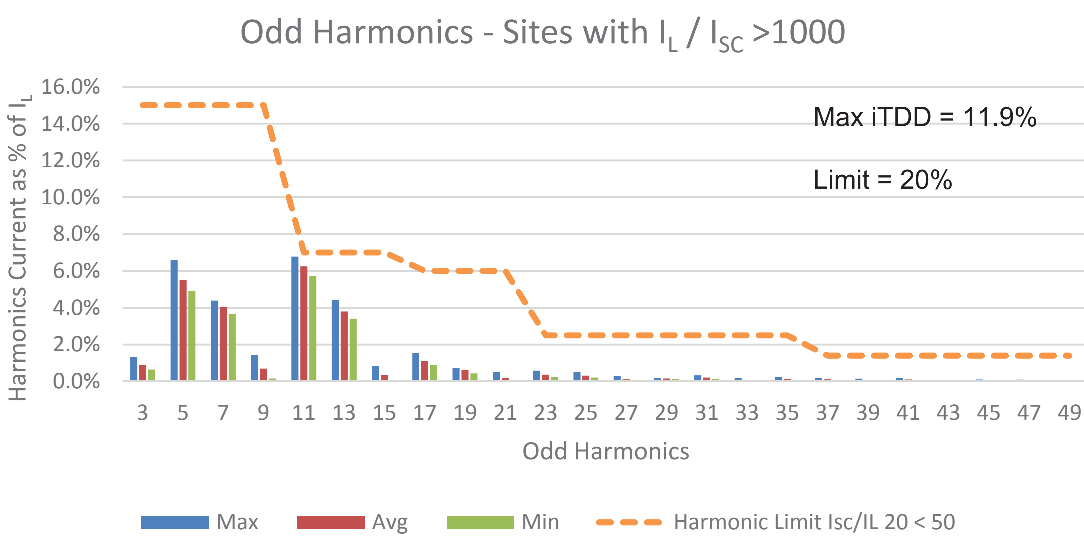

Figure 8 – Odd Harmonics for sites with 100 < I_L/I_{sc} < 1000

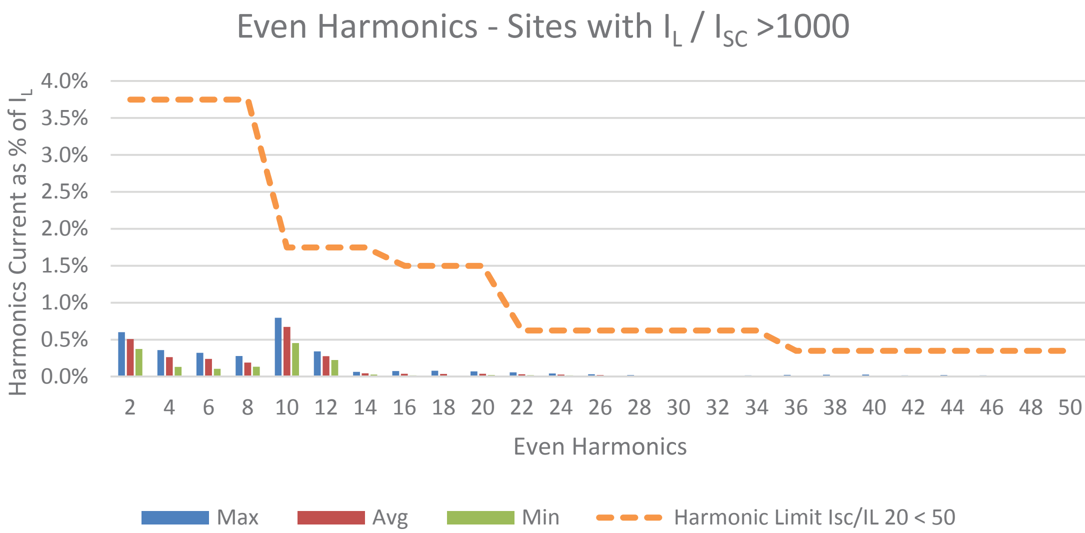

Figure 9 - Even Harmonics for sites with 100 < I_L/I_{sc} < 100Site Demand Data vs Circuit Data

The average site demand for the DC fast charger stations was compared to the circuit demand and planned loading limit at the time during the 1-month monitoring period for each site during the spring of 2018, in Figure 10 and Figure 11. Note that this only reflects what is known of the 13 destination DC fast charging centers that were monitored in this demonstration. Overall, SCE's system-wide average for all DC fast charging stations can vary, and this also negates the contribution that lower-level charging (i.e. for SAE J1772[2] Level 1 and Level 2 AC single/split-phase charging). Figure 10below shows the average contribution DC fast charging stations had on their connected circuits from a substation perspective, and how DC fast charging stations compared to the actual demand on the circuit at the time of the demonstration.

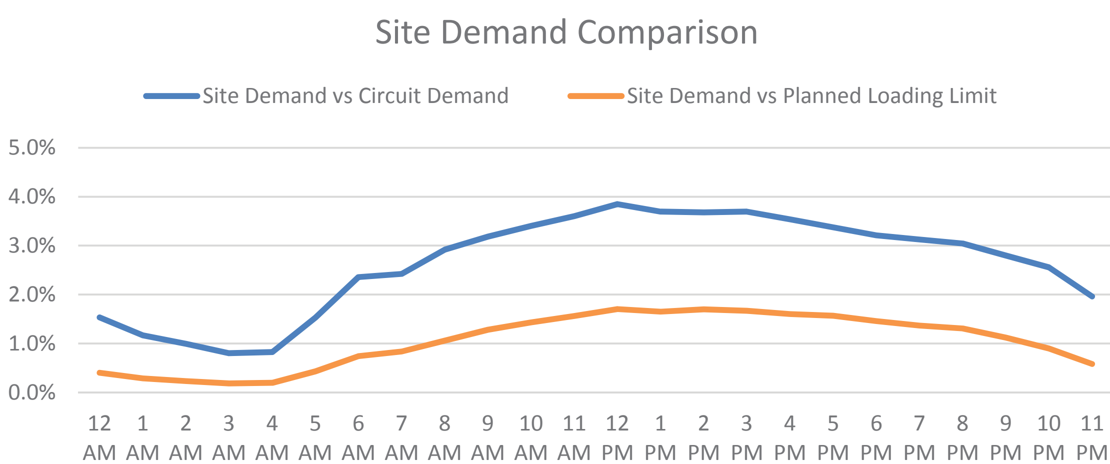

Figure 10 - Site Demand Data vs Circuit Data

[2] SAE Electric Vehicle and Plug in Hybrid Electric Vehicle Conductive Charge Coupler J1772_201710.

In Figure 10, on average all monitored DC fast charger sites occupied 4% of their connect circuit but was just shy of 2% of their connect circuit's planned loading limits at their peak. Looking at Figure 11 we see DC fast charger site demand comparisons based on whether charging was offered for free to customers versus charging a fee. Note that we do not differentiate the different fee structures in this chart (i.e. pay per hour vs flat fee per charging session). From Figure 11, there's no surprise that the DC fast charging sites that offer free charging have the higher demand compared to the sites that charge a fee for DC fast charging. In general, these comparisons in Figure 10 and Figure 11 show that DC fast charging loads are already starting to occupy a significant portion of our load. As customers purchase more electric vehicles we may see free charging go away, and more stations will likely charge a fee for customers to DC fast charge.

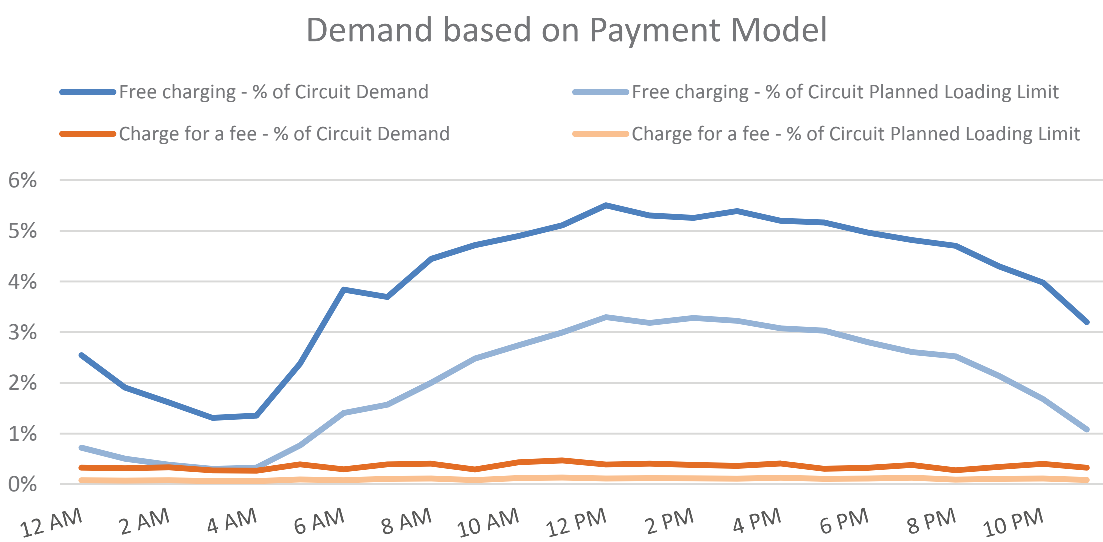

Figure 11 - Demand based on payment model

3.1.2 Evaluating Demand Management Integration Techniques

SCE installed a DC fast charging station, shown in Figure 12, at the SCE Electric Vehicle Technical Center (EVTC) in Pomona to evaluate the effectiveness of demand management integration techniques using the collected DC fast charger site data. SCE plans to evaluate integrating demand management in the future that it could test and demonstrate on the installed DC fast charger.

Figure 12 - Efacec DC fast charger installed at SCE's Electric Vehicle Technical Center (EVTC) in Pomona

In addition to using the installed DC fast charger for evaluating demand management techniques, SCE performed an IEEE 519 analysis for a baseline evaluation of its impact to the grid. This site installation was found to be compliant with IEEE 519 since the harmonic current as a percentage of I_L, and iTDD were below their defined limits as indicated by the dashed orange line in Figure 13 and Figure 14. vTHD remained below the recommended limit of 5 percent throughout the monitoring period. No electrical anomalies were discovered during the 1 month evaluating period of this site.

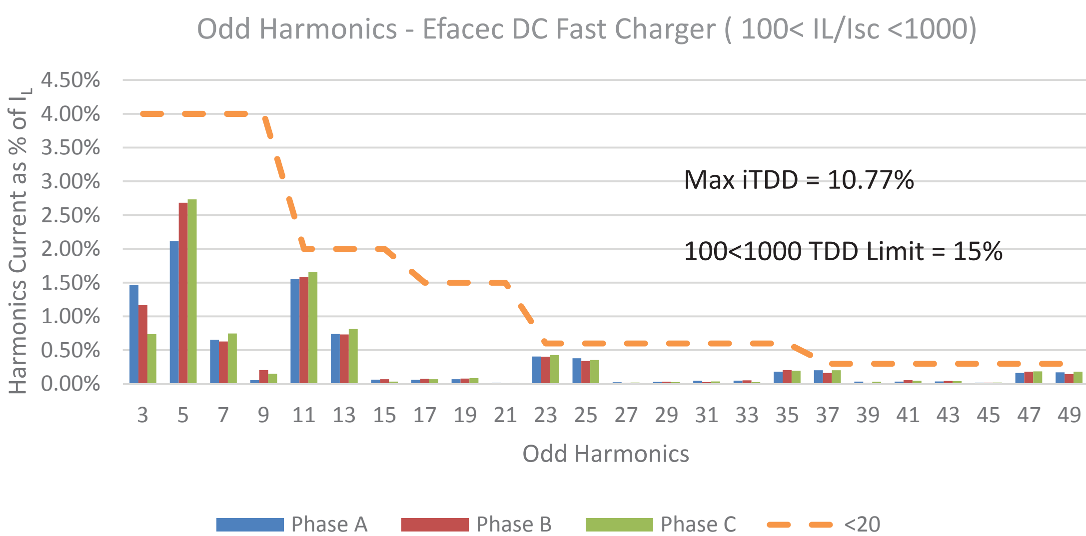

Figure 13 - Odd harmonics Efacec DC Fast Charger

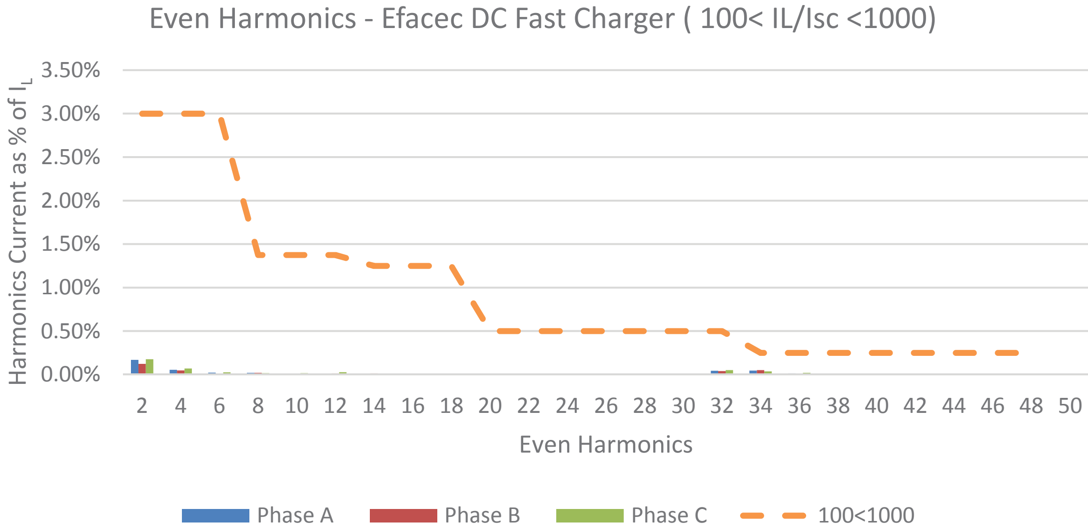

Figure 14 - Even Harmonics Eface DC Fast Charger

3.2 Achievements

3.2.1 Quantified Power Quality impact of DC Fast Chargers

This project evaluated the grid impact on a variety of DC fast chargers within SCE's territory and was able to categorize their impact based on their size relative to the available supply from the grid. To conduct a fair comparison, sites were averaged based on the ratio between their maximum demand load current (I_L) and the maximum short circuit current (I_{SC}) at the PCC. This ratio is a comparison between the size of the customer's load and the amount of demand the grid is capable of supplying. On average this has given SCE the ability to generalize the impact of DC fast chargers with respect to several categories of capable demand capacity on the grid. All sites monitored were evaluated for their compliance to IEEE 519, and all were found to be compliant, which indicates no adverse impact to the grid in terms of power quality. Results from the monitored sites seem to indicate that DC fast charger manufacturers are designing their equipment to ensure that the harmful effects of excessive harmonic current flow are not negatively impacting neighboring customers. In the future manufacturers need to continue this critical practice as DC fast charging stations become more numerous and consume more power. Aside from power quality, some DC fast charging sites did have grid-reliability and safety issues that are described in sections 3.5.4 and 3.5.5.These results were used to inform SCE's distribution engineering, and power quality groups of the impact that DC fast charging loads have on the grid.

3.2.2 Quantified Demand Impact of DC Fast Chargers

In term of quantifying the average impact DC fast charging sites are having on the grid, we found that on average the monitored DC fast charger sites made up to 4% of their circuit's demand, and at up to 2% of the circuit's planned loading limit at their peak average Also, based on the sites monitored, SCE observed that sites offered charging for free had more demand than those that charged a fee for DC fast charging. Although this evaluation's sample size is relatively small compared to the actual number of DC fast chargers installed on SCE's distribution system, these results nonetheless gives SCE insight into average demand. A consistent trend during the demonstration was that demand at these sites generally maintained their peak load from 9am to 4pm. SCE should consider how it will be able to accommodate for a higher than normal demand growth rate, as electric vehicle charging becomes more prevalent. Since peak load ranges from 9am to 4pm, solar could be used to augment the additional generation needed to support higher power charging during the day. In addition, energy storage could be charged off-peak to support DC fast charging at these hours as well.

3.3 Value Proposition

The project team worked with many internal and external stakeholders, in order to successfully achieve its goal to perform a grid impact assessment on DC fast charging stations in SCE's territory, and broadly study how to best minimize system impact. Internal and external project stakeholders included Transportation Electrification (TE) Project Management, Power Quality, Regulatory Affairs and Environmental Compliance, and various Transmission and Distribution groups. Externally, the project team worked with EV Service Providers and equipment suppliers. Additionally, the project team coordinated with other utilities through the Electric Power Research Institute.

This collaborative project successfully met its strategic initiative to prepare SCE for emerging technologies by collecting data that was used to understand the grid impact of DC fast chargers on the utility system by assessing the power quality impact at a sample of the DC fast chargers. Then, comparing the DC fast chargers demand to the total circuit demand.

In addition, SCE outlined the next steps that need to be taken to use this data to inform further integration of demand management using DER, or DR curtailment strategies through an optimal power flow analysis. The objective of this analysis will be to minimize the cost for the utility and SCE's customers to serve the site to improve grid reliability during peak hours. In performing this analysis at each site SCE can better optimize its grid assets to serve more DC fast charging stations that will be installed in the future by using smart grid controls, DER, or other demand management techniques to provide demand support.

3.4 Metrics

The following metrics were used to perform a grid impact analysis on each of the DC Fast Charger locations.

- Compliance with sections 5.1 and 5.2 of IEEE 519 - Recommended Practice and Requirements for Harmonic Control in Electric Power Systems.

3.5 Technical Lessons Learned and Recommendations

The following sections explain the technical lessons learned in this project regarding the methodology for assessing a site's power quality and best monitoring practices. Also, SCE discusses two safety and reliability issues that arose with DC fast charger manufacturers that SCE successfully resolved during the demonstration.

3.5.1 Assessing Power Quality and Demand Impacts

The Grid Impact Assessment of DC fast charging locations took longer than planned, since SCE had to reach out to SCE's power quality group and distribution engineering to best determine how to appropriately assess the grid impact of DC fast chargers. Initially, chargers were going to be examined at a site-level using SAE J2894[3], but after reaching out to SCE's power quality group

[3] SAE J2894/1: Power Quality Requirements for Plug-in Electric Vehicle Chargers.

we found that this did not capture the effects of harmonic current flow at a site-level. Instead SCE's power quality group recommended evaluating a site's compliance with IEEE 519.

In addition, we partnered with the distribution engineering group to compare DC fast charger station demand to its total connected circuit demand. The distribution engineering group supported the demonstration by providing circuit data, which allowed SCE to assess the DC fast charger site's demand impact and impact to the overall current carrying capacity of the circuit. Also, this internal stakeholder also provided the 3-phase short-circuit duty current for each customer site that fed into the IEEE 519 analysis.

3.5.2 Procuring specialized equipment for monitoring

For some DC fast charger sites, it was not possible to directly monitor voltage and current inside of an enclosure that would fit the power analyzer and its communications equipment. Initially power analyzers and its telemetry equipment was installed inside the customer's main switchgear where their utility billing meter was installed as shown in Figure 15 (effectively their point-of-common coupling), but there were some sites that did provide enough room to in their enclosure to install this equipment.

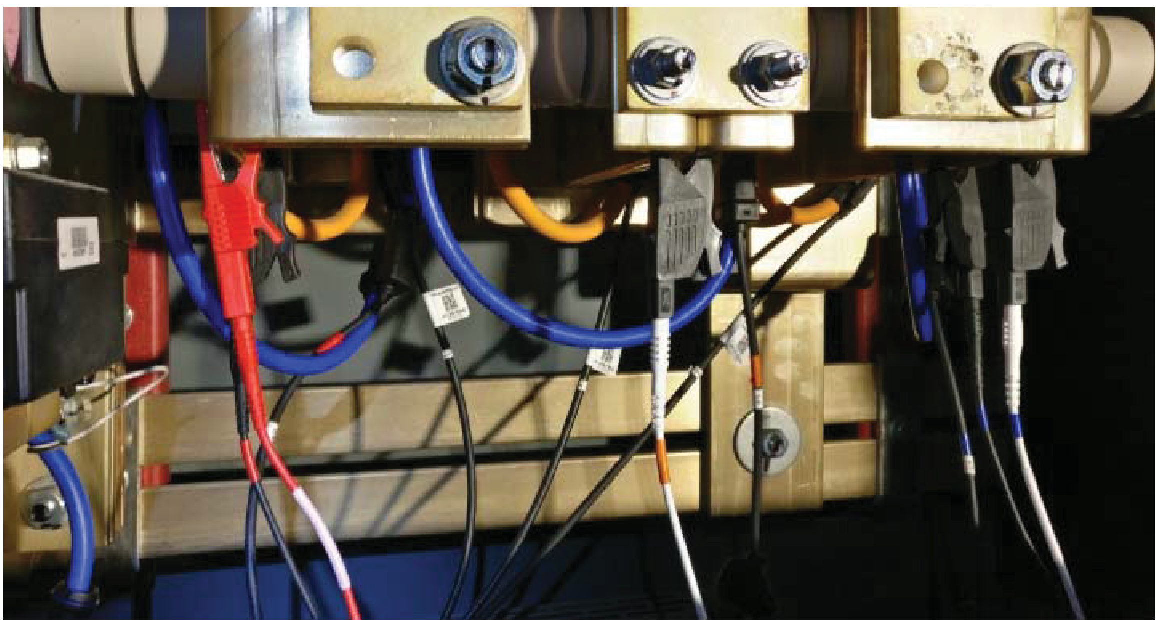

Figure 15 - Traditionally we monitored power quality by directly connecting to the main 3-phase bus feeding the site

By working with SCE's power quality group, the demonstration was able to use their method of monitoring power quality at the customer's service meter test switches, as shown in Figure 16 (another monitoring point at the point of common coupling). Test switches are typically used to view or simulate loading on a customer's installed meter to validate accuracy, but in this case, SCE leveraged the test switches to collect power quality data at the site. Additional work had to be done to adapt the setup to install on test switches, and miniaturize the equipment setup, but SCE was able to monitor 50 percent of our sites using this method.

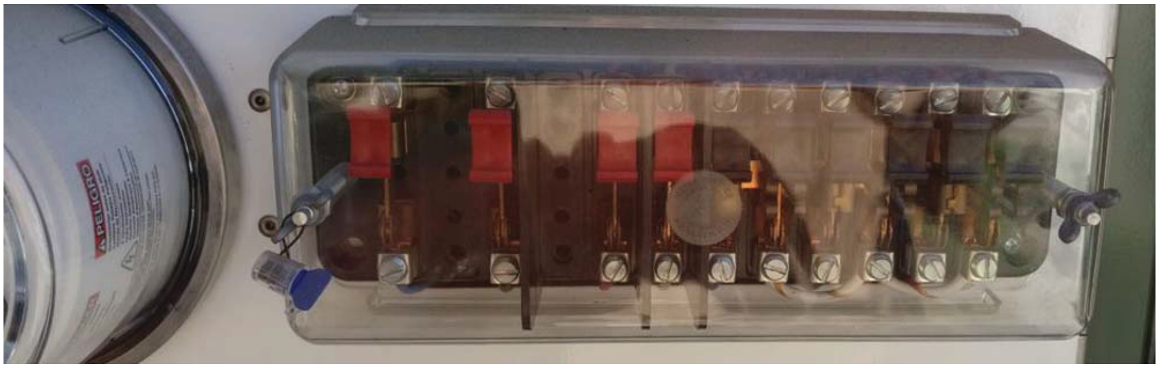

Figure 16 - Test switches

3.5.3 Informed Charger Standards

The methodology for monitoring power quality, and resulting findings, informed SAE J2894/1: *Power Quality Requirements for Plug-in Electric Vehicle Chargers*. SCE has co-chaired both SAE J2894/1 and J2894/2, *Power Quality Test Procedures for Plug-in Electric Vehicle Chargers*. Specifically, the project team helped encourage the adoption of a more comprehensive specification of current total harmonic distortion limits defined by power level category, rather than a single defined limit for all SAE J1772 power levels. This will help focus scrutiny in certain harmonic sectors and better describe potentially adverse impact levels. The revisions will be reflected in the soon to be published SAE J2894/1 revision.

Another example of the use of and influence of standards can be seen in deployment of Transportation Electrification infrastructure in SCE programs. SCE has adopted the SAE J2894 Recommended Practices as technical requirements for transportation electrification programs, including Charge Ready Pilot, Charge Ready Transport and future programs. This will ensure that designers and manufacturers develop and produce chargers that minimize unnecessarily impactful grid effects. One aspect of power quality not always considered is the effect of the power system on the charger device. SAE J2894 describes nominal transients that can and do occur on utility electrical systems. According to the standard, chargers must be able to endure these transients without unrecovered fault. This standard helps utilities communicate these examples, which helps designers produce less sensitive and more reliable chargers. This is described in further detail in the following sections.

3.5.4 Resolving Over-Voltage Sensitivity Issue

Some chargers were observed to be overly sensitive to voltages greater than 400V peak, as shown in Figure 17. As described above, SAE J2894 describes nominal grid transients that EV chargers are expected to handle without adverse impact. The chargers did disconnect from the grid when they ramped down current on the affected phase for approximately 10 minutes, however they are expected to ride-through and operate as normal according to SAE J2894.

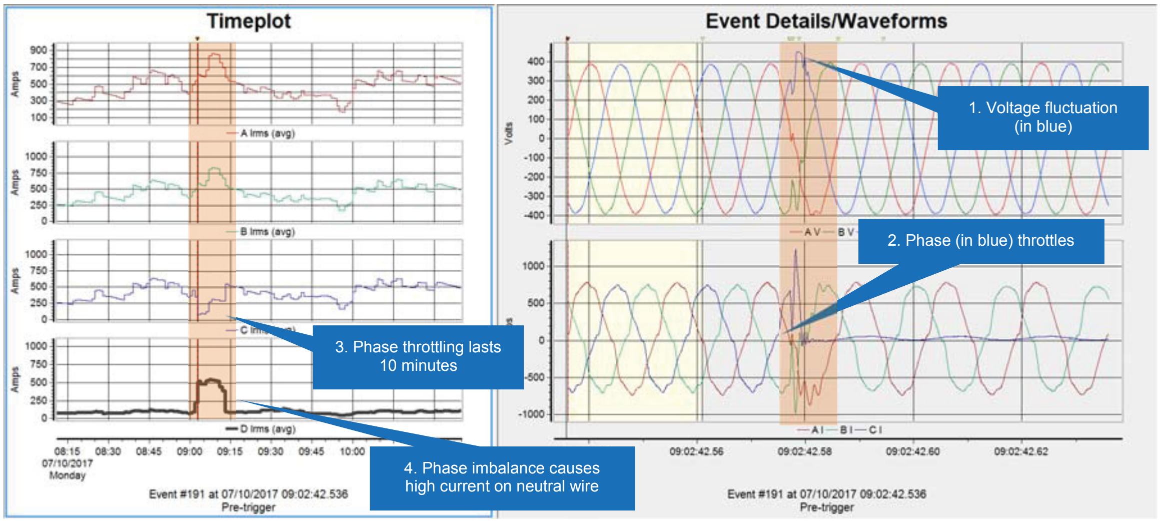

Figure 17 - Voltage rise causes load on the affected phase to throttle prematurely

This had some negative effects, which for one caused significant phase imbalance when drawing load and two caused high current to appear on the neutral phase since the load was no longer balanced on all 3 phases. The phase imbalance is an issue, particularly for large loads such as DC fast chargers that SCE tries to prevent and correct when designing their distribution system to achieve more predictable and balanced loading on its 3-phase distribution system. Although these phase imbalance scenarios were brief (10 minutes), at larger scale with more DC fast chargers operating under these limitations this could exacerbate any voltage events further since DC fast chargers draw a significant amount of load from the grid.

SCE referred the manufacturer to AC service voltage swell ride through limits found in Table 5 within Section 5, Characteristics of the AC Service in SAE J2894/1 *Power Quality Requirements for Plug-In Electric Vehicle Chargers*. SCE also referred the manufacturer to section 4.6 of SAE J2894/2, which details the AC service Event Tests that validate whether an EV charging system passes the criteria in Section 5 of SAE J2894/1. This guideline should help minimize the number of derations, neutral current events, and expand the ride-through capabilities of the chargers, improving reliability and utilization of the chargers. The charger supplier was appreciative of the guidance and engagement provided by SCE and is currently working on resolving the issue.

3.5.5 Resolving Ground Bonding Jumper Issue

Abnormally high voltage spikes of 1500 volts-peak were observed by the power analyzer at one of the DC fast charger monitoring sites, as highlighted in red in Figure 18. SCE went to inspect the installed power analyzer thinking a voltage probe connection from the power analyzer may have been loose, or potentially damaged, but found no issues with the installed analyzer.

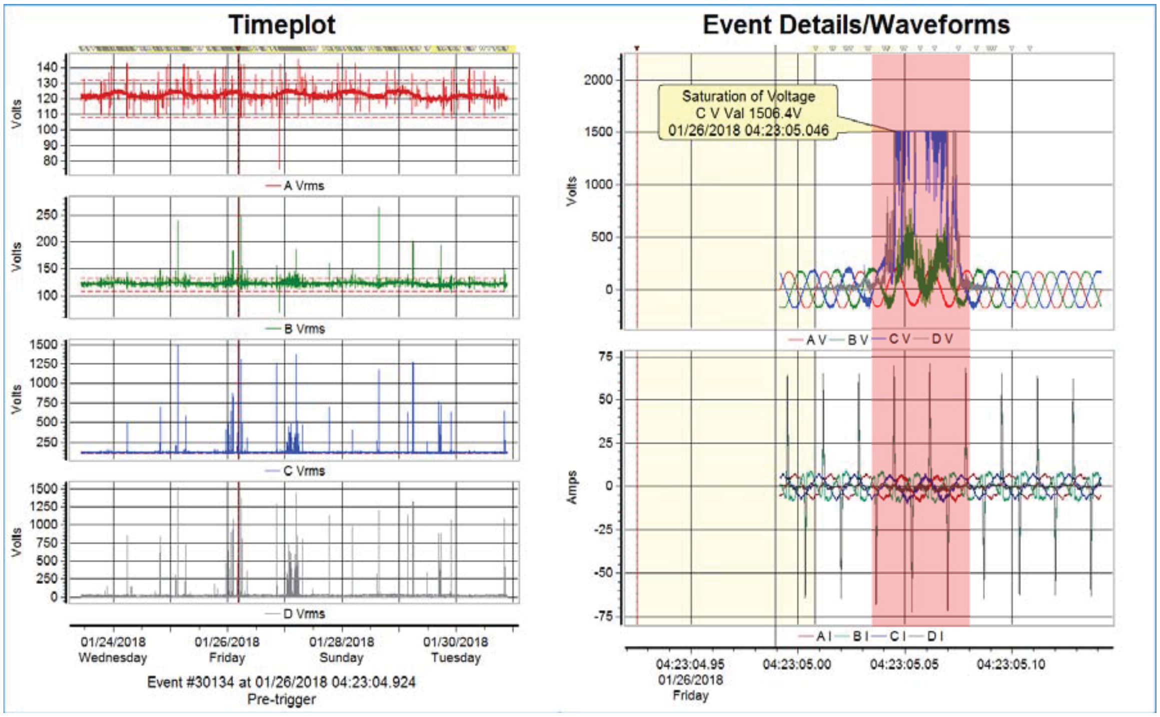

Figure 18 - Abnormally high voltage spikes saturated the voltage measurements at 1500 Volts-peak

We reached out to SCE's power quality group once again for assistance on diagnosing the issue. SCE's power quality group accessed the customer's service compartment and found that the main bonding jumper that connects the neutral and ground bus was disconnected and placed at the bottom of the pedestal, as shown in Figure 19. Without this bonding jumper a fault will not be cleared and presented a significant electrocution or fire safety hazard to the public in the event of a ground fault.

SCE notified the customer and charger manufacturer that a qualified, licensed electrical contractor was needed to be hired to install the bonding jumper within a week or SCE would de-energize the station for public safety concerns. Within a week the charger manufacturer installed the bonding jumper, resolving both the safety issue, and there were no further abnormally high voltage fluctuations captured on the power quality analyzers. This was an isolated incident and was not found at any other monitored locations.

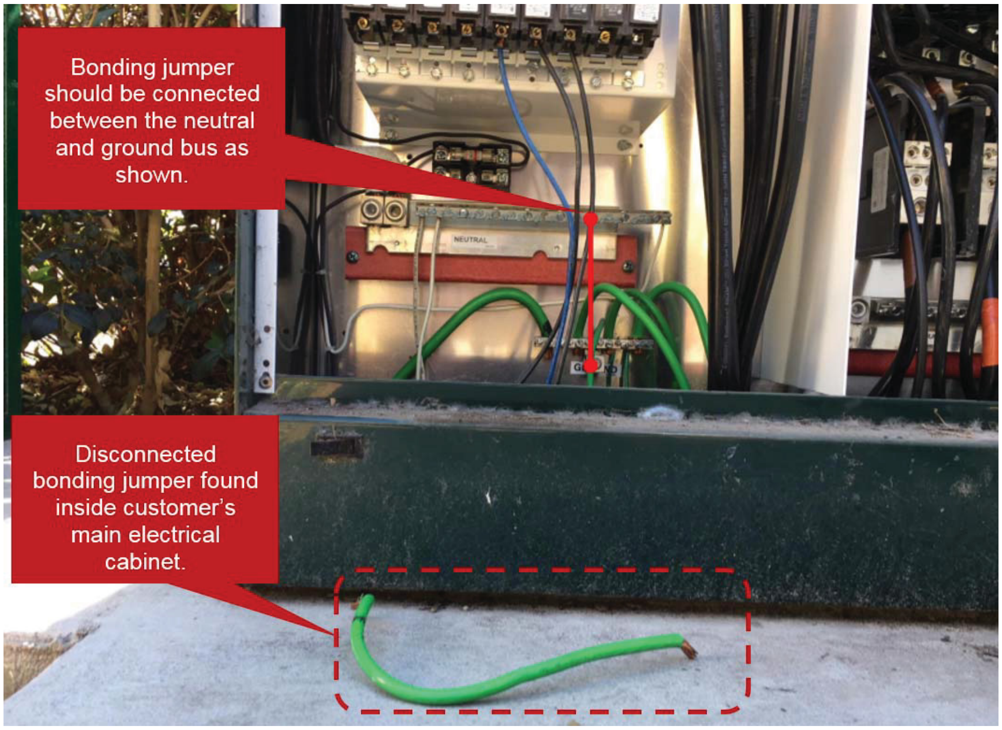

Figure 19 - Neutral to ground bonding jumper found at the bottom of a DC fast charger main electrical cabinet

3.6 Technology/Knowledge Transfer Plan

The project's many technical achievements is solidified into the following key lessons learned:

- Utilization, duty cycle, diversity: Understanding the diversity of load shapes informs SCE's Transportation Electrification program infrastructure design. Specifically, how to size transformers and configure protection, as well as aid planning and funding estimates to build out TE infrastructure.
- Fault behavior: Charging equipment can exhibit unexpected behavior, which could lead to adverse grid conditions, disturbances for customers and potentially increased costs for SCE. Through this project and industry conferences, SCE learned that one charger company exhibited an excessive sensitivity to voltage rises as described in section 3.5.4. Another utility was involved in a similar situation with that charger company, but was unaware of the root of these issues, and spent funds in an effort to filter and isolate the brief periods of voltage rises; however, utility rules require customers to install such filters at their expense if they require it due to sensitive electronics. To prevent this from happening in the future, SCE was able to educate this charger provider using published standard SAE J2894, which was written by SCE along with automakers and stakeholders. SAE J2894 describes expected grid transient events and requires that chargers ride through the voltage rise (and other transient) events and recover without intervention. Furthering knowledge and use of this standard assists the entire industry

with TE and vehicle grid integration. Without this project, our TE infrastructure programs[4] would have spent much more on DC Fast Charger (DCFC) installations.

- Safety: Installation of DCFCs can be faulty, because this equipment can be altered after installation. SCE learned that a supplier or builder caused a safety violation that could have resulted in injury or death. Through this project, SCE discovered and corrected the disconnection of safety ground. SCE immediately de-energized the system and notified the customer to correct the condition. This single incident in itself was a valuable result. However, it also informed SCE's TE infrastructure programs[5] and resulted in increased inspections in customer site advisory, as well as design and commissioning of TE projects.

The key lessons learned from evaluating private infrastructure installations, provided SCE the capability to update technical requirements, adjust construction inspection and commissioning practices and communicate with EV charging providers. This knowledge was transferred to stakeholders as summarized in **Error! Reference source not found.**. Results were presented in the form of raw data and PowerPoints that summarized the results for each site. The following table is a list of dates when knowledge transfer took place:

Date	Knowledge Transfer	Description
2017-04-23	2017 1st Quarter - Project Introduction	Preliminary results. Feedback was received on changing monitoring methodology to IEEE 519 and comparing circuit demand/capacity to site demand
2017-08-31	2017 2nd Quarter - Preliminary IEEE 519 results	Grid impact results on first 5 of 13 sites. First sites to be assessed using IEEE 519. Challenges were realized in monitoring newer sites. See section 3.5.2 of this report for details.
2018-11-28	2017 3rd Quarter – Plan to monitor additional sites, and circuit demand	6 of 13 sites monitored. Plan was created to support the monitoring new sites using the utility meter test switch method. Original 5 sites monitored for IEEE 519 contained additional data with circuit demand impact information.
2018-03-08	2017 4th Quarter – All sites monitored	13 of 13 sites were monitored. 2 sites needed to be revisited with the power quality group's help. All grid impact data was transferred to power quality and distribution engineering teams.

Table 2 - Knowledge Transfer to Project Stakeholders

3.7 Procurement

Lab costs for this project were higher than anticipated due to the project overrunning into 2017 and 2018. Additional labor costs were incurred in the form of employee training, power quality equipment setup design and configuration, and site assessments to determine the which DC fast charging locations would be the most valuable sites to assess as part of this study. The additional time spent in designing the power quality monitoring setup took longer than expected since there were frequent networking issues that reduced the operational reliability of the power quality analyzers. SCE was able to find work-arounds that allowed to reset units remotely to re-connect to power analyzers experiencing network issues, but the solution took time to develop and test since it was a non-standard solution.

[4] Charge Ready pilot projects and planning for subsequent filings including Charge Ready Transport, Priority Review Pilots, and Charge Ready 2.

[5] *Ibid.*

3.8 Stakeholder Engagement

As aforementioned in section 3.3, this project incorporated many stakeholders. Externally, the project team worked with EV Service Providers, equipment suppliers and EPRI. Internally, the project team and external project stakeholders included TE Project Management, Power Quality, Regulatory Affairs and Environmental Compliance, and various Transmission and Distribution groups. The major internal stakeholder for this project was SCE's Power Quality and Distribution Engineering group. The Power Quality and Distribution Engineering Group was engaged on a quarterly basis to update on milestone progress, and also served as the project's technical advisory committee. The stakeholder was present to review the power quality and circuit demand impact analysis that was performed in this demonstration and provided feedback on whether test results were reasonable. SCE shared all site results with the internal project stakeholders, but anonymized and aggregated the data for external reporting to protect customer data. More work can still be done to revisit the impact of these sites as more sites are constructed, and SCE can continue to monitor these large loads on our distribution systems if requested internally. For the goals outlined in this project stakeholder needs were satisfied through updates on the site results for the grid impact assessment.

4 List of Acronyms

DC	Direct Current (as in Direct Current Fast Charger)
DCFC	Direct Current Fast Chargers
DER	Distributed Energy Resource
DOE	Department of Energy
DR	Demand Response
EPIC	Electric Program Investment Charge
EVSE	Electric Vehicle Supply Equipment
EVTC	Electric Vehicle Technical Center
GHG	Greenhouse Gas Emissions
IEEE	Institute of Electrical and Electronics Engineers
iTDD	Current Total Demand Distortion
PCC	Point of Common Coupling
PEVs	Plug-in Electric Vehicles
PLL	Planned Loading Limit
SAE	Society of Automotive Engineers
SCE	Southern California Edison
vTHD	Voltage Total Harmonic Distortion

Glossary

None

Appendix C

Distributed Optimized Storage (DOS) Protection and Control Demonstration

Final Project Report

Distributed Optimized Storage (DOS) Protection and Control Demonstration Final Project Report

Developed by
SCE Transmission & Distribution, Grid Technology and Modernization
January 1, 2019

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1 Executive Summary

1.1 Project Overview

The objective of the DOS Protection and Control Demonstration is to effectively demonstrate the protection and control aspects of integrating energy storage devices on a distribution circuit to identify grid reliability benefits and increase the distributed energy resource (DER) integration capacity.

To accomplish this, the project team identified distribution system circuits where multiple energy storage devices could be operated centrally. Once the feeder was selected, the simulated energy storage devices were integrated into the control system and lab tested to demonstrate that the devices can be centrally monitored and controlled to perform grid services.

An additional part of this project was to investigate how energy storage devices located on distribution circuits can be used for reliability, while also being bid into the California Independent System Operator (CAISO) markets to provide ancillary services.[1] Initial use cases were developed to determine the requirements for the control systems necessary to accomplish these goals.

The DOS Protection and Control Demonstration project was approved in the SCE Electric Program Investment Charge (EPIC) 1 triennial Investment Plan. Furthermore, the DOS Protection and Control Demonstration is directly aligned with the Integrated Grid Project (IGP).[2] There are many synergies between these projects that seek to examine ways to control and integrate DERs. To leverage this alignment and synergies, the design, procurement, and testing of the control systems have been combined. In addition, since field demonstrations are difficult and costly to conduct, the DOS Protection and Control has merged its field demonstration with IGP, which will be executed as part of IGP EPIC 2 funding. Following successful testing of the IGP control systems in the laboratory environment and the pre-production Quality Assurance System, the controls will be deployed in SCE's production environment, as part of the IGP field demonstration.

1.2 Value of project to CPUC EPIC program and benefits to rate payers

The DOS Protection and Control project is designed to demonstrate how the distribution system can be managed with high penetrations of DERs – battery energy storage in particular. The lessons will be used by SCE to provide the requirements for future grid modernization. Many of these lessons will also have broad applicability to other utilities. A complete listing of the lessons learned for this demonstration project is presented in Section 5.2.

Before embarking on a major system upgrade, it is important to demonstrate technologies to confirm the system requirements. The DOS Protection and Control project is demonstrating battery energy storage control systems, communications protocols, cybersecurity and methods to work with customers and aggregators. Ultimately, this experience should result in a smoother, better-defined transition to a smarter grid that can operate reliably and safely with high penetrations of DERs. These lessons help to inform future modernization efforts.

[1] Known as dual-use energy storage.

[2] Formerly known as Deep Grid Coordination in the EPIC 1 Investment Plan.

1.3 Key accomplishments & lessons learned

⇨ Key accomplishments

- Identified site for utility-owned storage system on the test circuit (Titanium circuit out of Camden substation).
- Evaluated control system requirements and completed control system design for a high-penetration DER control system.
- Integrated the distribution control system into the distribution management system (DMS) through the integration platform in the lab setting.
- Completed the first series of factory acceptance testing (FAT) showing the control of multiple battery energy storage systems.
- Developed a use case that describes the requirements for using a battery energy storage system for circuit reliability needs and bidding into the CAISO markets (i.e., dual-use energy storage).

⇨ Key lessons learned

Lessons from DOS and IGP are reflected in SCE's Grid Modernization requirements and the associated procurements being conducted by SCE. This continuous feedback loop between the demonstration efforts and planning for system-wide deployment is essential in a dynamic technology environment. The DOS Protection and Control demonstration lessons learned cover newer technologies such as the integration of different systems, deploying publish-and-subscribe platforms, and the complexities of incorporating customer-owned DER. The following are some key lessons learned:

- Adopting a systems engineering approach for IGP offered multiple benefits. It provided a disciplined methodology for managing the project lifecycle, including deriving the system requirements, documenting the system design, aligning the requirements with system testing and ensuring detailed traceability of the technical deliverables to the key business and operational drivers. This approach helped keep the project focused on the overall system requirements during testing and evaluation.
- Performing thorough laboratory testing of DER control systems, a testing environment that allows system simulation in real-time is needed. This allows controls testing over a broad range of system conditions that would not be otherwise possible.
- Enticing customers to allow the utility to use their DER systems for grid reliability services has been difficult, due to existing customer contracts for system operations and maintenance, existing utility tariffs and lack of clear customer incentives. Others soliciting similar customer involvement in demonstration projects need to plan sufficient time and incentives to meet project objectives.
- When using a battery energy storage system for grid reliability purposes while simultaneously bidding into the CAISO markets, grid reliability needs must take priority over the market bidding to maintain grid dependability.

1.4 Direct Contributions to the Grid Modernization Program

The DOS Protection and Control demonstration has delivered the following accomplishments to assist the implementation of SCE's Grid Modernization System project:

- Assessment and demonstration of control application integration through an operational service bus to support energy storage systems.
- Completed evaluation of detailed Interface Service definitions for the GE Predix operational service bus to integrate with energy storage systems, which are now reusable for the Distributed Energy Resource Management System (DERMS) and Advanced Distribution Management System (ADMS) implementations.
- Demonstration of volt/VAR and power flow optimization for high penetration DER to improve ADMS request for proposal (RFP) requirements leveraging energy storage systems.
- Provided a use case that describes how a battery system could be used to satisfy both grid reliability requirements and allow bidding of the remaining resource into the CAISO markets.

1.5 Funding

Period of Performance: September 2014 thru April 2018

Dollars Spent: $76,288

2 Project Summary

2.1 Project Objectives

The objective of the DOS Protection and Control project was to demonstrate how battery energy storage systems can be controlled to provide grid benefits to a distribution circuit. To do this, control specifications were assembled and an RFP process was initiated to select the system. Initial testing of the control system took place in a laboratory environment with a simulated circuit configuration and storage resources. The project team identified distribution circuits where multiple energy storage devices could be operated. The project team selected a single circuit (Titanium) located in the Santa Ana/ Costa Mesa portion of Orange County. Energy storage devices were connected to the control system to demonstrate seamless utility integration, control and operation. The field demonstration work will be performed as part of the IGP EPIC 2 field demonstration. This project allowed SCE to investigate the benefits of utilizing distributed energy storage devices on distribution circuits and identify the necessary control function requirements for integrating with grid operations.

An additional component of this project investigated how energy storage devices located on distribution circuits can be used for reliability, while also being bid into the CAISO markets to provide ancillary services (dual-use energy storage). Initial use cases were created and requirements listed for the control systems necessary to accomplish these goals. This aforementioned concept will be demonstrated in a lab environment as part of the IGP project.

2.2 Scope

This project consists of four major stages all aimed at successfully demonstrating an end-to-end integration of energy storage devices on a distribution circuit. The following sections describe the major stages in further detail, explaining how each phase relates to the overall goal of enabling the distribution system to integrate increased amounts of DERs.

⇨ Circuit Identification and Modeling

This stage determined grid optimization and DER integration requirements for operating energy storage devices on SCE's distribution circuits. Identifying the appropriate circuit involves several considerations, including circuit electrical behavior, the circuit DER penetration level, circuit load profile, and the circuit's contributions to overall SCE system optimization. This analysis involves significant data mining of available databases and extensive use of SCE modeling tools.

