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 2021 ACTIVITIES OF THE ELECTRIC PROGRAM INVESTMENT CHARGE PROGRAM

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Dated: **February 28, 2022**

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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 2021. This is SCE's eighth 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, 2021 represents almost seven full years of implementing program operations of SCE's 2015-2017 EPIC Triennial Investment Plan (Application (A.) 14-05-005), after receiving Commission approval on April 9, 2015. Lastly, this is SCE's fourth 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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February 28, 2022

EPIC ADMINISTRATOR ANNUAL REPORT FOR 2021 ACTIVITIES

EPIC ADMINISTRATOR ANNUAL REPORT FOR 2021 ACTIVITIES

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1. Executive Summary

a) Overview of Programs/Plan Highlights

2021 represented SCE's eighth 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 2021 represented almost seven 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, Year 2021 represented SCE's second full year of implementing program operations of SCE's 2018 – 2020 Investment Plan Application[5] after receiving approval on October 25, 2018.

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

(1) 2012-2014 Investment Plan

For the period between January 1 and December 31, 2021, SCE expended a total of $169,076 toward project costs and $0 toward administrative costs for a grand total of $169,076. SCE's cumulative expenses over the lifespan of its 2012 – 2014 EPIC program amount to $38,571,263. SCE committed $436,567 toward projects and encumbered $121,241 through executed purchase orders during this period**.**

SCE executed 16 projects from its approved portfolio. Three projects were completed during calendar year 2015, four projects were completed in 2016, four projects were completed in 2017, two projects were completed in 2018, two projects were completed in 2019 and one project was completed in 2020. A list of completed projects is included in the Conclusion of this Report (section 4). In accordance with the Commission's directives,[6] SCE has completed Final Project Reports for all projects and included them with the Annual Report according to the years completed. There are no projects 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 A.17-05-005.
6 D.13-11-025, OP14.

(2) 2015-2017 Investment Plan

For the period between January 1 and December 31, 2021, SCE expended a total of $2,455,330 toward project costs and $55,951 toward administrative costs for a grand total of $2,511,281. SCE's cumulative expenses over the lifespan of its 2015 – 2017 EPIC program amount to $37,163,163. SCE committed $2,210,419 toward projects and encumbered $1,024,969 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, three projects have been cancelled for the reasons described in their respective project updates section.[7] Project execution activities continued for the remaining ten projects. Of those ten projects, one project was completed in 2017, three projects were completed in 2018, two projects were completed in 2019, one project was completed in 2020, and one project was completed in 2021. The Integrated Grid Project II was completed in 2021. Two demonstrations remain in execution.

(3) 2018-2020 Investment Plan

For the period between January 1 and December 31, 2021, SCE expended a total of $5,892,855 toward project costs and $931,796 toward administrative costs for a grand total of $6,824,651. SCE's cumulative expenses over the lifespan of its 2018 – 2020 EPIC program amount to $14,391,243. SCE committed $22,490,411 toward projects and encumbered $6,364,488 through executed purchase orders during this period. SCE has no uncommitted EPIC project funding for this period.

SCE received approval from the Commission for two replacement projects: Wildfire Prevention & Resiliency Technologies Demonstration and Beyond Lithium-Ion Energy Storage Demonstration, both of which were included in the Joint Utilities Research Administration Plan (RAP) Application.[8] During 2021, SCE completed one project, performed work on 15 projects, and deferred one project. Three other EPIC III projects were either canceled or deferred previously. The following 14 projects from the EPIC III portfolio remain in execution:

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[7] Starting at p. 17.

[8] A.19-04-028, Appendix E. These 2 projects replaced the following EPIC III projects, Beyond the Meter Phase 2 and Reliability Dashboard Tools, pp. 32-36.

1. Advanced Comprehensive Hazards Tool
2. Advanced Technology for Field Safety (ATFS)
3. Beyond Lithium-ion Energy Storage Demo
4. Control and Protection for Microgrids and Virtual Power Plants
5. Cybersecurity for Industrial Control Systems
6. Distributed Energy Resources Dynamics Integration Demonstration
7. Distributed PEV Charging Resource
8. Next Generation Distribution Automation III
9. SA-3 Phase III Field Demonstrations
10. Service Center of the Future
11. Smart City Demonstration
12. Storage-Based Distribution DC Link
13. Vehicle-to-Grid Integration Using On-Board Inverter
14. Wildfire Prevention & Resiliency Technology Demonstration

b) <u>Status of Programs</u>

(1) <u>2012-2014 Investment Plan</u>

As of December 31, 2021, SCE has expended $39,917,038[9] on program costs.