- Centralized Controller Specification and Evaluation

  This stage determined specifications for the centralized control system. SCE initiated an RFP process to procure the centralized IGP controller. The RFP clearly indicated the open standards nature of the solution, helping to ensure that the centralized controller can communicate with and control field devices from multiple vendors, and that it can integrate seamlessly with SCE's DMS. The project then performed an extensive evaluation of the centralized controller for its ability to optimally control and operate the individual energy storage devices for grid optimization and DER integration on the chosen circuit.

- Laboratory Testing for Utility Integration of Energy Storage Devices

  Since the project includes multiple energy storage devices along with other DERs, a comprehensive approach was followed to ensure that the devices can be successfully integrated with SCE's distribution system. Due to the complex nature of controlling multiple energy storage devices on a distribution circuit, detailed laboratory testing was conducted to prove out the control system and its integration with existing utility systems. This testing was conducted using a real-time grid simulation system to allow testing of multiple control scenarios in the shortest possible time.

- Field Deployment and M&V

  Following the testing of the control systems in the laboratory environment, the controls will be deployed in SCE's production environment. The IGP use cases can satisfy the DOS Protection and Control testing requirements. Consequently, the DOS Protection and Control project was closed at the end of the EPIC 1 funding, and field testing will be demonstrated by IGP in EPIC 2. The field tests results will be reported within IGP.

2.3 Project Background and Overview

SCE received approval from the CPUC of its EPIC 1 triennial investment plan in late 2013. The DOS Protection and Control project was started in early 2014, as part of SCE's EPIC 1 Portfolio. In 2015, the DOS Protection and Control project was incorporated into IGP because of significant synergies. Consequently, the DOS Protection and Control project was sited in the same location as IGP. This led to the selection of the Johnna Jr. substation as the DOS Protection and Control site for the demonstration. This site was also within SCE's Preferred Resources Pilot area that had resource procurements in place for DERs to relieve expected load growth and the loss of the San Onofre Nuclear Generation Station. In 2016 Camden substation was also incorporated into IGP (Figure 1), as there were seven existing large solar photovoltaic (PV) installations located there.

Control system procurement started in 2015 and final selection of the vendors was completed in 2016. Two companies were selected and would interface with the DMS through an operational service bus. Following initial lab testing, the two control vendors were reduced to one. More detailed lab testing was then conducted of the control system integrated with the operational service bus and DMS in late 2016 and early 2017. The rest of 2017 and early 2018 were taken up by additional lab testing with upgraded software and moving of software to the pre-production Quality Assurance System. As noted in section 2.2 above, this project would be closed at the end of the EPIC 1 funding and final system and field testing would be conducted as part of IGP.

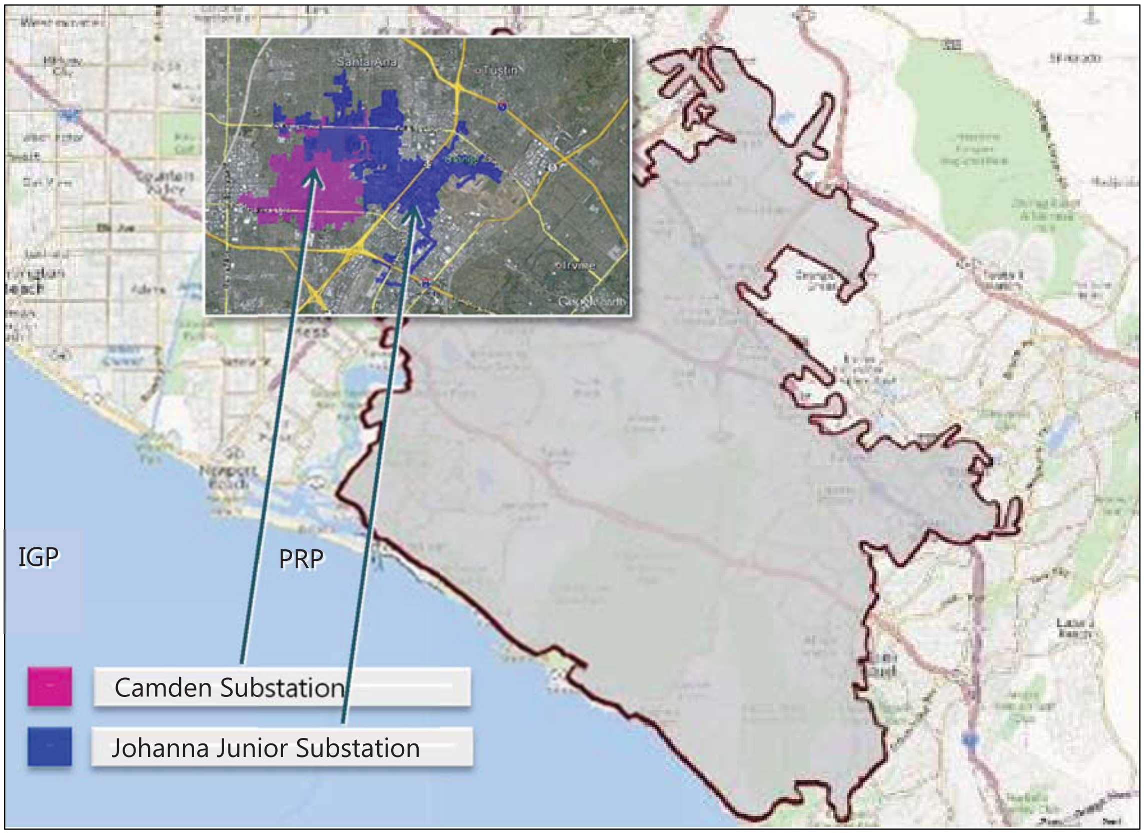

Figure 1: IGP and Preferred Resource Pilot (PRP) Demonstration Location

2.4 DOS Protection and Control/IGP Schedule

The schedule shown in Figure 2 below depicts the timing of completed milestones and anticipated timing of future milestones for the DOS Protection and Control/IGP project. While this schedule slipped a bit from what was originally expected, significant progress has been made. Most of the delays occurred in the initial testing phase of the project where control system integration problems had to be resolved. As noted in the overall project objective, one of the primary purposes of the DOS Protection and Control project was to design, test and refine the integration of new technologies that will assist with modernization of SCE's grid. As such, an essential part of DOS testing is to actively identify problems with these new technologies and develop effective solutions. The field testing portion of the DOS Protection and Control project is going to be performed under the IGP project using EPIC 2 funding.

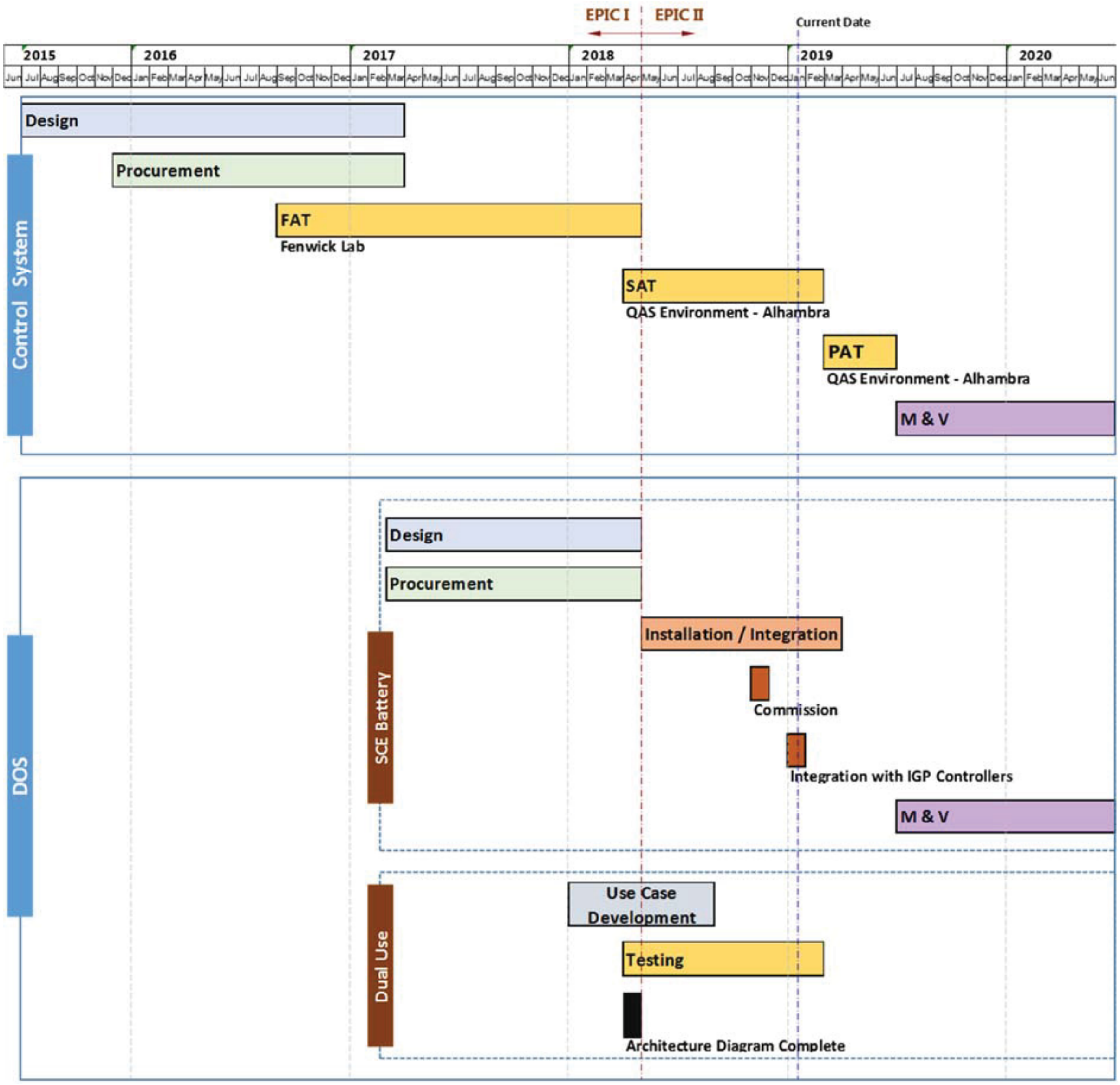

Figure 2: DOS/IGP Top Level Schedule

3 DOS Protection and Control System Design

The DOS Protection and Control system design involved a number of steps including the selection of the demonstration area, compilation of the controller system requirements, completion of the system design and the design and implementation of the laboratory testing environment. The following sections provide more details on the final system design.

3.1 Circuit Identification and Modeling

Selecting the proper circuit/substation for the demonstration was an important first step of the project. Initial siting work under the DOS Protection and Control project identified a number of sites for consideration and it was decided to site IGP and the DOS Protection and Control project in the same area. This allowed the project to obtain the highest penetration of DERs possible on the test circuit. Selection of these candidate circuits/ substations was based on a number of criteria established for the project, which were then weighted to obtain the most promising circuit/substation. A description of the criteria and their weights is shown in Figure 3.

Criteria	Description	Weight
Representative Test Bed	The site should reflect the general SCE service territory. Ideally it (1) contains a mix of overhead and underground construction, (2) serves a balanced variety of common SCE load types, including residential, commercial and industrial customers, and (3) is located in an urban area (i.e. load density similar to that of ~85% of SCE's load).	30%
High DER Penetration	Without high DER penetration, the overall goal of using DOS/ IGP as a test environment would not be fulfilled. The site must contain high penetration of existing DERs, including (1) 3rd Party-owned solar PV at residential and C&I scales. Ideally it also contains (2) SCE-owned storage and solar PV, (3) existing and/or feasible demand response resources, and (4) suitable future sites for 3rd party or SCE-owned energy storage. Additionally, (5) electric vehicle charging and (6) non-PV distributed generation are desirable.	30%
Capital Deferral Opportunity	Ideally, the selected site has short (1-2 years) and medium-term (3-5 years) capital-investment deferral opportunities, driven by the possibility for DERs (including monitoring, communications and control) to address present or forecasted constraints on (1) the transmission system, (2) the B-station ducts or transformer banks, and/or (3) individual circuits or circuit components.	20%
SCE Initiative Alignment	The site will also benefit from being a focus area for other SCE initiatives including, (1) Grid Modernization technology deployments (e.g. SA-3, RIS, RFI, field area network, fiber communications between substations, volt/VAR optimization), (2) DRP Demos D, (3) Distributed Energy Storage Integration initiative, (4) the Charge Ready program, (5) the CEC smart inverter demonstrations, and (6) regional focus areas (e.g. PRP – South Orange County, Goleta, and San Joaquin).	20%

Figure 3: Scoring Criteria for DOS/IGP Site Selection

Based on analysis, the team decided that a combination of the adjacent Camden and Johanna Jr substations would satisfy the project criteria. These systems have a mix of overhead and underground circuits with both residential and commercial customers. In addition, the Camden substation area offered several large PV and storage installations already in place with more installations under way to help meet the definition of high penetration of DER. Both of these substations are located within the PRP area, which has actively solicited installation of new DER resources in the area over the last few years. These substation areas are sites for the installation of remote fault indicators, remote intelligent switches and the latest version of SCE's substation automation (SA3). These technologies enable the DOS Protection and Control/IGP to demonstrate the next generation grid and identify any early deployment issues associated with these technologies.

After additional analysis, the Titanium circuit out of Camden Substation was selected as the focus for the DOS demonstration due to existing high levels of customer-owned DER (both PV and storage) and because the site contains an SCE-owned battery storage system. Figure 4 shows the DER in place or planned on the circuit as of the end of the EPIC 1 project period. With the installation of all of these DER, the circuit DER penetration will approach 50% of the circuit peak load.

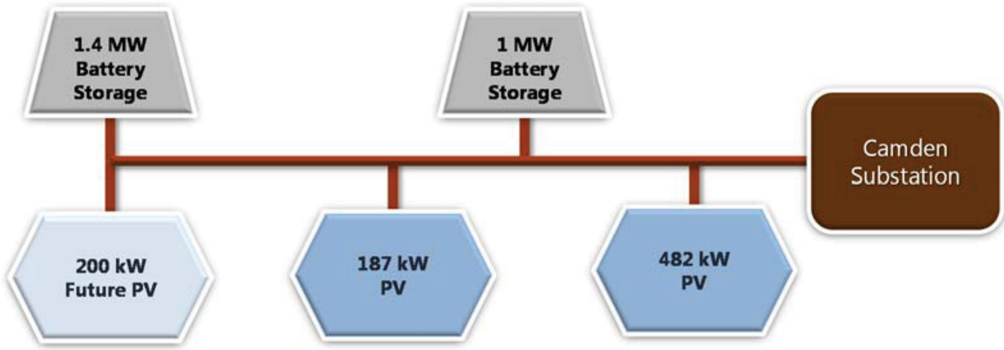

FIGURE 4: DERS ON THE TITANIUM CIRCUIT

The location selected for the installation of the SCE battery system was chosen after examining the available plots of land located along the Titanium circuit. Sufficient space was necessary to install a 1.4 MW/ 3.7 MWh battery. A site within an SCE transmission right-of-way had sufficient space and sits in proximity of the Titanium circuit. The interconnection method required a portion of an adjacent circuit be switched to the Titanium to ease the interconnection work. This battery system is in service as of the end of 2018.

3.2 Centralized Controller Selection and Evaluation

⇨ Use Cases

The first step in determining what controls would be necessary to manage multiple battery systems, PV systems and variable loads was to determine the use cases for the controls. Three main control use cases involving batteries were created along with functional and non-functional requirements (see Appendix 5.4 for more details on the use case summaries). These use cases include:

- 2.1 – Voltage Optimization with DER - The substation-level volt/VAR controller optimizes feeder voltage using capacitors and DERs (generation and storage devices) equipped with smart inverters. The IGP control application optimizes feeder voltage by lowering and flattening the voltage profile along the feeder, so it remains in the lower portion of the 114-120 volt range for commercial and residential customers.
- 3.3 – DERs Managed to Shape Feeder Loads - At the feeder level, the IGP control system and its optimal power flow (OPF) controller optimizes loads, generation and storage to shape the load to meet operational requirements at any given time.
- 4.1 – Microgrid Control for Virtual Islanding - A microgrid controller uses control of loads, generation and storage to reduce real and reactive power flows to zero at a specified reference point on a distribution feeder for a pre-determined period of time.

The requirements from these use cases were consolidated and included within an RFP for the DER control system. After evaluating the RFP responses, the team selected two vendor products for lab testing. After initial lab testing, one of the control systems was selected for additional lab testing, integration with existing SCE production systems, and eventual field deployment as part of the IGP project.

One additional use case was created to document the steps and requirements necessary to use a distribution-connected battery system to support grid reliability while also bidding into the CAISO markets. This use case, titled “Dual Use of Utility Controlled Distributed Energy Storage,” requires the creation of additional control capabilities to be tested in a future release of the IGP controls. Initial implementation of this control would require the control system to determine if the battery was needed for reliability operations a day in advance and then reserve the battery for utility reliability use only that day. A future version of the control would be able to determine the portion of the battery system needed for reliability and be able to release the balance for CAISO market use at the same time that the battery is being used for reliability. Detailed requirements and the architecture diagram for this use case were completed in April 2018.

⇨ Logical Context

The DOS Protection and Control and IGP demonstrations consist of a series of control applications which interact with each other (along with DERs and other grid resources), using an operational service bus. Communications between the back-office (central domain), the substation (distributed domain), and devices (edge domain) is provided by a combination of local area network (LAN), wide area network (WAN), and field area networks (FAN) technologies (Figure 5).

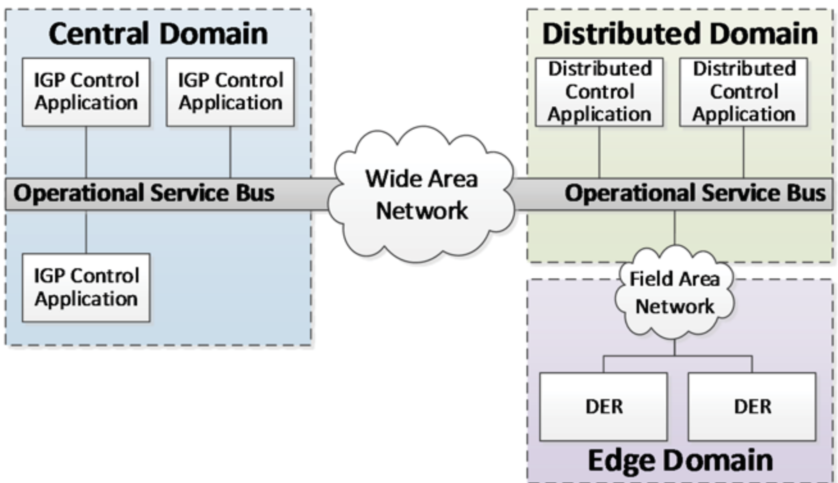

Figure 5: Overall DER Control Architecture Domains

While the high-level logical view presented above provides a general context for the interaction between IGP components, IGP will be deployed in broader IT and security environments. Additionally, as a demonstration project, the DER and the control applications associated with IGP must be production quality, yet the grid must be able to operate without them. This concern informs the overall approach to integrating the IGP control applications with each other, the production Distribution Management System (DMS), and the DER. Specifically, the production DMS must always be aware of any control actions taken by the IGP control applications. Because of this, the operational service bus must connect to both the IGP control systems and the production systems. Additionally, security requirements, such as North American Electric Reliability Corporation Critical Infrastructure Protection (NERC CIP), require that the SCE network be divided into different segments, separated by firewalls. The diagram below (Figure 6) shows how the IGP solution will be deployed with respect to these firewalls.

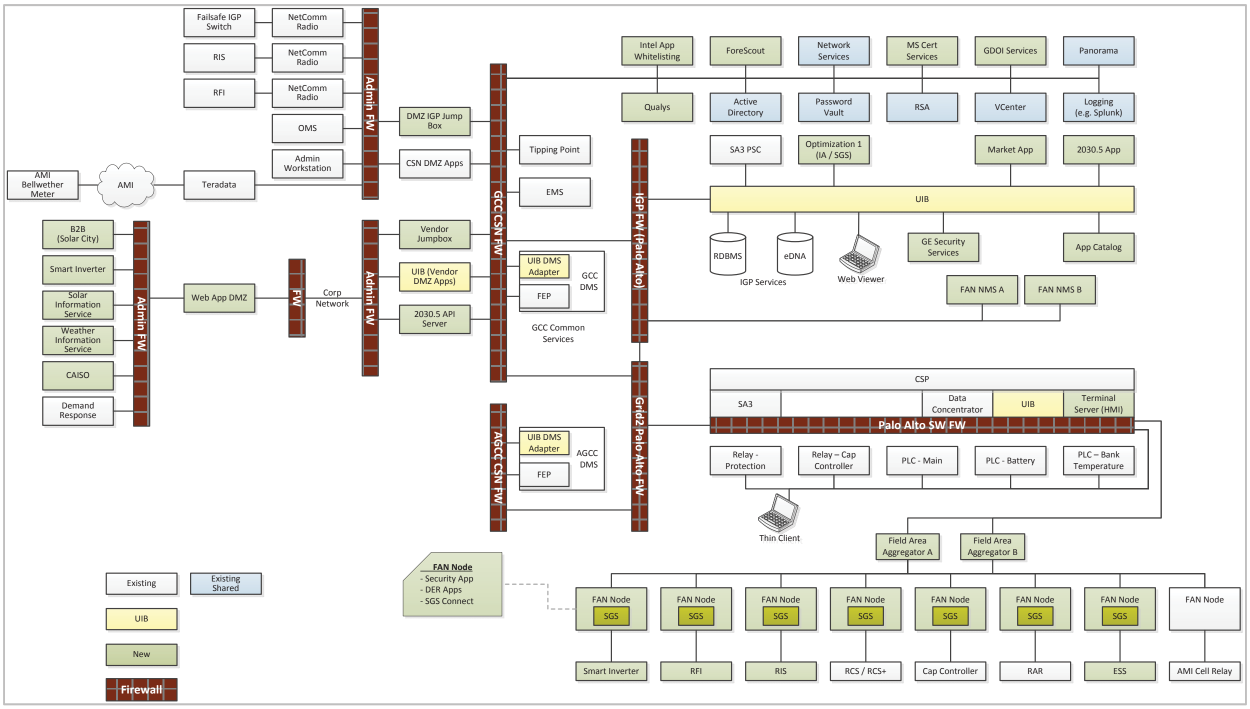

FIGURE 6: DETAILED LOGICAL CONTROL ARCHITECTURE

Initial design work also extended the operational service bus all the way to the FAN nodes. As work was being done to implement this design, the project team realized that this extension of the bus would be difficult to implement, due to the lack of maturity of these software products. Consequently, the design was modified to remove this feature before the FAT testing began.

3.3 Laboratory Testing for Utility Integration of Energy Storage Devices

The IGP used laboratory testing to validate functionality and performance capabilities of the control systems prior to field deployment. The benefit of this approach was that laboratory testing was performed in a controlled environment without adversely affecting the service provided to customers (e.g. creating actual faults on a feeder for testing is not permissible given the presence of customers). A leveraged lesson learned from a prior project, in this case the Irvine Smart Grid Demonstration project was that laboratory testing has limitations. For instance, extensive laboratory testing did not identify a battery error that only occurred after field deployment. It is therefore important to monitor devices in the field throughout operation to identify issues that cannot be replicated in a laboratory environment.

The testing was conducted in SCE's Advanced Technology (AT)[3] laboratory, which includes multiple test environments. IGP systems were tested utilizing: (1) Substation Automation Laboratory (for common substation platform), (2) Distribution Automation Laboratory (for field automation devices), (3) Control Systems Laboratory (for simulation testing of the controls software), (4) Computing Laboratory (for back-office system support), and (5) Grid Edge Solutions Laboratory (for FAN performance and interface to DER and automation devices). Testing was performed to ensure/determine the following:

- Show hardware and software operates according to IGP's and manufacturer's specifications.
- Verify field devices could be monitored and controlled by remote command through the control systems.

[3] Now known as Grid Technology.

- Determine if the IGP controller is capable of controlling capacitors and DER to meet circuit voltage requirements.
- Determine if the IGP controller is capable of controlling DER to optimize real/reactive power flow.
- Verify the precision and stability of the real and reactive power control over a range of durations and settings.
- Measure the response speed of the control system.
- Determine the battery energy storage system's reaction to grid events and control system limits.
- Verify that DER status can be communicated to the DMS and displayed to the operator.

The IGP is testing the power flow optimization and volt/VAR controller applications using a controller-in-the-loop test environment. This test environment uses a simulation system to dynamically model circuit conditions, as well as simulate dispatch of real and reactive power at multiple resource locations within the modeled distribution substation and its feeders. The testbed has implemented a detailed distribution system model of SCE's Camden substation and its 7 circuits. This model includes cables, conductors, switches, capacitors, and realistic PV and energy storage functionality. The control applications and integration bus then interact with the modeling environment in real-time to investigate performance. This testing setup is depicted below in Figure 7.

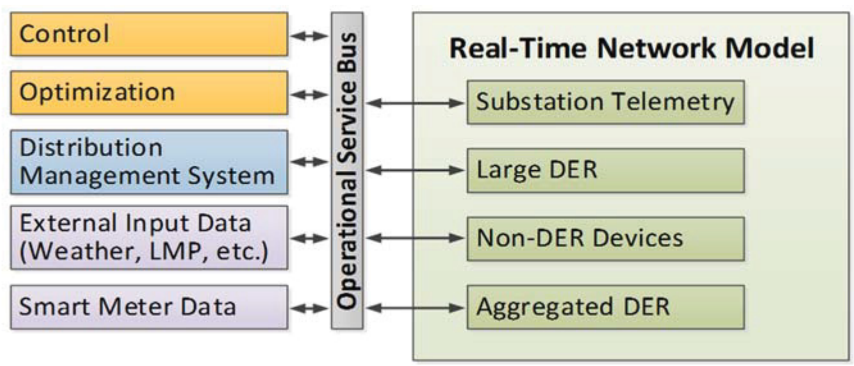

Figure 7: Test System Architecture for the Control Systems

The laboratory test setup utilized the DigSilent's PowerFactory RMS real-time simulation platform to perform circuit, substation and DER device modeling in real-time. This modeling environment was then connected to the operational service bus, DMS and the control applications being tested. Other external data sources were also connected to the operational service bus and shared with all the applications. The team was primarily interested in the steady-state/long term dynamics behavior of the network model, so simulations were run with a 1 second time step. This is the right amount of simulation speed to be able to talk to hundreds of distributed grid assets within a distribution substation. The distribution circuit model was converted from CYME into the PowerFactory format through a converter built for this project. The test system performed the translation between data types and control commands from different protocols (OPC, IEC 61580, DNP3, Modbus). This system allowed testing multiple controllers (e.g. storage controller, aggregated residential solar PV/storage) as if they were actually connected to a real power system. This realistic test environment allows for grid scenarios that seldom appear in a demonstration project (e.g. faulted conditions, heat storms), but are critical to determine how the control system would work under such conditions.

The lab environment design mimics the production system as closely as possible in an attempt to catch potential production issues as soon as possible. Work to move these control systems from the lab testing phase to the actual production system platform for field testing is being undertaken under IGP EPIC 2.

3.4 Field Deployment and M&V

During early project execution the project team determined that the controls needed for the DOS are similar to controls needed for IGP. The resources needed for the DOS Protection and Control and IGP field demonstrations also had considerable common synergies. These synergies were leveraged as requirements were assembled, controls were purchased and during lab testing. Furthermore, the project team also determined that field testing of the IGP use cases would also satisfy the requirement of the DOS Protection and Control. While the DOS Protection and Control project is closed out at the end of the EPIC 1 funding, the field testing work will be picked up and demonstrated by IGP under EPIC 2 funding. Results of the field tests will be reported under IGP.

4 Lab Testing

4.1 Control System Lab Test Cases / Procedures

The IGP testing was divided into several stages as illustrated in Figure 8. Initial unit testing of the system components was conducted at both the AT and vendor labs and was focused on isolated testing of the integration bus, control applications, edge computing platform and the FAN. Once these tests were successful, testing moved to the system integration testing at the AT labs. In these tests, all components were assembled as a functional system and tests of the exchange of data between the components was conducted. Once the data exchange problems were solved, testing moved to the initial FAT. There would be several rounds of FAT testing with the initial one, FAT1, covered in this report. Once the controls team is satisfied that the applications are working properly and controls are being properly executed in the AT lab environment, all software systems will be transferred to the SCE production quality assurance system (QAS) environment for system acceptance testing (SAT). This environment is set up just like the formal production environment, but is isolated so the actual production system is not disturbed. When the applications are operating properly in the QAS environment, they will be moved to the actual production environment for production acceptance testing (PAT). As part of the PAT testing, the control systems will be connected to real field apparatus (e.g. capacitor controllers, automated switches, DER) and the production DMS. After these tests are successfully completed, the IGP control software will be ready for measurement and verification (M&V). Under the EPIC 1 funding, the control system was taken through the FAT1 testing stage. Completion of SAT and PAT testing will be accomplished under the IGP EPIC 2 funding.

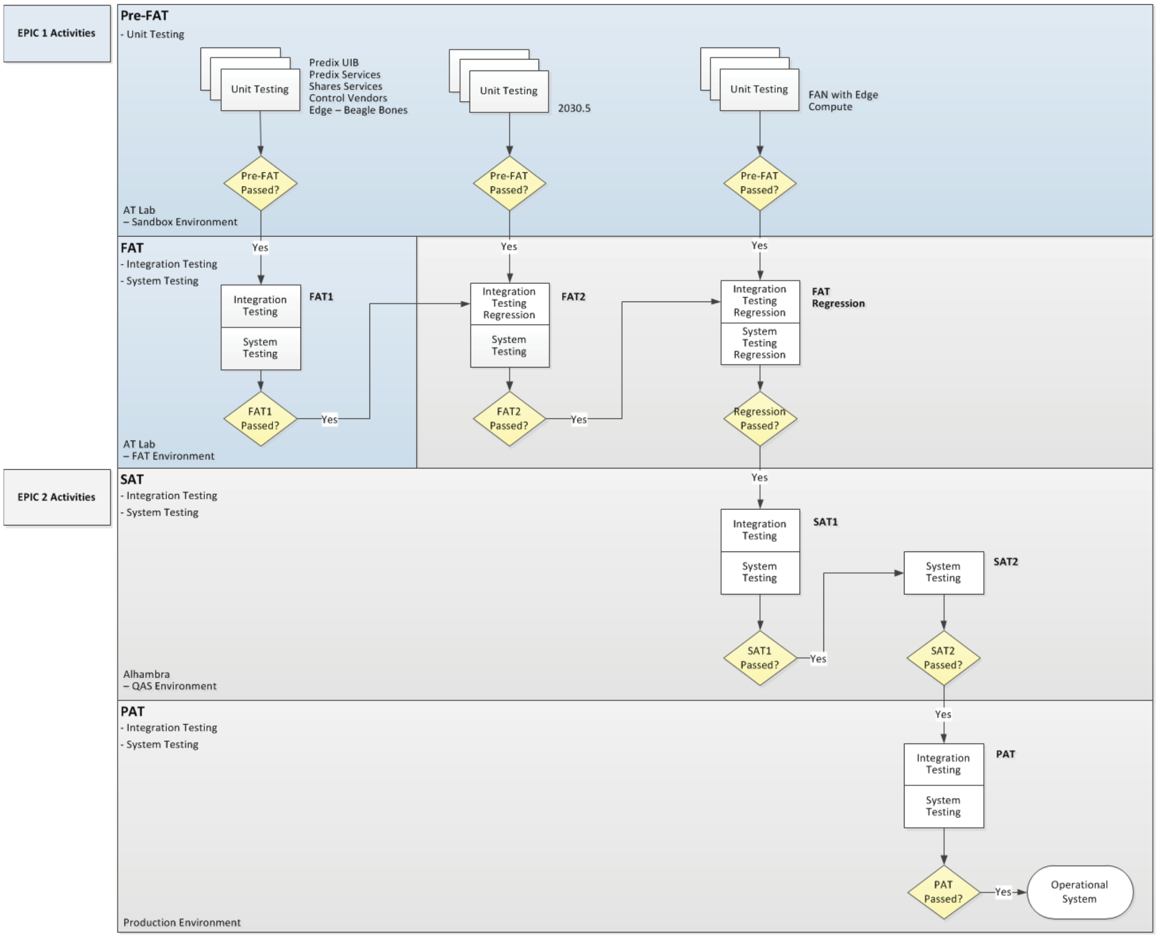

FIGURE 8: OVERALL IGP TEST APPROACH

⇨ Test Procedure Preparation

For FAT1 testing, a series of test procedures were created. In total, 49 distinct integration and 45 distinct system test procedures were written to cover the power flow optimization, volt/VAR optimization, and virtual microgrid use cases. The 45 systems test procedures were directly mapped to 100 unique procurement requirements for validation. See Appendix 6.3 for a listing and high-level descriptions of the test cases.

⇨ Lab Test Tracking and Reporting

While performing the lab testing as part of system integration and FAT1, progress was reported on daily 8:00 am calls with all pertinent SCE and supplier personnel. In addition, lab testing progress was tracked through the Atlassian Jira software and reports were issued both daily and weekly regarding progress, issues, and status of the resolution of the issues. Jira is a software issue tracking package that provides bug tracking, issue tracking and project management functions. Jira was accessible to all pertinent SCE and supplier personnel involved in testing. Examples of Jira tracking and reporting are provided in Appendix 6.2.

5 Project Results

5.1 AT Lab Test Results

⇨ Unit Testing

Unit testing was conducted by each of the vendors and SCE to verify product readiness for integration testing. This testing was conducted by GE for the integration bus, IA/SGS for the control system software, and by SCE for the edge simulation software and balance of system. This testing was conducted starting January 3, 2017. On January 27, the testing team agreed it was ready to move forward with system integration testing.

⇨ FAT1 Testing

Control system integration testing occurred between January 30, 2017 and March 10, 2017 at the AT labs. These tests were designed to determine the readiness of the control systems for the beginning of FAT1 system testing. The majority of the integration tests were automated to allow easy re-execution of the test cases when control software changes were made. These test scripts, which consisted of 2150+ lines of C# code and several configuration files, help prove system stability as the controls moved into the integrated test environment. While some integration issues emerged, they were resolved and proper system behavior was achieved as well as better system stability. On March 10, 2017, the testing team agreed it was ready to move forward with FAT system testing.

As the project moved into the FAT1 testing phase several changes in the project control system scope were made. These changes were done to reduce the time it would take to move the control into the production environment and remove features that had proved problematic in the earlier testing phases. These changes included:

- Initial FAT1 testing did not include any of the security or 2030.5 functionality and utilized a simulated FAN. The removal of these functions would help speed testing of the control functionality. They would be added in at a later stage of testing.
- Due to the results of earlier testing and assessment of the two original controls vendors, the scope was reduced to only one vendor. This scope reduction reduced the testing time since each control vendor needed to be tested separately in sequence.
- As the FAT1 testing proceeded, significant issues were found with the field agent software. After many attempts to stabilize this software, it was decided to abandon this design feature for now because the product did not seem to be sufficiently mature for the field demonstration. The project design was subsequently modified to eliminate the field agent code and testing resumed. While it would have been good to extend the operational service bus all the way to the edge devices, the project objectives could be accomplished with it.

FAT1 testing began utilizing the IA/SGS controller solution on March 13, 2017 and ran through April 7, 2017. Figure 9 shows the number of test cases executed as part of the FAT1 testing. When a test ended in failure, the root cause was determined and fixes developed. While many of these fixes were not implemented immediately, they were put in place when the control system testing moved into FAT2.

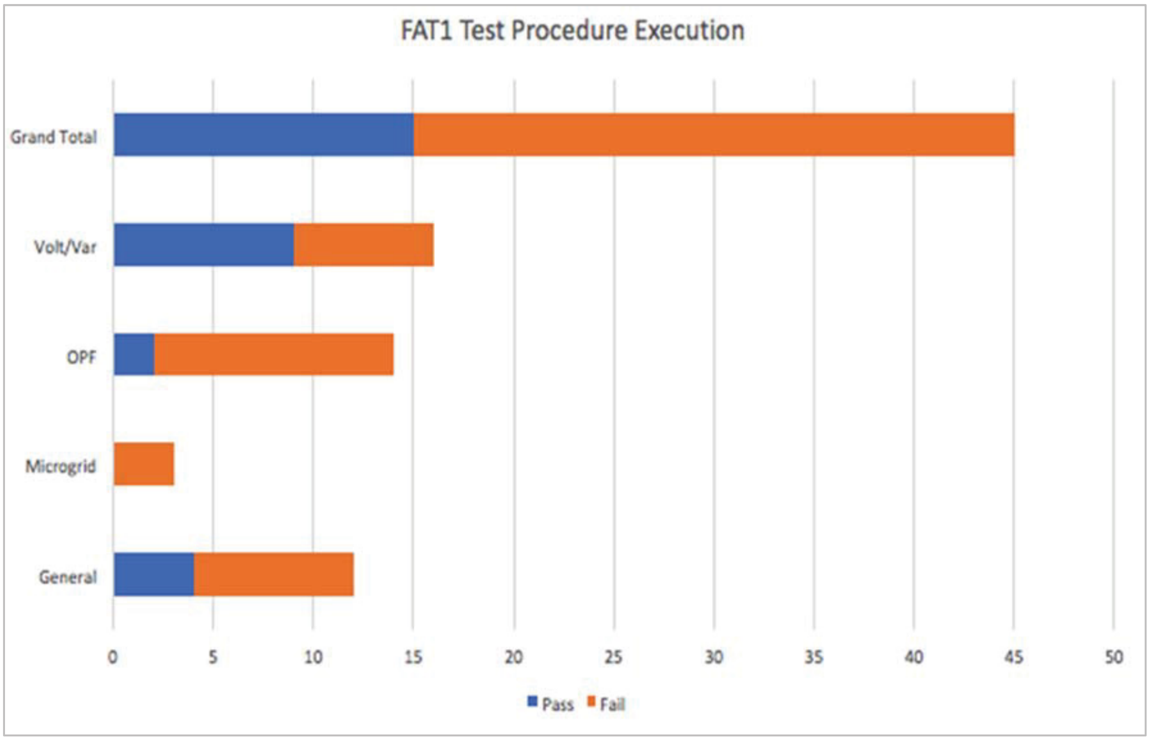

Figure 9: FAT Test Procedure Results Tracking

Below (Figure 10), are the results of a sample test case showing centralized control (from the back office) of a PV plus energy storage system where the battery was used to offset change in PV output as well as reduce the higher frequency PV output variations.

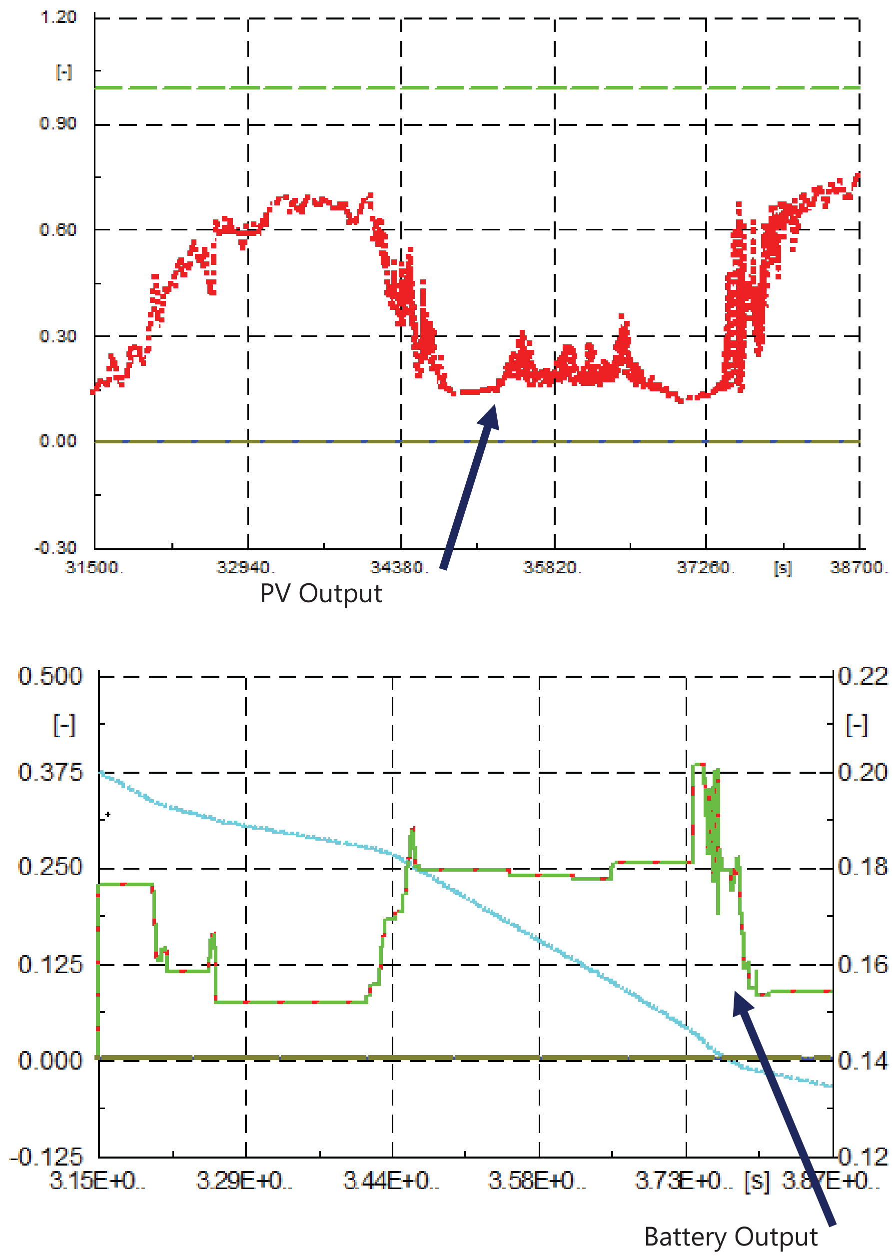

FIGURE 10: SAMPLE CONTROL SYSTEM LAB TEST CASE RESULTS

The simulation environment allowed for the execution of multiple scenarios to compare and contrast results. These cases allowed testing of:

- Different control schemes (e.g. optimal power flow, volt/VAR)
- Software modifications

- Examination of historical events
- What-if scenarios
- Load growth planning scenarios
- DER adoption rate scenarios

The work covered under this report concludes with the end of FAT1 testing in the AT labs. FAT2, SAT and PAT testing as well as field deployment will be covered under the IGP EPIC 2 work and reported on at the conclusion of the funding period under the IGP.

⇨ Additional FAT Testing

Additional FAT testing of the control system software in the lab environment was conducted between April 2017 and April 2018. These tests used control software that was modified based on defects found in the initial FAT1 round of testing. Additional testing was also conducted to replace the simulated FAN radio equipment with real radios. These additional tests better prepared the software to move to the SAT testing phase.

5.2 Lesson Learned

⇨ Requirements and Analysis Phase

- The decision to adopt a systems engineering approach for the IGP offered multiple benefits. It provided a disciplined methodology for managing the project lifecycle, including deriving the system requirements, documenting the system design, aligning the requirements with system testing, and ensuring detailed traceability of the technical deliverables to the key business and operational drivers. This approach helped keep the project focused on the overall system requirements during development and testing.
- The decision to utilize the Sparx Systems Enterprise Architect application to capture the requirements was very beneficial in establishing the link to the use cases, framing the design, and especially the tracking of the test cases.

⇨ System Development Phase

- The integration of multiple vendor products is a complex and difficult undertaking. The IGP is highlighting the importance of the industry's need to move towards open standards and interoperability.
- The decision to move to an agile software development process called "scrum" was a good choice given the time constraints. It allowed development to move forward as the full software requirements were being completed. These methods include the use of software "sprints" that develop workable pieces of software in fixed, short duration cycles. These methods allowed the integration of new features with minimal disruption.
- The advertised capabilities of the operational service bus were not readily available initially and several key issues had to be overcome to obtain a stable, reliable system. Lab testing helped to identify and resolve these issues.

⇨ System Integration Phase

- In order to reduce schedule risks, a project should have one dedicated software development environment for each vendor when there are competing solutions. Working with vendors that are doing development work in series significantly extends the schedule duration.
- Implement formal design reviews for system and unit/component designs in order to elicit more formal engagement by key stakeholders and reduce later technical issues.

- Aligning on an open standards data model for the operational service bus message payloads helps prevent vendor lock-in.

⇨ System Testing Phase

- To perform thorough laboratory testing of DER control systems, a test bed that allows system simulation in real-time is needed. This allows controls testing over a broad range of system conditions that would not be otherwise possible.
- A clear testing strategy, approach, and the associated workflows are essential to project success.
- Automated integration testing helped to quickly perform a large number of tests on the control systems, especially when these tests needed to be repeated after software modifications.
- Vendor debugging tools and related debugging processes were surprisingly lacking and inadequate. These tools should be required from the vendors early in the design/testing phases of the project.

⇨ Customer Recruitment

- To entice customers to allow the utility to use their DER systems for grid reliability services has been difficult due to existing customer contracts for system operations and maintenance, existing utility tariffs and lack of clear customer incentives. Others soliciting similar customer involvement in demonstration projects need to plan sufficient time and incentives to meet project objectives.

5.3 Metrics and Benefits Summary

The metrics and benefits table in Appendix 6.1 describes a number of areas where the DOS Protection and Control project can provide benefits. Financial benefits (energy savings, jobs, reductions in capital cost), are not large for the DOS Protection and Control project since it only affects a small geographical area. When these technologies are deployed to a larger area, these benefits will expand significantly. Other benefits relate to safety, reliability, and efficiency. Again, for this specific project, the effects are small, but would be expected to expand as the technologies are deployed more widely. There were significant lessons learned in the area of barriers to widespread deployment of DER controls, optimization, cost-effectiveness and standards. The final area in the metrics and benefits table is related to how SCE's lessons learned are being disseminated. SCE has published articles in trade magazines, delivered presentations at industry conferences, and shared the results of the IGP project with other utilities.

5.4 Technology / Knowledge Transfer Plan

Technology and knowledge transfer is divided into two areas. The first is transfer within SCE to the production environment. The second is to transfer SCE's lessons to other utilities.

SCE is deploying new grid technologies and systems across the SCE system. The DOS Protection and Controls project, funded through EPIC, is meant to demonstrate how these technologies could be deployed and to identify lessons that can resolve issues before full-scale deployment. Technology and knowledge are transferred to the team working on production systems by sharing staff between the groups and regular review of the production plans and requirements. The DOS Protection and Control project team has reviewed and made suggestions on how to improve the requirements for a number of RFPs for the new production distribution control and management systems including DERMS and ADMS.

For those outside of SCE, the IGP team has made a number of presentations at industry conferences and published articles in trade and professional magazines discussing IGP achievements. As the project moves into the field demonstration phase, additional presentations and articles will be put together to share the project results widely.

6 Appendix

6.1 Metrics

6.2 Test Report Material/ Diagrams

6.3 Test Cases / Procedures

6.4 Use Cases

APPENDIX 6.1: METRICS

Metrics (PS-13-xxx) – DOS Protection and Control

1.0 Potential Energy and Cost Savings

1. c. Avoided procurement and generation costs

The following is an estimate of the avoided procurement and generation costs at Johanna Jr and Camden substations over a one year period at the end of the EPIC 1 work (April 30, 2017). This estimate is based on the energy generated and the average CAISO daylight price of energy for the year ending April 30, 2017 (approximately $28/ MWh).
Avoided procurement and generation costs in Johanna Jr substation ~ $20,000
Avoided procurement and generation costs in Camden substation ~ $200,000

1.i. Nameplate capacity (MW) of grid-connected energy storage

The following is a tabulation of the capacity of grid-connected energy storage at Johanna Jr and Camden substations at the end of the EPIC 1 work (April 30, 2017):
Nameplate capacity of grid-connected storage at Johanna Jr = 0 MW
Nameplate capacity of grid-connected storage at Camden = 0.054 MW

2. Job Creation

2.a. Hours worked in California and money spent in California for each project

The following is a calculation of the hours worked and money spent in CA for project during the EPIC 1 period:
Hours worked in California = 1,102
Money spent in California = $76,288

3. Economic Benefits

3.b. Maintain / Reduce capital costs

While this demonstration project is not deferring any construction of new equipment or circuits at this time, it is expected the DER control capability demonstrated here would be able to delay the need for future circuit upgrades.

5. Safety, Power Quality, and Reliability (Equipment, Electricity System)

5.f. Reduced flicker and other power quality differences

Flicker and power quality problems on distribution circuits are caused by variations in customer loads and generation as well as things like capacitor switching. Through the use of inverter control of reactive power, the switching of capacitor banks can be minimized, imposing fewer switching transients on the circuits. If high speed inverter control were to be implemented, DER inverters could also help reduce customer load and generation induced flicker. While this fast control is not planned for this project, it may be possible with future inverter autonomous controls to perform this function.

5.i. Increase in the number of nodes in the power system at monitoring points

More monitoring points can provide finer detail of how the distribution system is operating. This better information can be used to fine tune the control systems to better control power flow and reduce voltage variations. In the DOS Protection and Control work, additional monitoring points (from DERs and additional line sensors) will be incorporated into the control systems to better estimate power flow and voltage levels. This additional data is expected to provide better control.

6.0 Other Metrics*

**To be developed based on specific projects through ongoing administrator coordination and development of competitive solicitations*

6.a. Benefits in energy storage sizing through device operation optimizations

The size of energy storage devices required can be minimized though coordinated control of other DER devices on the circuit. These other DER devices include photovoltaic arrays, other battery systems, and demand response. A control system with access to all of the resources for control can help reduce the size and cost of the battery systems required for grid management.

6.b. Benefits in distributed energy storage deployment vs. centralized energy storage deployment

Distributed and centralized energy storage systems help solve different problems on the grid. Due to where distributed energy storage systems are located (distributed throughout distribution system feeders), they can help solve voltage and power flow problems on specific distribution circuits. When the storage is more centralized (generally located in larger substations) it is able to address issues more focused on the transmission and subtransmission systems (e.g. load balancing or spinning reserve). So the selection of the location for a storage system should be done based on what issues the storage unit is being designed to solve.

7.0 Identification of Barriers or Issues Resolved that Prevented Widespread Deployment of Technology or Strategy

7.a. Description of the issues, project(s), and the results or outcomes

In the past, the biggest barriers to the widespread installation of DER were cost and integration with the grid. Costs for equipment and installation of DER are now declining to the point that cost is not the major barrier it once was. Work on projects such as IGP is demonstrating how these resources could be better integrated with the grid and helping resolve issues brought on by increasing amounts of DER on distribution circuits. The remaining issue blocking increased use of DER is how rates and incentives can be constructed so the costs and benefits of DERs can be properly apportioned among customers and DER suppliers.

7.b. Increased use of cost-effective digital information and control technology to improve reliability, security, and efficiency of the electric grid (PU Code § 8360)

Digital information helps an electric utility better understand what is going on in the grid and also helps suggest what actions can be taken to best control the grid. The DOS Protection and Control project is exploring the increased use of monitoring and control to optimize the operation of batteries to maintain proper power flow through circuits and substations as well as control voltage in a rapidly changing environment. The virtual microgrid portion is designed to control a battery on a portion of a circuit to shape load and generation to reduce grid congestion. The field demonstration part of this project, to be conducted by the IGP under EPIC 2 funding, will show the effectiveness of this monitoring and control technology in real distribution circuits.

7.c. Dynamic optimization of grid operations and resources, including appropriate consideration for asset management and utilization of related grid operations and resources, with cost-effective full cyber security (PU Code § 8360)

One of the goals of the DOS Protection and Control project is to show how multiple battery storage devices can be used to optimize circuit power flow and voltage. This is being done through the use of optimization software monitoring the circuit state and sending commands to grid devices (e.g. capacitors) and DER (e.g. battery energy storage inverters) to obtain the optimum configuration. Under EPIC 1 funding, the control requirements were developed, implemented in a lab environment, and went through initial testing. Laboratory test results show these control systems are able to better manage circuits under high DER penetration scenarios. Under EPIC 2 funding for the IGP project, this control system will be put into production to test the controls on a real circuit with high penetration of DER. An important part of this control system is reviewing, recommending and implementing cybersecurity measures that will increase the security of the distribution system when the advanced optimizations controls are implemented. These cybersecurity measures will be based on standard industry offerings wherever possible.

APPENDIX 6.2: TEST REPORT MATERIAL/ DIAGRAMS

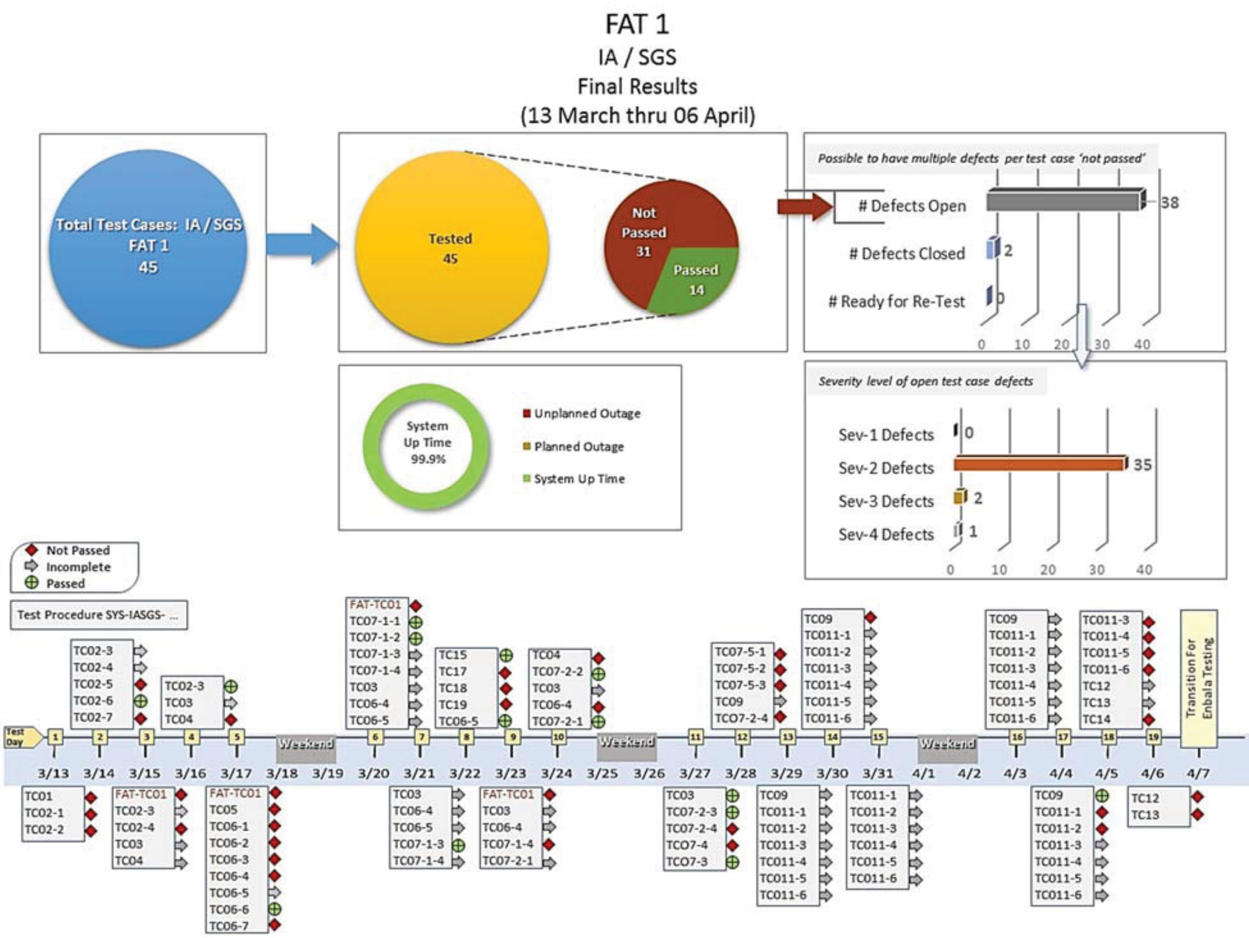

Figure 11: Overall and Daily Tracking of FAT 1 Results

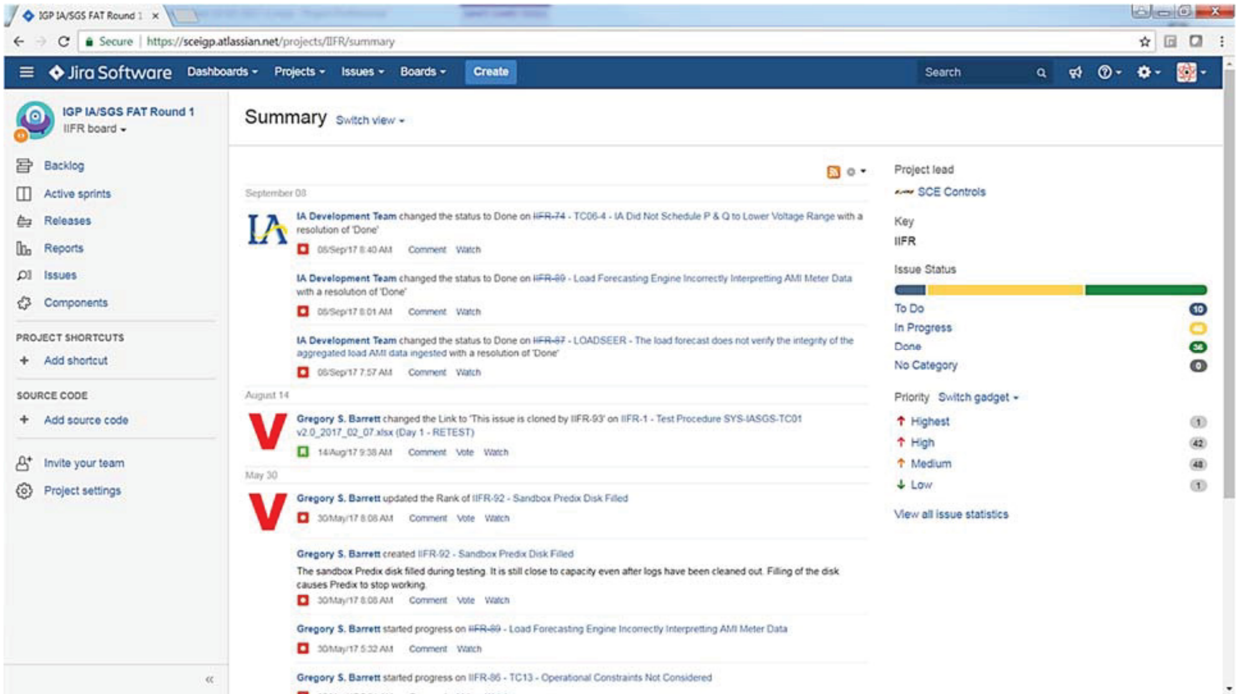

Figure 12: Sample Screen Shot of Jira FAT 1 Test Tracking

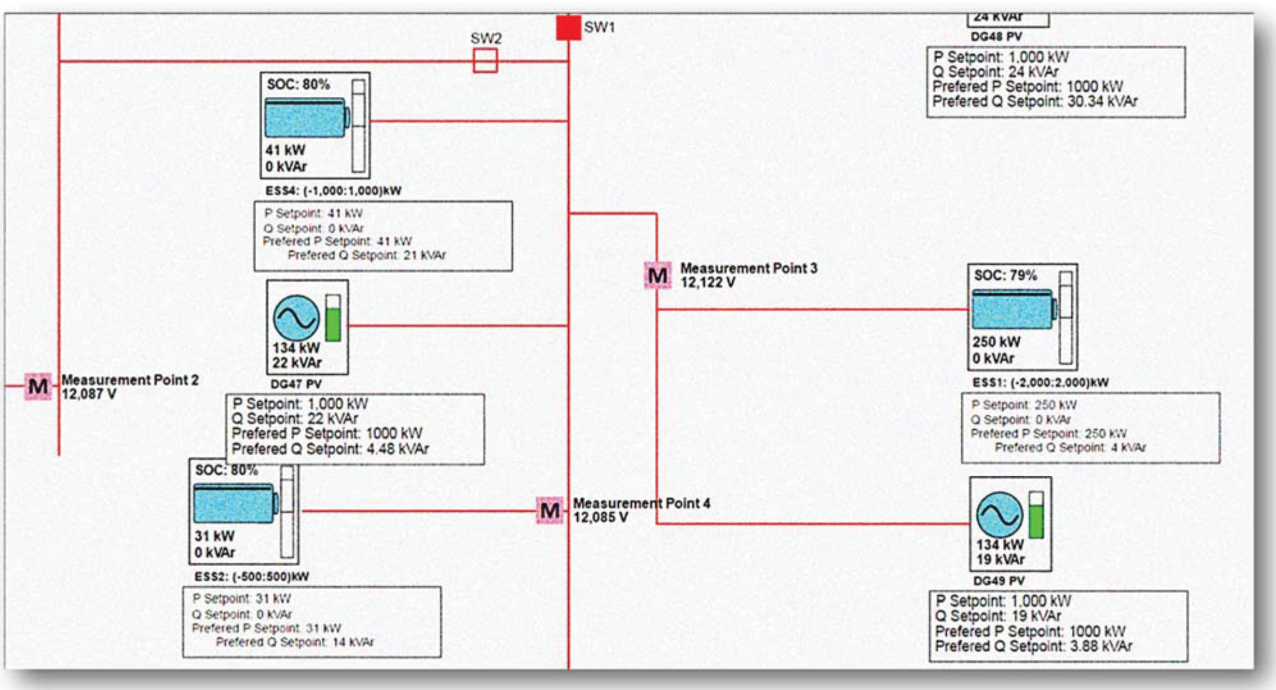

Figure 13: Sample Screen Shot of Reference Diagram Loaded Into Jira to Assist with Testing

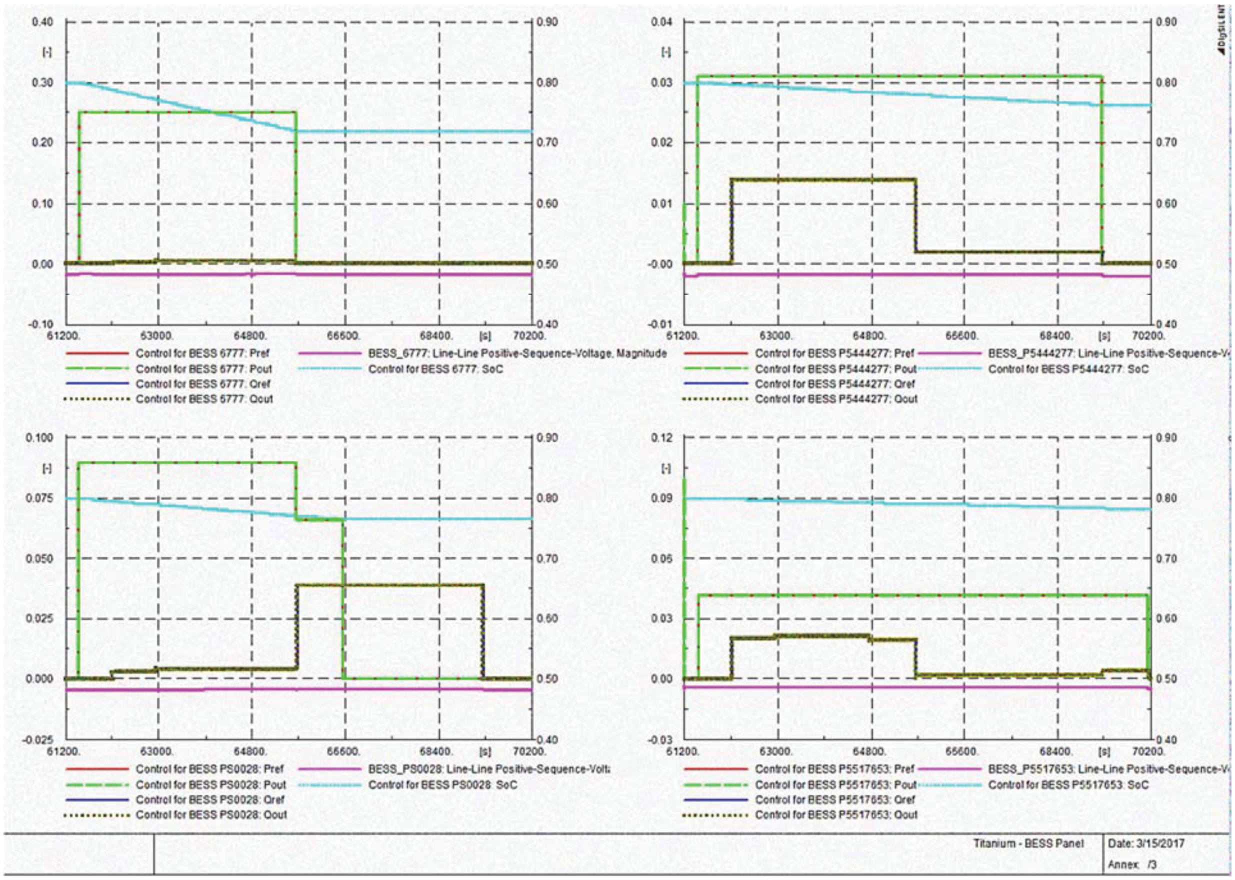

FIGURE 14: SAMPLE SCREEN SHOT OF TEST CHART LOADED INTO JIRA TO ASSIST WITH COMMUNICATING AND EVALUATING RESULTS

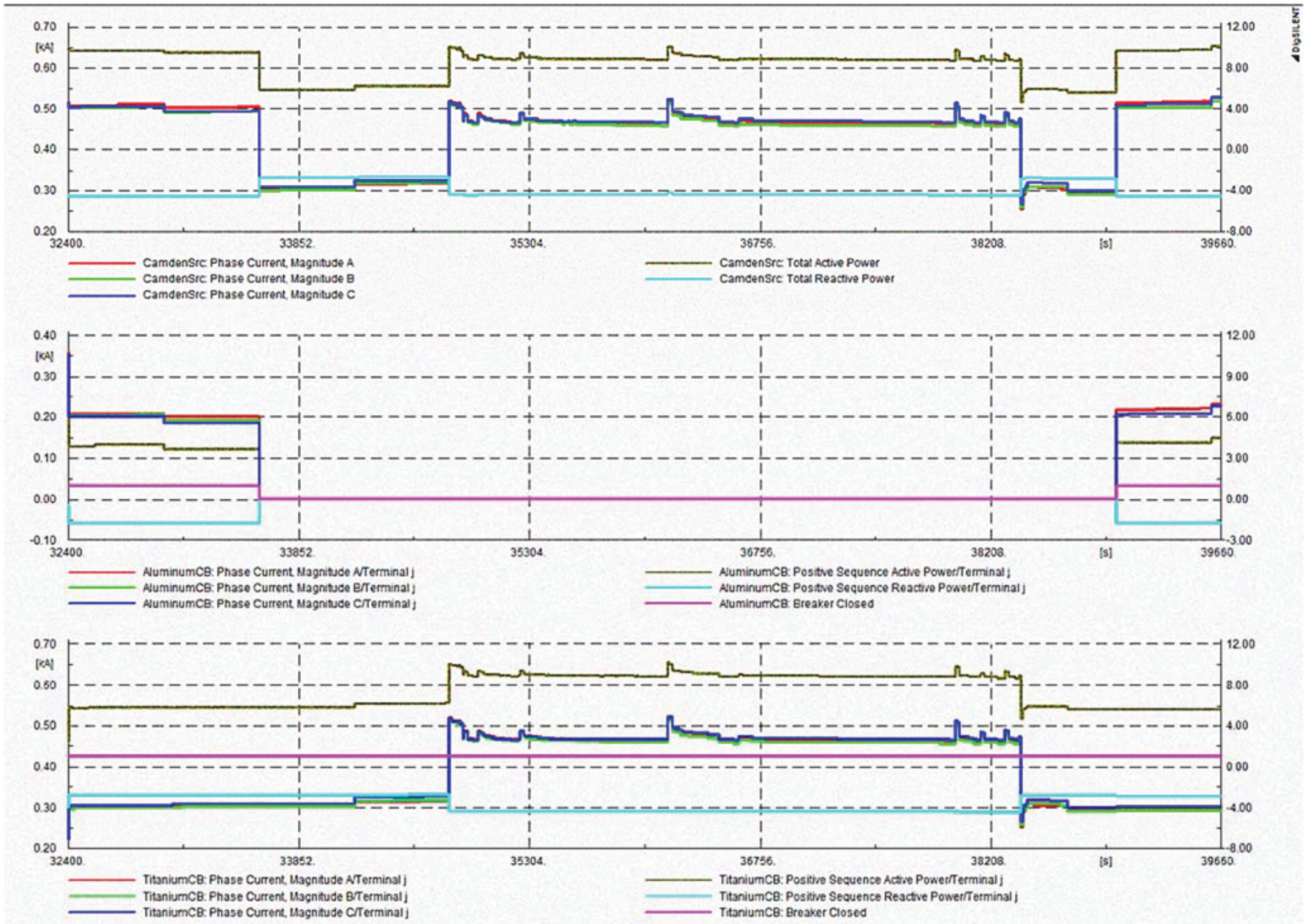

Figure 15: Sample Screen Shot of Test Chart Loaded Into Jira to Assist with Communicating and Evaluating Results

Appendix 6.3: Test Cases / Procedures

Unit Level Test Cases
Unit Testing: Pre-FAT

Test Number	Test Name	Test Description
Predix/UIB		
Unit-Predix-TC01	UIB Installation	This test validates the entire installation process for GE Predix Grid.
Unit-Predix-TC02	UIB Custom Service Installation/Update/Configuration	This tests validates that a services written for GE Predix Grid can be installed, updated, and configured.
Unit-Predix-TC03	UIB Benchmarking	This test case will validate the system's ability to capture standard UIB benchmarking metrics. These metrics will be used for all sub-test cases defined within this section.

Integration Level Test Cases
Integration Testing: FAT / SAT / PAT

Test Number	Test Name	Test Description
DMS		
INT-DMS-TC01	DMS Collection of Data	RFI, RCS+, RIS, DS, and various DER units are interfaced with the DMS during the testing. Data logs and DMS user interfaces are used to show that the data is valid. Trends of data streams from the various devices are compared with known states to confirm that the data is being obtained by the DMS system, and that the data is accurate.
INT-DMS-TC02	DMS Adapter Registration of IGP Assets	Validate the DMS Adapter has been properly configured to publish all required IGP asset data.
INT-DMS-TC03	Daily CIM 14 Electrical Network Topology File	This test validates the creation and availability of the CIM 14 file which gives the controller vendors the current topology of the electrical network.
INT-DMS-TC04	Validate Data Flow - Failsafe Switch	This test case validates the activation of the DMS Failsafe switch disconnects the IGP Assets and places the system in the failsafe mode.

Integration Testing: FAT / SAT / PAT

Test Number	Test Name	Test Description
IA - SGS		
INT-IASGS-TC01	IA/SGS Control System I/O	This test case verifies the IGP IASGS control application's ability to get system and sensor data in, control signals out, and each control action/response is logged as described in the associated tests.

2030.5		
INT-2030.5-TC01	2030.5 Integration Tests	This test case verifies the 2030.5 Server's ability to receive immediate and scheduled setpoint from the IGP controllers as well as posting status and alarm information back into the IGP system described in the associated tests.

SECURITY		
INT-SEC-TC01	Microsoft Certificate Services (MCS) Installation	This test verifies the proper installation of Microsoft Certificate Services components, described in the associated tests, and are available to IGP apps, users, devices and services.
INT-SEC-TC02	Splunk System Installation	This test verifies the proper installation of Splunk Enterprise and Forwarders Forwarder components to receive, process and store nSyslog messages for IGP as described in the associated tests.
INT-SEC-TC03	Palo Alto (PA) Firewall Installation and Configuration	This test verifies the proper installation and configuration of Palo Alto (PA) Firewall components to restrict the IGP information flows to the proper domains as described in the associated tests.
INT-SEC-TC04	Palo Alto Panorama	This test verifies the proper installation and configuration of a PA Panorama instance to manage, monitor, and collect logs for the Palo Alto firewalls as described in the associated tests.
INT-SEC-TC05	Imperva Installation and Configuration	This test verifies the proper installation and configuration of the Imperva system to support the IGP environment as described in the associated tests.
INT-SEC-TC06	CyberArk	This test verifies the proper installation and configuration of the CyberArk system to support the IGP environment as described in the associated tests.
INT-SEC-TC07	ForeScout	This test verifies the proper installation and configuration of the ForeScout system to support the IGP environment as described in the associated tests.
INT-SEC-TC08	RSA	This test verifies the proper installation and configuration of RSA system to support the IGP environment as described in the associated tests.
INT-SEC-TC09	Qualys	This test verifies the proper installation and configuration of Qualys system to support the IGP environment as described in the associated tests.
INT-SEC-TC11	Microsoft Certificate Services Usage	This test verifies that the IGP clients can request and use MCS certificates as described in the associated tests.
INT-SEC-TC12	Splunk Usage	This test verifies the proper establishment of, monitoring by, and alerting by Splunk in the IGP environment as described in the associated tests.
INT-SEC-TC13	Active Directory Installation and Configuration	This test verifies the proper installation and configuration of Active Directory (AD) system to support the IGP environment.

Integration Testing: FAT / SAT / PAT

Test Number	Test Name	Test Description
Predix/UIB		

INT-UIB-TC01	Integration Service Performance and Functional Tests	This test case verifies the UIB Integration Service performance and function as described in the associated tests.
INT-UIB-TC03	UIB Management	This test case validates proper operation of the management and monitoring functionality of GE Predix Grid using the management user interface as described in the associated tests.
INT-UIB-TC04	UIB Troubleshooting	This test case verifies the GE Predix Grid's troubleshooting abilities, described in the associated tests, as required by IGP.

FAN

INT-FAN-TC01	Customer Smart Inverter Control Test	This test case verifies the proper interfacing to a third party control application (FAN connected Distributed Energy Resource (DER)).
INT-FAN-TC02	FAN NMS Connectivity	This test case verifies the proper connectivity of the FAN Network Management System (NMS) to Grid2 for monitoring and control of FAN radios.
INT-FAN-TC03	FAD/WID to CSP	This test case verifies the proper interfacing of the FAN Aggregation/Wide Area Interface Device to Common Substation Platform (CSP) platform.
INT-FAN-TC04	Substation IEDs to CSP	This test case verifies the proper connectivity of substation (SS) IEDs to CSP.
INT-FAN-TC05	Substation Cap Bank to CSP	This test case verifies the proper connectivity of an SS Capacitor (Cap) Bank to CSP.
INT-FAN-TC06	FAD to Field Radios	This test case verifies the proper connectivity of the FAN Aggregation Device (FAD) to field radios at Intelligent Edge Devices (IEDs).
INT-FAN-TC07	FAN RIS Radio to FAN RIS Field Agent	This test case verifies the proper interfacing of a Remote Intelligent Switch (RIS) radio to the field agent.
INT-FAN-TC08	FAN Smart Inverter Radio to Field Agent	This test case verifies the proper interfacing of Smart Inverter radio to the field agent.
INT-FAN-TC09	FAN ESS Radio to Field Agent	This test case verifies the proper interfacing of an Energy Storage (ESS) radio to the field agent.
INT-FAN-TC10	FAN PCC Radio to Field Agent	This test case verifies the proper interfacing of a Programmable Cap Controller (PCC) radio to the field agent.
INT-FAN-TC11	FAN Radio to RIS	This test case verifies the proper interfacing of a FAN radio to a RIS IED.
INT-FAN-TC12	FAN Radio to Smart Inverter	This test case verifies the proper interfacing of a FAN radio to a Smart Inverter IED.
INT-FAN-TC13	FAN Radio to ESS	This test case verifies the proper interfacing of a FAN radio to an ESS IED.
INT-FAN-TC14	FAN Radio to PCC	This test case verifies the proper interfacing of a FAN radio to a PCC IED.
INT-FAN-TC15	FAN Field Agent to SGSConnect	This test case verifies the proper interfacing of a FAN field agent to the SGSConnect app.
INT-FAN-TC16	FAN Smart Inverter Field Agent to SGSConnect	This test case verifies the proper interfacing of a Smart Inverter field agent to the SGSConnect app.
INT-FAN-TC17	FAN ESS Field Agent to SGSConnect	This test case verifies the proper interfacing of a FAN ESS field agent to the SGSConnect app.

INT-FAN-TC18	FAN PCC Field Agent to SGSConnect	This test case verifies the proper interfacing of a FAN PCC field agent to the SGSConnect app.
INT-FAN-TC19	Legacy NetComm System to Failsafe Switch	This test case verifies the proper interfacing between the legacy NetComm system and the IGP Failsafe switch.
INT-FAN-TC20	FAN Microgrid Control Point Radio to Field Agent	This test case verifies the proper interfacing of the Microgrid Control Point (MCP) radio to the field agent.
INT-FAN-TC21	FAN Radio to Microgrid Control Point	This test case verifies the proper interfacing of a FAN radio to a Microgrid Reference Point (MRP) IED.
INT-FAN-TC22	FAN Microgrid Control Point Field Agent to SGSConnect	This test case verifies the proper interfacing of an MRP field agent to the SGSConnect app.
INT-FAN-TC23	Beaglebone to FAN Radio	This test case verifies the proper interfacing of a Beaglebone to a FAN radio. (Contingency Test)
INT-FAN-TC24	PCC to Beaglebone	This test case verifies the proper interfacing of a PCC IED to a Beaglebone. (Contingency Test)
INT-FAN-TC25	RIS to Beaglebone	This test case verifies the proper interfacing of a RIS IED to a Beaglebone. (Contingency Test)
INT-FAN-TC26	Smart Inverter to Beaglebone	This test case verifies the proper interfacing of a Smart Inverter IED to a Beaglebone. (Contingency Test)
INT-FAN-TC27	ESS to Beaglebone	This test case verifies the proper interfacing of an ESS IED to a Beaglebone. (Contingency Test)
INT-FAN-TC28	Loss of Radio Communications - Single Device	This test case verifies the proper response of the IGP system for a loss of radio communications with a single FAN device.
INT-FAN-TC29	Loss of Radio Communications - Multiple FAN Devices	This test case verifies the proper response of the IGP system for a loss of radio communications with multiple FAN devices.
INT-FAN-TC30	Remote FAN Radio Firmware Upgrade	This test case verifies the proper firmware upgrading of a remote FAN radio.
INT-FAN-TC31	Remote Field Agent upgrade on FAN Radio	This test case verifies the proper upgrading of a remote field agent on a FAN radio.

ESS

INT-ESS-TC01	Bulk Power System Markets Communications for ESS	This test case verifies the proper communication of Bulk Power System (BPS) market information for an IGP ESS.
INT-ESS-TC02	Aggregation of ESS Available for BPS Market Participation	This test case verifies the proper aggregation by the IGP system of available ESSs for participation in BPS market.

Network Infrastructure

INT-NET-TC01	Provisioning of New DER on Network	This test case verifies the proper provisioning of a new DER on the network infrastructure.

INT-NET-TC02	Removal of Existing DER from Network	This test case verifies the proper removal of an existing DER from the network infrastructure.
INT-NET-TC03	Loss of Network COMMs between IGP SS and Back Office	This test case verifies the proper response of the IGP system for a loss of network communications between an IGP substation (SS) and the back office.
INT-NET-TC04	Restoration of Network COMMs between IGP SS and Back Office	This test case verifies the proper restoration of network communications between an IGP SS and the back office.

System Level Test Cases
System Testing: FAT / SAT / PAT

Test Number	Test Name	Test Description
DMS		
SYS-DMS-TC01	Improved DMS Power Flow Estimation	This test verifies collection of actual field data allows for the DMS power flow state estimation to be improved by modifying assumed loads and energy sources to match the measured conditions. The DMS is able to use the actual power values of a DER inverter or storage unit. Additionally, any current flow where there is a difference between the actual flow and the state estimation allows for iteration of the feeder load profile to better match the measured condition. A power flow situation is established where the actual flow through a monitored switch is much higher than the state estimation provides.
SYS-DMS-TC02	Improved CLT Capability of DMS	This test does switching to allow the re-connection of feeder load for maintenance purposes. The Contingency Load Transfer (CLT) capability of the DMS is enhanced by the improved power flow state estimation. A condition is set up where the monitored current magnitude is much larger than the value returned by the state estimation. The CLT system initially provides a recommended switching scheme that would result in an overload, because the estimated power flow does not include the higher value of current through the switch. When the "blinder" is lifted, the system receives the current switch current magnitude, and the CLT responds to the corrected power flow state estimation. As a result, a better switching scheme is put forward, so that an unnecessary outage does not occur which would have negatively affected feeder reliability (SAIDI, CAIDI) levels.
SYS-DMS-TC03	Improved FDIR Capability of DMS	This test case tests response to a fault condition where the re-connection of feeder load is done following the isolation of a faulted section. The Fault Detection, Isolation, and Restoration (FDIR) capability of the DMS is enhanced by the improved power flow state estimation. A condition is set up where the monitored current magnitude is much larger than the value returned by the state estimation. The FDIR system initially provides a recommended switching scheme that would result in an overload, because the estimated power flow does not include the higher value of current through the switch. When the "blinder" is lifted, the system receives the current switch current magnitude, and the FDIR responds to the corrected power flow state estimation. As a result, a better switching scheme is put forward, so that an unnecessary second outage does not occur which would have negatively affected feeder reliability (SAIDI, CAIDI) levels.
SYS-DMS-TC04	Validate Failsafe Switch	This test case validates the operation of IGP failsafe switching.

System Testing: FAT / SAT / PAT

Test Number	Test Name	Test Description
IA/SGS		
SYS-IASGS-TC01	Communication Failure Testing	This test case validates that the control system responds to loss of communication with necessary system devices in a manner that does not damage or cause instability in the electrical distribution system. This test is specifically to test the resilience and stability of the control system when experiencing communication failures as described in the associated tests.
SYS-IASGS-TC02	System Objectives and Priorities for Automated Control Modes	This test case validates the IGP control system maintains proper priority in all of the modes of operation as described in the associated tests.
SYS-IASGS-TC03	Demand Forecast and State Estimation	This test case validates the IGP controller accepts inputs from the SCADA and the DMS systems and adds to it information on controlled DER status and power levels.
SYS-IASGS-TC04	Controller Settings and Business Rules	This test case validates the ability to add/change/delete business rules to govern the operation of the IGP controller and the operation of control is constrained by these parameter. Business rules will include compensation during curtailment and also cover third party aggregators and controlled PV.
SYS-IASGS-TC05	Volt/VAR Circuit Conditions and State Estimation	This test case validates the IGP system's analytic capability to perform state estimation from the system topology, measured, and status information. The system is able to screen for a site that is reporting a value (bad data) that is outside the normal range.
SYS-IASGS-TC06	Volt/VAR Modes of Operation and Settings	This test case validates the Volt/VAR control system modes of operation and settings as described in the associated tests.
SYS-IASGS-TC07	Volt/VAR Controller Performance	The associated test cases validate the Volt/VAR controller maintains feeder and substation voltage and VAR within Setpoints of operation, sends control commands to system devices, responds to changes in circuit load, and responds to changes in availability of DER based on environmental factors such as PV production and storage capacity forecasts. The distribution circuit emulator, Digsilent, will be used to present various control scenarios to the test system.
SYS-IASGS-TC08	Optimal Power Flow Communication Failure Testing	This test case validates the IGP Optimal Power Flow (OPF) controller responds to loss of communication with necessary system devices in a manner that does not damage or cause instability in the electrical distribution system. This test is specifically to test the resilience and stability of the IGP Optimal Power Flow (OPF) control system when experiencing communication failures.
SYS-IASGS-TC09	Optimal Power Flow Demand Forecast and State Estimation	This test case validates the OPF controller accepts inputs from SCADA and the DMS system; augments those inputs with information on controlled DER status; estimates non-controlled PV generation and non-controlled BESS characteristics; provides a state estimation of the feeder conditions based on all of these inputs every 15 minutes; and provides a demand forecast every 15 minutes. This state estimation is used by the optimization in the controller.
SYS-IASGS-TC10	Optimal Power Flow Controller Settings and Business Rules	This test case validates the ability to add/change/delete OPF controller settings and business rules to govern the operation of the OPF controller and that the operation of the OPF controller is constrained by these parameters.

System Testing: FAT / SAT / PAT

Test Number	Test Name	Test Description

SYS-IASGS-TC11	Feeder or Feeder Segment Overload Protection	This test case validates the system manages DER to mitigate a monitored overload condition on a feeder or feeder segment (lateral) that ampacity limits (coordinated with system relaying protection) are being exceeded as described in the associated tests.
SYS-IASGS-TC12	Feeder Peak Load Reduction	This test case validates the DER output is optimized so as to reduce peak load conditions on a circuit when the IGP controller is in Feeder Peak Load Reduction mode of operation. The conditions is detected through monitoring from an RFI, RIS, or RCS+.
SYS-IASGS-TC13	Feeder Load Profiling	his test case validates the DER output is optimized to reduce the ramp rate of a changing load profile on a feeder circuit when the IGP controller is in Feeder Load Profiling mode of operation.
SYS-IASGS-TC14	Distribution Cost and Loss Minimization	This test case validates the OPF controller accepts LMP Node Cost for the feeder circuits and outputs dispatch signals to DERs in order to minimize distribution costs and losses. The LMP Node Cost from OASIS establishes the marginal cost of energy for the feeder, used in the calculation of line losses.
SYS-IASGS-TC15	Virtual Microgrid Communication Failure Testing	This test case validates the Virtual Microgrid controller responds to loss of communication with necessary system devices in a manner that does not damage or cause instability in the electrical distribution system. This test is specifically to test the resilience and stability of the Virtual Microgrid control system when experiencing communication failures.
SYS-IASGS-TC16	Microgrid Control Settings and Business Rules	This test case validates the ability to add/change/delete Virtual Microgrid controller settings and business rules to govern the operation of the Virtual Microgrid controller and the operation of the Virtual Microgrid controller is constrained by these parameters.
SYS-IASGS-TC17	Virtual Microgrid Controller	This test case validates the Virtual Microgrid function controls the available DER to reduce real and reactive power flow at a defined (microgrid) reference point under specified load conditions.
SYS-IASGS-TC18	Virtual Microgrid Speed of Response	This test case validates the microgrid control management of the real and reactive power dispatch. The lab environment will be optimal to evaluate the round-trip speed from change-in-load to optimal power flow control response, to inverter re-dispatch, and inverter response. This response characteristic in terms of speed of response.
SYS-IASGS-TC19	Dispatching the Reserve Capacity of Energy Storage Systems (ESSs)	This test case collects data for IGP determination/dispatch of Energy Storage Systems (ESSs) reserve capacity to maintain reliability on the circuit.

System Testing: FAT / SAT / PAT

Test Number	Test Name	Test Description
General		
SYS-GEN-TC01	Provisioning of New DER	This test case verifies the provisioning of a new DER described in the associated test cases.
SYS-GEN-TC02	Decommissioning of Existing DER for IGP	This test case verifies the decommissioning of an existing DER under the conditions described in the associated cases.
SYS-GEN-TC03	Manage Market Participation of ESS	This test case validates the management of market participation of an ESS.

Appendix 6.4: Use Cases

⇨ Use Case 2-1

Title: Voltage Optimization with DER

Summary: The substation-level volt/VAR controller optimizes feeder voltage using capacitors and DERs (generation and storage devices) equipped with smart inverters. The grid management system (GMS) optimizes feeder voltage by lowering and flattening the voltage profile along the feeder so it remains in the lower portion of the 114-120 volt range for commercial and residential customers.

Detailed Narrative:

- The centralized volt/VAR system being deployed at SCE uses circuit and substation switched capacitors (SCs) to obtain the lowest, flattest voltage profile through switching the optimum capacitor combination. The algorithm works well with light penetrations of variable generation resources, but falls short in high penetration cases. This use case describes how inverter-based distributed energy resources (DERs), including PV and distributed storage (DS) can be integrated into the GMS and its optimization system (OS) in order to facilitate a centralized volt/VAR algorithm to respond more quickly to voltage variations caused by high penetrations of DERs and still maintain the proper circuit voltage profile.
- In addition to the voltage data being obtained today from SC controllers, the new centralized volt/VAR controller will have access to voltage information from DERs, remote fault indicators (RFIs), remote intelligent switches (RISs), and remotely controlled switch retrofits (RCSs). The volt/VAR controller processes the input voltage data and determines the best combination of SCs and inverter set points to maintain proper circuit voltage. In this scenario, the inverters will operate autonomously using the set points passed to them by the centralized volt/VAR controller. The communications path for the 3rd party-owned DER will be either through the Internet, cell data connection or SCE field area network (FAN). For aggregators, this communications will most likely be through the Internet portal for the aggregator.
- The project will utilize battery energy storage system inverters installed by SCE, as well as other 3rd party-owned inverters as available. Smaller inverters controlled by aggregators will be integrated in a later portion of the project if possible.
- Example: On a 15-minute basis the centralized volt/VAR algorithm will examine voltages from monitoring points in its area of control and determine which capacitors need to be switched and what set points need to be sent to the inverters. These switching commands and inverter set points are then sent to the field devices. Second-to-second control will be the responsibility of the SC or inverter controller.

⇨ Use Case 3-3

Title: DERs Managed Shape Feeder Load

Summary: At the feeder level, the GMS and its OPF optimizes loads, generation, and storage to shape the load to meet operational requirements at a given time.

Detailed Narrative:

- Increasing amounts of distributed energy resources (DERs) are being connected to distribution circuits requiring a change in the way these circuits are operated. At the same time, these DERs provide the opportunity to regulate real and reactive power flows in manners not possible in the past. These circuit optimization opportunities require good communications to the DER as well as a centralized optimization control system to coordinate actions and keep distribution operations informed of the circuit status. This use case describes how control of DERs and monitoring provided by DERs, remote fault indicators (RFIs), remote intelligent switches (RISs), and remotely controlled switch retrofits (RCSs) can be used to shift peak load to improve the load shape. It is important to keep in mind that contracts with 3rd party DERs need to allow for these functions.

- The installation of advanced monitoring devices on distribution circuits will allow for the identification of cases where peak load could be shifted using PV output reduction, distributed storage (DS) discharge, and/or load control. The monitoring data will be communicated to the grid management system (GMS), which manages the optimal power flow (OPF). Monitoring will be provided by RFIs, RISs, and RCSs, and the DERs themselves. Interfaces will be implemented to allow the grid management system (GMS) to exchange status and control information with SCE-owned DERs, DER aggregators, and 3rd party-owned DERs. The communication path for the SCE-owned DERs, RFIs, RISs, and RCSs will be the SCE field area network (FAN). The communication path for the 3rd party-owned DERs will be either through the Internet, cell data connection or FAN. For aggregators, this communications will most likely be through the Internet portal for the aggregator. Additional information will need to be exchanged with the aggregator so each DER resource can be associated with a circuit segment. This will allow the DER data to be integrated into the OPF.
- In addition to monitoring, control will be needed to vary the real and reactive power from DER devices. The communication needed to control the DER devices will be provided by the same communication channels that provide monitoring capabilities. The GMS will collect status information and use the OPF to help uncover cases where DERs can be used to shift peak load to improve the load shape and calculate needed modifications to DER operating points. The GMS then determines the best option to reduce circuit peak loading and sends commands to the DER devices through the FAN or Internet to flatten the peak circuit load. Data is forwarded back to the GMS so that distribution system operators will be updated on the present state of the system.
- Example 1: Peak Load Reduction
- Battery storage discharge during peak periods can reduce peak load conditions of a circuit. This condition is detected through monitoring from RFI, RIS or RCS+. The GMS observes this condition and calculates levels of DER output that would best flatten the peak load condition.
- Example 2: Managing the Duck Curve
- Use of all available DERs during the afternoon's decrease of solar output can reduce the ramp rate needed for other generation sources. This condition is detected through monitoring from RFIs, RISs or RCSs. The GMS observes this condition and calculates levels of DER output that would best minimize the ramp rate of other generating sources.

⇨ Use Case 4-1

Title: Microgrid Control for Virtual Islanding

Summary: A Microgrid controller uses control of loads, generation and storage to reduce real and reactive power flows to zero at a specified reference point on a distribution feeder for a pre-determined period of time.

Detailed Narrative:

- Increasing interest in microgrids coupled with greater amounts of distributed energy resources (DER) being connected to distribution circuits may provide an opportunity to investigate islanding portions of the SCE distribution system. These microgrids are different than most others because they are on the utility side of the meter and involve utility assets and multiple customers. While the microgrid contemplated as part of this use case will not be able to island, it will show how a distribution grid operator (DGO) with support from the grid management system (GMS) could control the load and generation on a circuit segment. This control of load and generation will enable shaping of the circuit load pattern to minimize losses and defer the need to upgrade circuit infrastructure. This use case describes DER can be controlled to reduce the real and reactive power flow on a portion of a circuit to zero. Since the microgrid will not be islanded, there is no risk of dropping customer loads due to imbalance of load and generation. Load control and DER (e.g. PV and battery storage) used in this subproject will be owned by SCE and 3rd parties so it is important to keep in mind that contracts with these 3rd party resources need to allow for these functions.

– In addition to the monitoring capability added to the distribution circuits by installation of remote fault indicators (RFIs), remote intelligent switches (RISs), and remotely controlled switch retrofits (RCSs) another reference point may be installed on the selected circuit to act as a control point. Data from this control point will be used by the GMS and its optimization system (OS) and/or, if a microgrid controller is installed, the microgrid controller software to balance load and generation. All of the monitoring data will be communicated using the SCE field area network (FAN) or other communication channels. This data could flow to the OS or, if applicable, directly to the microgrid controller. In either case the DGO would have to be informed on the state of the distribution circuit. The intent of this use case is to be able to control current at the reference point to a low value that is below a pre-set threshold.

– The choice of the reference point will depend upon the amount of connected load and available DER and distributed storage (DS) required to balance it. Temporary monitoring of the circuit at several locations will provide information to select the reference point. If an RIS is installed at the right location, a separate reference point will not need to be installed. While it would be ideal to control real and reactive power on a second-by-second basis, the need for this high-speed control is unclear. The use case will establish the timing needed for this control function.

– Example: Load and sufficient PV generation and DS are located beyond a reference point on a distribution circuit segment. A microgrid controller polls the reference point to determine the real and reactive power flows. It then issues commands to modify the set points for demand response, PV generation and battery storage to reduce the flows to zero. This process is repeated on a regular basis to keep the flows at the reference point below the pre-set low threshold. Status information is forwarded to the DGO on a regular basis to maintain situational awareness.

⇨ Use Case 9.1

Title: Dual Use of Utility Controlled Distributed Energy Storage Systems.

Summary: Utility controlled energy storage systems (UCESS) deployed on the distribution grid are integrated, configured, and controlled so as to allow their use for the following two functions:

– Use of UCESS by the utility for distribution grid reliability and optimization needs.

– Bidding of UCESS assets (or portion of) to the wholesale market when not needed for reliability and optimization purposes.

– Operationally, the UCESS will be operated, including when bid into the wholesale market, constrained by the reliability needs of the distribution grid.

Detailed Narrative:

– In October 2013, the CPUC issued Decision 13-10-040, which adopts an energy storage procurement framework and establishes an energy storage target for independently owned utility companies including SCE. Per the CPUC decision, SCE now has an energy storage procurement requirement of 580MW, with procurement required no later than 2020 and installations no later than 2024. SCE may elect to own and operate ESS or procure the service of third-party ESS to serve the two described functions.

– This use case will accomplish this goal by utilizing UCESS for (1) improving grid reliability and optimization resulting in upgrade deferral of grid assets and (2) generating revenue through UCESS participation in wholesale energy markets. The following sections elaborate on this dual use concept. This use case applies to any energy storage system (ESS) that is under full utility control, whether it is own by the utility or under a service contract.

Utilization Scenario Phase 1: Determine UCESS usage for Reliability and Optimization

– SCE's priority is to use the UCESS to improve grid reliability and mitigate the cost of distribution system upgrades. UCESS will be a key component of the overall utility's Distributed Energy Resources (DER) and will be used/leveraged for the following control applications for which dedicated use cases exists:
  1) Volt/VAR Control described in the document "IGP Use Case: 2.1 Voltage Optimization with DER"

2) OPF control described in the document “IGP Use Case: 3.3 DER Managed to Shape Feeder Load”
3) Virtual Microgrid described in the document “IGP Use Case: 4.1 - DER Microgrid Control for Virtual Islanding”

- For this utilization scenario phase, the ESS under utility control will be integrated with centralized and/or distributed control applications and will be managed by a hierarchical control methodology based on the entire DER composition. Given the distributed nature of the UCESS, adequate and reliable communications infrastructure and network availability will be required.
- The IGP control application will forecast the output of the various DER resources, as well as the load on the connected customers, starting with the closest DER resources to the UCESS and the closest customers and working outward. Once this forecast is created, the IGP controller can determine the optimal capacity and schedule for the UCESS to charge and discharge. Because of the difference in operational life, and other characteristics of each UCESS, the forecasting system has to take into account the associated operational cost (including life degradation) by the UCESS for each operation and assess the system true operating cost. The second optimization may cause a divergence from a pure technical optimization.
- Once a converged schedule is created that maximizes the production of DER, creates manageable ramp rates, and manages the costs of using storage and demand response, the IGP control application can finalize the storage schedule and release it for operation. Typically, the schedule will be for day ahead operation. The UCESS needs to be monitored as the day progresses, to see that the actual forecasts are being realized and that the UCESS schedule continues to be within the parameters (e.g., charging rates, discharge times, etc.) set for the specific UCESS unit.
- Should the UCESS or the forecast deviate beyond the limits set by the schedule, an updated schedule will be calculated and, if necessary, distributed generation or demand response schedules will be changed. The monitoring and adjustments will be made as needed, and operate within the parameters set by the characteristics of the UCESS.
- Typically, the process for using UCESS for grid reliability and optimization could be summarized as follows:

1) IGP control application will forecast the output of the various DER resources, as well as the load

2) The IGP controller will determine the optimal capacity and schedule for the UCESS to charge and discharge

3) UCESS will be monitored as the day progresses, to see that the actual forecasts are being realized

4) Should the UCESS or the forecast deviate beyond the limits set by the schedule, an updated schedule will be calculated

Utilization Scenario Phase 2: Manage UCESS Wholesale Market Participation

- For this phase, the utility’s distribution operation is assumed to be optimized and the UCESS assets or a portion of can be considered available for alternate use such as participation in the wholesale market. The dispatch of the market allocated capacity will be facilitated by an application that aggregates the capacity distributed among various available UCESS within the same wholesale market price node. Integration with SCE’s existing generation management system and generation outage management system will be required.
- The aggregated UCESS units or portion thereof that are available for the wholesale market can be bid into a number of market segments, such as the energy market, frequency regulation (up and down), spinning reserve, non-spinning reserve, or other segments. Some of these segments exist in the current CAISO market, but many of them are under discussion although they may be in use in other US wholesale markets (e.g., PJM). In many cases the ancillary services bids are more lucrative and offer more flexibility in the case of an emergency or when a circuit drifts out of forecast.
- Typically, the process for using UCESS in the wholesale market would be as follows:

1) Assess the aggregated UCESS capacity (as generation and load) that can be made available to the wholesale market; the following criteria should be considered

a. Generation (discharge) and load (charge) capacity made available to the market could be constrained independently

b. Capacity may be dispatched at any time, without notice within the set constraints (as such, the application need to define not the un-used UCESS capacity, but rather the capacity that can be used by the market without impacting the grid optimization scheme)

2) Provide generation and load capacity, and additional constraints to the wholesale market

3) Upon reception of a dispatch command from the wholesale market.

a. Allocate the dispatch command between the various aggregated UCESS based on optimization model or current condition

b. Send appropriate commands to each individual UCESS

4) Adjust aggregated UCESS capacity available to the wholesale market based on current grid condition (e.g., unexpected event, drift in forecast)

Third party owners of ESS have the option of directly bidding their storage systems into the wholesale market without direct control from the distribution operator (but respecting distribution system constraints). The ESS approved wholesale schedule may be available to the distribution operator, and may be added to the forecast as both a load (charging) and generation (discharging). The schedules are typically accepted 8 to 24 hours prior to operation. These ESS are not available to distribution management scheduling except in emergency.

For the purposes of the IGP field demonstration, a phased approach will be taken and the following three implementation phases will be considered in chronological order:

- Implementation Phase 1: IGP control system keeps all available UCESS capacity for internal reliability/optimization. No capacity is offered to the wholesale market.
- Implementation Phase 2: IGP control system offers specific UCESS capacity for a specific fixed period of time.
- Implementation Phase 3: IGP control system offers UCESS capacity to the wholesale market dynamically.

Appendix D

Proactive Storm Impact Analysis Demonstration

Final Project Report

Proactive Storm Impact Analysis Demonstration Final Project Report

Developed by

SCE Transmission & Distribution, Grid Technology and Modernization

December 2018

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Acknowledgments

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1 Executive Summary

Climate change is increasingly affecting weather and the environment, specifically producing more extreme weather events. After experiencing significant outages from severe windstorms in late 2011, SCE conducted an extensive evaluation, known as the Corporate Storm Process Improvement Program (CSPIP), which determined the need for improvements in the areas of storm operations, management and restoration. As part of the California Public Utilities Commission's (CPUC) approval of Southern California Edison's (SCE) 2012 Rate Case.[1] SCE submitted a plan via advice letter, identifying additional improvement steps for demonstration of an enhanced situational awareness model.[2]

Initial models that met the CPUC requirements for improving windstorm-related outage durations were created outside the scope of the Proactive Storm Impact Analysis Demonstration Project described in this report. Through the CSPIP, tools for storm modeling and management using basic weather, outage and resource data were developed. However, these models required manually intensive operations to prepare input data and run the tools. Based on this challenge, SCE determined that the opportunity still existed to demonstrate predictive storm analytics to proactively plan and provide more accurate and reliable post-storm assessments.

The Proactive Storm Impact Analysis Demonstration Project aimed to evaluate more robust storm predictive analytics based on improved modelling tools, including integration of weather forecasts, operations and resource usage data. SCE's Grid Technology and Modernization group worked in collaboration with a third-party partner on a proof-of-concept (PoC) with visualization and reporting capabilities.

Results from this solution – which comprises a storm classifier model and asset models for cables, conductors, transformers and poles – indicate potential to help contribute toward SCE's ability to better predict the number of staff and materials needed prior to the arrival of a storm, and at what location. Given these capabilities to forecast the impact of the intensity and duration of rain, wind and heat, SCE should have the ability to pre-stage crews and materials, thereby enhancing the ability to respond as quickly and efficiently as possible.

2 Project Summary

The Proactive Storm Impact Analysis Demonstration Project was designed to improve operational efficiency and reduce the costs associated with storm-related outages through enhanced data analytics and forecasting capabilities. Based on the results and learnings from the project, SCE is better prepared to react to more extreme weather events from climate change. Specific expected benefits to SCE include:

1. Shorter and more accurate response times achieved due to the pre-emptive allocation of operational resources across SCE's service territory;
2. Pre-emptive customer communication/engagement in the event of expected storms;
3. Enhanced resource utilization efficiency and planning for the Transmission & Distribution (T&D) and Corporate Incident Management teams during storm conditions;
4. Operational cost savings by providing awareness that enables Grid Operations to appropriately pre-stage and schedule T&D operations resources to avoid excessive overtime;
5. Improved intelligence for enhanced decision-making by SCE Incident Management teams, Corporate Communications, Government Affairs, and Customer Service; and

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1 CPUC Decision (D.)12-11-051.

2 CPUC Advice Letter 2845-E.

6. Increased corporate-wide situational awareness of potential outage conditions related to inclement weather.

The Proactive Storm Impact Analysis Demonstration Project was proposed as part of SCE's Electric Program Investment Charge (EPIC) investment plan application.[3] EPIC, adopted by the CPUC in 2011, aims to fund applied research and development technology demonstrations and deployments, as well as market facilitation programs, for the benefit of ratepayers of California's investor-owned utilities (IOU). During the first EPIC triennial (2015-2017) planning period, the IOUs collaborated to develop a common methodology for assessing technology demonstrations and deployments. This Joint Utilities EPIC Framework (Figure 1. Joint Utilities EPIC Framework), which the CPUC adopted, presents a broad spectrum of smart grid capability gaps.

As part of the EPIC process, before IOU EPIC administrators can submit an investment plan application, the administrators must hold at least two stakeholder engagements. During a joint IOU webinar in 2014, NASA raised a question that identified a possible industry gap, inquiring whether EPIC administrators have an interest in cloud prediction technologies together with photovoltaic (PV) modeling to better estimate the impact of grid stability.

In response to NASA concern, SCE incorporated this feedback and created the Proactive Storm Impact Analysis Demonstration Project described in this report.

Based on the Joint Utilities EPIC Framework (Figure 1), SCE's demonstration project addressed both increased electric system safety and reliability due to its ability to provide a reliable and accurate warning system for identifying storm-related impacts and resulting outages.

This project also supported Grid Modernization and Grid Operations business resiliency strategic goals, as well as affordability, by proactively and cost-effectively predicting resources required for storm-related pre-staging, as well as resources needed to replace assets damaged from storm conditions.

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3 See "Application (A.)14-05-005 amendment to Application of Southern California Edison Company (SCE) for Approval of Its 2015-2017 Triennial Investment Plan for the Electric Program Investment Charge," May 1, 2014, for more details on the EPIC program and SCE's investment plan.

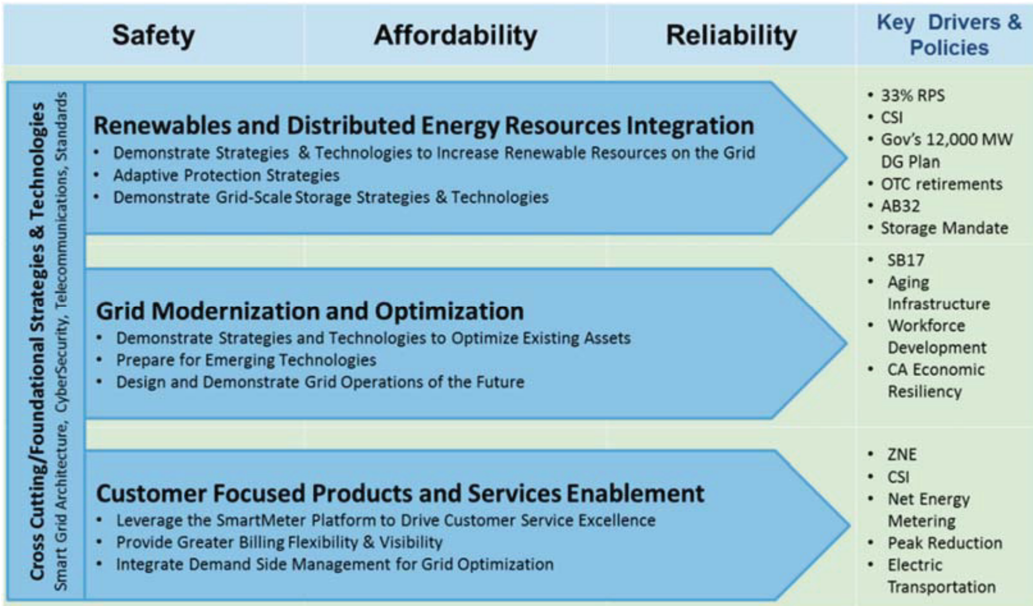

Figure 1. Joint Utilities EPIC Framework[4]

2.1 Problem Statement

Efficiently dealing with storm-related outages has long provided operational challenges for SCE and other electric utilities. Climate change is increasing the severity of these storms, making it critical for utility operations personnel to find a solution to more proactively respond in order to dispatch field crews quickly and efficiently and thus mitigate and minimize outage interruptions for customers.

Analysis from initial predictive models exhibited several limitations, including incomplete use of historical data, unknown or undocumented assumptions, limited application of advanced statistical methods, and a reliance on an inadequate amount of weather data.

The Proactive Storm Impact Analysis Demonstration Project focused on resolving these limitations by demonstrating a combination of enhanced data analytics and forecasting capabilities to improve SCE's ability to minimize customer impacts, improve operational efficiency, and reduce costs associated with storm-related outages.

2.2 Project Scope

The project team implemented the Proactive Storm Impact Analysis Demonstration Project via the three phases shown in Figure 2. Overview of the Predictive Storm Analytics Demonstration.

[4] For additional details on the Joint IOU EPIC Triennial Investment Plan Program Framework, see SCE's 2015-2017 Triennial Investment Plan Application, Amendment at pp. 12-13.

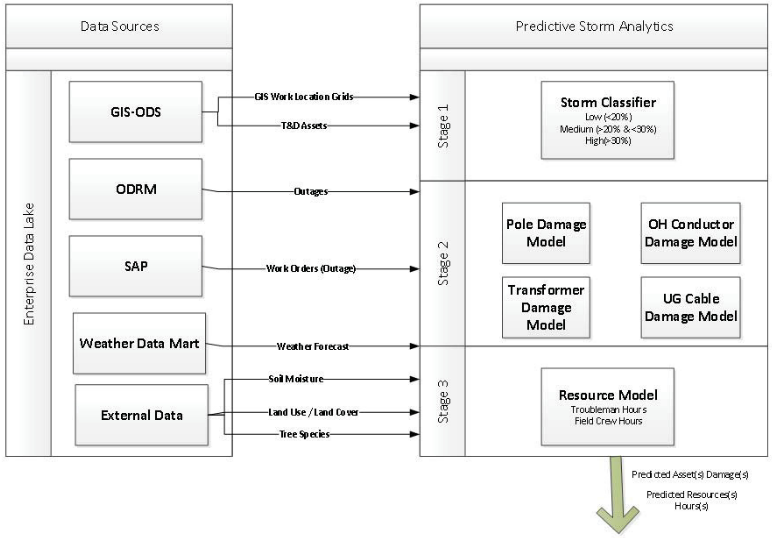

Figure 2. Overview of the Predictive Storm Analytics Demonstration

2.2.1 Phase 1: Proof-of-Concept Demonstration

In Phase 1, after collaborating with suppliers, SCE's project team assessed a proof-of-concept (PoC) using a cloud environment. The PoC included a Weather Forecast Model that ran on a cloud-based virtual machine (VM). The suppliers worked with the project team to ensure that reliable and continuous data collection services ran without failure within the VM, and the supplier for the prediction model also worked with the team on tuning the model and updating it with new storm data. The tuning resulted in several versions, with the performance assessed and the best features (variables) selected over the course of several iterations.

The steps performed during each iteration included selecting new data sets, evaluating the predictive model and its accuracy and performance, and integrating the solution. The goal was to offer strong predictive accuracy in out-of-sample testing for each asset.

Phase 1 resulted in 1) a binary classifier to identify the likelihood of a storm, and 2) integration of an Asset Damage Predictive Model (one per asset for poles, transformers, underground cables and overhead conductors) into predictive storm analytics, shown in Figure 3.

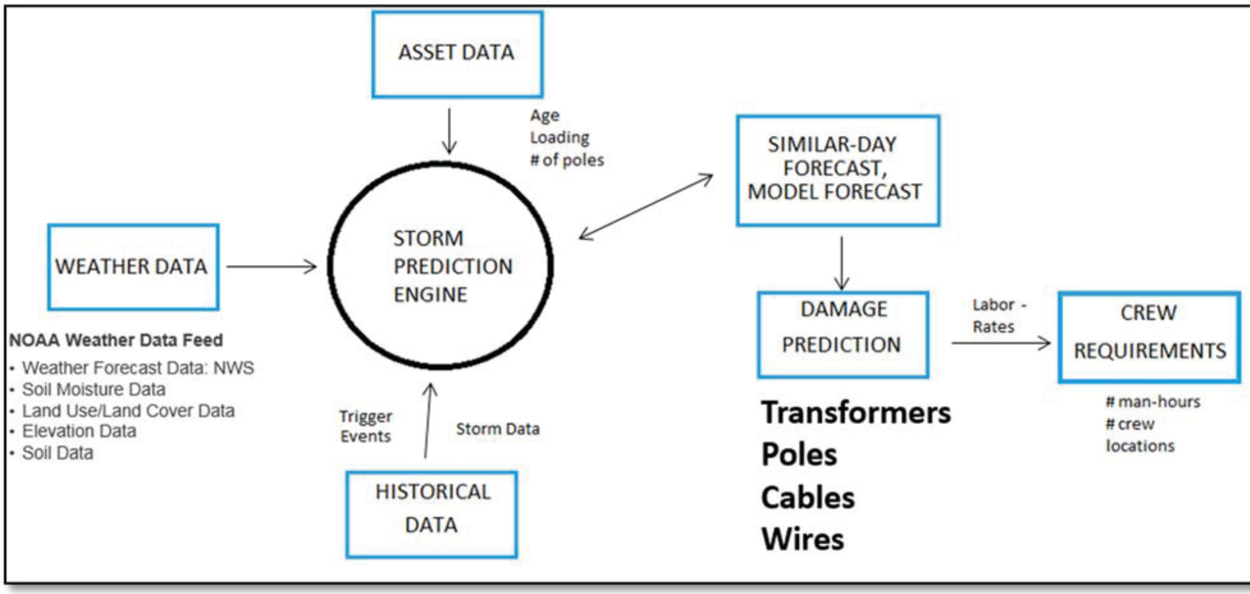

Figure 3. Predictive Storm Analytics Overview

The key predictive characteristics are defined as follows:

- Capability to be performed at different area levels, including district, sector and regional (distribution), with inclusion of field crew and troubleman utilization estimates for storm response at these levels.
- Estimates based on daily and event-level forecasts.
- Capability to provide forecasted asset damage and customer outage numbers from predicted resource utilization estimates.
- Capability to run on-demand for any period.
- Generation of one- to five-day forecasts.
- Analysis generated from integrating multi-stage predictive models.
- Visualization and reporting capabilities that can be developed to easily articulate areas and intensity of damage. The interface uses mapping layers from SCE's Geographic Information System (GIS).

2.2.2 Phase 2: Field Demonstration

In Phase 2, the project team incorporated an assessment of capabilities from key stakeholders and business users based on the previously identified requirements.

Once this initial work was completed, the project team began field demonstration activities by selecting participants, determining the supporting tools to automate formatting, integrating the input data from the multi-stage prediction models, and completing a Measurement & Validation (M&V) plan. During each iteration, stakeholders provided feedback and recommendations for refining the visual interface in order to improve understanding and usability.

2.2.3 Phase 3: Technology Transfer

In Phase 3, the project team worked with SCE's Technology Strategy and Architecture, Digital Architecture and Advanced Analytics, Business Resiliency, and Grid Operations organizations to complete a Technology Transfer Plan to migrate the project solution from public cloud to on premise, and also to migrate the public cloud VM to the on premise hybrid cloud account. The project team established a Knowledge Transfer Plan that included administration guides, user guides, hands-on training, user acceptance testing, and support.

The demonstration project's results are being utilized by Grid Operations for pre-storm planning for SCE's entire service territory based on the expected damage and resource requirements. This allows Grid Operations to collectively recognize where the greatest resource needs are likely to be during a major event, thereby optimizing the dispatch of resources across the entire storm area and benefitting the greatest number of customers in a region.

2.3 Schedule and Milestones/Deliverables

The project plan was organized into multiple phases. These consisted of sub-tasks, each of which had a report documenting the activities and results. The following table presents the phased approach that was used during the project.

<table>
<tr><th>Phase</th><th>Milestone Description</th><th>Milestone Date</th></tr>
<tr><td rowspan="4">Phase 1</td><td>Project Planning Completion</td><td>Aug. 2015</td></tr>
<tr><td>Procurement</td><td>Nov. 2015</td></tr>
<tr><td>Test Environment</td><td>Dec. 2015</td></tr>
<tr><td>Stage 1 Model Refinement</td><td>Feb. 2016</td></tr>
<tr><td rowspan="6">Phase 2</td><td>Solution Selection</td><td>March 2016</td></tr>
<tr><td>Requirements /Use Cases</td><td>April 2016</td></tr>
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<tr><td>Technology Transfer Completion</td><td>May 2018</td></tr>
<tr><td>Technology Transfer Handoff</td><td>Oct. 2018</td></tr>
</table>

Table 1. EPIC II Demonstration Project Phased Approach

3 Project Results

The predictive storm analytics demonstrated in the project are designed for use as both a proactive planning tool and a post-storm assessment tool. From a planning perspective, the demonstration results showed the capability to provide a more precise set of weather data than currently utilized so management can better use the information in response planning. Furthermore, the demonstration results showed the capability to provide an estimate of damage(s) expected in each district based on the anticipated severity of the storm (rain and wind), as well as an estimate of the required resources for restoring services from the damage. This capability has the potential to enable SCE's storm response management group to stage materials (poles, transformers, resources, etc.) and provide logistics for the areas where they will be needed most ahead of the impact of a potential storm.

The demonstration was designed to help SCE's operations management determine the proper number of personnel to assign to restoration efforts. As currently envisioned by the District Operations management team, the focus will be on the staff managed by that organization (e.g., line crews). However, the demonstration also had the capability to project resource requirements from other groups (e.g., troubleshooters, substation electricians)[5], and can be applied across the overall SCE organization to guide response planning.

Anticipated outcomes for future field deployment, based on the results of this project, include the following:

- Ability to forecast summaries for time frames of 0-12 hours, 12-24 hours, 24-48 hours, 48-72 hours and 72-120 hours.
- Capability to generate forecasts using historical and real-time data to run simulations that test the system under various operational conditions.
- Export of data in a format (e.g., Excel, CSV and ASCII) suitable for data manipulation by other analytic tools.
- Ability to generate forecasts on weekly scheduled runs.
- Ability to generate forecasts with real-time data points up to four times a day, and recalibrate daily during storm events and weekly during non-storm event periods.
- Capability of operating continuously for any time period based on forecasted weather data and real-time operations data.
- Capability of reporting daily and event-level forecasts.

In addition, by integrating given weather predictive analysis with outage data, the demonstration had additional predictive capabilities, including the following:

- Type and quantity of major equipment failures, such as transformers, poles, cables, and switch failures, for each affected city or district.
- Number of field crews required for storm response in each city or district.
- Probability of distribution asset failure (e.g., fragility curve) by city or district.
- Customer outage numbers given operations data.
- Weather event impact assessments on a regular (up to hourly) basis as the event time approaches (select users).
- Ability to create and perform "what-if" analyses.

3.1 Achievements

The Proactive Storm Impact Analysis Demonstration Project's results indicated potential to help respond to the severity of storms induced by climate change to improve planning. The results of this project will help SCE achieve the following improved data analytics and forecasting capabilities once deployed and operational:

- Identify the potential operational effects from the severity of storms (rain and wind).
- Have the ability to proactively plan measures in advance of these storms to help minimize potential operational impacts (e.g., the number of customers affected by outages) and enhance reliability.
- Improve operational efficiency and reduce the costs associated with storm-related outages through improved data analytics and forecasting capabilities.
- Maximize resource utilization efficiency and planning in the Transmission & Distribution Operations and Corporate Incident Management teams during storm conditions.
- Enhance corporate-wide awareness of potential outage conditions related to storm severity.

[5] Information fed via look-up feature.

Results also indicated that the technology solution demonstrated has the following additional capabilities when used in the field:

- Utilize a data warehouse-based solution that correlates input data across disparate systems, thus allowing SCE unit business users to make more effective decisions at all levels.
- Integrate data (from multiple sources), which then can be executed for predictions.
- Graphically display and query maps of predicted asset damage at grid, district and regional levels.

SCE already has expertise in predictive analytics, and results from this demonstration once deployed and operational will contribute toward establishing an ecosystem capable of smart grid power outage intelligence.

See Section 2 (Project Summary) for additional expected benefits/achievements for this project.

3.2 Value Proposition

The purpose of CPUC's EPIC funding is to support investments in energy technologies that benefit customers of the state's investor-owned utilities by promoting greater reliability, lower costs and increased safety.

The Proactive Storm Impact Analysis Demonstration Project showcased the project's strategic objectives as detailed in Section 2 (Project Summary) and Section 3.1 (Achievements) by addressing increased electric system safety and reliability, affordability and grid modernization.

3.3 Metrics

The following metrics were identified for this project and evaluated during project execution:

Safety, Power Quality and Reliability: The machine learning and advanced data analytics demonstrated in this project can help SCE stakeholders predict the failure of equipment based on current and historical operational and other data. With advanced data analytics, SCE can analyze and quantify where possible the following sub-metrics when the project solution enters the production environment:

- Number of outages, frequency and duration reductions.
- Forecasted accuracy improvement.
- Public and utility worker safety improvement and hazard exposure reduction.

Economic Benefits: Advanced data analytics also can provide significant economic benefits by helping to identify failing equipment or aging equipment before it fails. The following sub-metrics can be addressed with these analytics:

- Maintain/reduce operations and maintenance costs.
- Maintain/reduce capital costs.

3.4 Lessons Learned and Recommendations

During conceptualization of this project, SCE sought to demonstrate machine learning algorithms, prescriptive analytics, and integration of disparate data sources across the enterprise. Through collaborations among SCE business unit management, SCE Information Technology, and external technology consultants, SCE gained an improved understanding of the principal logistics of predictive algorithm development. The project team collaborated with stakeholders and recommended further deployment of predictive storm analysis into operations.

3.4.1 Predictive Storm Analysis Learnings

Induced by climate change, the severity of storms is increasing within SCE's service territory. Proactive awareness of these storms is needed in order to plan for potential damages to the grid.

The learnings from the results of the Proactive Storm Impact Analysis Demonstration Project indicated the potential capability to produce estimates of damage and resource needs for each SCE district. As shown in the project, damage was first estimated to determine if it would exceed a pre-identified threshold, and then the number of damaged assets for those cases where it was projected that the threshold would be exceeded was estimated. Since a single-point estimate does not provide the level of accuracy required to credibly inform users of the range of potential outcomes for a storm event, the project used a probabilistic approach.

A separate resource prediction forecast took the predicted results and analyzed the relationship between the damages and number of resources applied to repair those damages for a range of past storms. A significant amount of variability was produced, driven by the range of severity from past storms and accuracy of past forecasts.

Based on the project results, use of probabilistic forecasts introduces variability in the prediction, which requires analysis by SCE business users to interpret results. Since the probability varies for each SCE district due to the probability of a storm event's severity and damage history, users are presented with a range of results for each asset category. The project results do well to inform users what districts have a high possibility of damage for high storm events.

For predictive storm analysis to be operational on an ongoing basis, an expertise in data science to interpret and understand the results is required.

Consequently, the project team recommends continuing to work with stakeholders toward further understanding results in order to further deploy with grid operations.

3.4.2 Potential Uses

On a post-storm analysis basis, the project evaluation showed that both the asset damage and resource estimates can be reviewed for accuracy, as well as patterns within that accuracy, to improve planning capabilities for the SCE operations team. Comparisons of actual resource deployments versus the deployments suggested by the resource forecast improves planning of future deployments, and consequently of outage restoration performance.

3.4.3 Recommendations

The project team recommends further deployment with Grid Operations and encourages other utilities to adopt predictive storm analytics as well. Once operational, the predictive storm analytics have the potential to improve the effectiveness of responses to damage caused by the severity of storms. Other utilities have the option to implement tools that were demonstrated in this project, or other industry tools that meet their implementation criteria for utilizing machine learning and predictive analytics to predict storm damage.

The use of an enterprise data lake (centralized data repository) provides a means to store large amounts of data from disparate sources and allows multiple stakeholders within the utility to access various data sets for their individual use cases.

A key recommendation includes leveraging an existing data science life cycle like Cross Industry Standard Process for Data Mining (CRISP-DM), Knowledge Discovery and Database Team Data Science Project, shown in Figure 4. Team Data Science Life Cycle, which is comprised of the following key components:

- A data science life cycle definition,
- A standardized project structure,
- Infrastructure and resources for data science projects, and
- Tools and utilities for project execution.

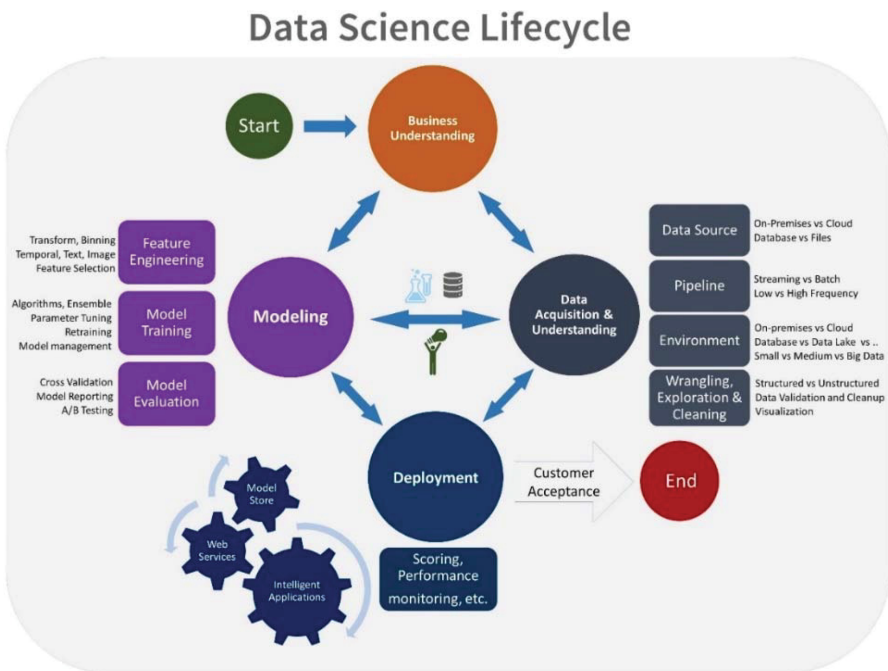

Figure 4. Team Data Science Life Cycle

Climate change is increasing the severity of storms, and consequently storms in the past five years are the greatest indicator of storm-related damage impacts and resource requirements. Leveraging a data science life cycle means that, using supervised machine learning, predictive analytics should be continually evaluated for performance and updated when necessary based on changing assets. The existing infrastructure has been prepared to enable automatic updates based on storm response work orders. If newer assets are installed due to previous storm events, scheduled maintenance or failure, these assets will be less prone to damage in subsequent storms.

Due to the variable nature of damage caused by the severity of storms, further predictive analysis is recommended at a much more granular level. Specifically, assets such as transformers, poles, underground cables and overhead conductors can be analyzed at a regional and possibly at a local level. Furthermore, if imported into external tools, existing infrastructure has the functionality to support machine learning model performance analysis.

3.5 Technology/Knowledge Transfer Plan

3.5.1 Preparation for Future Operations

The initial data processing script used in the Proactive Storm Impact Analysis Demonstration Project was evaluated utilizing public cloud services with a Linux VM. This provided the project consultant with the flexibility to work in an environment unconstrained by corporate firewalls. This also allowed SCE to more efficiently collaborate with external consultants. Eventually, there was a need to migrate the VM on premise and ensure that the running services complied with internal cybersecurity standards.

The VM thus was migrated into SCE's internal hybrid cloud service onto a similar Linux VM. In particular, the file contents from the source VM were copied onto the destination VM using rsync Linux utility. The Linux kernel services and other applications needed to run the data collection and Web application server were installed on the destination VM as well.

The migration was successful and further enhancements were performed to prepare for operationalization. These enhancements included conversion to RData files, using a database to store the prediction results, and running a shiny[6] Web application to read the predictions from a database and display them in a Web-based report. Figure 5. Web Application Report below shows the Web-based report.

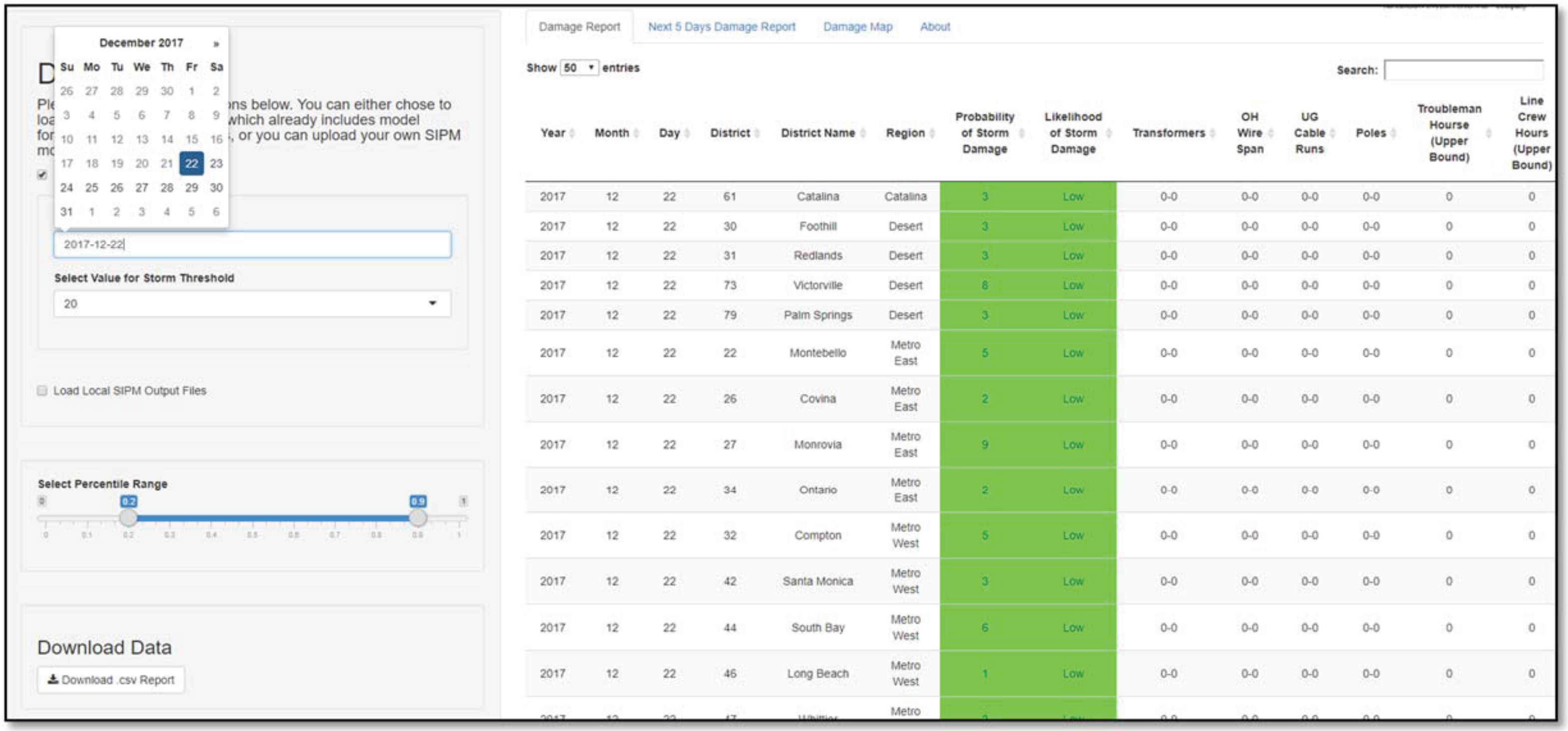

Figure 5. Web Application Report

[6] Shiny is an R package that allows developers to create interactive Web apps straight from R. R is an open source programming language and environment typically used for statistical computing and graphics.

The results can be exported to PDF or Excel and then viewed in tabular or graphical (Web map) format, shown in Figure 6. Map View of Web Application below.

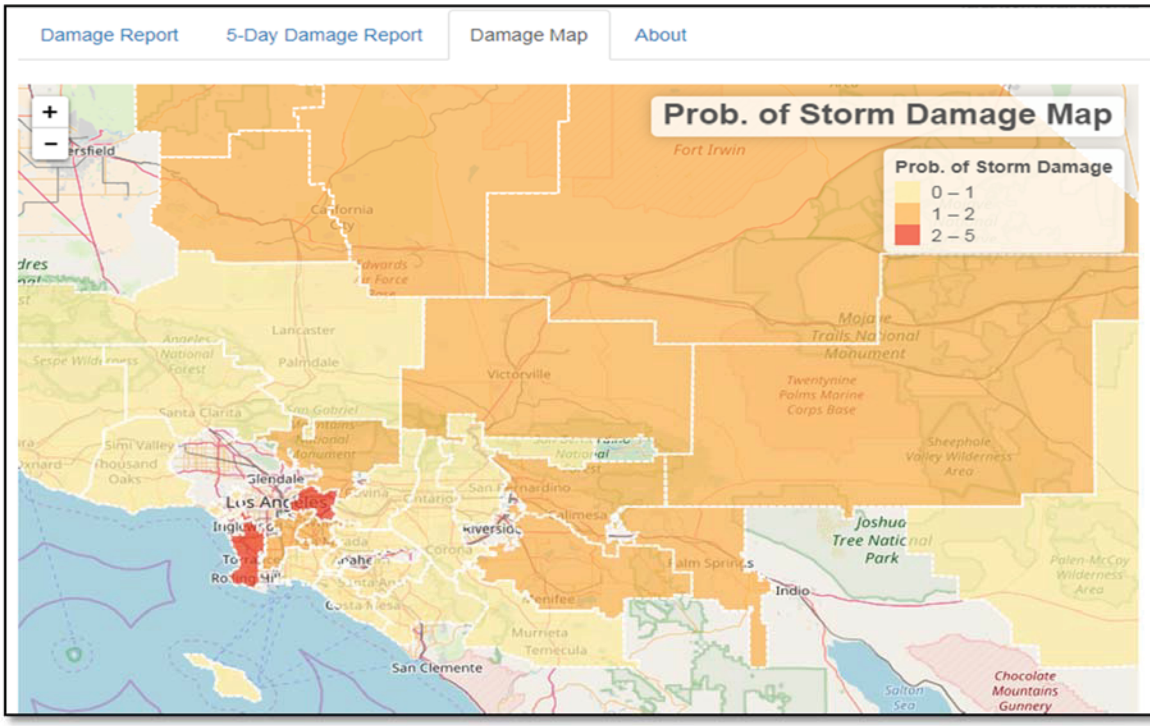

Figure 6. Map View of Web Application

Model parameters that can be changed through the Web application include the date and threshold. These enhancements were performed to make it less labor-intensive for SCE's Information Technology (IT) organization to move from the demonstration environment to the production environment, depicted in Figure 7. System Context Diagram for Production Environment below.

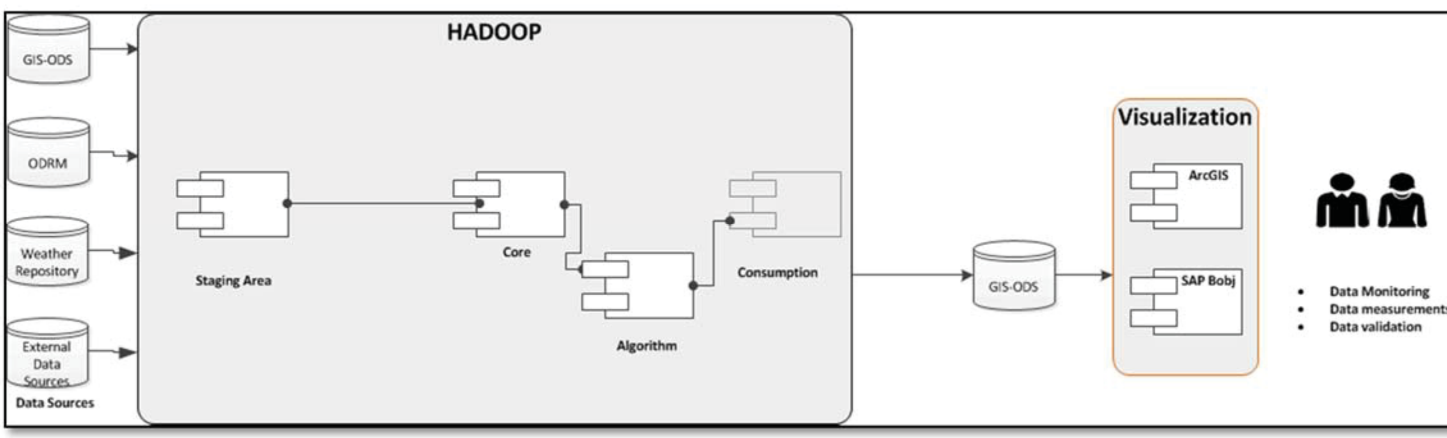

Figure 7. System Context Diagram for Production Environment

3.5.2 Ownership Transfer

In May 2018, the project team agreed with stakeholders to transfer ownership of the Predictive Storm Analysis to Grid Operations, which moving forward will work with IT to deploy in SCE's production environment.

Once the Predictive Storm Analysis is in field production and becomes operational, SCE will have improved capabilities to more effectively plan resources and prepare for necessary reconfigurations in advance of a storm event, helping to minimize operational costs (through pre-staging and avoidance of excessive overtime) and potential reliability impacts.

3.6 Procurement

SCE's project team chose a supplier to provide high-resolution, localized weather data in SCE's service territory, including historical, real-time and forecasted data, at a cost aligned with what was estimated. Details on how this localized weather data is processed and used to generate predictions is provided in Appendix A: Data Parameters.

A second supplier created a Web report with visualizations in accordance with the requirements specified, including SCE's IT and cybersecurity policies. .

At the time of the Request for Proposal procurement, there were no commercial products readily available on the market to support this project. Three years later, there are now products available from major vendors.

3.7 Stakeholder Engagement

The table below shows the stakeholders involved in the Proactive Storm Impact Analysis Demonstration Project:

Stakeholder Organization	Interest in the Project
Business Resiliency – Plans and Programs	Corporate ownership of predictive models and outage forecasting capabilities
Grid Operations- Storm Management, Grid Management Center, Distribution Operations Center	Management of Grid Operations personnel
Business Resiliency – Watch Office	Use of forecasting data for corporate-wide situational awareness
Grid Technology & Modernization	Personnel from Technology Demonstration & Pilots who execute the project plan
Information Technology Organization – Enterprise Strategy & Architecture	Advise to ensure project success from an architecture technology standpoint
Information Technology – Digital Architecture and Advanced Analytics	Advise to ensure project success from a technology standpoint
Energy Forecasting and Integration/ Short-Term Demand Forecasting	Advise to ensure project success with in-house modeling effort
Incident Management Teams (various operational units)	Provision of high-level business needs; identification of tool effectiveness from a management perspective; identification of Incident Management team users for testing

Business Resiliency Watch Office – Watch Standers	Field test tool in SCE Watch Office to determine the tool's utility for corporate-wide situational awareness

Table 2. Stakeholder Organizations' Involvement

4 List of Acronyms

CPUC	California Public Utilities Commission
CRISP-DM	Cross Industry Standard Process for Data Mining
CSPIP	Corporate Storm Process Improvement Program
EPIC	Electric Program Investment Charge
GIS	Geographic Information System
IT	Information Technology
IOU	Investor-Owned Utility
M&V	Measurement & Validation
PoC	Proof-of-Concept
PV	Photovoltaic
SCE	Southern California Edison
T&D	Transmission & Distribution
VM	Virtual Machine

5 Appendix A: Data Parameters

5.1 Overview

A Random Forest is a non-parametric ensemble data mining method. Using this method, a large number of regression trees are developed, with each tree based on a bootstrapped sample of the data set. Random Forests are good for data sets with non-linear data, outliers, and noise. Two types of output from the Random Forest fit well with the objectives of this analysis. The first is variable importance, which is a measure of the contribution of a given covariate to the model prediction accuracy. The second is the partial dependence plot. These plots show the marginal effect of a covariate on the response variable. The Random Forest package in R was used for this analysis.

Quantile Regression Forests provide a non-parametric way of estimating conditional quantiles based on an underlying Random Forest. Quantiles give more information about the distribution of the response variable as a function of the covariates than just using the conditional mean (provided by a standard Random Forest). Using this method, regression trees are grown as in the Random Forest method. Then the weighted distribution of the observed response variables is used to estimate a conditional distribution. The difference between a Random Forest and Quantile Regression Forest is that the Random Forest keeps only the mean predictions and disregards other information. Quantile Regression Forests estimate the quantiles of the predictions based on the trained forest.

The quantregForest package in R was used for this analysis. Predictions made using this package are based on off-the-shelf data generated through the standard random forest bootstrapping process.

5.1.1 Parameters

This section provides details on the input data for the project. The input data sources are listed in the following table, and a complete list of variables used is included in Table 4. Static and Dynamic Variables Used in the

Data Type	Data Provider	Refresh Frequency	Data Format	Description
Weather Forecast Data: NWS	National Weather Service-National Digital Forecast Database	Hourly	GRIB2	Maximum temperature, minimum temperature, average temperature, bulb temperature, dew point temperature, surface temperature (computed/optimized), maximum sustained wind speed, average sustained wind speed, maximum gust speed, average gust speed, 50-meter wind, precipitation amount, precipitation rate, snowfall, snow accumulation, relative humidity, snow water equivalent, atmospheric pressure, visibility, cloud conditions, heating degree days (computed), cooling degree days (computed), lightning.
Soil Moisture Data	NOAA Environmental Modeling Center	Daily	GRIB1	Layer 1 soil moisture (0 to 10 cm), layer 2 soil moisture (10 to 40 cm), layer 3 soil moisture (40 to 100+ cm).
Land Use/Land Cover Data	National Land Cover Database 2011	Every 5 years	raster	There are eight major land cover classes in the NLCD 2011. The fractional coverage of each type will be determined for each location grid: water, developed land, barren land, forest, scrub LC, grassland, pasture, and wetlands.

Data Type	Data Provider	Refresh Frequency	Data Format	Description
Topographic Data	USGS	One Time	raster	These variables will be derived from a global 30-arcsecond digital elevation model (DEM) produced by the United States Geological Survey (public and freely available data) and they include: mean elevation, median elevation, standard deviation of elevation, minimum elevation, and maximum elevation.
Tree Species Data	USDA Forest Service	One Time	raster (ArcInfo GRID)	The tree species data are from the 2012 National Insect and Disease Risk Map. The NIDRM identifies a single, dominant tree species in each 240 m grid cell. Eight tree-related variables that are considered in this study are: fractional area of the location grid covered by trees, percentage of trees with a deep root system, percentage of trees with a taproot system, maximum tree species height, maximum tree species diameter at breast height, tree density, Janka Hardness scale, and crushing strength.
GIS Work Location Grids	GIS-ODS	Quarterly	ArcGIS Shapefile	The work location grid will have following information: 1) Location grids for the entire SCE service territory a) Location grid cell information b) ID: This should match the grid ID system that is used in the internal SCE GIS system c) Latitude of the grid cell: This could be for one of the corners or the center of the grid. Longitude of the grid cell: This could be for one of the corners or the center of the grid. 2) The region boundaries 3) The district boundaries Model will generate predictions of outages and damage for each location grid over the SCE territory (approximately ~20,000). The shapefile from GIS will be used to visualize the results (show model output).
SCE Assets	GIS-ODS	Quarterly		Number of poles without transformers in the grid, number of poles that support pole-mounted transformers in the grid, number of pole-mounted transformers in the grid, number of pad-mounted transformers in the grid, number of customer meters in the grid.
Storm Response Staff	Access DB/file	Quarterly		Staffing by classification, including line workers, tree-trim personnel, engineers, field service reps, etc.
Outage Data	ODRM	Quarterly		Date/times of outage, cause code, number of customers affected, and customer minutes of interruption
Work Order Information	SAP	Quarterly		For poles, switches, cable, wire, transformers being replaced along with work order number

Data Type	Data Provider	Refresh Frequency	Data Format	Description
Vegetation Management Data	SCE	Yearly	Excel	Summarized for each district. Data were provided by SCE Vegetation Management

Table 3. Data Sources for Storm Impact Prediction Model

The information contained in the six output files can be divided into two categories:

1. Static variables (described in Table 4. Static and Dynamic Variables Used in the Demonstration)
2. Dynamic variables
    a. Weather forecast data (data provider: National Digital Forecast Database (NDFD))
    b. Antecedent precipitation and soil moisture conditions (data provider: North American Land Data Assimilation System (NLDAS-2))

The following table provides a summary of the static and dynamic variables used. A total of 198 explanatory variables are used to generate predictive results. The table contains a description of the type of data, units, whether it is dynamic (changes each day) or static, the native spatial resolution, data source (see Table 3. Data Sources for Storm Impact Prediction Model), and the specific variables used as input (and which column in the input.csv data file they are found in).

Type	Units	Static or Dynamic	Spatial Resolution	Source	Variables (column in input.csv)
Mean Apparent Temperature	Kelvin (K)	dynamic	5 km	NDFD	Mean (AM), median (BJ), maximum (DD), minimum (CG), standard deviation (EA)
Minimum Apparent Temperature	Kelvin (K)	dynamic	5 km	NDFD	Mean (AN), median (BK), maximum (DE), minimum (CH), standard deviation (EB)
Maximum Apparent Temperature	Kelvin (K)	dynamic	5 km	NDFD	Mean (AO), median (BL), maximum (DF), minimum (CI), standard deviation (EC)
Mean Dewpoint Temperature	Kelvin (K)	dynamic	5 km	NDFD	Mean (AP), median (BM), maximum (DG), minimum (CJ), standard deviation (ED)
Minimum Dewpoint Temperature	Kelvin (K)	dynamic	5 km	NDFD	Mean (AQ), median (BN), maximum (DH), minimum (CK), standard deviation (EE)
Maximum Dewpoint Temperature	Kelvin (K)	dynamic	5 km	NDFD	Mean (AR), median (BO), maximum (DI), minimum (CL), standard deviation (EF)
Mean Relative Humidity	%	dynamic	5 km	NDFD	Mean (AS), median (BP), maximum (DJ), minimum (CM), standard deviation (EG)
Minimum Relative Humidity	%	dynamic	5 km	NDFD	Mean (AT), median (BQ), maximum (DK), minimum (CN), standard deviation (EH)
Maximum Relative Humidity	%	dynamic	5 km	NDFD	Mean (AU), median (BR), maximum (DL), minimum (CO), standard deviation (EI)
Mean Sky Cover	% coverage	dynamic	5 km	NDFD	Mean (AV), median (BS), maximum (DM), minimum (CP), standard deviation (EJ)
Minimum Sky Cover	% coverage	dynamic	5 km	NDFD	Mean (AW), median (BT), maximum (DN), minimum (CQ), standard deviation (EK)
Maximum Sky Cover	% coverage	dynamic	5 km	NDFD	Mean (AX), median (BU), maximum (DO), minimum (CR), standard deviation (EL)
Mean Air Temperature	Kelvin (K)	dynamic	5 km	NDFD	Mean (AY), median (BV), maximum (DP), minimum (CS), standard deviation (EM)
Minimum Air Temperature	Kelvin (K)	dynamic	5 km	NDFD	Mean (AZ), median (BW), maximum (DQ), minimum (CT), standard deviation (EN)
Maximum Air Temperature	Kelvin (K)	dynamic	5 km	NDFD	Mean (BA), median (BX), maximum (DR), minimum (CU), standard deviation (EO)
Mean Wind Direction	Degrees (0 to 360)	dynamic	5 km	NDFD	Mean (BB), median (BY), maximum (DS), minimum (CV), standard deviation (EP)
Minimum Wind Direction	Degrees (0 to 360)	dynamic	5 km	NDFD	Mean (BC), median (BZ), maximum (DT), minimum (CW), standard deviation (EQ)

Maximum Wind Direction	Degrees (0 to 360)	dynamic	5 km	NDFD	Mean (BD), median (CA), maximum (DU), minimum (CX), standard deviation (ER)
Mean Wind Speed	m/s	dynamic	5 km	NDFD	Mean (BE), median (CB), maximum (DV), minimum (CY), standard deviation (ES)
Minimum Wind Speed	m/s	dynamic	5 km	NDFD	Mean (BF), median (CC), maximum (DW), minimum (CZ), standard deviation (ET)
Maximum Wind Speed	m/s	dynamic	5 km	NDFD	Mean (BG), median (CD), maximum (DX), minimum (DA), standard deviation (EU)
Quantitative Precipitation Forecast	mm	dynamic	5 km	NDFD	Mean (BH), median (CE), maximum (DY), minimum (DB), standard deviation (EV)
Maximum 12h probability of precipitation	% probability	dynamic	5 km	NDFD	Mean (BI), median (CF), maximum (DZ), minimum (DC), standard deviation (EW)
1-month Standardized Precipitation Index	Unitless index	dynamic	1/8 degree (~12 km)	NLDAS-2	Mean (EX), median (FC), maximum (FM), minimum (FH), standard deviation (FR)
3-month Standardized Precipitation Index	Unitless index	dynamic	1/8 degree (~12 km)	NLDAS-2	Mean (EY), median (FD), maximum (FN), minimum (FI), standard deviation (FS)
6-month Standardized Precipitation Index	Unitless index	dynamic	1/8 degree (~12 km)	NLDAS-2	Mean (EZ), median (FE), maximum (FO), minimum (FJ), standard deviation (FT)
12-month Standardized Precipitation Index	Unitless index	dynamic	1/8 degree (~12 km)	NLDAS-2	Mean (FA), median (FF), maximum (FP), minimum (FK), standard deviation (FU)
24-month Standardized Precipitation Index	Unitless index	dynamic	1/8 degree (~12 km)	NLDAS-2	Mean (FB), median (FG), maximum (FQ), minimum (FL), standard deviation (FV)
Soil moisture percentiles (0 to 10 cm)	Percentiles	dynamic	1/8 degree (~12 km)	NLDAS-2	Mean (FW), median (FZ), maximum (GF), minimum (GC), standard deviation (GI)
Soil moisture percentiles (10 to 40 cm)	Percentiles	dynamic	1/8 degree (~12 km)	NLDAS-2	Mean (FX), median (GA), maximum (GG), minimum (GD), standard deviation (GJ)
Soil moisture percentiles (40 to 100 cm)	Percentiles	dynamic	1/8 degree (~12 km)	NLDAS-2	Mean (FY), median (GB), maximum (GH), minimum (GE), standard deviation (GK)
Consecutive days with maximum temperatures	count	dynamic	5 km	NDFD	≥80°F (AG), ≥85°F (AH), ≥90°F (AI)
Consecutive days with minimum temperatures	count	dynamic	5 km	NDFD	≥70°F (AJ), ≥75°F (AK), ≥80°F (AL)
Number of trees	count	static	district	SCE	Number of trees (F)
Number of padmounts with transformers	count	static	district	SCE	Number of padmounts with transformers (G)
Number of padmounts without transformers	count	static	district	SCE	Number of padmounts without transformers (H)
Number of poles with transformers	count	static	district	SCE	Number of poles with transformers (I)

Number of poles without transformers	count	static	district	SCE	Number of poles without transformers (J)
Number of OH segments	count	static	district	SCE	Number of OH segments (K)
Length of OH segments	m	static	district	SCE	Length of OH segments (L)
Number of UG segments	count	static	district	SCE	Number of UG segments (M)
Length of UG segments	m	static	district	SCE	Length of UG segments (N)
Transformer Age	% of district	static	district	SCE	ageGT20 = fraction of the transformers in the district >20 years old (GQ); ageGT40 = fraction of the transformers in the district > 40 years old (GR); ageGT50 = fraction of the transformers in the district >50 years old (GS); ageGT60 = fraction of the transformers in the district >60 years old (GT)
Transformer Loading	% of district	static	district	SCE	loadGT25 = fraction of the transformers in the district with a loading >25% (GL); loadGT50 = fraction of the transformers in the district with a loading >50% (GM); loadGT100 = fraction of the transformers in the district with a loading >100% (GN); loadGT125 = fraction of the transformers in the district with a loading >125% (GO); loadGT150 = fraction of the transformers in the district with a loading >150% (GP)
Elevation	m	static	30 arc second (~900 m)	USGS	Mean (O), median (P), maximum (R), minimum (Q), standard deviation (S)
Land Use/Land Cover	% of district	static	30 m	NLCD	Water (T), Developed (U), Barren (V), Forest (W), Scrub (X), Grass (Y), Pasture (Z), Wetlands (AA)
Root Zone Depth	cm	static	10 m	gSSURGO	Mean (AB), median (AC), maximum (AE), minimum (AD), standard deviation (AF)

Table 4. Static and Dynamic Variables Used in the Demonstration

Overall, for the weather forecast dynamic variable data category, the native spatial resolution is 5 km, the refresh frequency is hourly, and the data format is GRIB2. For the soil moisture/ precipitation dynamic variable data category, the native spatial resolution is 1/8th degree (~14 km), the refresh frequency is daily, and the data format is GRIB1. The data provider for both categories is ftp.

5.2 Grid Spatial Information

5.2.1 SCE Grid

The entire SCE service area was partitioned into a grid with 2-km spacing, totaling 33,915 grid cells and an area of 135,660 km2. The following table shows the number of grid cells in each of the nine regions and 35 districts in the SCE coverage area (see Figure 9. The Grids for SCE (Gray Outlines with Colors), NDFD (Yellow) and NLDAS-2 (Black)

Region Name	Region	# Grid Cells	District Name	District	# Grid Cells
Catalina	1	47	Catalina	61	47
Desert	2	2222	Foothill	30	188
			Redlands	31	364
			Victorville	73	1305
			Palm Springs	79	365
Metro East	3	684	Montebello	22	42
			Covina	26	162
			Monrovia	27	266
			Ontario	34	214
Metro West	4	223	Dominguez Hills	32	61
			Santa Monica	42	14
			South Bay	44	65
			Long Beach	46	51
			Whittier	47	32
North Coast	5	3330	Thousand Oaks	35	275
			Antelope Valley	36	1538
			Ventura	39	658
			Santa Barbara	49	408
			Valencia	59	451
Orange	6	401	Santa Ana	29	83
			Huntington Beach	33	65
			Saddleback	43	174
			Fullerton	48	79
Rurals	7	23571	Arrowhead	40	89
			Shaver Lake	50	560
			Tehachapi	52	739

Region Name	Region	# Grid Cells	District Name	District	# Grid Cells
			Kernville	53	975
			Barstow	72	6609
			29 Palms	84	3390
			Bishop/Mammoth	85	3908
			Ridgecrest	86	4415
			Blythe	87	2886
San Jacinto	8	840	Menifee	77	481
			Wildomar	88	359
San Joaquin	9	2597	San Joaquin Valley	51	2597
Catalina	1	47	Catalina	61	47
Desert	2	2222	Foothill	30	188
			Redlands	31	364
			Victorville	73	1305
			Palm Springs	79	365
Metro East	3	684	Montebello	22	42
			Covina	26	162
			Monrovia	27	266
			Ontario	34	214
Metro West	4	223	Dominguez Hills	32	61
			Santa Monica	42	14
			South Bay	44	65
			Long Beach	46	51
			Whittier	47	32
North Coast	5	3330	Thousand Oaks	35	275
			Antelope Valley	36	1538
			Ventura	39	658
			Santa Barbara	49	408

Region Name	Region	# Grid Cells	District Name	District	# Grid Cells
			Valencia	59	451
Orange	6	401	Santa Ana	29	83
			Huntington Beach	33	65
			Saddleback	43	174
			Fullerton	48	79
Rurals	7	23571	Arrowhead	40	89
			Shaver Lake	50	560
			Tehachapi	52	739
			Kernville	53	975
			Barstow	72	6609
			29 Palms	84	3390
			Bishop/Mammoth	85	3908
			Ridgecrest	86	4415
			Blythe	87	2886
San Jacinto	8	840	Menifee	77	481
			Wildomar	88	359
San Joaquin	9	2597	San Joaquin Valley	51	2597

Table 5. Number of Grid Cells in Each Region and District in SCE's Coverage Area

5.2.2 National Digital Forecast Database (NDFD) Grid

The NDFD data archive goes back more than a decade. Prior to August 2014, NDFD provided data on a 5-km grid. Since that time, it has used a 2.5-km grid. The demonstration of storm events took place largely before the transition date, so SCE decided to use the 5-km grid for this project. In addition, the downloaded NDFD regional files, such as those for the NDFD Pacific Southwest (PSW) region (see Figure 8. NDFD Pacific Southwest Region (Yellow) and SCE Districts (Different Colors)

), maintained the 5-km resolution. NDFD data are interpolated to the SCE grid using an inverse distance weighting (IDW) of the four closest grid cells, with distances computed using the centroids of the SCE and NDFD grid cells.

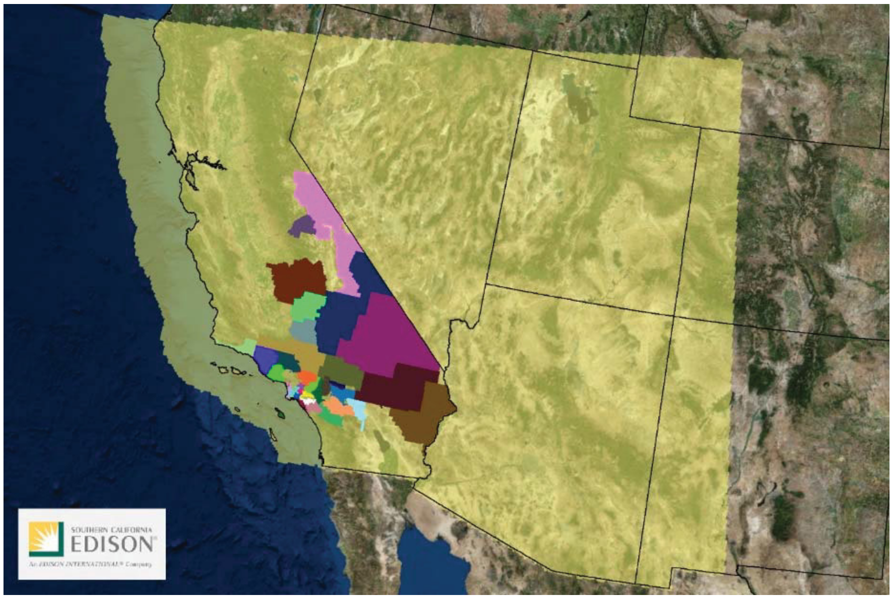

Figure 8. NDFD Pacific Southwest Region (Yellow) and SCE Districts (Different Colors)

5.2.3 North American Land Data Assimilation System (NLDAS-2) Grid

The NLDAS-2 precipitation and soil moisture data are available at 1/8th degree resolution, which provides a nominal resolution of about 14 km. As with the NDFD data, the NLDAS-2 precipitation and soil moisture values are interpolated to the SCE grid using IDW of the four closest grid cells. Figure 9. The Grids for SCE (Gray Outlines with Colors), NDFD (Yellow) and NLDAS-2 (Black)

provides a look at the spatial properties of all three grid systems in the greater Los Angeles area.

Aggregating Weather Data to the District-Level

The six final output files contain district-level information. For each weather-related variable that is computed at the SCE grid cell level (detailed in the previous section), district-level data are equal-weighted statistical summaries of the data within the district:

- Mean
- Median
- Minimum
- Maximum
- Standard deviation

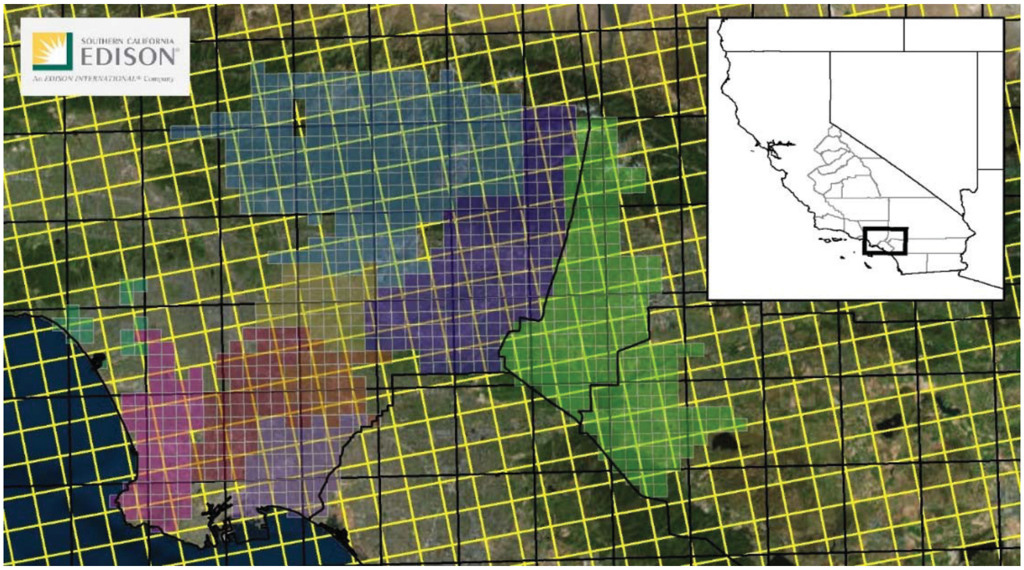

Figure 9. The Grids for SCE (Gray Outlines with Colors), NDFD (Yellow) and NLDAS-2 (Black)

NDFD Weather Elements

Downloading

On a daily basis data are retrieved for 22 different NDFD weather elements at varying temporal resolutions from the NDFD URL. If possible, the script downloads the file for the Pacific Southwest (PSW) region, which overlaps all of the SCE districts in this project (see Figure 9. The Grids for SCE (Gray Outlines with Colors), NDFD (Yellow) and NLDAS-2 (Black)

above). The PSW data are found in subfolder "NDFD_url/AR.pacswest/." If a particular element is not available for the PSW region, the NDFD data are downloaded for all of the Continental United States (CONUS) at "NDFD_url/AR.conus/." Downloading the regional files saves greatly on computational and storage resources relative to the CONUS files.

The NDFD files are stored in "GRIdded Binary" (GRIB) format, which is commonly used for historical and operational weather data and standardized by the World Meteorological Organization. Both NDFD (.bin extension) and NLDAS (.grb extension) now use the GRIB version 2 (GRIB-2) format, and use a compiled C program executable wgrib2.out to decode into csv format (available at http://www.cpc.ncep.noaa.gov/products/wesley/wgrib2/).

Both the PSW and CONUS subdirectories contain three subdirectories with files for short-range (e.g., "NDFD_url/AR.pacswest/VP.001-003/"), medium-range (e.g., "NDFD_url/AR.pacswest/VP.004-007/"), and long-range NDFD forecasts (e.g., "NDFD_url/AR.pacswest/VP.008-450/"). The script uses the short-range and long-range subdirectories, which each contain binary (.bin extension) files for individual weather elements. Table 4. Static and Dynamic Variables Used in the summarizes that temporal resolution of the different variables for short-range (0-72 hours) and medium-range (3-7 days) forecasts.

Each individual weather element .bin file contains the most up-to-date forecasts, with the ability to extract data from each individual forecast "valid time," which refers to the exact time in which a forecast is valid. The day in which the NDFD files are being downloaded will be called "Day 0." Using the element "Temperature" as an example, for Days 0-2 (0-72 hours), there are eight valid times (03 UTC, 06 UTC, 09 UTC, 12 UTC, 15 UTC, 18 UTC, 21 UTC and 00 UTC) and four valid times for Days 3-7 (06 UTC, 12 UTC, 18 UTC and 00 UTC).

The NDFD forecast elements are used to make daily district-level outage predictions for Days 0-5, so only elements available on all six forecast days are used in the model (see Table 6. Forecast Elements). However, all elements are downloaded to maintain flexibility for future model adjustments.

The only weather element data not downloaded directly from the NDFD Web server are quantitative precipitation forecasts (QPFs), because they are only available for short-range NDFD forecast grids. However, the National Oceanic and Atmospheric Administration (NOAA) Weather Prediction Center (WPC) has QPF data available out to 168 hours (7 days) at ftp.wpc.ncep.noaa.gov/5km_qpf/.

Temporal Statistics

The NDFD data that is used in the outage prediction model (except maximum temperature, minimum temperature, and QPF) are aggregated from sub-daily values to daily statistics. These include the mean, median, maximum, minimum and standard deviation for each weather element.

The NDFD data set uses UTC for the timing of available forecast, with a time offset between UTC and Pacific that varies throughout the year (PST = UTC-8 hours and PDT = UTC-7 hours). To account for this offset, an “NDFD day” for which daily statistics are computed is defined as beginning at 0700 UTC and ending at 0659 UTC. This works to confine the NDFD forecasts within a single calendar day. The NDFD daily statistics are stored in the output files for each forecast day.

The following table shows the NDFD forecast elements downloaded each day and used.

Element	File Name	Forecast Frequency (0 - 72 hours)	Forecast Frequency (3 - 7 days)
Apparent Temperature	ds.apt.bin	3 hourly	6 hourly
Dewpoint	ds.td.bin	3 hourly	6 hourly
Quantitative Precipitation Forecast	ds.qpf.bin	6 hourly	6 hourly
Relative Humidity	ds.rhm.bin	3 hourly	6 hourly
Sky Cover	ds.sky.bin	3 hourly	6 hourly
Temperature	ds.temp.bin	3 hourly	6 hourly
Wind Direction	ds.wdir.bin	3 hourly	6 hourly
Wind Speed	ds.wspd.bin	3 hourly	6 hourly
12-Hour Probability of Precipitation	ds.pop12.bin	12 hourly	12 hourly
Maximum Temperature	ds.maxt.bin	Daily (00 UTC)	Daily (00 UTC)
Minimum Temperature	ds.mint.bin	Daily (12 UTC)	Daily (12 UTC)
Convective Hazard Outlook	ds.conhazo.bin	Daily (12 UTC)	N/A
Critical/Extreme Critical Risk Fire Weather Outlook	ds.critfireo.bin	Daily (12 UTC)	N/A
Dry Lightning Thunderstorm Risk Fire Weather Outlook	ds.dryfireo.bin	Daily (12 UTC)	N/A
Probability of Damaging Thunderstorm Winds	ds.ptstmwinds.bin	Daily (12 UTC)	N/A
Probability of Extreme Hail	ds.pxhail.bin	Daily (12 UTC)	N/A
Probability of Extreme Thunderstorm Winds	ds.pxtstmwinds.bin	Daily (12 UTC)	N/A
Probability of Extreme Tornadoes	ds.pxtornado.bin	Daily (12 UTC)	N/A
Probability of Hail	ds.phail.bin	Daily (12 UTC)	N/A
Probability of Tornadoes	ds.ptornado.bin	Daily (12 UTC)	N/A
Snow Amount	ds.snow.bin	6 hourly	N/A
Wind Gust Speed	ds.wgust.bin	3 hourly	N/A

Table 6. Forecast Elements

Heat Load Information

The only other NDFD-extracted weather data included in the final output files can be categorized as “heat load” information. The impact of warm weather on the SCE power system was determined by tabulating the number of consecutive days surpassing maximum and minimum temperature thresholds (see table below). This is done using the district-level aggregation of the maximum and minimum temperature values.

Variable	Consecutive Days Exceeding:		
Minimum Temperature	≥ 70°F	≥ 75°F	≥ 80°F
Maximum Temperature	≥ 80°F	≥ 85°F	≥ 90°F

Table 7. Heat Load Information Variables

NLDAS-2 Precipitation and Soil Moisture

Downloading

NLDAS-2 precipitation and soil moisture are available at hourly resolution from the NASA Goddard Earth Sciences Web portal at https://hydro1.gesdisc.eosdis.nasa.gov/data/s4pa/NLDAS/.

At each NLDAS-2 grid cell in the SCE domain, the 24-hourly precipitation values are aggregated to daily values and are in mm day-1. The daily values of soil moisture at each depth are represented by the 12 UTC hourly values of total water volume (m3). Similar to the NDFD files, the NLDAS-2 files are available in GRIB format.

The NLDAS-2 data set has serial spatiotemporal completeness with data from January 2, 1979, to current, with daily updates and a latency time of about three days for new files. The script uses the most recent precipitation and soil moisture information for the forecast output files. Unlike the NDFD forecast elements, the NLDAS-2 data are model-derived observations, so each district contains the same values for all forecast days.

Rather than using the raw NLDAS-2 precipitation and soil moisture values, these were converted to normalized quantities, taking advantage of the long record of available data. Precipitation is converted to the Standardized Precipitation Index (SPI) and soil moisture is converted to volumetric water content, and then mapped to an empirical cumulative distribution function (CDF).

Standardized Precipitation Index (SPI)

The SPI transforms an aggregated precipitation total on time scales of 1 month and longer, and maps that total on a parametric CDF. In this script, we aggregate precipitation for 1, 3, 6, 12 and 24 months with an ending date corresponding to the most up-to-date NLDAS-2 file. We use the Pearson Type III (P3) distribution, which is widely used for quantifying historical precipitation frequencies. For each calendar day, the P3 distribution parameters for the five time scales were computed using data from 1979-2015. After determining the P3 cumulative probability (also called percentile), this is mapped to an inverse Gaussian function with mean zero and variance one. In statistical terms, the final SPI value is the number of standard distributions above or below the median (called a Z score).

Soil Moisture

Soil moisture data are from the NLDAS-2 Variable Infiltration Capacity forecast, which is based on land surface water and energy fluxes and is available for three different soil layers. Values of total water volume are converted to volumetric water content using the depth of the layers.

Figure 10. Interpolation of Soil Moisture Values below shows the interpolation of soil moisture values in the left column with soil layer 1 (orange) depth of 10 cm, soil layer 2 (green) depth of 20 cm, and soil layer 3 (blue) depth of 30 cm to the standard depths (right). The center of each original soil layer is denoted by an open circle.

The soil layer depths vary spatially across grid cells, so a technique was developed for one dimensionally interpolating these values to standardized depths: 1) 0 cm-10 cm, 2) 10 cm-40 cm, and 3) 40 cm-100 cm. The interpolation assumes that the VWC value for each layer can be shrunk to its center and the boundaries of the layers are midway between these points. In the example, the center is 5 cm in layer 1, 20 cm in layer 2 and 45 cm in layer 3. Computationally, the standardized layers 1 and 3 maintain their original values. The standardized layer 2 (right column) is a linear combination of the values from all three original soil layers.

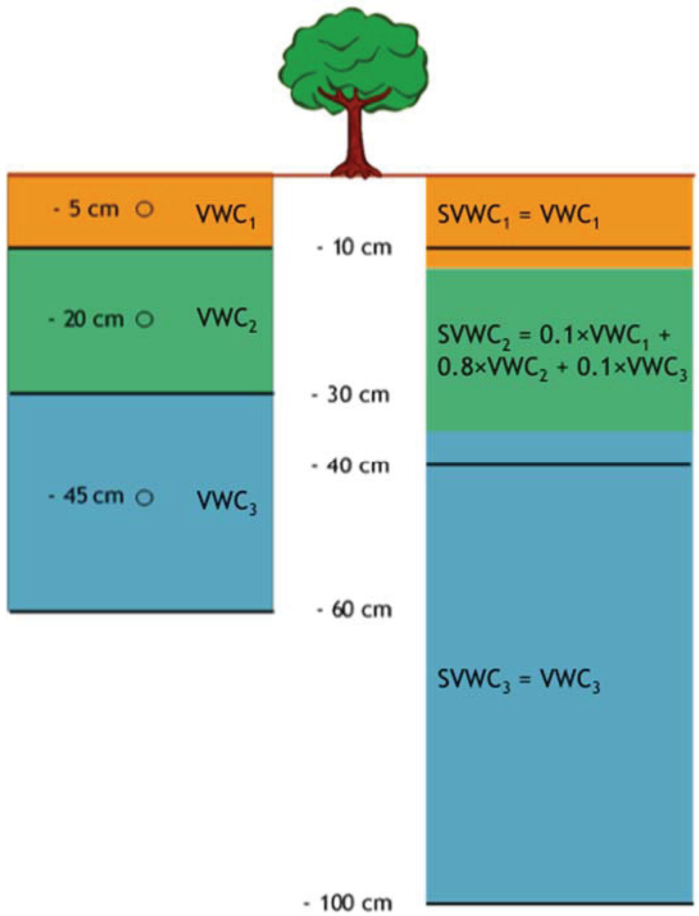

Figure 10. Interpolation of Soil Moisture Values

Appendix E

Integration of Big Data for Advanced Automated Customer Load Management

Final Project Report

Integration of Big Data for Advanced Automated Customer Load Management Final Project Report

Created by

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Disclaimer

Acknowledgments

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1 Executive Summary

As ordered by the recently released Rule 21 Interconnection requirements[1], the California Investor Owned Utilities (IOUs)[2] are required to deploy systems that can communicate using the Institute of Electrical and Electronics Engineers (IEEE) 2030.5[3] standard in order to interface with third Parties (e.g., photovoltaic (PV) and energy storage systems (ESS) aggregators), facility inverter management systems and customer owned technologies. To support the use of this standard, the IOUs developed the Common Smart Inverter Profile (CSIP)[4] of IEEE 2030.5, which describes its use for Rule 21 required monitoring and control capabilities and was used to create the SunSpec test procedures[5] to certify clients and servers. The Rule 21 stakeholders expects these new capabilities will eventually support the IOUs grid reliability requirements, reduce upgrade costs and allow localized optimization of the distribution grid. Additionally, the capabilities should mitigate the impact of a much larger deployment of Distributed Energy Resources[6] (DERs) on the grid, allowing for the further deployment of customer renewable generation. To accomplish these goals, stakeholders will first need to evaluate and demonstrate the use of these new communication-related capabilities and create deployment and integration strategies to and requirements.

Southern California Edison (SCE) conducted the Electric Program Investment Charge (EPIC) II Integration of Big Data for Advanced Automated Customer Load Management ("Big Data") project in order to demonstrate the CSIP use cases (Grouping, monitoring, control and registration), evaluate the use the IEEE 2030.5 standard for end-to-end communications and demonstrate the integration of new communication systems with SCE's back office systems. The Big Data project accomplished objectives and, in coordination with the California Energy Commission (CEC) Program Opportunity Notice (PON) 14-303, also discovered issues related to aggregate smart inverter commissioning and support processes, including setting up communications, monitoring and troubleshooting issues, as well as the need for clearly defined roles and responsibilities for multiple stakeholders involved.

2 Introduction

The penetration of inverter-based generation has significantly increased on the electric grid in recent years due in large part to California energy policies focused on integrating increasing amounts of renewables generation, especially from customer owned DERs. In order to optimize and manage these generating facilities impact on the distribution system in the near future, as well as allow for greater deployments of these customer owned DERs, advanced inverter functions that support the grid need to be implemented. Therefore the Smart Inverter Working Group (SIWG) was formed in 2013 as a joint effort between the California Public Utilities Commission (CPUC) and CEC to provide recommendations for revising the California Electric Rule 21 interconnection tariff (Rule 21)[7] to include new grid support functions required to be supported by newly interconnected inverters. These activities resulted in the adoption of new

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1 http://www.cpuc.ca.gov/General.aspx?id=3962.
2 The Utilities are comprised of Southern California Edison, San Diego Gas & Electric, and Pacific Gas & Electric.
3 https://standards.ieee.org/standard/2030_5-2018.html.
4 https://sunspec.org/download/.
5 *Ibid*.
6 DER definition can be found at: http://www.cpuc.ca.gov/uploadedFiles/CPUC_Public_Website/Content/About_Us/Organization/Commissioners/Michael_J._Picker/DER%20Action%20Plan%20(5-3-17)%20CLEAN.pdf.
7 http://www.cpuc.ca.gov/Rule21/.

inverter requirements related to Autonomous Functionality (Phase 1), Communications (Phase 2), and Advanced Functionality (Phase 3).[8]

The ability to monitor and control the growing amount of customer-owned DERs is critical for their integration onto SCE's distribution grid. The Big Data project supports the improvement of grid reliability and specifically demonstrates technologies that allow customers to generate and manage energy, while supporting the grid. As can be seen in Figure 1 below, the Big Data project also aligns with the EPIC investment framework by:

- Demonstrating technologies that can support the furtherance of DERs on the grid
- Evaluating and preparing for emerging technologies
- Supporting the design and integration of new DER management systems

Finally, the Big Data project also supports SCE's various Grid Modernization initiatives, including the Distribution Resources Plan (DRP), Preferred Resources Pilot (PRP), and Energy Storage Deployment initiatives which will use similar communication and behind the meter technologies.

Figure 1- EPIC Investment Framework for Utilities

2.1 Project Background

As part of an effort to prepare for new smart inverter capabilities to come online, SCE's Grid Technology and Modernization (GTM) group received approval to conduct the EPIC 2 Big Data project in order to demonstrate and evaluate the use of the IEEE 2030.5 protocol for smart inverter controls, monitoring and other functions as defined by CSIP and required by the new Rule 21 interconnection requirements. The project intended to demonstrate these communications-related Phase 2 and 3 functions first in a lab setting and then in a pre-production field environment. Concurrent with the Big Data project, the CEC PON 14-303 funded initiative proposed by SunSpec Alliance and SCE had originally been tasked with demonstrating the ability of multiple DER assets providing ancillary grid services, including real and reactive power dispatch. The project goal was to install and operate 50 residential smart inverter systems with ESS and PV and demonstrate the impacts associated with high penetrations and management of these aggregated DERs. Due to the synergistic nature of the CEC project, SCE was able to save

[8] http://www.cpuc.ca.gov/General.aspx?id=4154. Parts of Phase 3 are still under development and not yet ruled upon.

funds by leveraging and the CEC-sourced vendors, DERs and customers for the field demonstration portion of the Big Data project which would procure the IEEE 2030.5 server[9].

The CEC-sourced DERs were originally intended to be deployed at residential customer sites on a single circuit. However, due to contractual issues with the original CEC installer and the DER vendor/aggregator, which decided not to participate, the installation of these systems was delayed until late 2018[10]. Additionally the DER systems deployed for the projects, due to the original installer dropping out of the project and the lack of time to find new customers on a single circuit, deployed across SCE's territory. Thus the CEC project's field demonstration scope and objectives were altered to somewhat reflect SCE's Big Data project. The CEC project will release a separate report that will discuss similar learnings, but from the 3rd parties' points of view.

3 Rule 21 Smart Inverter Requirements

3.1 Phase 1 Autonomous Functions

Phase 1 functionalities, which were approved by the CPUC at the end of 2014, became mandatory for all inverters connected under Rule 21 from September 8, 2017. While deemed "autonomous", most of these default settings can potentially be remotely updated, set or activated/de-activated via IEEE 2030.5 as defined by CSIP, though currently only Dynamic Volt/Var is allowed to be modifiable remotely in Rule 21 via the Phase 3 Scheduling function.

Phase 1 Function	Description[11]
Anti-Islanding	Anti-islanding protection requires Inverter DER (I-DER) systems to disconnect or otherwise cease to energize an unintentionally created electrical island when the Area Electric Power System (EPS) is de-energized, with the purpose of ensuring the safety of personnel and equipment that might come in contact with that electrical island.
Low/High Voltage Ride-Through	Low/High Voltagse Ride-Through (L/HVRT) refers to the connect/disconnect behavior of the I-DER systems during anomalous voltage conditions. L/HVRT defines the voltage levels and time durations during which the I-DER systems should remain connected to the Area EPS and, similarly, the voltage levels and time durations at which the I-DER system must disconnect.
Low/High Frequency Ride-Through	Low/High Frequency Ride-Through (L/HFRT) refers to the connect/disconnect behavior of the I-DER system during frequency deviations. L/HFRT defines the frequency levels and time durations during which the I-DER system should remain connected to the Area EPS and, similarly, the frequency levels and time durations at which the I-DER system must disconnect.
Dynamic Volt/Var Operations*	Dynamic volt/var operations, also called dynamic reactive power compensation, allow I-DER systems to counteract voltage deviations from the nominal voltage level (but still within normal operating ranges) by consuming or producing

[9] This was provided by Kitu Systems through a competitive bid.
[10] Kitu Systems provided the aggregation and IEEE 2030.5 communications and integration. Pika Energy provided the ESS and Smart Inverters, as well as project managing the custom installations. Approximately 8 installers ended up supporting the customer installations.
[11] Descriptions are taken from the SIWG Recommendations- http://www.cpuc.ca.gov/WorkArea/DownloadAsset.aspx?id=3189

	reactive power. Dynamic volt/var curves are defined that specify the changes in vars in response to changes in the local voltage measured by the I-DER system.
Ramp Rates	I-DER systems can ramp the rate of increasing and/or decreasing their power output. These ramp rates are constrained by what the I-DER systems can physically do. For instance, if they are outputting their maximum power, they can ramp down but cannot ramp up, while a completely charged storage system may ramp up (discharge power into the Area EPS) but cannot ramp down.
Fixed Power Factor*	The most efficient operation of an Area EPS is if it has zero reactive power, and thus has the optimal power factor (PF) of 1.0. However different types of loads and I-DER systems can generate reactive power, thus lowering the PF below the optimal value of 1.0. The purpose of establishing fixed power factors in I-DER systems is to help compensate for those loads and other I-DER systems that generate reactive power. If, on average, a circuit has a power factor of +0.95, then some of the I-DER systems on that circuit can be set to have a power factor of -0.95.
Reconnect by "Soft Start" Methods	Following an outage, when power is restored to the Area EPS, the I-DER systems on that circuit will need to reconnect to start generating power. If all I-DER systems started to output real power at exactly the same time, the circuit could experience a sharp transition, which could cause instability, possibly voltage spikes, or even sharp frequency increases. The purpose of the reconnection by "Soft-Start" is to ameliorate these sharp transitions by ramping or staggering the reconnections of the I-DER systems.

Table 1- Rule 21 Phase 1 Autonomous Functions

3.2 Phase 2

The SIWG Phase 2 Communications requirements, which were approved in April 2017[12], include the following requirements. Note that Phase 2 deferred to other documents to specify how communications are to be used:

1- All inverters or inverter systems must be able to communicate
2- Communications shall be between IOUs and a- DER systems/inverters; b- facility or plant DER management systems; or c- aggregators
3- IEEE 2030.5 will be the default protocol
4- The California Smart Inverter Profile (CSIP) of IEEE 2030.5, developed by IOUs, shall provide detailed requirements and implementation guidelines for the use of the IEEE 2030.5 standard (See below)
5- Other application protocols may be used by mutual agreement

At the time of this Report, Phase 2 functionality is required to be implemented August 22nd 2019.

[12] SCE Advice Letter and approval notice with all requirements can be found at https://www.sce.com/NR/sc3/tm2/pdf/3532-E.pdf.

3.2.1 Common Smart Inverter Profile of IEEE 2030.5

Throughout 2015 and the first half of 2016, the three IOUs developed and gained SIWG consensus for a profile of the IEEE 2030.5 standard[13]. The CSIP document meant to ensure interoperability by removing any ambiguity that would result from just pointing to the standard by defining which functions are required to be implemented by clients and servers. Due to evolving Rule 21 requirements, the creation of CSIP and some early IEEE 2030.5 demonstrations by the IOUs (including Big Data), both the base IEEE 2030.5 standard[14] and CSIP were revised in 2018. Also in 2018, the SunSpec Alliance developed CSIP test and certification procedures[15] which were referenced by Rule 21 as the 6-9 month trigger for Phase 2 and Phase 3 Functions 1 (Monitor Key DER Data), 5 (Frequency Watt Mode), 6 (Volt Watt Mode) and 8 (Scheduling Power Values and Modes)[16] to become active. CSIP includes:

-Security requirements for the use of the protocol. Requirements are derived directly from the IEEE 2030.5 specification but also include additional requirements from the IOUs (e.g., Cypher Suites).

-IEEE 2030.5 control, curves and metering functions to achieve Phase 3 requirements. CSIP allows for event based dispatch (with a start time and defined duration) or modification of inverters' default settings (no duration), though the latter is not currently called out as a required capability in Rule 21

-Aggregator Mediated vs Direct requirements, including messaging patterns based on architectures (e.g., the use of subscription/notification for aggregators vs polling for residential systems) and how controls are dispatched

-Enrollment and commissioning requirements for utility servers, aggregators and inverters. This includes the set-up and maintenance of groupings that can be used to target controls to groups of inverters (e.g., on a single feeder) if desired. See figure below

Importantly, Rule 21 does not specifically require all the above but points to CSIP as the implementation guide that provides "detailed communication requirements and implementation guidelines that ensure consistent interoperability."[17]

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[13] https://sunspec.org/download/.
[14] https://standards.ieee.org/standard/2030_5-2018.html
[15] https://sunspec.org/download/
[16] The original interconnection requirements for inclusion of Phase 2 and Phase 3 Functions 1 & 8 were originally February 22, 2019, but were pushed back 6 months to August 22, 2019. See https://sunspec.org/wp-content/uploads/2019/01/20190103120450.pdf
[17] https://www.sce.com/NR/sc3/tm2/pdf/3532-E.pdf

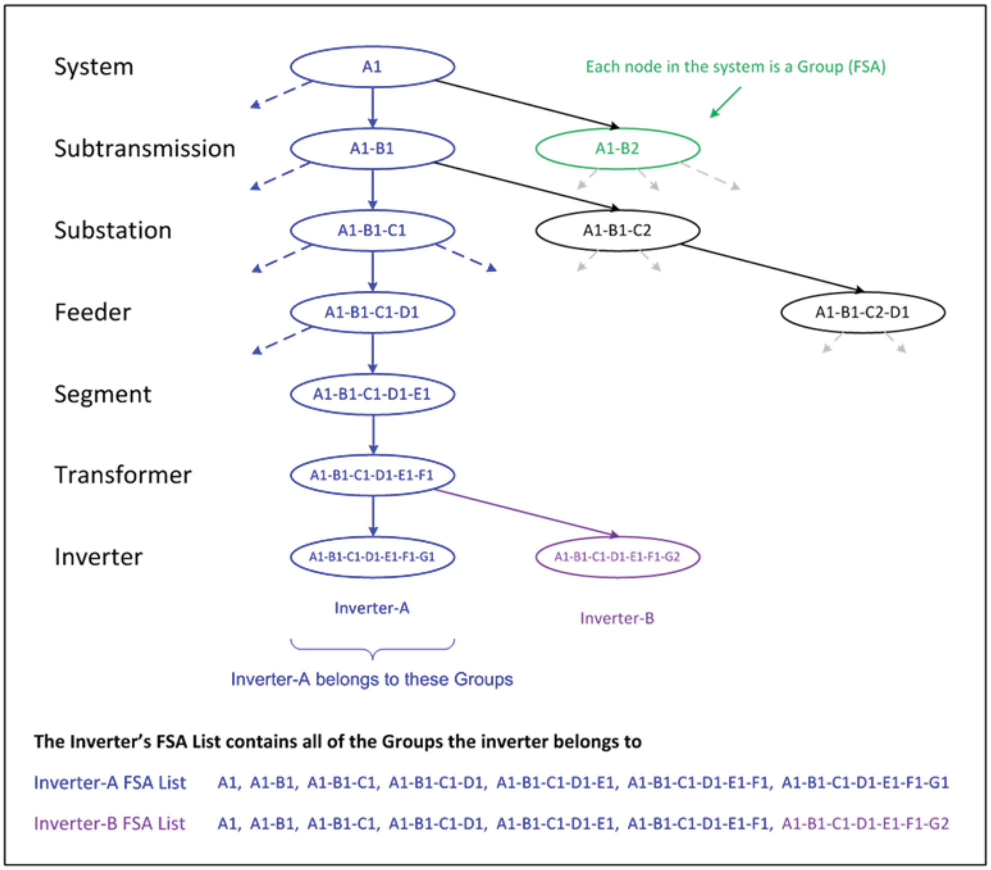

Figure 2- Sample grid network topology and grouping according to CSIP.

In Figure 2 above, each inverter (e.g., Inverter-A) represents one IEEE 2030.5 client and one or more DERs at a service account. Each circle equates to a specific DER program that can dispatch all clients beneath. A topological grouping is not required.

3.2.2 Phase 2 Communications Architecture

The CSIP document describes two different scenarios for smart inverter communications between the utility and DER system as depicted in Figures 2 and 3 below[18]. *Direct* communications between the utility and a DER site (which may include one or more DERs) and *Aggregator Mediated*. An aggregator, unlike a Generating Facility Energy Management System (GFEMS), manages a fleet of inverters that are widely distributed across the utility's service territory rather than having a single point of common coupling. The aggregator, like the GFEMS, is responsible for relaying any requirements for inverter operational changes or data requests to the affected systems and returning any required information to the utility, including measurements, responses and status (per inverter client).

[18] The diagram are taken from the CSIP v2.1 document (https://sunspec.org/download/)

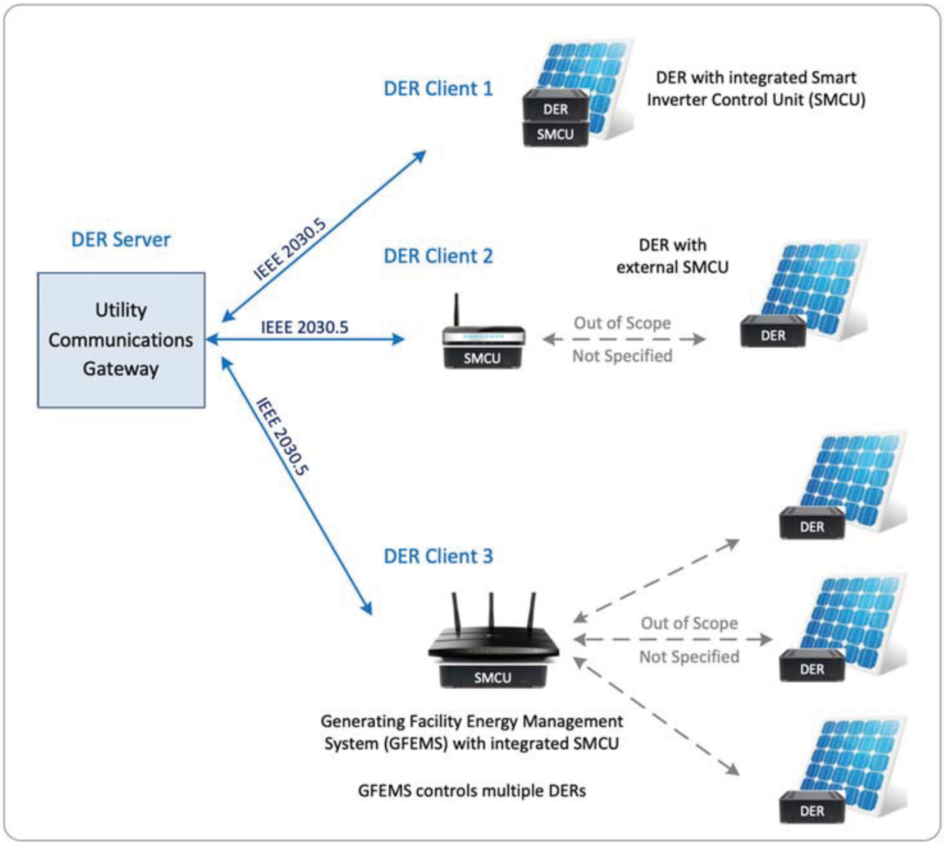

Figure 3- 'Direct' DER communications to IEEE 2030.5 clients

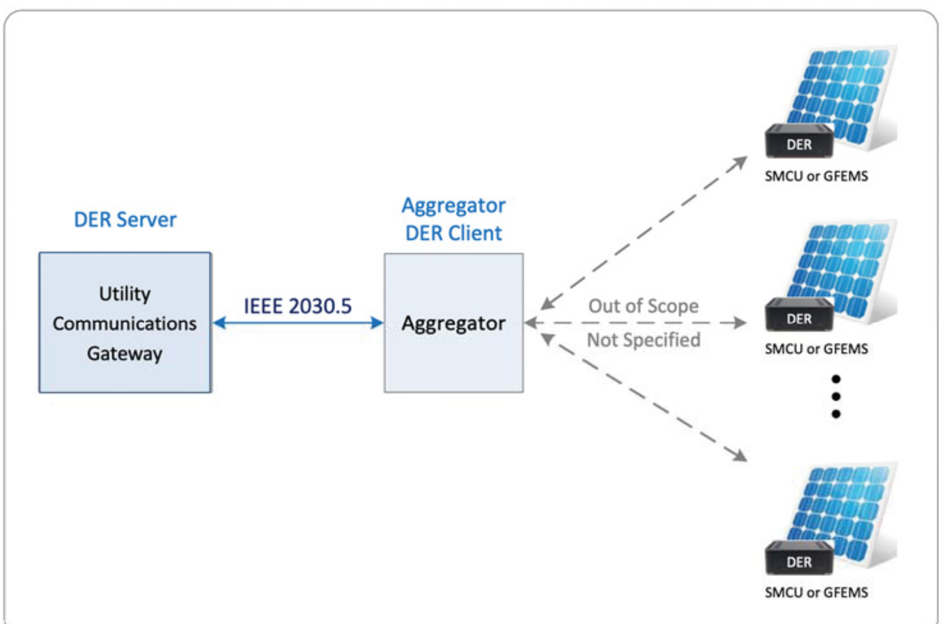

Figure 4- Aggregator mediated communications

CSIP only defines the interface between the utility and the customer/aggregator's gateway, not the inverter itself. Though IEEE 2030.5 may be used downstream of the aggregator or DER gateway, other protocols are allowed to be used between the gateway and the inverter system (as denoted by the "Out of Scope" designation in above figures), as long as the system complies with the required Rule 21 and CSIP functional capabilities. Many if not most inverters implement Modbus[19] at the inverter interface. This means that the utilities IEEE 2030.5 messages must ultimately be translated to Modbus and vice versa. It is possible three or more protocols are in use if other protocols are used behind the aggregator's or GFEMS gateway to the inverter. SunSpec has developed standardized Modbus implementations (called Models)[20] which are widely adopted by the inverter industry[21] and at the time of this Report are working on adding missing Rule 21 capabilities. For these two projects, Kitu Systems used IEEE 2030.5 from their cloud-based aggregator to their client which was integrated into the Pika Energy inverter (no device was used) and communicated to the inverter using SunSpec Modbus.

3.3 Phase 3 Advanced Functions

The Rule 21 Phase 3 functions include further autonomous curve implementation requirements, real and reactive power controls, monitoring capabilities, and scheduling of curve modification. The Phase 3 functions are described below in table 2.[22]

Phase 3 Function	Description
1- Monitoring	All DER systems shall have the capability to provide key DER data at the DER's Point of Connection (PoC) and/or at the Point of Common Coupling (PCC) and/or aggregated at some other ECP.
2- Cease to Energize and Return to Service	The cease to energize command shall cause a "cease to energize" state at the PCC or optionally shall allow the opening of a switch. The cease to energize shall cause the DER to cease exporting active power and (close to zero) reactive power flow.
3- Limit Maximum Active Power Mode	The Limit Maximum Active Power Percent mode shall limit the active power level at the Referenced Point as a percent of the maximum active power capability.
4- Set Active Power Mode	The Set Active Power Percent mode shall set the active power value to be output at the Referenced Point.
5- Frequency Watt Mode	The Frequency-Watt mode shall counteract frequency deviations by decreasing or increasing active power. The change in active power may be provided by changing generation, changing load, or a combination of the two.

[19] http://www.modbus.org/ Modbus may be used with either serial (Modbus RTU) or TCP/IP (Modbus TCP).
[20] https://sunspec.org/download/.
[21] https://sunspec.org/portfolio-type/contributing-members/.
[22] Descriptions are taken from the Phase 3 Smart Inverter Working Group Document-http://www.energy.ca.gov/electricity_analysis/rule21/documents/phase3/SIWG_Phase_3_Working_Document_March_31_2017.pdf.

6- Volt-Watt Mode	The Volt-Watt mode shall respond to changes in the voltage at the Referenced Point by decreasing or increasing active power. The change in active power may be provided by changing generation, changing load, or a combination of the two. The Volt-Watt mode may be used in coordination with the Volt-Var mode to avoid excess VArs or to increase the combined impact on the voltage. In general, Volt-Var would be used first, with volt-watt used if necessary
7- Dynamic Reactive Current Support	The Dynamic Reactive Current Support mode shall provide reactive current support in response to dynamic variations in voltage (rate of voltage change) rather than changes in voltage.
8- Scheduling Power Values and Modes	Scheduling relates to updating Phase 1 settings and curves. Schedules shall be capable of setting active and reactive power values as well as enabling and disabling of DER modes for specific time periods (minutes, hours, days, seasons, etc.). Either the DER system or a proxy, such as a facility energy management system or aggregator, shall have the capability to handle schedules. The schedule shall consist of one or more events with a specific start time and duration of the event as define for each schedule.

Table 2- Rule 21 Phase 3 Functions

Function 1 Monitoring requires the provisioning of facility DER consumption or production of watts (W) and reactive power (VAr), and frequency (Hertz or Hz) and voltage (V) measurements, as well as available operational energy of any energy storage systems. Function 8 includes scheduling (for a set duration) modifications to the volt-VAr, fixed power factor and volt-watt autonomous functions[23]. As mentioned above, both functions 1 and 8 are required as a capability on inverters and managements systems by August 22, 2019. Autonomous functions 5 and 6 are required on February 22, 2019. Functions 2 thru 4 and 7 do not yet have specific implementation dates though publication of IEEE 1547.1[24] is called out as a gating factor[25] and will also include specific implementation requirements.

4 EPIC II Big Data Project

4.1 Scope and Objectives

The originally proposed scope of the Big Data project was to demonstrate and evaluate load management schemes leveraging data from SCE distribution equipment, smart meters and advanced customer energy management systems and behind-the-meter controllable loads (e.g., electric vehicles, thermostats, energy storage systems). As the new Rule 21 Smart Inverter and CSIP requirements were developed, and the implications for new SCE interfaces and systems emerged, the project's focus shifted toward evaluating and demonstrating these new smart inverter and back office control capabilities.

The Big Data project acquired an IEEE 2030.5 CSIP conformant server, deployed and integrated the server into SCE's lab and field environment, conducted lab-based interoperability testing with

[23] http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M213/K658/213658887.PDF. CSIP allows for the scheduled modification of many other settings, as well as modification of default (permanent) settings.
[24] http://grouper.ieee.org/groups/scc21/1547.1_revision/1547.1_revision_index.html.
[25] See ibid and https://sunspec.orgbeh/wp-content/uploads/2019/01/20190103120450.pdf. IEEE 1547.1 is currently under development and projected to be published late 2019.

the aggregator and simulated inverters, and completed field testing based upon project use cases.

The big data project included the following objectives:

1. Demonstrate the IEEE 2030.5 CSIP use cases (grouping, monitoring, controls, and registration) being developed by the IOUs, with results being used to inform development of the profile
2. Evaluate the use of the IEEE 2030.5 DER Function Set for effectiveness and completeness, with results being used to inform future revisions of the standard
3. Define and demonstrate the integrations of IEEE 2030.5 applications with SCE's back office systems in order to securely exchange data and implement controls

While these objectives were ultimately met, the project, in coordination with the CEC project, also discovered possible issues related to the roll out of Rule 21 Phase III requirements and related programs, as well as the deployment and commissioning of smart inverters at customer sites.

4.2 Schedule

The Big Data and CEC projects had several delays from conception to completion. For the Big Data project, integration delays were mainly due to the necessary development of cyber security requirements and designs, as well the deployment, configuration and testing of tools necessary to support the integration of new interfaces over the internet to non-SCE systems. Following the completion of pre-field testing in the lab (unit, integration and interoperability testing) the project redeployed and retested with a new design that included additional cyber tools necessary for the IEEE 2030.5 lab work to move forward. Ultimately, the IEEE 2030.5 system was never allowed to be integrated into SCE's production environment, and the lab environment was used for field testing. SCE is still in the process of securing the production environments in order to support future Rule 21 smart inverter programs.

As mentioned previously, the CEC project's original aggregator/inverter manufacturer and installer decided to discontinue participation at various points in the project. When the original aggregator/manufacturer dropped out in late 2017, SunSpec (the lead on the CEC project) brought in Kitu Systems as the aggregator and communications integrator, and Pika Energy as the inverter provider. These project changes pushed back some of the lab testing milestones and inverter integration work. The decision to drop out by the original partner installer, who had already identified and worked with customers into the second quarter of 2018, caused even more significant delays as new customers had to be procured and project contracts secured. In the end, only 12 of the intended 50 smart inverter systems were interconnected and registered on the IEEE 2030.5 server starting in October 2018. Field testing (simultaneous with field integration testing) began in November 2018 and concluded in January 2019.

Milestone	Completion Date
Procurement of Server	February 2017
Unit Testing	October 2017
Integration and Controls Testing	April 2018
Interoperability Testing	July 2018
Lab Redeployment and Testing	October 2018

Final Project Inverter Interconnection	December 2018
Field Testing and Final Report	January 2019

Table 3- Project Milestones

4.3 Architecture

Figure 5 shows the final lab architecture for the Big Data project. During field testing SCE used a browser based graphical user interface (GUI) provided by the IEEE 2030.5 server to perform commissioning and registration processes, implement controls and manage inverter measurement data. Prior to field testing, SCE successfully integrated the application with lab-based control systems being used for another project using application programming interfaces (APIs) provided by the control systems and integrated with by Kitu. The use of these APIs were limited to consuming measurements and dispatching real and reactive power per inverter due to the control systems functionality.

Kitu used IEEE 2030.5 downstream of its aggregator to communicate with the DER systems and, due to the Pika system having an integrated processor platform that performed their command, control, and communications, Kitu was able to build their IEEE 2030.5 client application to run on the Pika inverter's existing platform and no separate gateway needed. The client communicated to the inverter using SunSpec Modbus over a local Transmission Control Protocol/Internet Protocol (TCP/IP) port. All inverters were connected to the customer's existing internet via a wired Ethernet connection.

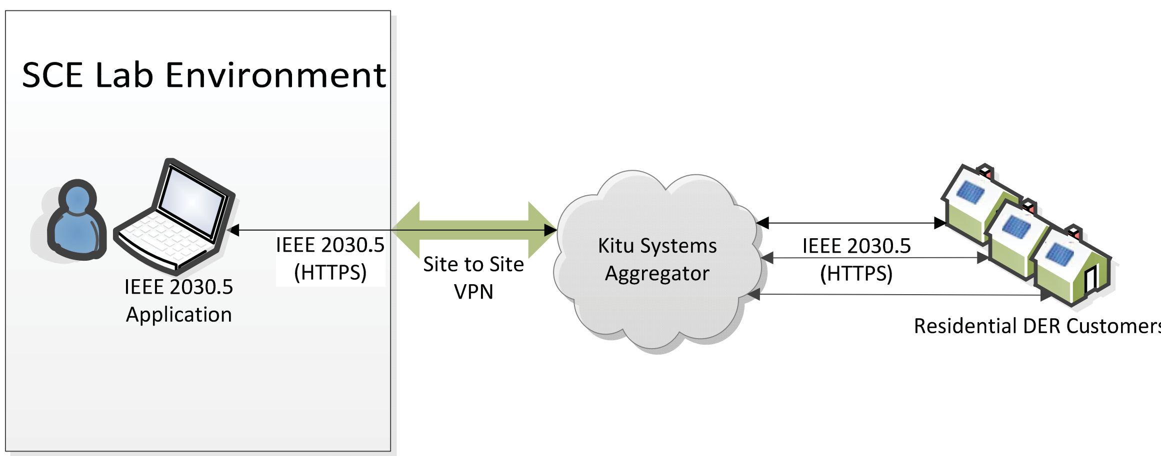

Figure 5- System Architecture

4.4 Cyber Security

SCE currently has systems in its production network to collect telemetry data from large 3rd party systems using remote servers and private networks. However, communicating over the public internet to customer devices either directly or through an aggregator has not been previously attempted and presents a significant cyber security risk that needs to remediated. Though specific details relating to SCE's production cybersecurity requirements and design cannot be shared, the lab design eventually included the use of a Site to Site Virtual Private Network (VPN), a reverse proxy, a web application firewall (WAF), and the use of SCE's Public Key Infrastructure (PKI) for Certificate based authentication to its IEEE 2030.5 Server. Implementing each of these features presented challenges either due to IEEE 2030.5 or the communication infrastructure being used:

WAF- A WAF is an advanced firewall that monitors, inspects and filters communications. Currently IEEE 2030.5 mandates one cipher suite (CS): TLS_ECDHE_ECDSA_WITH_AES_128_CCM_8 which includes the use ephemeral keys. After procurement of the Kitu provided application server and integration services, it was determined that the WAF used in the lab did not support the IEEE 2030.5 CS unless acting as a proxy and terminating the traffic. As IEEE 2030.5 depends on the Transport Layer Security (TLS) handshake and hash of the certificate to support authentication and authorization of the requesting entity, terminating traffic at the WAF was deemed infeasible. To resolve this issue, SCE initially separated the authentication and authorization functionality from the server and implemented in a separate *TLS EndPoint* provided by Kitu (see

Appendix B: TLS EndPoint). This design was used for the duration of the lab testing but was eventually deemed too insecure and SCE used a different CS and removed the TLS EndPoint. Additionally, the IOUs amended CSIP to require that aggregators implement an alternate CS in addition to the one required for clients by IEEE 2030.5 and CSIP

VPN- SCE's VPN requirements include the use of the Internet Key Exchange (IKE) v2 protocol and the use of certificates to set up the tunnel. Kitu had deployed their aggregator on a very popular cloud services platform which at the time of writing supports only IKE v1 and pre-shared keys (PSK). As it was deemed not feasible to have Kitu deploy their services elsewhere, an exception was granted to allow the use of IKE v1 and pre-shared keys for the duration of the project. Such exceptions will most likely not be made in production implementations and thus it is critical that IOU cyber security requirements are clear and provided to Rule 21 stakeholders as early as possible so that the requirements can be used to support deployment decisions.

Reverse Proxy- Besides supporting performance by managing traffic flow and balancing load, a reverse proxy anonymizes servers behind it and limits traffic access[26]. SCE additionally required the reverse proxy to authenticate all traffic. Based on the above mentioned protocol requirements (IEEE 2030.5 depends on the TLS handshake and hash of the certificate to support authentication and authorization of the requesting entity), integrating the reverse proxy for IEEE 2030.5 traffic was an issue. In the end, SCE ended up customizing the implementation of the proxy by having it pass the aggregators certificate to the server along with certificate based authentication and proxying the traffic. It is unclear if this customized implementation of the reverse proxy is a scalable solution and will need to be further explored as SCE moves to a production implementation.

PKI- While the use of SCE's PKI was somewhat straight forward for the small Big Data project, the use of a utility's private certificate authority (CA) is most likely scalable to the millions of possible IEEE 2030.5 clients. CSIP allows for multiple other options, including use of self-signed certificate, a 3rd party CA or the use of an IEEE 2030.5 or CSIP defined CA[27]. For the latter, SunSpec is implementing a CA for Rule 21 testing and certification. It may be that all of the above are used, but SCE's PKI is only used for the small set of Rule 21 aggregators.

End to End Cyber Security- One issue that has arisen as SCE plans for the integration of customer data into its production system is that while CSIP and the Rule 21 interconnection process allows for the IOUs to define cyber security requirements for their interfaces, Rule 21 cannot set requirements for 3rd party owned DERs and networks that are beyond their interface. Therefore it is imperative that standards development organizations (SDOs), user groups, manufacturers and manufacture alliances develop strong cyber security and privacy best practices and requirements that require implementation. Among these, high level requirements would consist of communication authorization, end to end encryption (including for data at rest), PKI for authentication and non-repudiation, and active monitoring. This is even more important when considering the amount of slightly or completely unprotected customer networks that will be connecting to aggregators' and IOU systems.

4.5 Testing

Lab testing consisted of Unit, Integration and Controls, and Interoperability testing. Unit (or Acceptance) testing consisted of testing with the IEEE 2030.5 server and CSIP IEEE 2030.5 clients hosted on Raspberry Pi platforms, also provided by Kitu Systems. Integration and Controls

[26] https://en.wikipedia.org/wiki/Reverse_proxy.
[27] https://sunspec.org/download/. See Section 5.2.1 Security requirements.

testing lasted approximately six months and included integrating with the APIs provided by the SCE Integrated Grid Project (IGP)[28] lab-based control systems (for consuming inverter measurements and dispatching real and reactive power), and demonstrating closed-loop optimization use cases with the Raspberry Pi clients and virtual DERs under simulated grid scenarios. While the intent was to also use these control systems (with expanded interfaces) for the Big Data project in SCE's production environment, the cyber security concerns previously mentioned ultimately caused the project to remain in the lab and use the application's GUI.

Interoperability testing lasted approximately three months and was intended to ensure that SCE's Big Data IEEE 2030.5 application could interoperate with the CEC project's IEEE 2030.5 aggregator client, both of which were provided by Kitu. This testing included the GUI, aggregator, clients and emulated DERs, and covered the Big Data use cases. Despite the use of the same vendor's code throughout, the testing discovered many bugs, not only related to the IEEE 2030.5 communications but the applications as well, and thus saved critical time and effort that would have had to been completed during the short duration available for field testing. In the end, interoperability testing was critical for the Big Data Project's success. For Rule 21, the equivalent to interoperability testing is the SunSpec CSIP testing and certification processes[29]. As it is doubtful the IOUs will have the resources to support this testing, it is suggested that the IOU's IEEE 2030.5 servers also be required to undergo testing and certification in order to support interoperability.

Unlike the interoperability testing, neither the Big Data nor the CEC projects completed end to end functional testing until the DER systems were interconnected, and only 'on the fly' as part of the use case demonstrations. As can be seen in the sections below, there were some issues with the integration of the SunSpec Modbus inverters with IEEE 2030.5 and their support for the use cases. In Rule 21-based programs, where there might be many inverters with different Modbus implementations, multiple aggregators using a variety of protocols including proprietary ones, and many different servers, it is imperative that end to end communications and functional testing regimes be developed and enforced prior to programs being implemented. As IEEE 1547 will include inverter testing and be enforced through new United Laboratories (UL) 1741[30] testing, and SunSpec IEEE 2030.5 testing includes IOU interfaces, it would be suggested that an end to end Nationally Recognized Testing Laboratory (NRTL)[31] test and certification program be developed that includes both tests along with aggregator interfaces in order to ensure every inverter system (aggregator to inverter) can support Rule 21 and CSIP required capabilities.

4.6 Field Demonstrations

The following sections describe the field demonstration of the project use cases. The term Use Cases here denotes CSIP based capabilities rather than grid services provided by these capabilities. Between November 14, 2018 and January 24, 2019, a total of 31 events were dispatched to the aggregator managed DER clients. From an IEEE 2030.5 perspective, the uses of the protocol as described by CSIP were as expected. However, during the field demonstrations problems were seen related to customer communications and the integration and implementation of SunSpec Modbus inverters and related smart inverter capabilities, all of which took time to identify and resolve.

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[28] https://www.sce.com/sites/default/files/inline-files/EPIC_IGPWinterSymposiumPresentation_0.pdf.
[29] https://sunspec.org/seven-sunspec-alliance-authorized-test-laboratories-announced/.
[30] https://standardscatalog.ul.com/standards/en/standard_1741_2.
[31] https://www.osha.gov/dts/otpca/nrtl/.

4.6.1 Grouping, Primacy, Overriding and Canceling, and Registration

4.6.1.1 Grouping

In order to effectively manage the customer owned DER systems for distribution reliability, the DER location from an electrical topology standpoint must be known by the utility. There may be cases where curves will be sent to the entire group of DERs under a specific aggregator's control, or curves may be sent to a limited number of inverter systems to support the needs in specific areas of the distribution system. As outlined in the CSIP specification document, each inverter can belong to multiple groups to support utility management at different levels of the system. For the Big Data project, prior to registering the DER clients, the project engineers created a three layer topology on the server as represented in the below diagram.

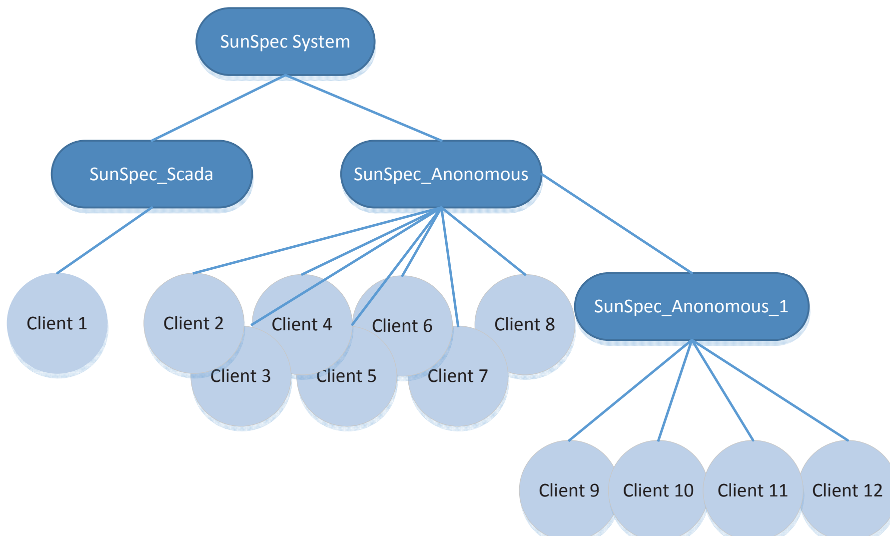


Figure 6- Big Data Topology for the Kitu Aggregator

On the diagram, each dark blue ellipse represents a group (or DER Program) for which all controls effect the inverters below it. For example, a DER control targeted at the SunSpec group would cause the aggregator to dispatch all 12 inverters. A control targeted at the SunSpec_Anonomous group would dispatch the 7 clients underneath it and the 4 clients underneath its child node, SunSpec_Anonomous_1. During the field demonstration, dispatching to various levels was successfully demonstrated, as was moving clients to different nodes, deleting clients and adding clients.

4.6.1.2 Primacy

Each grouping (or program) is assigned a Primacy level which is used by IEEE 2030.5 to determine which programs should take precedence over another if overlapping events occur. Primacy was successfully demonstrated during the project when overlapping DER Controls were dispatched to the same group. Figure 7 below shows that an existing control was superseded by another.

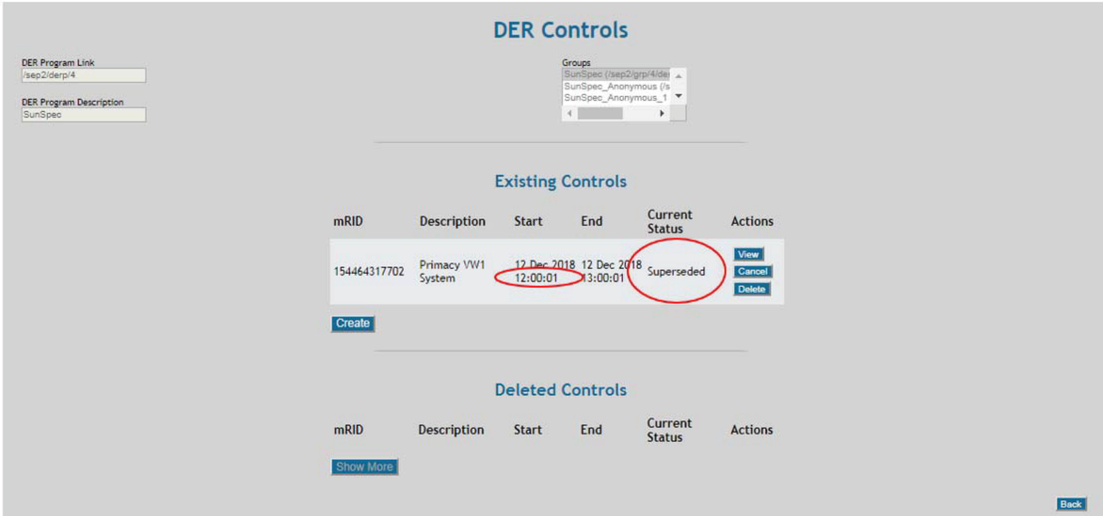


Figure 7- Superseding Control

Figure 8 below shows the Primacy of the SunSpec system group. The lower the primacy the higher the precedence.

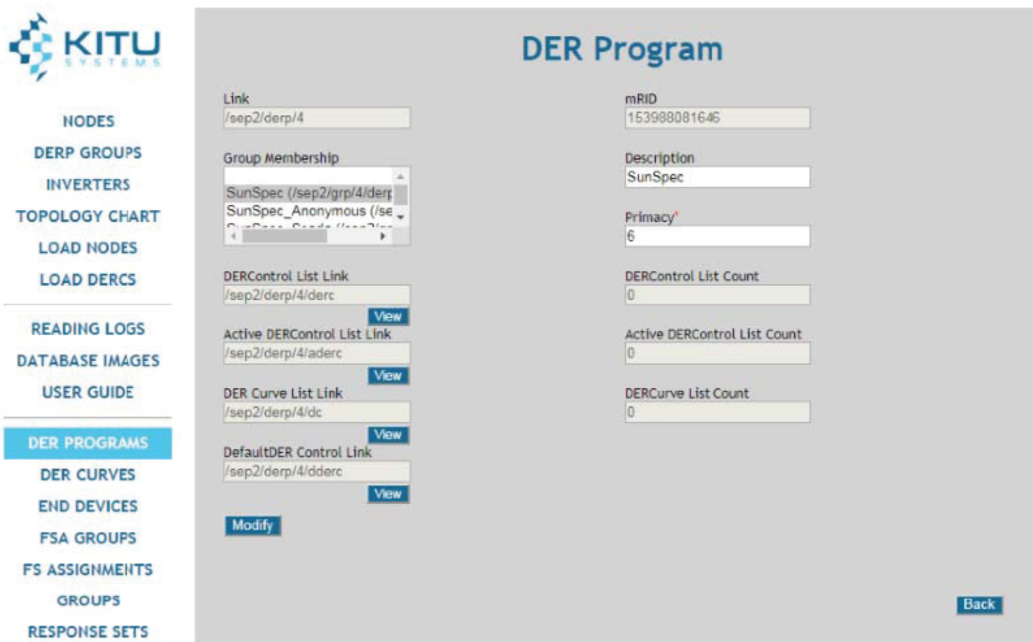
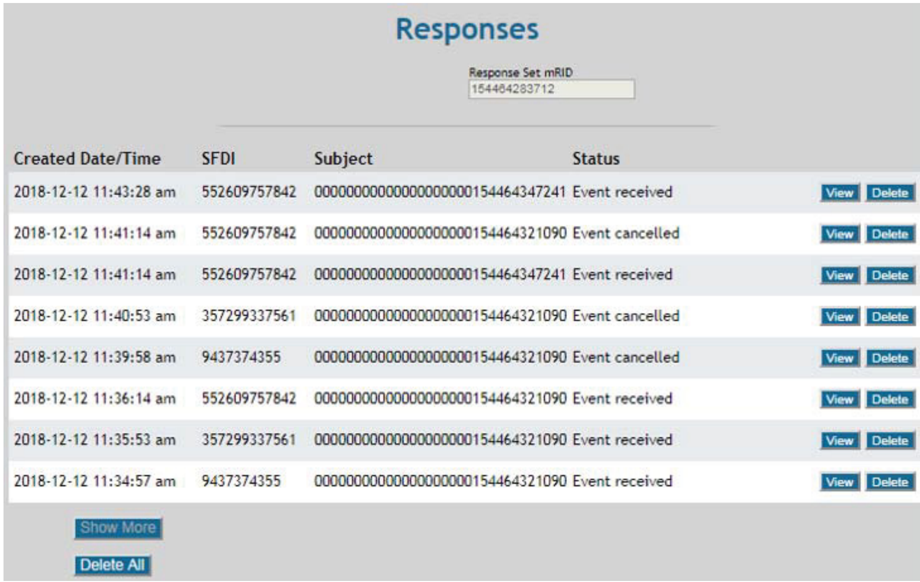


Figure 8- Screenshot of the IEEE 2030.5 Server showing Primacy level of the SunSpec System Group (or DER Program)

4.6.1.3 Overriding and Canceling Events

IEEE 2030.5 and CSIP allows for both overriding and canceling events, but not modification to existing ones. The Big Data Project successfully demonstrated the ability to do both prior to event start and during events. Though somewhat similar to superseding based on Primacy, overriding an event is scheduling a new event prior to or during the existing scheduled event. When cancelled, inverters will indicate (see Responses) that the previously scheduled event is Cancelled as shown below.



Responses

Response Set mRID 154464283712

Created Date/Time	SFDI	Subject	Status		
2018-12-12 11:43:28 am	552609757842	00000000000000000000154464347241	Event received	View	Delete
2018-12-12 11:41:14 am	552609757842	00000000000000000000154464321090	Event cancelled	View	Delete
2018-12-12 11:41:14 am	552609757842	00000000000000000000154464347241	Event received	View	Delete
2018-12-12 11:40:53 am	357299337561	00000000000000000000154464321090	Event cancelled	View	Delete
2018-12-12 11:39:58 am	9437374355	00000000000000000000154464321090	Event cancelled	View	Delete
2018-12-12 11:36:14 am	552609757842	00000000000000000000154464321090	Event received	View	Delete
2018-12-12 11:35:53 am	357299337561	00000000000000000000154464321090	Event received	View	Delete
2018-12-12 11:34:57 am	9437374355	00000000000000000000154464321090	Event received	View	Delete

Show More

Delete All

Figure 9- Event Cancelled Response

4.6.1.4 Registration

A total of 12 customer DER systems were interconnected under the CEC project. As inverters were commissioned in the field, the Short-Form Identifiers (SFDI)[32] were used to register the inverters on the server and associate them with the aggregator and desired group. Project customer information, including which groups the inverter clients ended up residing in, is shown in Table 4. Note that where ESS were deployed along with the PV, a Direct Current (DC) coupled inverter was used.

CEC Project Inverter Information (All inverters 7.6kW)			
Client ID #	2030.5 Node (All registered under SunSpec System)	ESS Size	SFDI
1	SunSpec_Scada	N/A	098440025431
2	SunSpec_Anonymous	N/A	009437374355
3	SunSpec_Anonymous	17.1kWh	066995305782
4	SunSpec_Anonymous	11.4kWh	531739775337
5	SunSpec_Anonymous	N/A	572466358716

[32] SFDI, along with Long Form Device Identifier (LFDI), are IEEE 2030.5 ID derived from a hash of the device certificate. It, along with an optional pin, are used for authorization. The use of an LFDI is required by CSIP in direct communication scenarios to prevent collisions (the use of the same ID by 2 different clients). CSIP requires the use of SFDI and LFDI for non-IEEE 2030.5 DER clients as well.

6	SunSpec_Anonymous	17.1kWh	038459715242
7	SunSpec_Anonymous	17.1kWh	357299337561
8	SunSpec_Anonymous	34.4kWh	514401931976
9	SunSpec_Anonymous_1	N/A	552609757842
10	SunSpec_Anonymous_1	N/A	185644417488
11	SunSpec_Anonymous_1	N/A	638877322293
12	SunSpec_Anonymous_1	17.1kWh	669042003433

Table 4- Final Customer Inverter and Grouping Information

The grouping and registration process for the Big Data project resorted to being done manually because of the small population of clients and use of the GUI. In the future it will be important for production SCE systems to be able to support automated enrollment, commissioning and grouping. This includes:

- Interconnection processes that support inverter and aggregator identification (capabilities/ratings, location, IDs).
- The provisioning of interconnection data, including interconnection IDs, to systems that can support IEEE 2030.5 registration and grouping set up.
- Systems that understand network topologies, inverter locations and capabilities, and the ability to maintain the models as distribution system (e.g., switching activities) or DER system changes (e.g., upgrades) occur.
- Ability to associate devices to aggregators and groups (e.g., interconnection IDs may be a common key between what aggregators provide and what is known via interconnection).

4.6.2 Monitoring

Monitoring is the Phase 3 Function 1 capability which requires the provision of performance data at the facility level. Once registered, and unless experiencing communications faults, the 12 clients provided five minute interval data (instantaneous readings) for the duration of the demonstration. Though Rule 21 requires the provisioning of Volts, Watt, Frequency and Reactive Power, the project inverters also provided Amps, Apparent Power and Power Factor. The interval data was used to validate the expected dispatch of inverters when controls were issued.

Besides measurement values, each interval reading includes the inverter ID(s), reading group ID, timestamp of reading, quality bit, unit of measure, phases, power of ten multiplier and other items. Even for a small set of clients, this amount of data was very large. As each inverter is required to post data (separate TCP connections), the utility networks and systems capabilities need to be taken into account. On average, the size of a HyperText Transfer Protocol (HTTP) POST payload packet sent by an inverter that contains a single meter reading value is about 460 bytes. The total packet size, including all the HTTP, TCP, IP, and Ethernet headers is about 680 bytes. Additionally, project engineers have queried IEEE about support for the ‘batching’ of readings from aggregators.

Moving forward into program implementations, IOUs should also evaluate and define the behavior of the inverter systems, management systems and aggregators with the following considerations:

- The duration 3rd party systems should persist reading data.

- The behavior of 3rd party systems when communications are down, including what data should be provided upon resumption of communications

4.6.3 Responses

Responses are an event status provided by individual inverter clients when receiving, starting, canceling and completing events (other response types are available). In the Big Data project Responses were useful for quick identification of issues (e.g., if no response was received then there was a communication fault). However, Responses are optional in IEEE 2030.5 and implementations should determine if thousands or more responses are needed for each control. It took approximately five minutes for all related responses (e.g., Event Received) to show on the GUI for this project.

Responses

Created Date/Time	SFDI	Subject	Status	
2018-12-05 03:00:00 pm	9437374355	00000000000000000000154404219906	Event completed	View Delete
2018-12-05 03:00:00 pm	38459715242	00000000000000000000154404219906	Event completed	View Delete
2018-12-05 03:00:00 pm	66995305782	00000000000000000000154404219906	Event completed	View Delete
2018-12-05 03:00:00 pm	98440025431	00000000000000000000154404219906	Event completed	View Delete
2018-12-05 03:00:00 pm	357299337561	00000000000000000000154404219906	Event completed	View Delete
2018-12-05 03:00:00 pm	514401931976	00000000000000000000154404219906	Event completed	View Delete
2018-12-05 03:00:00 pm	531739775337	00000000000000000000154404219906	Event completed	View Delete
2018-12-05 02:00:00 pm	9437374355	00000000000000000000154404219906	Event started	View Delete
2018-12-05 02:00:00 pm	38459715242	00000000000000000000154404219906	Event started	View Delete
2018-12-05 02:00:00 pm	66995305782	00000000000000000000154404219906	Event started	View Delete
2018-12-05 02:00:00 pm	98440025431	00000000000000000000154404219906	Event started	View Delete
2018-12-05 02:00:00 pm	357299337561	00000000000000000000154404219906	Event started	View Delete

Figure 10- Partial screenshot of Client Responses.

4.6.4 Status

CSIP includes support for IEEE 2030.5 status information including provisioning of nameplate ratings, adjusted settings, Operational Energy Storage Capacity, inverter operational state (e.g., on/off) and inverter alarms (e.g., Over Voltage, Under Frequency, etc.). While Status was not included in the Big Data project demonstrations, the inverters did provide the nameplate ratings (which IOUs also get from the interconnection process). The only Status type that is required in Rule 21 is the Operational Energy Storage Capacity of batteries. In Rule 21, this is called out as a monitoring (or measurement) point. In IEEE 2030.5 however it is a Status. As IOUs implement programs they will need to determine which if any of this available Status information is valuable.

4.6.5 Scheduling Curves and Controls

4.6.5.1 Curves

The project use cases included dispatch Volt/Var, Frequency/Watt and Volt/Watt curves. Curves are first created on the server and then dispatched with a DER Control event that possibly contains other controls in addition to other information such as start time, duration, etc.

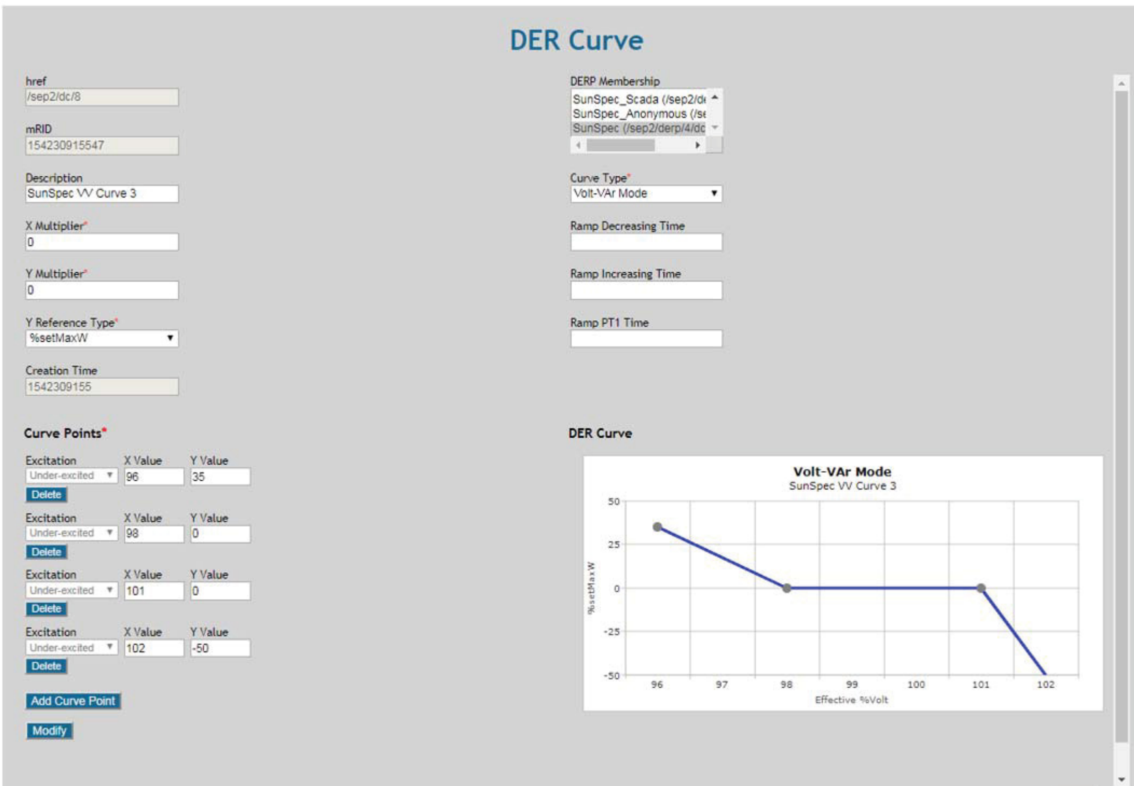


Figure 11- DER Curve Creation Screen

Figure 10 above shows a Volt/VAr DER Curve used in the project and the below picture shows the effect of the curves dispatched to a specific inverter. The graph is based on the evaluation of interval readings post event.

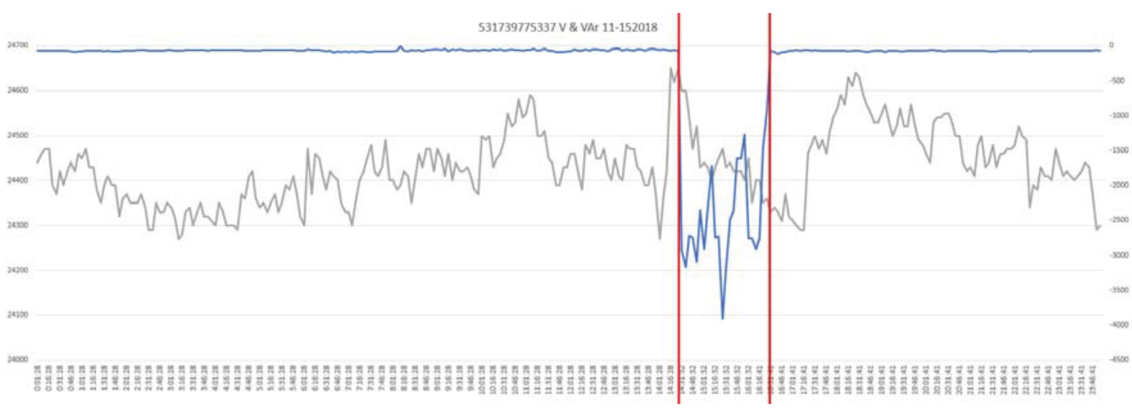


Figure 12- Curve Dispatch of Inverter

The red lines in Figure 11 show the start time and duration of the event. The blue line is the VArs and the grey line is the voltage. The project also successfully demonstrated the ability to use IEEE 2030.5 controls to generate and absorb reactive power overnight (Figure 13).

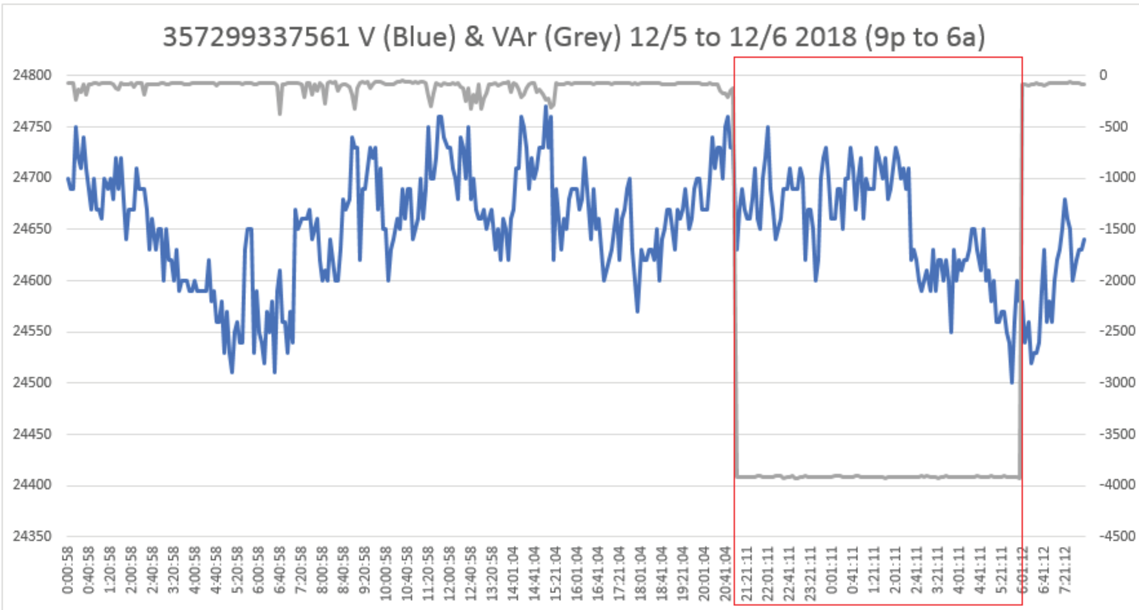


Figure 13- Overnight Volt/Var Event

Unfortunately, due to the frequency measured at each inverter being very near to nominal (60 Hz), the project was not able to see any impact of the Frequency/Watt curve controls. Responses confirmed confirmation of receipt and that inverters completed the events. SCE's upcoming DRP Demo E[33] project will, among many other things, explore the use of Frequency/Watt curve controls using IEEE 2030.5.

The Volt/Watt curve dispatches revealed possible conflicts related to the current interconnection standards and the use of communications to modify curves. The curve shown in Figure 15 was dispatched on November 21, 2018. The second curve point shows inverters should reduce to 50% of Watt nameplate capacity at 102% of nominal voltage (244.8V on a 240V system).

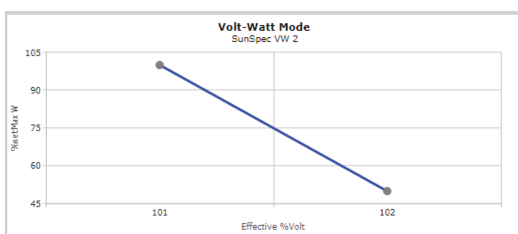


Figure 14- Volt/Watt Curve

However, Figure 16 shows the inverter reducing power production immediately to 0 Watts. This was seen multiple times during the project. After discussions with Pika Energy, the project team

[33] http://www.cpuc.ca.gov/general.aspx?id=5071.

determined that the related curve registers were not writeable and set to 100% and 0%. Additionally, only 2 points were allowed for Volt/Watt and Frequency/Watt curves, and 4 for Volt/Var curves. As IEEE 1547.1[34] is developed and Phase 3 requirements implemented in Rule 21, additional clarifications on how to apply IEEE 1547-2018 are necessary (e.g., CSIP allows for up to 10 points per curve to be written to). For the project, Pika Energy relaxed the restrictions and the expected behavior was seen during later Volt/Watt curve dispatches.

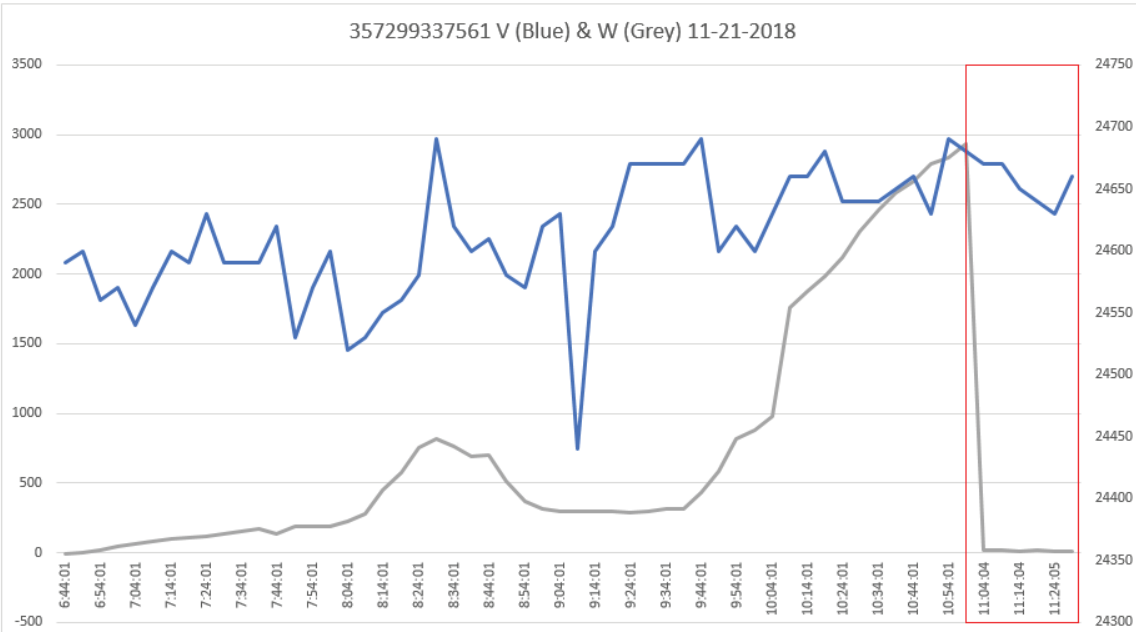


Figure 15- Volt/Watt Curve Dispatch

4.6.5.2 Controls

Phase 3 includes four non-curve based controls: DER Disconnect and Reconnect, Limit Maximum Active Power, Set Active Power and Dynamic Reactive Support. The Big Data project, through much trial and error, successfully demonstrated the latter three (DER Disconnect and Reconnect was not a use case). Among the issues discovered were:

-Inverter modes did not allow remote dispatch of real and reactive power: The Pika Energy inverters have five configurable modes that are set depending on the customer tariff, programs, or other criteria. Besides determining schedules and amounts of power production and generation, the modes also configure which registers are able to be modified. To dispatch the 3 aforementioned controls, Pika Energy remotely changed the inverters to 'Arbitrage Mode' for a short duration. It is unclear if such issues would pose problems in the future if other inverters support similar different modes, though a concern arises about who has access to modify modes (assuming other inverters also provide similar configurations), especially in situations where the aggregator and inverter are different entities and have no relationship.

-The implementation requirements related to the Limit Real Power vs Real Power Setpoint are not yet developed in Rule 21. Consequently, additional integration work on behalf of Kitu and Pika

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[34] http://grouper.ieee.org/groups/scc21/1547.1_revision/1547.1_revision_index.html.

Systems needed to get both capabilities operational. In the end, the project team determined that the SCE operator could use the IEEE 2030.5 opModFixedW parameter to dispatch both, as it caused PV systems to limit power and PV+ESS systems to go to a setpoint. As mentioned in Testing, such issues could be prevented with requirements developed for both PV and PV+ESS systems as well as a strong end to end testing and certification program

-During the project, the team determined that Real Power Setpoint is not currently in any SunSpec models. SunSpec is currently working on adding this and other required Rule 21 capabilities.

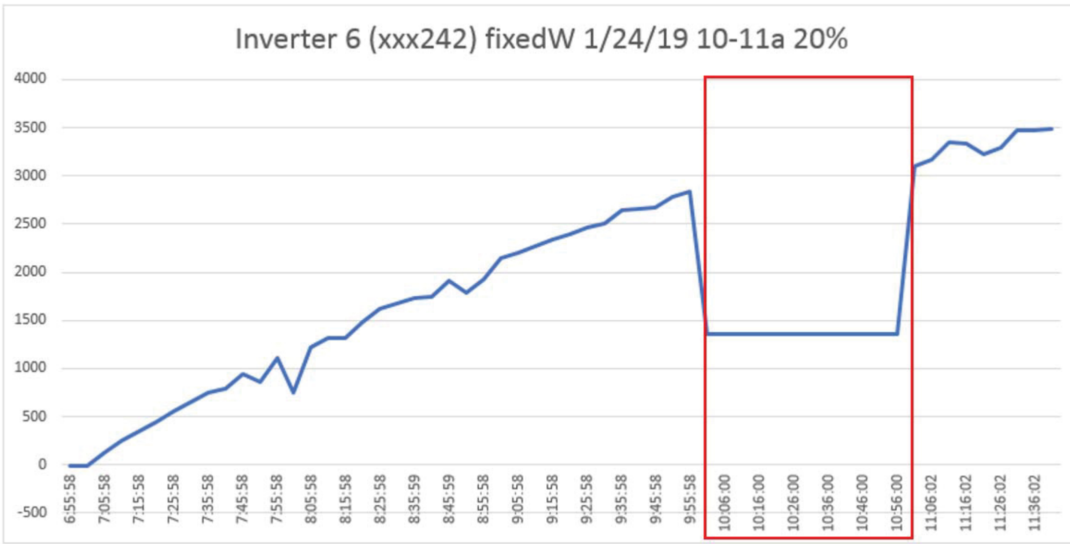


Figure 16- PV+ESS Inverter Real Power Setpoint Dispatch

Figure 17 above shows an opModFixedW dispatch event causing an inverter system consisting of PV and ESS to curtail to a 20% setpoint. Figure 18 below shows an opModFixedVar dispatch event causing a DER system to dispatch reactive power from 2 am to 4 am.

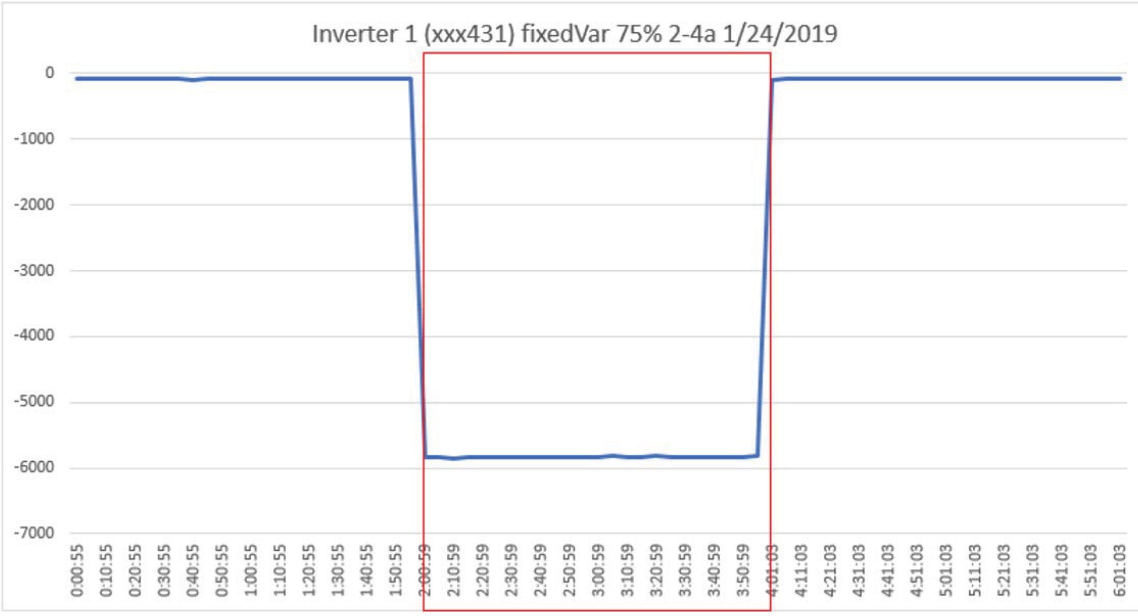


Figure 17- Dynamic Reactive Power Dispatch

It is important to note that for this project, Kitu passed SCE's real and reactive power control signals directly to all of the DER systems. In future programs, it might be the case that aggregators will receive the utility real and reactive power control signals and variably dispatch the systems under their control based on the status, other information or customer and program agreements, Such aggregator capabilities should be defined and tested prior to program implementations.

4.6.6 DER Communications

The need to ensure DER systems' network communications are properly commissioned, monitored and problems are able to be corrected simply and quickly emerged as one of the most critical learnings gleaned from the project. As mentioned previously, all inverters had a wired connection to customer routers and installers connected these as part of the installation and commissioning processes. However, at no point during the project did all inverters have working connections to the internet and Kitu's aggregator platform. On average, approximately 33% of the inverters were down at any one time. During the final Dynamic Reactive Power dispatch, only 7 of the 12 inverters were dispatched due to communication issues.

A related lesson learned was how the problems were often discovered- the SCE project engineer reviewing reading logs or looking at client event responses a day or more after a scheduled event. There was no active monitoring of communications by any party associated with the project (Pika Energy, Kitu or SCE) set up for the projects. And once the problems were identified, it was up to the installer to support reconnection[35] if the customer could not be reached or was not able to fix the communications issues (presumably if the customer's internet was down they would have noticed and restarted their router or gone through other troubleshooting steps). Because the resolution of these issues took weeks (e.g., two DER systems' communications

[35] Neither Kitu or Pika Energy are located in SCE territory

were down for the majority of the project), this meant that some systems were not controllable or providing measurement data for a majority of the field demonstration period.

While the CEC project report will delve into this issue further and lessons learned, SCE provides the following suggestions related to Rule 21 and Utility programs are as follows:

-Aggregators or other entities need to implement strong installer commissioning procedures to ensure communications are working.

-Customers need to be educated about how connections are set up at their site so they do not inadvertently disconnect the inverters and also know about communication resolution processes.

-Utility operation engineers need to understand that at any one time a certain % of residential customer inverter systems cannot be relied upon to provide data or grid support. It would be valuable to determine what the expected numbers are and how they would affect operations, planning or other uses of new smart inverter interfaces and capabilities.

-Where in use, a customer inverter’s internet connection will eventually fail. Where critical systems exist, more reliable communications should be used.

-Fault monitoring and resolution timeline requirements should be developed in any agreements with aggregators and/or customers. This could take the form of aggregator performance requirements (e.g., Network Uptimes).

5 Project Results

5.1 Achievements

While additional time for all participants would have been useful for this project, the Big Data project (along with the CEC project) still achieved the project objectives. Among the learnings/successes were:

-Successfully demonstrated how new smart inverter capabilities can be utilized using IEEE 2030.5 as defined by CSIP;

-Supported the design and related testing for the secure integration IEEE 2030.5 services into SCE’s production environment.

-Updated IEEE 2030.5 and CSIP based on the early project work;

-Identified possible inverter integration and customer communication issues; and

-Supported the continuing development of Rule 21, CSIP and related proceedings through internal and external knowledge transfer activities and regulatory activities such as developing aggregator agreements

5.2 Lessons Learned and Recommendations

While specific lessons learned and recommendations are provided throughout the document, a summary is provided below:

The project inverters’ modification of curves and dispatch of real power based on external controls were not very easily implemented. The developing grid connection standards (e.g., Rule 21 and IEEE 1547.1), inverter standards (e.g., SunSpec Modbus) and communication standards (e.g., IEEE 2030.5, CSIP) need to be aligned and end to end functional testing and certification procedures need to be established.

Customer and inverter communications issues were experienced throughout the short project field demonstration period. Strong communication commissioning (at installation), monitoring and related performance requirements need to be developed and included within interconnection and program requirements. Where necessary, the use of non-customer communications (e.g., cellular) should be used.

As with the Rule 21, the Big Data project was not able to define cybersecurity requirements for the systems and communications beyond its aggregator interfaces. The DER industry, vendor alliances, vendors and SDOs should work with the utility industry to develop and implement strong cybersecurity requirements.

5.3 Technology/Knowledge Transfer

The Big Data project successfully demonstrated some CSIP functionality that is not yet specifically defined or required in Rule 21 (e.g., provisioning of inverter Status, event Responses, inverter settings, and monitoring data upon communication resumption). Rule 21 or related documents and future programs will need to define whether and how these and other CSIP capabilities not demonstrated (e.g., modification of default inverters settings) are implemented.

The project proved that the IEEE 2030.5/CSIP communication protocol will be able to meet the smart inverter requirements as defined in Rule 21 Phase 3. However, the project did not demonstrate its use for supporting grid reliability or optimization purposes. Further demonstrations are necessary to prove out how these communications-related smart inverter capabilities can support the grid, as well as how other DERs (e.g., electric vehicles) may be able to implement these capabilities.

5.4 Stakeholder Engagement

The Big Data project engineers met regularly with internal SCE stakeholders to provide project updates and to receive input on demonstration needs for the project. Project engineers also supported SCE in the development and revisions to CSIP, SIWG and Rule 21 proceedings. Additionally, engineers supported requirements development and deployment and integration designs for the procurement of SCE's new grid management systems, its DRP Demo C, D and E Department of Energy (DOE) demonstrations. SCE stakeholder groups that supported or received support from the Big Data project included Cyber Security, Interconnections, DER Demonstrations, Information Technology, Enterprise Architecture, Grid Modernization and Regulatory.

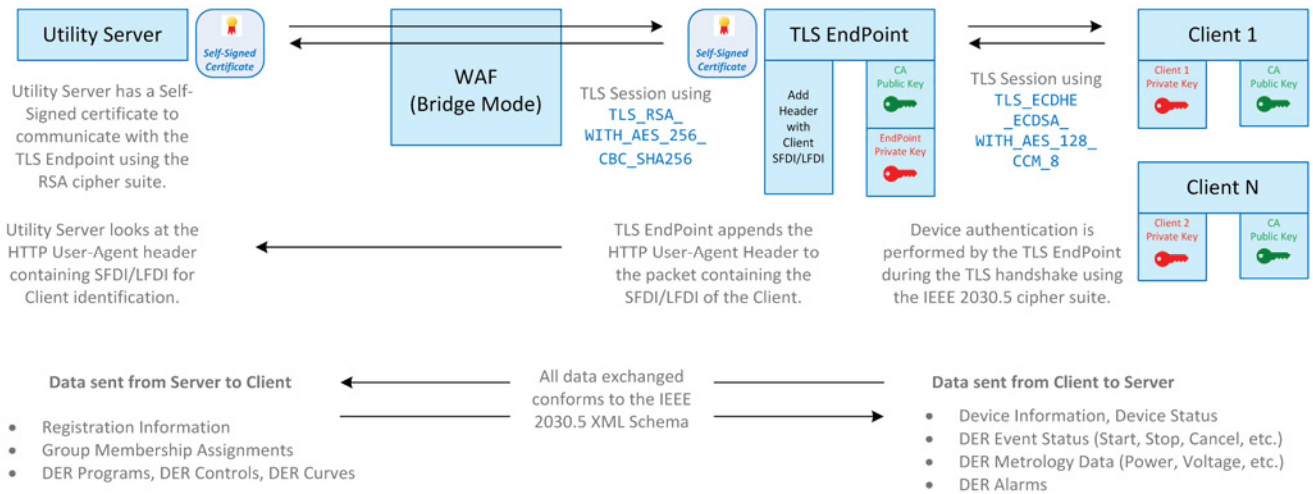
Appendix A: List of Acronyms

CA	Certificate Authority
CEC	California Energy Commission
CPUC	California Public Utilities Commission
CS	Cipher Suite
CSIP	Common Smart Inverter Profile
DC	Direct Current
DER	Distributed Energy Resources
DRP	Distribution Resource Pilot
EPIC	Electric Program Investment Charge
ESS	Energy Storage System
GFEMS	Generating Facility Energy Management System
GTM	Grid Technology and Modernization
GUI	Graphical User Interface
Hz	Hertz
IEEE	Institute of Electrical and Electronics Engineers
HTTP	HyperText Transfer Protocol
ID	Identifier or Identification
IGP	Integrated Grid Project
IKE	Internet Key Exchange
IOU	Investor Owned Utility
IP	Internet Protocol
NRTL	Nationally Recognized Testing Laboratory
PKI	Public Key Infrastructure
PON	Public Opportunity Notice
PRP	Preferred Resources Provider
PSK	Pre-Shared Key
PV	Photovoltaic
SA	Supplement A
SCE	Southern California Edison
SDO	Standard Development Organization
SIWG	Smart Inverter Working Group
SOC	State of Charge
TCP	Transmission Control Protocol
TLS	Transport Layer Security

UL	United Laboratories
V	Volt
Var	Reactive Power
WAF	Web Application Firewall
VPN	Virtual Private Network
W	Watt

Appendix B: TLS EndPoint

The below diagram and following information depicts the IEEE 2030.5 traffic flow with the TLS Proxy (Endpoint). The utility server is SCE's IEEE 2030.5 application.



Key Processing Steps:

- The TLS EndPoint is the entity that is in direct communications with the DER Clients.
    - These connections use the IEEE 2030.5 cipher suite (TLS_ECDHE_ECDSA_WITH_AES_128_CCM_8).
    - These connections use the IEEE 2030.5 certificates that chain back to the IEEE 2030.5 Root Certificate Authority
    - The TLS EndPoint performs device authentication using the IEEE 2030.5 certificates
- After authenticating the DER Client, the TLS EndPoint calculates the LFDI/SFDI[36] of the device.
    - The LFDI/SFDI are different size hashes of the Client's IEEE 2030.5 certificate
    - The LFDI/SFDI is put into an HTTP User-Agent header.
    - The new HTTP User-Agent header is appended to the headers of the original HTTP packet.
- After appending the HTTP User-Agent header, the new HTTP packet is transmitted to the Utility Server over a separate TLS connection
    - This connection uses WAF supported RSA cipher suite (TLS_RSA_WITH_AES_256_CBC_SHA256).
    - This connection uses self-signed certificates or certificates provided by SCE
    - This connection is monitored by the WAF
- The Utility Server receives the packet from the TLS EndPoint
    - The Utility Server decrypts the packet
    - The Utility Server uses the new HTTP User-Agent header to extract the SFDI/LFDI of the Client making the request
    - The Utility Server may use the LFDI/SFDI information to tailor its response.

[36] LFDI/SFDI- IEEE 2030.5 IDs that stand for Long Form Device Identifier/Short Form Device Identifier. The LFDI is the certificate fingerprint left-truncated to 160-bits (20 octets) The SFDI is the certificate fingerprint left-truncated to 36-bits

Appendix C: Metrics

The following metrics were specified for the Big Data project:

Metric	Outcome
7b. Increased use of cost-effective digital information and control technology to improve reliability, security and efficiency of the electric grid	The project demonstration of new smart inverter capabilities support their eventual use for grid reliability and optimization purposes.
7c. Dynamic optimization of grid operations and resources, including appropriate consideration for asset management and utilization of related grid operations and resources, with cost-effective full cyber security	The project demonstrated the integration of new smart inverter management systems into SCE environments and thus supports the production level deployment efforts, especially related to cyber security
7d. Deployment and integration of cost-effective distributed resources and generation, including renewable resources	The project demonstrations and learnings will be used to support the effective integration of smart inverters
7f. Deployment of cost-effective smart technologies, including real time, automated, interactive technologies that optimize the physical operation of appliances and consumer devices for metering, communications concerning grid operations and status, and distribution automation	Smart inverter curves and monitoring functions as demonstrated in the project support grid operations
7k. Develop standards for communication and interoperability of appliances and equipment connected to the electric grid, including the infrastructure serving the grid	The project supports the ongoing development of IEEE 2030.5, CSIP and IEEE 1547.1
8e. Stakeholders attendance at workshops	Project stakeholders have attended and spoke at industry events about related topics
8f. Technology Transfer	Stakeholders and sponsors of the project have been kept up to data and solicited for needs in relation to project activities. Among these are cyber security, information technology, grid operations and interconnections

Appendix F

Next-Generation Distribution Automation: Summary of Subprojects

Next-Generation Distribution Automation: Summary of Subprojects

Created by
SCE Transmission & Distribution, Grid Technology and Modernization

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1 Executive Summary

The goal of the Electric Program Investment Charge (EPIC) Next-Generation Distribution Automation project is to improve grid resiliency, safety, reliability and affordability. The project focused on circuit switching devices, communications, smart algorithms and sensing technologies to demonstrate progress towards the following three objectives:

1. Provide advanced distribution automation for fault detection and auto circuit reconfiguration.
2. Provide real-time monitoring, control of field devices, and greater situational awareness and analytics tools for operators.
3. Incorporate greater levels of telemetry[1] to support integration of distributed energy resources (DERs).

This demonstration was divided into the following four subprojects in order to better manage the project's execution:

1. Remote Fault Indicators (RFIs)
2. Remote Intelligent Switch (RIS)
3. Intelligent Fuse (I-Fuse)
4. High-Impedance Fault Detection

Figure 1 shows the subprojects that constitutes the EPIC I Next-Generation Distribution Automation project as components of a distribution circuit.

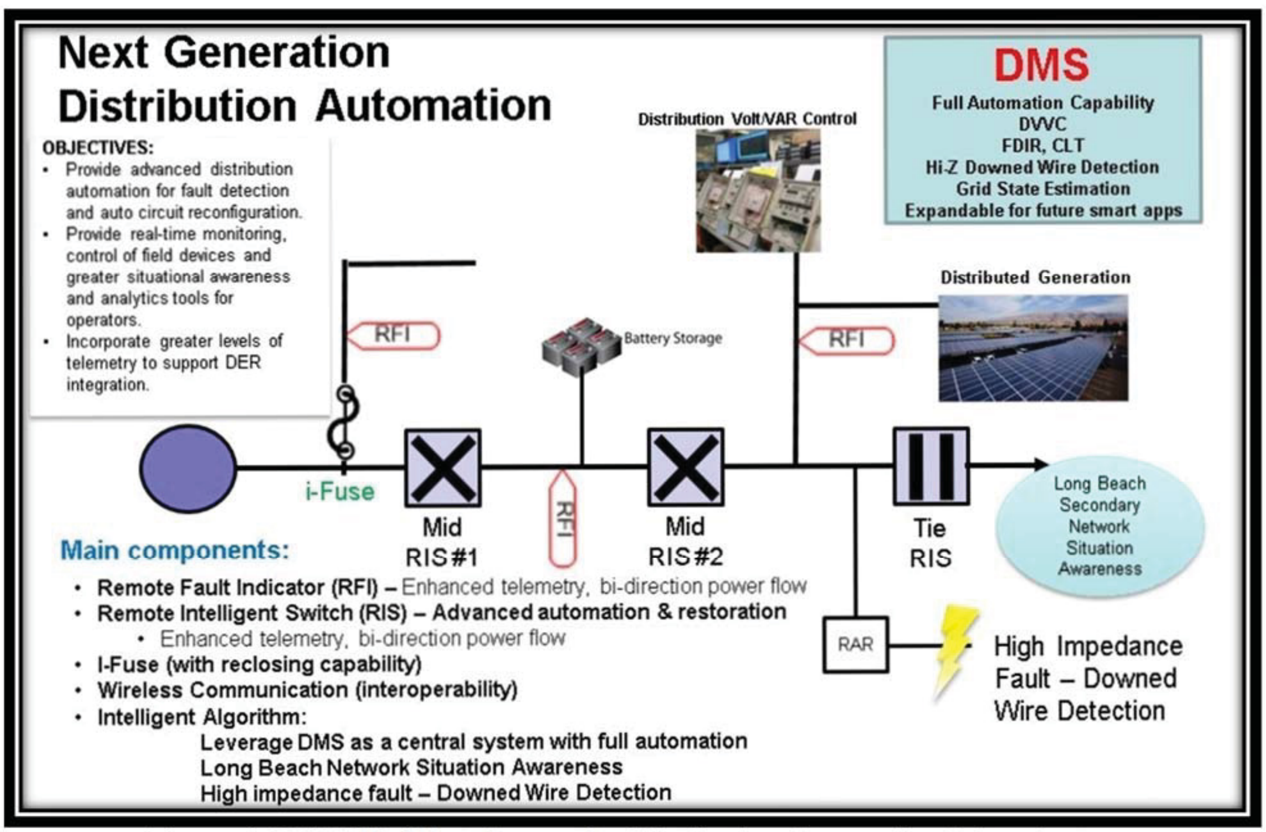

Figure 1. SCE EPIC I Next-Generation Distribution Automation Subprojects

[1] Telemetry is an automated communications process by which measurements and other data are collected at remote or inaccessible points and transmitted to receiving equipment for monitoring.

Subproject Descriptions and Benefits

Remote Fault Indicators (RFIs)

Project Description

For the RFI project, SCE assessed a current and fault sensing device, in both the laboratory and the field, for identifying faulted sections on 12- and 16-kilovolt distribution circuits in order to lessen the time needed by crews to isolate these faults. SCE also demonstrated this capability for the 120/208-volt Long Beach Secondary Network. Specifically, the latter work involved providing remote monitoring capabilities for the network protectors and Metal-Oxide-Limiters (which are used to limit secondary faults) to collect status information and display it via the Distribution Management System.

Support of Next-Generation Distribution Automation Objectives

- **Objective 1**: Provide advanced distribution automation for fault detection and auto circuit reconfiguration.
- **Objective 2**: Provide real-time monitoring, control of field devices, and greater situational awareness and analytics tools for operators:
    - When there is a power interruption, RFIs can send a signal with an estimated location of the malfunction to grid operators, allowing them to quickly map the location, isolate the outage and dispatch a crew.
    - Wireless communications from RFI devices can assist in rapid fault location identification for SCE troublemen, and provide monitoring of operating currents for distribution grid planning purposes.
- **Objective 3:** Incorporate greater levels of telemetry to support DER integration:
    - With their line-sensing capability, RFIs provide real-time current and directional power flow data to help grid operators make more informed decisions on circuit operation in a highly penetrated DER system.

Results/Benefits

- Enhanced ability to monitor and record circuit load, downstream peak load, average load, minimum load, and power flow magnitude and direction.
- Algorithm to automatically set the trip point based on historical line current data.
- Gridstream® radio (license-free spectrum) to provide wireless communication capability to share fault indication and power system data with SCE's Distribution Management System.
- Alarm function to monitor battery life and conductor temperature.

Remote Intelligent Switch (RIS)

Project Description

In the RIS project, SCE demonstrated an advanced distribution automation switching system that provides circuits with self-healing capabilities without operator intervention.

Support of Next-Generation Distribution Automation Objectives

- **Objective 1**: Provide advanced distribution automation for fault detection and auto circuit reconfiguration.
    - The project demonstrated that the RIS system can provide advanced automation for circuit fault detection, isolation, automatic load restoration and circuit reconfiguration, thus reducing the need for operator intervention and for field support to perform switching operations.

- **Objective 2:** Provide real-time monitoring, control of field devices, and greater situational awareness and analytics tools for operators:
    - RIS technology can reduce outage durations, bring substation-style protection to the distribution system, and provide improved situational awareness of conditions on the entire system through automatic data measurement and communication.
- **Objective 3:** Incorporate greater levels of telemetry to support DER integration:
    - The voltage and current telemetry provided by RIS technology delivers real-time current and directional power flow data to help grid operators make more informed decisions on circuit operation in a highly penetrated DER system.

Results/Benefits

- Incorporation of de-centralized logic (decisions to restore and transfer load at the individual device level) into an advanced distribution automation switching system.
- Utilization of overcurrent interrupting devices on distribution circuits as the "switching" component.
- The ability to ensure that one-third or greater of circuit load can be quickly restored after overcurrent conditions occur.
- When possible, the ability to ensure that one-third or greater of circuit load never experiences service interruptions as a result of a fault condition.

Intelligent Fuse (I-Fuse)

Project Description

The I-Fuse project demonstrated an advanced automation device for distribution circuit branch line protection to assess the ability to improve power system reliability and thus help to reduce the duration of customer outages.

Support of Next-Generation Distribution Automation Objectives

- **Objective 1:** Provide advanced distribution automation for fault detection and auto circuit reconfiguration:
    - Project testing showed that during a temporary fault, the I-Fuse design recloses to clear the momentary outage, minimizing lost customer outage interruption minutes.
    - For a permanent outage, the testing showed that the I-Fuse design opens and isolates the faulted section. It performs one reclosure before locking out, and if that occurs, the Remote Fault Indicator (RFI) installed beyond the I-Fuse detects the outage and sends an alarm to the Distribution Management System.

Results/Benefits

- During a simulated temporary fault scenario, after 100 milliseconds the I-Fuse opened, isolated the fault, and sent an open alarm to the Distribution Management System. After 15 seconds, the I-Fuse reclosed, the customers came back online, and the I-Fuse sent a close status. Under a simulated permanent fault scenario, the I-Fuse opened after 100 milliseconds; after 15 seconds it reclosed, locked out due to a permanent fault, and sent a lockout status.
- During project testing, the I-Fuse had telemetry after 20 minutes of energization, and full supercapacitor back-up capacity after 30 minutes of energization.

High-Impedance Fault Detection

Project Description

In the High-Impedance Fault Detection project, SCE assessed a reflectometry-based technology solution – Spread Spectrum Time Domain Reflectometry[2] (SSTDR) – to detect high-impedance faults[3] on distribution circuits and thus improve public and utlity worker safety caused by downed wires.

Support of Next-Generation Distribution Automation Objectives

- **Objective 2:** Provide real-time monitoring, control of field devices, and greater situational awareness and analytics tools for operators:
    - The high-impedance fault system is capable of identifying anomalous impedances on energized circuits, providing a reliable and accurate warning system to identify one or more broken/fallen energized conductors. This can enable utility workers to quickly de-energize a downed wire manually or automatically, versus needing to perform a driven inspection of the circuit to identify the fault location.

      Results/Benefits:

    - Improvement in the ability to detect energized conductors that have fallen to the ground.
    - Decreased number of false alarms.
    - Increased resolution and accuracy in the detection and localization of high-impedance faults.
    - Enhancement of public and utility worker safety through the reduction of high-impedance fault detection time.

All of the above Next-Generation Distribution Automation EPIC I subprojects support SCE's goal of improving grid resiliency, modernization and optimization. Detailed reports for each project can be found in SCE's 2018 EPIC Annual Report, provided at the following link: https://www1.sce.com/wps/wcm/connect/1e3a4642-e960-4254-958a-e3755c3c0064/SCE_AnnualEPICReport2017.pdf?MOD=AJPERES.

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2 Time-domain reflectometry or TDR is a measurement technique used to determine the characteristics of electrical lines by observing reflected waveforms.

3 High-impedance faults occur when a fallen conductor touches a high-resistance surface such as asphalt. The faults do not generate high enough current to trip traditional protection devices (e.g., a substation circuit breaker). Because high-impedance faults may not be detected and isolated by conventional means, downed power lines can remain energized and represent a hazard to bystanders and utility workers.

Appendix G

Transmission Volt-VAR Optimization Final Project Report

Transmission Volt-VAR Optimization
Final Project Report

Created by

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Disclaimer

Acknowledgments

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1 Executive Summary

The transmission Volt-VAR optimization project (VVO) is a tool demonstrated for Grid Control Center use that attempts to minimize the system voltage violations observed within the SCE transmission system. The VVO provides a list of control actions to operators recommending switching actions to improve the system voltage profile. By considering system-wide effects and through the use of an optimal power flow, the VVO tool reallocates the reactive power resources to minimize the system total MW losses.

2 Project Summary

This project evaluates the proof of concept for a Volt-VAR optimization tool that recommends switching actions to improve the system voltage profile. If successful, this tool could be used as part of an automated substation Volt-VAR control system. This tool was installed at SCE's Grid Control Center on a standalone system with loose integration with the Energy Management System (EMS) to avoid redundancies associated with a production system.

The project was supported by the Grid Control Center, Power System Controls Advanced Applications, Operations Planning and Analysis as well as Advanced Technology (now Grid Technology and Modernization). The project includes the following four key milestones:

1) Project Feasibility and Cost-Benefit Analysis
2) Definition of Business Requirements and Functionalities
3) System Design and Implementation
4) System Testing and Validation (Cancelled)

Major procurements concerning this project include:

- Design, Implementation and Installation of the VVO tool $350,000.
- EMS software upgrade for interfacing with VVO tool $54,346.

Figure 1 illustrates the EPIC investment framework for utilities with the strategic initiatives, as well as, key drivers and policies. As shown in Figure 1, this project falls under the Grid Modernization focus area and improves system reliability by advancing grid modernization and optimization. By optimizing the VAR resources throughout the SCE transmission system, a successful demonstration increases system reliability and performance. In addition, the tool performs a real-time contingency analysis that determines the feasibility of the suggested switching actions and confirms system security prior to providing any recommendations. VAR resource management also provides benefits concerning the integration of renewable energy and distributed energy resources. Since technology associated with renewable penetration provides different characteristics concerning voltage control and VAR management, high penetration of renewable energy traditionally have placed a significant strain on system VAR resources. Tools that help manage and maximize VAR resources also can help integrate a larger amount of renewable generation.

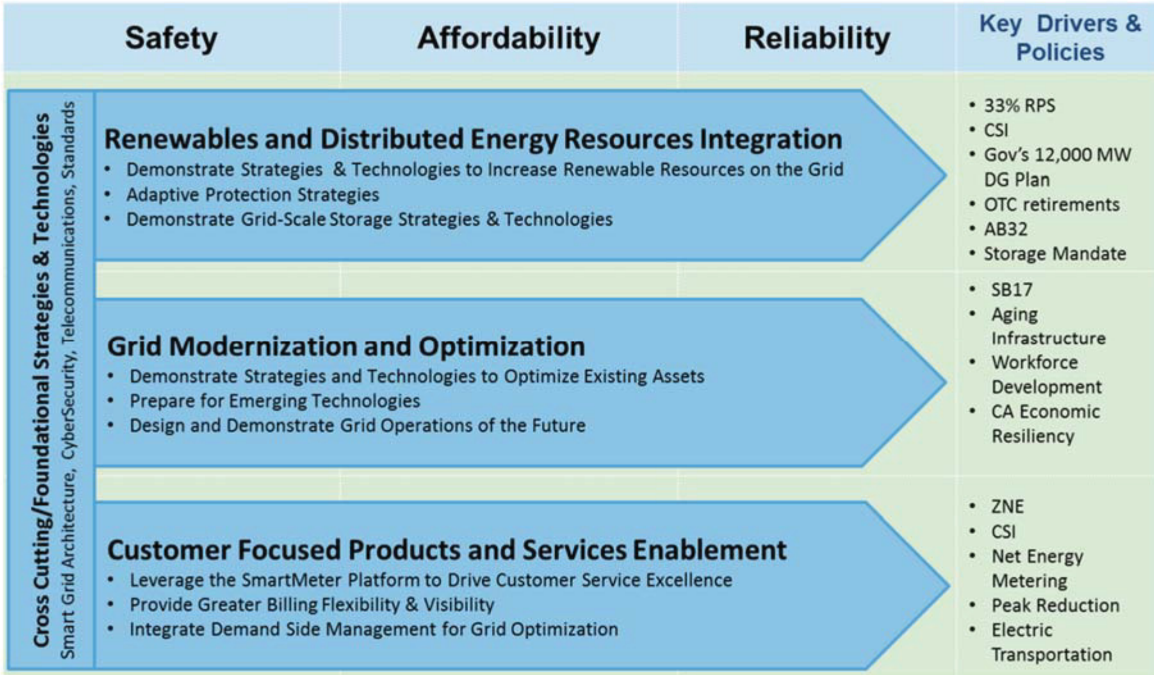

Figure 1. EPIC Investment Framework for Utilities

A cost-benefit analysis was performed based on the loss reduction percentages of two selected cases averaged to calculate the total loss reduction over a year. As a result, combining the cost savings on a net present value basis over five years yielded a total potential savings of $7,449,000 demonstrating confidence that the VVO can bring significant value to system operation in the form of reliability, security and cost reduction.

2.1 Problem Statement

Maintaining voltage schedules at the transmission and sub-transmission levels of the bulk power system is mostly done manually by switching discrete reactive power resources available at substations, including shunt capacitors, reactor banks and transformer tap changers. Only few automation systems have been implemented to assist Grid Control Center (GCC) dispatchers and system operators to maintain the security and the stability of the grid when voltage drifts from its schedule.

The manual processes involved in grid operation put a significant burden on the operator to meet reliability requirements and also optimize the economic operating point. This coupled with the fast acting devices that are becoming more prominent within the grid, make system operation including voltage control very difficult to manage in real time. For certain system conditions, operators may need to operate system voltages outside the band in response to other reliability requirements or system limitations. Figures 2 and 3 illustrate data for 500 and 230 kV buses within SCE for June 2015.

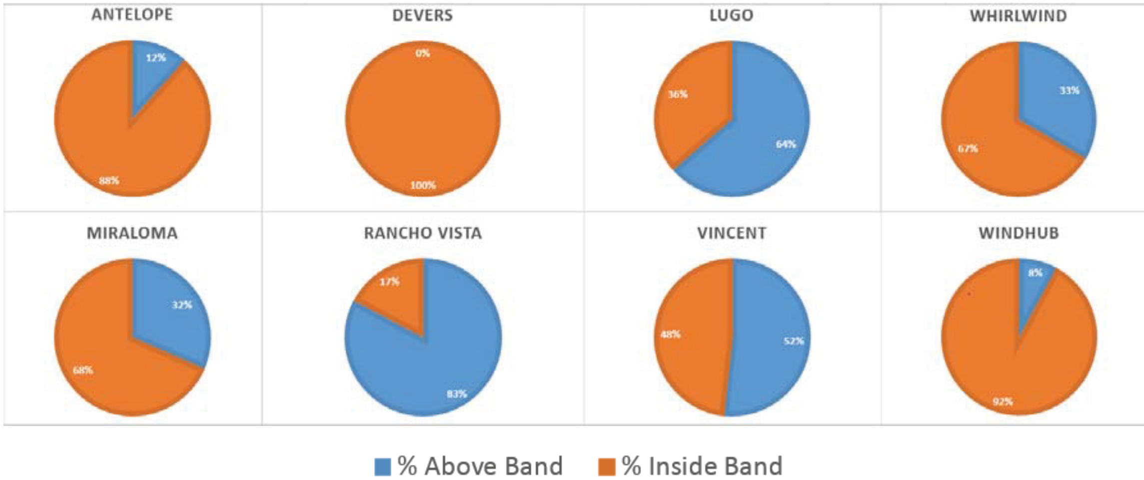

Figure 2. SCE 500 kV Voltage Performance analysis for June 2015

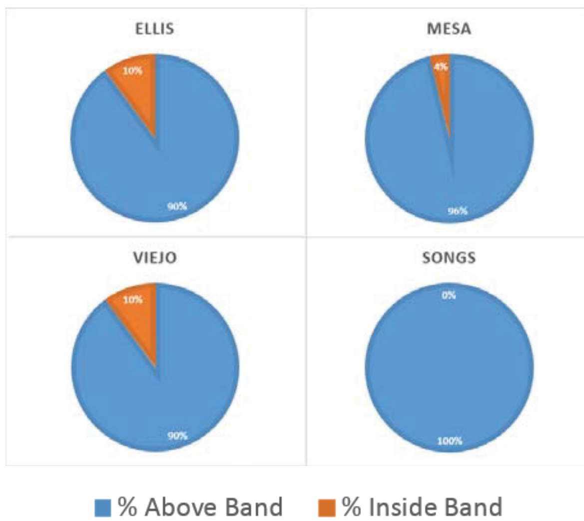

Figure 3. SCE 220 kV Voltage Performance analysis for June 2015

Although the current practices within the Grid Control Center may maintain system security and reliability, the system can be operating far from optimal conditions. Therefore, resources may be used inefficiently leading to reduced system VAR reserves, increased system losses and higher operational costs. Processing and evaluating optimal conditions for competing objectives while deriving system-wide mitigations is an analytically intensive task which requires optimization tools for implementation.

2.2 Project Scope

Transmission Volt-VAR Optimization (VVO) is a system-wide optimization tool that assist operators in improving the system voltage profile. The VVO application examines the system condition using information from the Energy Management System (EMS) and suggests control actions that mitigate voltage violations while attempting to minimize system total MW losses. Control actions recommended by the VVO application are limited to devices connected to the Transmission and Sub-transmission system under SCE control which include: Capacitors, Reactors and Load Tap Changing (LTC) Transformers.

The VVO produces a list of recommended actions that is used as an input by the operators in decision making. No automatic control action is being performed by the VVO. The VVO will look at the latest system condition and solve the optimization problem as an integrated solution for the transmission system and produce one set of recommended actions that will seek to improve the voltage profile. The specific objectives of the VVO for formulation purposes are:

Objective 1: Minimize voltage violations in the Transmission System

The VVO application's main priority is to minimize voltage violations in the system. A voltage is considered to be in violation when it is outside the allowable range as defined in SCE System Operating Bulletin 17 (SOB 17) or CAISO 3100B documentation. These documents contain all applicable limits for the buses in the SCE transmission system subject to the VVO. SOB 17 is limited to only pre-contingency limits, while CAISO 3100B provides limits applicable to pre- and post- contingency conditions.

A bus voltage is recorded through direct measurement or through solution of the state estimator. In all cases, after the state estimator executes, the EMS produces a file that contains the system condition which includes voltages for the entire system, load, power flows, generation and other system variables and parameters. VVO uses the EMS output to evaluate buses that are outside the allowable range and through a security constrained power flow identifies control actions within a pool of decision variables that shall return the system voltage profile to an acceptable operating condition.

Objective 2: Satisfy Operational Constraints

The VVO application recommends control actions that meet all operational constraints. Operational constraints accounted by the VVO include:

- Maintain all control devices operating ranges. These are physical ranges that cannot be violated.
- Keep the SVC output within user defined ranges. SCE has two SVC's in the system, one located at Rector 230 kV and the other is located at Devers 500 kV.
- The VVO solution will not create any additional transmission line flow violations beside those already existing in the base case.
- The VVO solution will satisfy the reactive power flow constraints between transmission and sub-transmission systems. There are preferred reactive power flow limits on the A-Bank transformers that connect the 230 kV to 115 kV systems. These MVAR limits vary based on MW flows, as defined in SOB 17 Appendices.
- VVO will try to keep connected generators at unity power factor. The reactive power flows from the generators should be close to or zero.

These constraints differ in priority and can be adjusted to further improve VVO performance.

Objective 3: Minimize System Losses

The third objective is to minimize the system MW losses in the SCE transmission and sub-transmission systems. MW loss reduction translates into actual monetary savings from VVO for SCE. Reduction of system MW losses is a commonly used objective for reactive power management. System losses are proportional to the current in the branches.[1] , The objective of the VVO is to provide switching actions that improve the total system losses as computed before and after the execution of the application. Note that, if minimizing losses is infeasible, the algorithm focuses on minimizing voltage violations where possible.

As described in the objectives, the VVO recommends an operation strategy that provides a reduction in voltage violations and, when applicable, total system losses. The VVO demonstration

[1] Defined as $\sum_{j=1}^{n} I_j^2 R_j$ where n is the number of branches in the system. Computation of system losses is carried through system analysis and power flow.

system is implemented by using Nexant Grid360 Transmission Analytics Security Constrained Optimal Power Flow (SCOPF) software.

The project included the following four key components:

1) Project Feasibility and Cost-Benefit Analysis: This task evaluates the feasibility of implementing Volt-VAR Optimization through an optimal powerflow algorithm. The objective of this phase is to establish the viability of the tool by performing a preliminary implementation, sample runs and conducting a cost-benefit analysis using SCE system data. In addition, this phase helps define business objectives, design and demonstration requirements of later phases.
2) Definition of Business Requirements and Functionalities: This task develops the requirements that meet the business needs for a successful implementation of the VVO. The business requirements were established through joint meetings with the stakeholders and reflect the specific functional requirements and capabilities needed to produce a viable operations tool.
3) System Design and Implementation: This task entails the VVO system design and implementation plan. Specific subtasks include data quality assessment, gap analysis, EMS-VVO system integration design, User Interface Design, Reporting, System implementation, pre-delivery integration testing, system delivery, post-delivery integration testing and VVO system training. Post-delivery integration testing and VVO system training were cancelled.
4) System Testing and Validation (Cancelled): After the system installation at the Grid Control Center, this task validates the results being produced by the tool and with operator participation, performs a demonstration of the system to further validate that tool is performing as designed. Due to inability to secure operations support for the testing phase, project was cancelled prior to executing item 4.

Testing and Validation procedures for the VVO are described below. Since the testing and validation are part of item 4, these tests were not carried out due to a determination by the project team that this task was no longer needed for business needs.

Test 1: Operator Actions Validation

Objective: System measurements is used to evaluate VVO performance before and after Operator actions. Measurements is obtained from the EMS via the auto-download capability at the EMS. The main objective is to record system violations and system state before and after actions from the Operator and perform a power flow analysis to determine the impact of the action taken. The combined actions shall lead to a reduction of voltage violations as documented in the VVO results. Any increase in violations or failure to eliminate violations would be considered an unsuccessful VVO solution. The steps concerning the operator actions validation test are shown in Table 1.

Step	Action
1	Record before and after system condition from VVO.
2	Record VVO solution.
3	Record operator switching actions for the hour under evaluation.
4	Record from the EMS the system condition for each of the switching actions.
5	Compute system violations after each switching action from EMS. EMS violations shall be less than those from VVO results (Step 2).
7	Repeat Steps 1 - 6 for all conditions to be tested.

Table 1. Operator Actions Validation Test

Test 2: VVO Validation

Objective: Commercial software is used to solve the system condition and display all system quantities (e.g. Voltage, Flows) resulting from the VVO algorithm solution. Output from the VVO is be loaded to commercial software and solved with no adjustments to control variables to confirm that: 1) the solution obtained by VVO is feasible, 2) the solution of the VVO engine is consistent with other tools. Commercial software shall produce, within a reasonable threshold, the same objective function and constraint results as that produced by the VVO. The VVO systems validation test is detailed in Table 2 below.

Step	Action
1	Import T-VVO output to designated software.
2	Confirm all powerflow solution parameters meet desired settings. Settings include Full Newton-Raphson solution, Lock all devices (Taps, Shunts, Phase Shifters, DC Line taps), Enforce Area Interchange Control, Apply VAR limits immediately.
3	Run the commercial software powerflow
4	Record voltage profile and power flows (real and reactive), interface flows, objective function and system constraints as defined in the T-VVO.
5	Compare all recorded quantities from commercial software with T-VVO solution. Quantities shall be within reasonable thresholds. Network Topology and status for all devices must be identical.
6	Confirm that no adverse conditions result from the algorithms optimal solution recommendation.
7	Repeat Steps 1 - 6 for all conditions to be tested.

Table 2. VVO System Validation Test

2.3 Schedule and Milestones/Deliverables

The VVO project was started in Q2, 2016 and closed Q2, 2018. The project was conducted in phases as shown in Figure 4. All project phases and relevant milestones are described in Table 3.

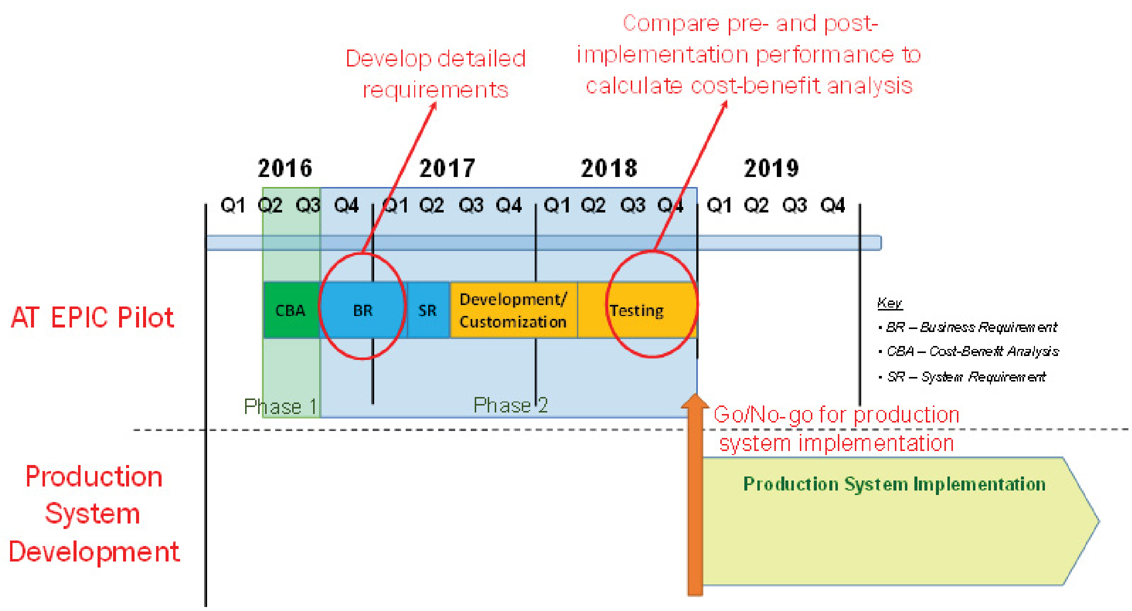

Figure 4. Project Timeline

Phases 1 and 2a involving system evaluation, requirement identification and implementation design were completed on-time. Phase 2b was closed prior to completion, with about 90% of the involved tasks completed. Tasks not completed within phase 2b due to project closure include the final tool training and the post-delivery integration testing. As part of phase 2b, the EMS-VVO system integration was successful.

Phase	Description	Projected Start	Projected Stop	Completed	Deliverable
1	Cost Benefit Analysis	Q2 2016	Q3 2016	9/27/2016	Feasibility and Cost-Benefit Analysis
2a	Business and System Requirements	Q4 2017	Q2 2017	4/28/2017	Business Requirements Document Implementation Document
2b	VVO Development and Customization	Q3 2017	Q1 2018	5/3/2018 P.O. closed	Final application design VVO demonstration system deployment
2c	System Testing and Validation	Q2 2018	Q4 2018	Cancelled	Demonstration system results Tool Validation and Testing report

Table 3. Project Schedule and Deliverables

Phase 2b experienced a delay from the projected ending date shown in Table I. This was the result of a change in source data from that used in phases 1 and 2a. During phases 1 and 2a the main system information as obtained from the EMS was the PSLF EPC format. During the VVO final implementation, it was identified that the EPC format contained errors that were due to the exporting function from the EMS. This prevented the VVO tool from achieving accurate results. As replacement to the PSLF EPC format, the Common Information Model (CIM) 14 was adopted. Use of the CIM format eliminated the conversion issues and represented a higher fidelity model, since it is supported by the Advanced Applications group. The use of CIM 14 introduced additional complexities due to the relaxed definition of the specific profile under use making the validation of the results very complex. This profile (CIM 14) is not uniform in the industry and for that reason not supported by other commercial tools. It was determined that for this to be implemented in a production environment it required a more uniform profile which is available starting from CIM version 16 or later. This new format is expected to be included during the EMS refresh currently in progress.

Prior to conclusion of Phase 2b, efforts were made to secure a commitment from the operations group to perform the demonstration. Due to limited availability from operations and their involvement in other projects that were of higher priority to the operations group (e.g. EMS refresh, ADMS and PMU-based linear state estimator demonstration), securing a demonstration commitment was unsuccessful. Since the project would not move to Phase 2c, then the remainder of the project was closed.

3 Project Results

The project scope as devised in the last project management plan was not completed in full. As shown in Table I and stated in Section 2.3, the final portion of Phase 2b and the entire phase 2c were cancelled. The portion cancelled under Phase 2b amounted to operator training for the VVO tool and post-delivery integration testing while Phase 2c included demonstration, testing and validation.

The project throughout its execution was closely aligned with the scope presented for each of the phases. The main change required was the use of the CIM format as the EMS model, instead of the more basic and well documented PSLF EPC format. The change, which delayed phase 2b, was required due to the PSLF EPC format not being maintained by Grid Control Center or being regularly used for other analysis within operations. At the same time the format was prone to reactive power mismatch for certain system conditions which rendered the results of the VVO inaccurate.

The VVO tool was integrated with the EMS as described in the implementation plan produced in phase 2a and executed in Phase 2b. The VVO application workflow process is described below and illustrated in Figure 5. The remainder of this Section will describe the VVO application capabilities and illustrate the user interface.

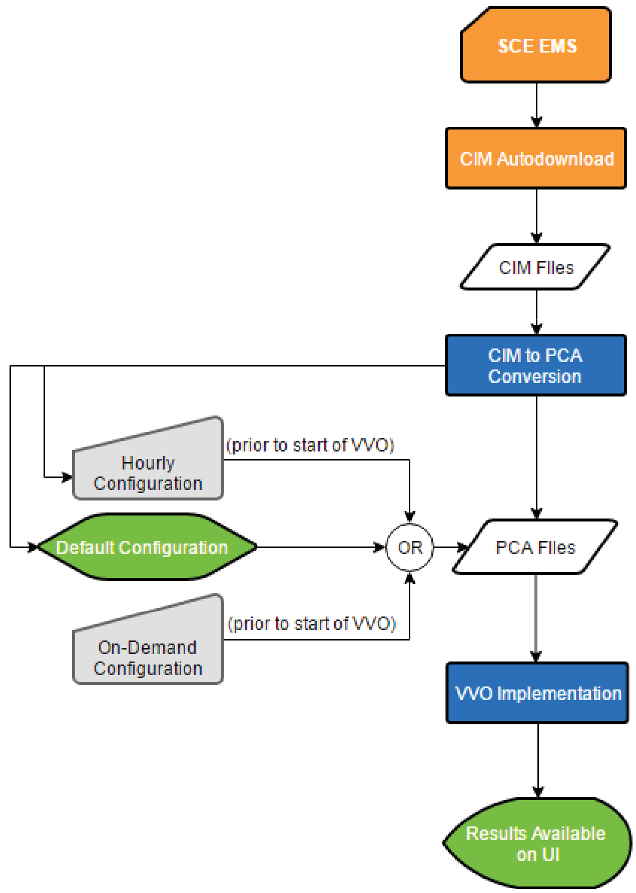

Figure 5. Hourly VVO Process

The VVO tool is linked to the EMS through an export function for the Common Information Model (CIM) format. The EMS uploads the system condition in CIM format to the VVO virtual server once every hour. The VVO then executes the optimization, based on a number of predefined objectives and constraints (also known as configuration) and produces results in the form of customized reports which assess system conditions. Once the VVO execution is completed, results including summaries of inputs, recommended switching actions and detailed reports are available for review. Hourly VVO results are stored for up to 7 days and accessible by selecting the date from the calendar and hours from the list shown on the Hourly VVO display. This is shown in Figure 6.

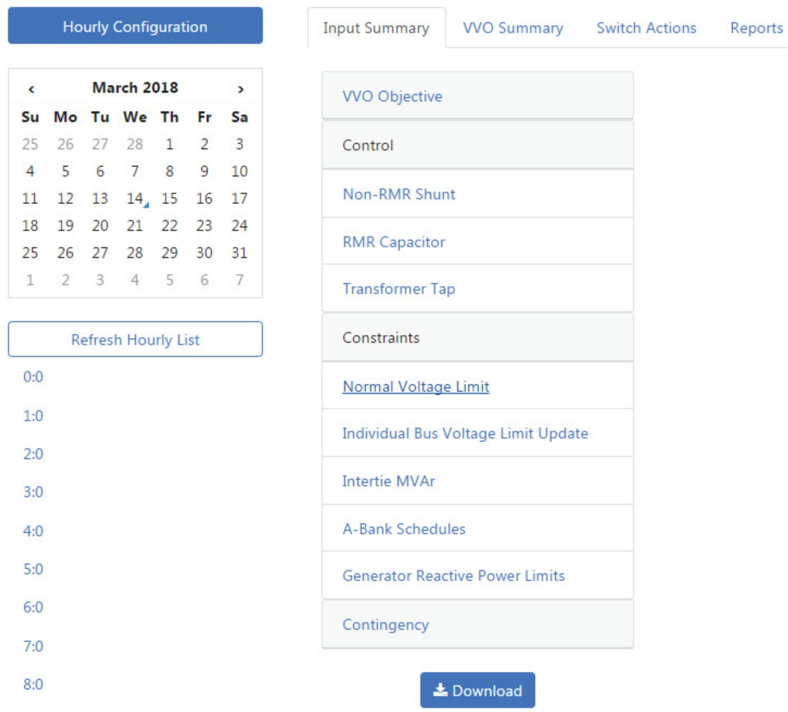

Figure 6. Hourly VVO

For each VVO execution (Hourly or On-Demand), the result window includes four menus: Input Summary, VVO Summary, Switch Actions and Reports. These menus provide a summary of the configuration used for VVO set up and access to the features of the VVO. Each menu is described below:

- The Input Summary tab includes all configuration inputs as shown in Figure 7. This tab provides a review of the configuration and cannot be used to change the configuration.
- The VVO Summary tab provides an overview of the case study, inputs and VVO results (Figure 8). Detailed results are available either through the links on this page (blue boxes in Figure 8) or through the Reports tab to be described later.
- Available Switching Actions tab include the list of shunts (Figure 9) and tap changers (Figure 10) with recommended settings. Shunts and tap changers are identified by CIM names and other information including shunt capacity and transformer substation.
- Reports tab include detailed results for voltage, shunt, transformers and a summary of system reserves before and after the VVO execution and VVO binding constraints. Additional reports for constraints such as interties, A-Bank and generators are also included in the reports. A sample report is shown in Figure 11.

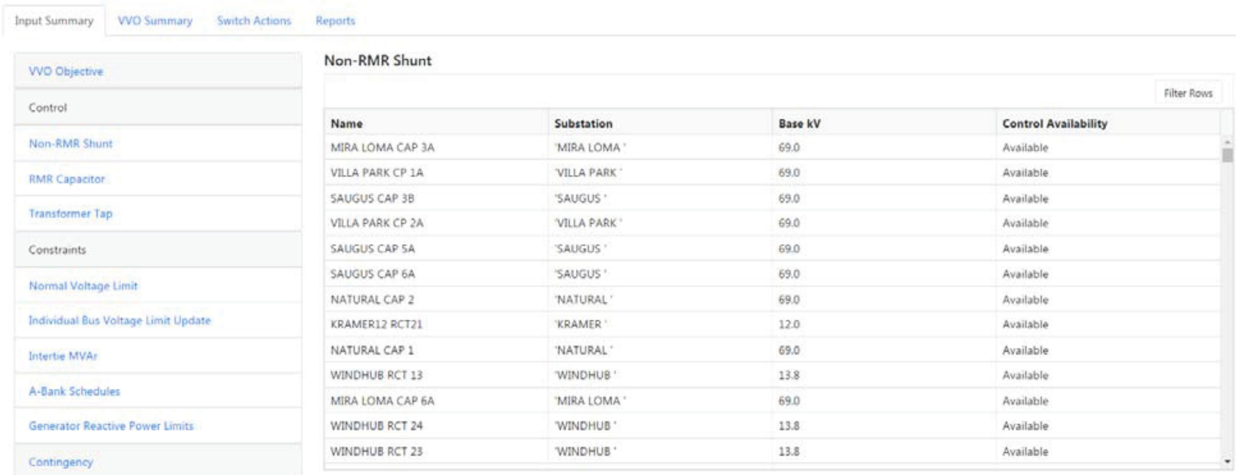

Figure 7. VVO input summary for Hourly and On-Demand VVO

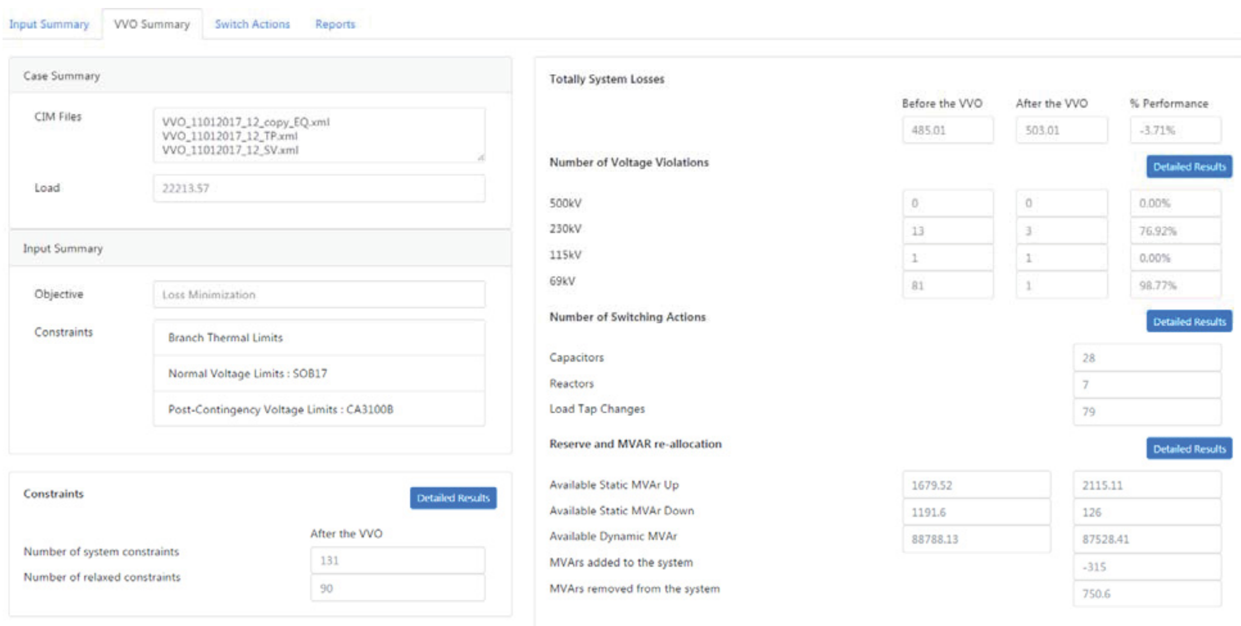

Figure 8. VVO Summary for Hourly and On-Demand VVO

Input Summary | VVO Summary | Switch Actions | Reports

Shunt | Tap Changers

Filter Rows

Shunt Name	Capacity ▲	Switching Action
MRLM 4AA 41	-45	Off
VIN 13 RCT 13	-45	Off
RNCH V RCT31	-45	Off
RNCH V RCT32	-45	Off
RNCH V RCT42	-45	Off
RNCH V RCT41	-45	Off
VIN 13 RCT 14	-45	Off
POPLAR CAP 2	10.8	Off
BLISS CAP 5A	12.6	Off
NEWBURY CAP 3	14.4	Off
VESTAL CAP 3	14.4	Off
CARPINTERIA 3	14.4	Off
WATSON CAP 2	20.71	Off
PICO CAP 5	20.71	Off
WALNUT CAP 3	27	Off
LA FRESA 7	28.8	Off
LA FRESA 5A	28.8	Off
LA FRESA 4A	28.8	Off
JOHANNA CAP 3	28.8	Off
HINSON CAP 4	28.8	Off

Figure 9. VVO recommended switching actions for shunt devices for Hourly and On-Demand VVO

Input Summary | VVO Summary | Switch Actions | Reports

Shunt | Tap Changers

Filter Rows

Transformer Name	Substation	Initial Step ▲	Final Step
EL NIDO_1A_	EL NIDO	-5	-10
ELDORADO_4AA_H	ELDORADO	-4	6
MESA_2A_	MESA	-3	-9
JOHANNA_3A_	JOHANNA	-2	-6
JOHANNA_4A_	JOHANNA	-2	6
VALLEY_4AA_H	VALLEY	-1	11
GOULD_1A_	GOULD	-1	8
VALLEY_3AA_H	VALLEY	-1	-2
KRAMER_1A_L	KRAMER	0	2
MIRAGE_4A_	MIRAGE	0	11
ANTELOPE_4A_	ANTELOPE	0	8
WINDHUB_2A_	WINDHUB	0	-6
ELDORADO_5AA_H	ELDORADO	0	-3
RANCHO VIS_4AA_H	RANCHO VISTA	0	9

Figure 10. VVO recommended switching actions for tap changers for Hourly and On-Demand VVO

Input Summary | VVO Summary | Switch Actions | Reports

Voltage | Shunt | Transformer Tap | Reserve | Binding Constraints | Intertie | A-Bank | Generator

Voltage Results Before and After OPF for 69kV-500kV Buses

Filter Rows

Bus Name	Bus ID	KV	Constraint	Min Limit	Max Limit	Voltage Before	Violation Before	KV Violation Before	Voltage After	Violation After	KV Violation After
INYO 230	1153.4	230	ON	0.979	1.022	1.084	0.063	14.279	1.084	0.063	14.279
ORMOND 66	738.2	69	ON	0.916	1.012	1.07	0.058	3.988	1.049	0.037	2.512
	1026.5	69	ON	0.91	1.005	1.051	0.047	3.186	0.995		
TAP 32	2284.999	69	ON	0.91	1.005	1.051	0.047	3.175	0.995		
TAP 30	2283.999	69	ON	0.91	1.005	1.05	0.046	3.138	0.995		
LAKEGEN 66	1032.1	69	ON	0.91	1.005	1.05	0.046	3.136	0.995		
KERNVILL 66	1029.999	69	ON	0.91	1.005	1.043	0.039	2.649	0.987		
GREENHORN 66	1024.999	69	ON	0.91	1.005	1.038	0.034	2.279	0.982		
TAP 4	2282.999	69	ON	0.91	1.005	1.038	0.034	2.279	0.982		
TAP 5	2281.999	69	ON	0.91	1.005	1.038	0.033	2.270	0.982		
GLENNVIL 66	1022.999	69	ON	0.91	1.005	1.038	0.033	2.267	0.982		
POPLAR 66	1039.1	69	ON	0.91	1.005	1.03	0.025	1.719	0.954		
TAP 80	2276.999	69	ON	0.91	1.005	1.029	0.025	1.677	0.956		
	776.15	230	ON	0.957	1	1.023	0.023	5.090	1.002	0.002	0.388
SOLEMINT 66	772.999	69	ON	0.923	1.02	1.041	0.021	1.414	1.017		
NEWHALL 66	765.9	69	ON	0.923	1.02	1.041	0.021	1.412	1.017		
TAP 90	2261.902	69	ON	0.923	1.02	1.04	0.021	1.408	1.017		

Figure 11. VVO reports for both Hourly and On-Demand VVO

3.1 Achievements

Project deliverables that were realized during the life of the project include:

- VVO feasibility study and Cost Benefit analysis
- Business Requirement Document
- System design
- Implementation plan
- EMS-VVO system integration

From a technical aspect, the main achievement of this project at the time of closure was the implementation design and EMS-VVO integration of the tool, which includes significant lessons learned associated with data requirements, Grid Control Center systems architecture, operational guidelines, processes and others.

Based on the results of a cost-benefit analysis the project team determined a reduction in losses due to the implementation of this tool could be significant and should benefit all of SCE's customers. During the feasibility study, it was estimated that when used on a regular basis over a 5 year span, the VVO may save costs for customers through a forecast reduction of approximately $US 7.4M. As system components are operated within their limits, SCE benefits from enhanced utilization of the devices and a reduction in risk as these devices are operated near desired, optimal ranges.

Although the project was not completed in full, the design and lessons learned can be used to further improve any future implementations within SCE or by other utilities. One specific recommendation relates to the use of a global optimal solution. Although this tool is great for providing a benchmark and desired setup for the entire system, it may result in a large number of actions being recommended to the operator. An optimal control based approach or an action prioritization tool providing a more limited set of recommended switching actions may be better suited for this implementation.

3.2 Value Proposition

The project was closed after Phase 2b which accounted for the integration of the tool to the EMS. As part of the value obtained from the project demonstration through Phase 2b, the project illustrated the implementation of a global OPF tool for voltage and VAR control. Strategic objectives that can be met by this tool in its present form include:

- Provide benchmarking for system operations performance.
- Recalculate voltage and VAR limits for the transmission system.
- Collect data and inform system guidelines (e.g. SCE System Operating Bulleting 17).

In addition, the tool in its present form can be fine-tuned to provide incremental switching actions providing a path for full automation of this process. Switching action prioritization may form part of a longer demonstration with a dedicated team.

3.3 Metrics

The following two metrics were identified within the Volt-VAR revised project management plan:

1. Job Creation - Hours worked in California and money spent in California for each project: The project was executed within the state of California. Nexant based in San Francisco was the primary vendor utilized for the design, implementation and execution of the VVO tool.
2. Other Metrics - Recommendation results could indicate less voltage violation to meet CAISO 3100B and SCE system operating bulletin 17: The VVO tool provided switching actions that minimized system violations. A violation was defined as any voltage condition that was outside of SCE system operating bulletin 17 or CAISO 3100B as identified during the scope development. Although the tool provides the optimal switching conditions in a software environment the project was closed prior to the demonstration portion, and this could not be validated.

3.4 Technical Lessons Learned and Recommendations

The VVO project was cancelled prior to completion. The cancellation was due to lack of resources within operations to validate the results, limited alignment with Grid Control Center priorities and apparent limited value concerning execution of results (switching actions) vs overall benefit (reduction in system losses). This section provides technical lessons learned and recommendations. Conclusions are limited to usability, implementation and challenges observed during the project execution.

- Implementation: The VVO tool utilizes models and data presently available within the operations group, to compute optimal and secure scenarios that minimize voltage violations, meet all system operational constraints and minimize reactive power flows which in turn reduce the total system losses. Implementation of this tool was performed as a stand-alone system to minimize IT requirements and facilitate integration with existing systems. To effectively implement VVO for day-to-day operations, integration of this tool within the EMS would need to be required to facilitate access to results and processing of information. EMS integration also provides the additional levels of redundancy required for safely deploying this tool. However, for purposes of the demonstration, the proposed implementation approach was considered adequate due to its simplicity of implementation and low cost. In addition, the proposed implementation provided the necessary flexibility for updating the tool. The project team recommends that a stand-alone system be adopted for any future demonstration solutions. The project team also recommends to understand costs associated with the full integration to the EMS. Within the evaluation of this project, implementation of the stand-alone system was approximately $350,000, whereas full integration would have required 3-5 times that budget based on provided estimates.
- Value: The VVO project provides a valuable asset for operators to optimize the system voltage profile by managing SCE's reactive power resources. One of the benefits of this approach is the global optimization capabilities. Due to this formulation, understanding the system boundaries and what is needed to achieve optimality was made available. In contrast, the tool provided only one solution that covered a number of switching actions

sometimes in the range of 30-40. Since no well understood prioritization of the switching actions was provided, implementation of the tool in this form would require additional efforts by operators to assign priorities or understand the reasoning behind the results, placing an additional burden on the operator.

- Usability: Operations planning activities may be more feasible for this tool due to the capability of evaluating multiple scenarios off-line and developing guidelines contribute toward enhancing system operations. Since operator reaction time is in the order of seconds to minutes, the tool in its present form appears to be more valuable for benchmarking and/or off-line analysis of system conditions, rather than real-time system operations. In addition, implementation of the tool 'automatically' would require additional prioritization of the results. In the event that the tool provides a large number of switching actions, there would be a need to prioritize and sequentially execute the actions to better mimic a system operations environment.
- Computational Execution Time: Execution of the tool was found to not be satisfactory. It was initially indicated that execution times will be in the order of a few minutes (3-5 mins). After implementation, using specified hardware requirements, it was found that the operation was on average 8-9 minutes. This effectively prevents execution of the tool in a real-time environment. Some solutions provided by the vendor included changing the server specifications, as well as performing enhancements to the tool. Due to the lack of funds, no additional improvements were made to the tool.
- Demonstration of tools at the control center: To demonstrate and validate the tool for transmission level switching actions a prior commitment from the operations group to evaluate the efficacy of the tool is needed. Although interest and agreement to test the tool were provided, defining parameters for testing and validation were not established. Such commitment is difficult to obtain due to the very complex work performed at control centers and also other demonstrations or systems being tested.

To further advance the project capabilities in alignment with SCE's technology roadmap the following tasks are recommended:

- Implement fast-response grid operation function: Project currently relies on operator intervention to perform switching actions. To fully enable the capability and implement fast response grid operation, automated actions that bypass operators is required. Communicating system conditions and actions to local controls for fast response will be instrumental in advancing the project capabilities.
- Improve data management and processing of the tool: In the present configuration, the VVO evaluates a number of system conditions simultaneously accounting for all specified control variables within the SCE footprint. In some instances, the application may suggest a large number of switching actions (e.g. 40 switching actions) in the transmission system to achieve the desired voltage profile. This, coupled with other internal goals within operations may be difficult to manage by an operator or to implement in a fast-response grid operation function. To better advance the capability, the decision making or prioritization processes need to be simplified.

- Perform Day-Ahead analysis for optimal scheduling and system benchmarking: Producing a day-ahead reactive power resource schedule helps prepare operators, as well as help understand if the system conditions are manageable. A day-ahead schedule will significantly improve operation and also provide a benchmark to understand if any guidelines or processes need to be revised (e.g. System Operating Bulletins).

3.5 Technology/Knowledge Transfer Plan

The VVO project provides a way to implement Volt-VAR optimization tool for systems operations. By executing this project through Phase 2b, the demonstration provided data points associated with the cost/benefit of the tool, user/tool interaction, typical VVO results and implementation requirements. Data points obtained through Phase 2b helped influence Grid Operations understanding of the requirements needed to implement voltage and VAR control not only regarding computational resources, but also human resources and training. Additional lessons learned and important design components were also identified during this project.

3.6 Procurement

All of the items and services procured during the project were aligned with those originally envisioned. The main procurement involved the primary vendor Nexant, which conducted a Cost-Benefit analysis, Business Requirement, Implementation Plan Design, VVO tool software development and customization. Additional procurements involved a software update to the EMS system to enable exporting the CIM file and procurement of software for the Virtual Machine.

Due to the EMS software update requiring cybersecurity clearance, the exporting function required additional lead time for commissioning and presented a deviation from the expected schedule. It is to be noted that the next generation EMS (EMS Refresh project) includes this exporting function from deployment, so this type of procurement would not be required in the future.

3.7 Stakeholder Engagement

The stakeholder expectations from Grid Operations regarding the project was to demonstrate a tool that would process system conditions and support system operators eliminate system violations. While implementation of the tool was ultimately deemed to require too much operator participation offsetting some of the benefits the tool provided to the operator, the demonstration was still useful from the numerous lessons learned, in particular, understanding the feasibility of implementation of a global OPF tool for voltage and VAR control. The performance of the global optimization tool for real-time operations is not presently suitable due to the computational requirements and execution time. However, the tool may be used for benchmarking purposes related to system operations performance. In addition, due to the global optimization engine, the tool can be used to collect data and inform system guidelines (e.g. determine better voltage and VAR limits for the transmission system). Although global optimization can be useful to understand the best possible system solution, the testing runs performed during the system integration phase consistently returned dozens of switching actions (close to 40) that would be difficult to manage for operators in a real-time environment and in a time frame of a few minutes. Fine tuning the algorithm or solution method to provide incremental switching actions based on prioritization would not only interact better with operators, but also provide a better path for full automation of this process.

The stakeholders from SCE's Grid Control Center, Power Systems Controls Advanced Applications and Operations Planning and Analysis were kept aware of the project performance through regular face-to-face meetings primarily conducted at the Grid Control Center facilities in Alhambra, CA and also conference calls/emails when addressing smaller tasks. Face-to-face meetings included participation from the primary vendor Nexant and also several stakeholders. All update meetings were followed up with distribution of the materials presented in the meetings, follow-up notes including action items and next steps. In addition, feedback on project scope and project direction was also requested from the stakeholders. Three main deliverables were provided to the stakeholders namely the Feasibility Study, Business Requirement Document and Implementation Plan Document. A final set of files including this report and other observations will also be made available to the stakeholders for review.

4 Appendix

4.1 VVO Application Basics

To implement the VVO four components are required:

- **A Power Flow Case**: represents a single steady state system at a particular time. Real time power flow cases are used for online studies and historical cases or typical planning power flow cases may be used for off-line studies. SCE power flow cases for the VVO applications are in CIM format.

- **Objective Function**: a mathematical expression of desired objectives of optimal power flow (OPF), e.g. Loss Minimization to minimize MW or MVAR transmission losses in designated parts of the power system or Minimum Shift to minimize the shifts of the relevant controls from their initial or target settings, to avoid or alleviate operating limit violations.
- **Controls**: reactive power controls that can be optimized to achieve the OPF objective e.g. shunt capacitors and reactors, in-phase transformer taps, static VAR controllers and bus voltages regulated by generators, transformers or static VAR controllers. Controls available for SCE VVO are shunt capacitors and reactors and transformer taps.
- **Grid Constraints**: includes operating limits of grid, e.g. branch flows in ampere, MVA, voltage limits and VAR control ranges as well as post- contingency constraints (A list of contingencies provided by SCE is used to perform post-contingency analysis). SCE VVO grid constraints are:
    - **Branch flows for pre- and post-contingency**: If the branch flow constraints are violated in the power flow case (before VVO implementation), VVO will automatically expand the limits to the current flow.
    - **Voltage limits**: SOB17 and CA3100B limits are available for pre-contingency and CA3100B for post-contingency.
    - **Intertie MVAR**: the reactive power flow constraints for intertie MVAR as defined in SOB17.
    - **A-Bank Schedules**: the reactive power flow constraints between transmission and sub-transmission systems. MVAR limits vary based on MW flows before VVO implementation as defined in the SOB17.
    - **Generator Reactive Power Limits**: keep the connected generators at unity power factor.

Two main applications for SCE VVO are defined based on the types of power flow base cases (online or offline), the objective functions and types and frequency of implementation (automatic or manual):

- **Hourly VVO**: the Hourly VVO is an online application and is automatically executed hourly (or a pre-defined periodicity). VVO uses CIM power flow cases automatically downloaded from the EMS. The periodic run of VVO applies the Loss Minimization objective and is also called Hourly VVO in other documents.
- **On-Demand VVO**: the On-Demand VVO can be used for both online and offline applications. During the time between two periodic Hourly VVO executions, On-Demand VVO can be executed (manually) to determine the most effective control actions that can mitigate voltage violations present in the system as soon as possible with Minimum Shift as the objective function. This function is also called On-Demand VVO. In addition, On-Demand VVO can be used for offline analysis using desired CIM power flow cases and objective functions.

The term **Configuration** is a collection of parameters related to three of VVO components (Objective, Optimized Controls and Grid Constraints). A new configuration for the same power flow case is developed by modifying one or more of the three components. For example, changing the voltage limits from SOB17 to CA300 will create a new configuration or the Objective Function may be changed to move the most effective controls for voltage mitigations. Below are notes about configuration changes:

- A default configuration is developed for each Hourly and On-Demand VVO using predefined data for parameters and topological information available in the power flow case, e.g. availability of devices for control. Below are examples of predefined parameters:
    - <u>Voltage limits</u>: SOB17 for Pre-Contingency and CA3100B for Post Contingency

  - Shunts: all non-RMR capacitors and shunt reactors are available for switching
  - Transformers Taps: a list of Load Tap Changers (LTCs) provided by SCE
  - Intertie definition and limits: from SOB17
  - Objective: Loss Minimization
- The default configuration is applied to the Hourly VVO, unless otherwise is applied by users before the Hourly process starts. Any changes applied to the configuration after the start of process will be applied to the next hour implementation.
- The default configuration is applied to the On-Demand VVO during the initialization. For On-Demand VVO, saved cases that include previous configuration changes are also available for further changes and analysis.

4.2 Volt-VAR Optimization System Business Requirements

The business objectives of VVO are:

- Mitigate voltage violations while considering both pre- and post-contingency voltage limits
- Recommend control actions to operate the grid so that all operational constraints are satisfied
- Minimize total MW losses in the SCE transmission network when resolving voltage violations

Mathematically, a security constrained OPF, which optimizes power grid, with respect to the given objectives and system-wide considerations, is the most suitable analytical tool for implementing the VVO application.

4.2.1 Performance Metrics

The VVO solution recommends a "better" operation strategy than what is being implemented today, where "better" is defined through the following metrics:

Total Number of Voltage Violations

- If the case is an operational feasible case, all voltage violations are eliminated after VVO.
- When it is infeasible to eliminate all the violations, the total number and/or the severity of violations is reduced after VVO.

Total System MW Losses

- If there are no violations before the optimization solution (i.e. no violations in the base case or in the post-contingency case), the total system MW losses are reduced after VVO.
- If there are existing violations in the base case or in the post-contingency case, and it is infeasible to eliminate all the violations by using available control devices, the VVO provides a solution that is a trade-off between relaxing the limits and reducing the system MW losses.
- The VVO uses pre-defined weights that represent the degree-of-preference between reducing MW losses versus allowing certain amount of violations.

4.2.2 VVO Objectives

Eliminate voltage violations

The first objective of VVO is to eliminate voltage violations in the transmission system. The VVO solution attempts to satisfy pre- and post-contingency voltage limits. In general:

- The VVO solution attempts to satisfy all pre-contingency bus voltage limits as defined in the SOB17 which are implemented in the SCE EMS database.
- The VVO solution attempts to satisfy all post-contingency bus voltage limits as defined by California ISO, i.e. CA3100B.

However, in some occasions, GCC Dispatchers may want to have the flexibility of using different voltage limits. The VVO allows such flexibility.

- VVO allows users to select the set of voltage limits (i.e. either SOB17 or CA3100B) that are to be used for optimization (e.g. using CA3100B in pre-contingency).
- VVO allows users to temporarily modify the limits of certain buses for optimization solution that may be considered as practical adjustments due to the nature of SCE system conditions.
- VVO allows users the option to optimize the system without considering contingencies. (i.e. only satisfy pre-contingency constraints)

For purposes of the VVO implementation, the SOB17 voltage limits are “desired” targets; while the CA3100B limits are “hard” limits in normal operations.

Satisfy system operational constraints

The second objective of VVO is to recommend control actions to operate the grid so that all operational constraints are satisfied.

VVO allows user-defined operation requirement priorities. In other words, some requirements are more important than the others. In certain occasions, GCC Dispatchers and area of responsibility (AOR) AOR Operators may choose to relax the lower priority requirements. VVO users can assign different enforcement priorities to different types of constraints. In the following, examples of high, medium, and low priority requirements are listed. This classification may be adjusted as needed by SCE users.

High Priority Requirements

Voltage limits shall be the highest priority requirements. Additionally:

- The VVO solution must satisfy all control device operating ranges. These are physical ranges that cannot be violated.

SCE has two SVCs in the system, one located at Rector 230kV substation while the other is located at Devers 500kV substation. These SVCs’ output must be kept within user defined ranges in the VVO solution.

- The VVO solution must keep the SVC output within user defined ranges.

Since the VVO solution is mainly managing the reactive power controls and MVAR flows, although the transmission line, transmission corridor, and transformer flow limits must be enforced by the VVO solution, if there is any existing violation in the base case, VVO will not eliminate those violations. The flow limits of those lines, corridors, or transformers must be relaxed to the base case flow values,

- The VVO solution does not create any additional transmission line flow violations besides those that already existed in the base case, i.e. will not make the situation worse.

Although SCE grid operation has nomogram[2] constraints, these constraints will not be considered in the VVO solution.

Medium Priority Requirements

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[2] A Nomogram is used to define a constraint relationship between two power system MW variables. CAISO derived Nomograms are based on network analysis and reliability studies. CAISO maintains a library of Nomogram definitions and associated parameters, which is maintained by CAISO Regional Transmission Engineers to reflect current power system conditions.

Examples of medium priority requirements include:

- The VVO solution must satisfy the reactive power flow constraints between transmission and sub-transmission systems. There are preferred reactive power flow limits on the A Bank transformers that connect the 230kv to 115kv systems. These MVAR limits vary based on MW flows as defined in the SOB 17 Appendices.

Low Priority Requirements

In the ideal situation, SCE would try to meet the following requirements:

- VVO must attempt to keep the connected generators at unity power factor, i.e. the reactive power flows from the generators are nearly zero.

Although GCC does consider the limit on the total number of switching actions of each capacitor within a day, VVO does not consider this constraint in its solution in this version.

Minimize system MW losses

The third objective is to minimize the system MW losses. MW loss reduction translates into actual monetary savings from VVO for SCE.

"MW Loss Reduction" is a commonly-used optimization objective for reactive power management.

- VVO will minimize the total MW loss, in the SCE transmission and sub-transmission systems.

It is also preferable that VVO allows pre-defined weighted sum of multiple components in the objective. The formulation and weighting factor of each component need to be pre-defined. The weighting factors of the multiple components are pre-defined and will be adjusted during the implementation and testing stages.

Components of the VVO objective function include:

- Minimize the number of control moves (i.e. apply the most effective control actions) to eliminate violations. This objective may be used to quickly suggest a mitigation solution for violations.

Since the external model is not completely known to SCE, it is impractical to derive a control strategy based on the amount of intertie flows. Instead, the intertie reactive power flows will be monitored and any deviations from the existing base case values due to VVO shall be kept as small as possible.

- Minimize the intertie MVAr flow deviations from the base case values.

This section describes how VVO shall be implemented in GCC environment and its overall design principles.

4.3 VVO System Implementation

This section describes the VVO implementation within the GCC environment and overall design principles.

4.3.1 Voltage Control Schemes

It is expected that the existing CGCC tool will continue functioning "as is" to immediately mitigate the voltage violations in the system.

- CGCC will continuously monitor SCE's 500kv and 230kv bus voltages. It will take immediate, but in sections, close-loop automated mitigation actions by switching RMR capacitors. This is the current CGCC design.

The VVO recommends a solution that offers a secure system operation in the presence of (N-1) contingencies and satisfying respective limits, both pre- and post-contingency. The VVO follows the current SCE voltage control architecture whenever practically possible.

- Performed at GCC level hourly.
- Allow on-demand execution by GCC Dispatchers.
- Allow both online and offline executions. The offline execution is used for case studies by GCC engineers.

The recommended execution schemes are:

- The end-to-end execution time allows the VVO tool to be used in the operation environment, e.g. complete solution within 5 minutes.
- The system-wide VVO would be executed hourly (or a pre-defined period) through GCC. The periodical run of VVO would apply the loss minimization objective and requirements as described above.
- During the time between two consecutive hourly VVO executions, if voltage violations are detected in the system, GCC would execute on-demand VVO (manually) to recommend most effective control actions to mitigate the voltage violations as soon as possible (i.e. minimizing number of control moves).

The Hourly VVO and On-Demand VVO have identical system modeling principles and satisfy the same operational constraint considerations. Hourly VVO and On-Demand VVO are different only in the optimization objectives, Hourly VVO is to reduce the MW losses, while the On-Demand VVO is to move the most effective controls for voltage violation mitigations.

- Authorized users (e.g. GCC dispatchers and/or engineers) are allowed to run Hourly VVO and/or On-Demand VVO.

GCC Dispatchers may review the VVO suggested solution and communicate with Switching Center AOR Operators for execution.

During the demonstration, VVO-generated control actions must be acted upon manually.

4.3.2 System Modeling

VVO, once in the production environment, may be considered as one of the Advanced Network Applications in SCE's EMS. This means:

- VVO may utilize the same full AC network model that is used by the EMS Network Applications.
- VVO may use the most recent EMS TSM saved results as the base case for optimization.
- VVO may use the SCE defined N-1 contingency list that is used by EMS Network Applications.

Each VVO solution would be based on real-time snapshots of Transmission System Model solutions.

4.3.3 Controllable Reactive Power Devices

VVO allows user-defined control priorities. User can assign different control action priorities to different types of controls.

Global (system-wide) Controls

- VVO to consider all shunt control devices and tap changers as control devices, including RMR capacitors and both A & AA LTCs.
- VVO to use shunt reactors and tertiary reactors: there are 4 shunt reactors (2 at Rector 66 kV and 2 at Springville 66 kV); and 106 reactors at tertiary of AA Banks and at designated A Bank transformers (Kramer). These reactors are controlled manually by system

operators through EMS. VVO must be capable of using them during the optimization solution process.

Automated LTC (local) Controls

There are approximately 100 LTCs ''local controls'' that are equipped with automated control algorithms. The automated algorithms are rule-based and consider only system conditions that are presented locally to the LTC.

- VVO will be able to respect the Auto LTCs control algorithm during the VVO solution, i.e. use them to regulate the terminal bus voltages during the optimization solution process. Auto LTCs, once the automated logic is turned on, will not participate in the system-wide optimization.
- VVO will allow optionally disabling the Auto LTCs control algorithm and use the LTCs in the optimization process.

4.3.4 Managing Infeasibility in VVO Solutions

There are situations in which the Dispatchers/Operators cannot enforce all required constraints.

Similarly, there are situations that the VVO cannot reach a feasible solution that satisfies all constraints and eliminates all voltage violations, by means of the available control variables. The VVO infeasibility logic shall kick-in after detecting the infeasibility.

- VVO may relax the "soft constraints" along the assigned constraint priorities.

The "soft constraints" are the requirements that are allowed to have certain amount of violation under practical operation, such as MVAR flows at A-Bank, generation MVAR injections, inter-tie MVAR flows, SOB limits, etc. While the "hard constraints" are the requirements that can never be violated regardless, such as CA3100B voltage limits, equipment physical sizes/limits, etc. Note that the soft vs hard constraints are categorized through constraint priorities by users.

4.3.5 System Integration Requirements

Network Data Management in the EMS

The EMS network model utilizes Oracle relational database. The network models, including equipment attributes, are defined using SQL relational data structure. Any permanent update of the network data should be populated and managed through the RDB.

Network data in the RDB will be used to create up-to-date GE's proprietary User Files (UF) in EMS production environment. The UF has hierarchical data structure that contains data model and its states/values for applications and displays. Network Applications, such as State Estimation, Power Flows, etc., use data model in the UF, together with the current states/values from the SCADA measurements, to produce real-time application solution and saved into the UF. Users can modify data in EMS production environment temporarily until the next UF creation. UF is designed to improve the performance of the online and study functions.

Data Availability for VVO Tool

The status of data availability can be grouped into three categories:

- **Category 1**: Data structure, tables, and attributes are implemented in the RDB and correct data have been populated.
- **Category 2**: Data structure, tables, and attributes have been designed in the RDB, but the data are either incomplete or still using default values. Efforts are required to prepare and populate these data, as well as verify data integrity and quality.
- **Category 3**: Data structure, tables, and attributes are not yet defined in the RDB. This requires both GE and SCE to design and modify the data structure and data tables in the RDB, modify the data transfer module, and modify the UF data structure.

IT Configuration

The demonstration was implemented using a Standalone demonstration tool with loosely interfaces with EMS. In addition, the VVO tool is available via Intranet URL. The VVO demonstration system was set up at the Quality Assurance System (QAS) of GCC.

Real-time power flow saved cases are downloaded from SCE EMS, periodically (every hour). The VVO function will retrieve the data files and solves the OPF problem based on the already defined objective functions, security constraints, available control devices, etc. The results are then presented via simple user interface and are available through Intranet URL.

The demonstration system is a stand-alone system, on a Linux server without redundancy, which has interface modules to receive data files from SCE servers. Note due to this being a demonstration system, in order to reduce the overall cost on hardware, no redundancy is needed. Only standard back-up was required.

- VVO tool was installed on a separate Intel-based server, with Linux OS, that is located in GCC.
- VVO tool did not have the same system redundancy requirement as the production EMS. Reasonable and practical IT configuration with minimum redundancy was sufficient.
- VVO results are viewable by both GCC Dispatchers and Switching Center AOR Operators as an Intranet application.

The essential input data are from the EMS SE saved cases that will be in CIM format to eliminate possible translation errors. The CIM format was then converted into Nexant VVO “PCA” input format.

There are data that are in the RDB, but not in the CIM files. Those were implemented directly into the tool via spreadsheets data files.

There are additional data sets used by VVO that are not yet defined in the RDB. A separate data file will be created to manage these data separately in Excel files.

All three data sources will be consolidated into the VVO input data files.

VVO solutions can be output to user interface displays as well as off-line reports.

User Interface and Display Requirements

Key required capabilities of the VVO user interfaces are listed below.

- VVO results, during the demonstration period, are displayed on friendly user interfaces through web interfaces.
- Both GCC Dispatchers and Switching Center AOR Operators can view the VVO results through a URL based User Interface.
- The VVO solution displays the total MW losses before and after the optimization.
- Users are allowed to modify the priority assignments in the VVO system; default values of the priorities will be used if no edits.
- Users are allowed to select the set of voltage limits that are to be used, or modify the limits when desired.
- Users are allowed to enable/disable special constraints, such as generation reactive power, A-bank reactive power, inter-tie reactive power flows, etc.
- Users are allowed to select on-demand run for either to perform VVO for loss minimization or VVO for violation mitigation.
- VVO system can provide and use defaults (expert suggestions) if user inputs for parameters are left empty.
- The VVO solution displays the voltages before and after the optimization.
- The VVO solution displays the control devices status before and after the optimization.

- The VVO solution displays the static reactive power reserve before and after the optimization.
- The VVO solution displays the SVC status and output before and after the optimization.
- The VVO solution highlights the relaxed limits if the case is infeasible.
- The VVO solution displays voltage violations, if any, both pre-contingency (exceeding normal limits) and post contingency (exceeding emergency limit).

Output Requirements (CSV format)

Additional offline reporting capabilities were implemented for the pilot demonstration VVO system. This was to facilitate the testing and assessment.

- The performance metrics that are described in Section 3 of this document are reported.
- The deviations of the intertie flows, the reactive power flows between transmission and sub-transmission systems, and number of violations (before and after the VVO) are reported as additional references for benefit metrics.
- VVO system is be able to download:
    - Violations (station name, bus number, base KV, actual KV, deviation, violation type, etc.)
    - Reactive devices (station name, bus number, device name, reactive capabilities, on/off status, switching history (during one day), etc.

4.4 VVO Configuration Menu

Table 4 describes several options available within the VVO application, as well as those that provide the option of being modified.

Type	Title	Item	Can be modified	Options
Objective	VVO Objective	Loss Minimization	No	
Control	Non RMR Shunt	Name Substation Base kV	No	
		Control Availability	Yes	Available Not Available
	RMR Capacitor	Name Substation Base kV	No	
		Control Availability	Yes	
	Transformer Tap	Name Substation From/To Base kV	No	
		Control Availability	Yes	Available Not Available
Constraints	Normal Voltage Limit	-	Yes	SOB17 CA3100B
	Individual Bus Voltage Limit Update	Bus Name Max/Min Limit 1 Max/Min Limit 2	No	
		Constraint Status	Yes	Enable Disable Expanded
	Intertie MVAR	Name Before VVO MVAR Max/Min MVAR	No	
		Status	Yes	Enable Disable Monitored Expanded

Table 4. VVO Configurable Options

List of Acronyms

AOR	Area of Responsibility
CAISO	California Independent System Operator
CIM	Common Information Model
CGCC	Centralized Grid Capacitor Control
EMS	Energy Management System
EPIC	Electric Program Investment Charge
GCC	Grid Control Center
GTM	Grid Technology and Modernization
kV	kilovolt
LTC	Load Tap Changer
MW	Megawatt
MVA	Mega Volt-Ampere
MVAR	Mega Volt-Ampere Reactive
UF	User Files
OPF	Optimal Power Flow
PSC	Power Systems Control
RDB	Relational Database
RMR	Reliability Must Run
SCE	Southern California Edison
SCOPF	Security Constrained Optimal Power Flow
SOB	System Operating Bulletin
SVC	Static Var Compensator
URL	Uniform Resource Locator
VAR	Volt Ampere Reactive
VVO	Volt-VAR Optimization