Table 1 below summarizes the current funding status of SCE's EPIC projects:

Table 1: 2012-2014 Triennial Investment Plan

1. Energy Resources Integration
• 3 Projects Funded o 1 Project Completed in 2016[10] o 2 Projects Completed in 2018[11]

[9] SCE's cumulative project expenses amounted to $37,016,441 based on the project spreadsheet in Appendix A. SCE's cumulative administration expenses amounted to $1,554,822. SCE's accounting system calculates in-house labor and overheads separately, which amounted to $1,475,837 for projects and $61,147 for administrative labor. As a result, SCE expended a total of $40,108,248 on program costs.

[10] Distribution Planning Tool.

[11] DOS Protection & Control Demonstration and Advanced Voltage and VAR Control of SCE Transmission.

2. Grid Modernization and Optimization
• 5 Projects Funded o 1 Project Cancelled in Q2, 2014[12] o 1 Project Completed in 2015[13] o 1 Project Completed in 2016[14] o 1 Project Completed in 2017[15] o 1 Project Completed in 2020[16]
3. Customer Focused Products and Services
• 3 Projects Funded o 1 Project Completed in 2015[17] o 1 Project Completed in 2016[18] o 1 Project Completed in 2017[19]
4. Cross-Cutting/Foundational Strategies and Technologies
• 5 Projects Funded o 1 Project Completed in 2015[20] o 1 Project Completed in 2016[21] o 2 Projects Completed in 2017[22] o 1 Project Completed in 2019.[23]
Total Projects Funded: 16 Total Authorized Project Budget: $37,656,998[24] Total Project Spend: $37,016,441[25] Total Funding Committed: $436,567[26] Total Encumbered: $121,241[27] *Note: Due to intrinsic variability in TD&D/R&D projects, amounts shown are subject to change*

[12] SCE cancelled the Superconducting Transformer project in 2014. Please refer to the project's status update in Section 4 for additional details.
[13] Portable End-to-End Test System.
[14] Dynamic Line Rating.
[15] Next Generation Distribution Automation, Phase 1.
[16] Substation Automation-3 (SA-3), Phase 1.
[17] I. Outage Management and Customer Voltage Data Analytics Demonstration.
[18] Submetering Enablement Demonstration.
[19] Beyond the Meter: Customer Device Communications Unification and Demonstration.
[20] Cyber-Intrusion Auto-Response and Policy Management System.
[21] Enhanced Infrastructure Technology Report.
[22] State Estimation Using Phasor Measurement Technologies and Deep Grid Coordination (otherwise known as the Integrated Grid Project).
[23] Wide Area Management and Control.
[24] D.12-05-037, as updated by D.13-11-025. Includes $2,045,000 transfer from administrative funds to project funds.
[25] For additional details regarding SCE's Committed Funds, please see the attached spreadsheet.
[26] *Ibid.*
[27] *Ibid.*

Table 2 below summarizes SCE's 2021 administrative expenses:

Table 2: 2012-2014 Triennial Investment Plan: 2021 Administration

• Program Administration	Total Authorized Budget: $1,855,002[28] Total Cumulative Cost: $1,554,822 Total 2021 Cost: $0

(2) 2015-2017 Investment Plan

As of December 31, 2021, SCE has expended $38,501,132[29] on program costs. Table 3 below summarizes the current funding status of SCE's EPIC projects:

Table 3: 2015-2017 Triennial Investment Plan

1. Energy Resources Integration
• 3 Projects Funded 2 Projects canceled in 2016[30] 1 Project canceled in 2017[31]
2. Grid Modernization and Optimization
• 6 Projects Funded o 1 Project completed in 2017[32] o 1 Project completed in 2018[33] o 1 Project completed in 2019[34] o 1 Project completed in 2020[35] o 2 Projects in execution in 2021[36]
3. Customer Focused Products and Services
• 3 Projects Funded o 2 Projects completed in 2018[37]

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28 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.

29 SCE's cumulative project expenses amounted to $34,268,814 based on the project spreadsheet in Appendix A. SCE's cumulative administration expenses amounted to $2,894,351. SCE's accounting system calculates in-house labor and overheads separately, which amounted to $$1,142,688 for projects and $195,279 for program administration. As a result, SCE expended a total of $38,501,123 on program costs.

30 Bulk System Restoration under High Renewables Penetration and Series Compensation for Load Flow Control.

31 Optimized Control of Multiple Storage Systems.

32 Advanced Grid Capabilities Using Smart Meter Data.

33 Proactive Storm Impact Analysis Demonstration.

34 Versatile Plug-in Auxiliary Power System.

35 Dynamic Power Conditioner.

36 Next-Generation Distribution Equipment & Automation - Phase 2 and System Intelligence and Situational Awareness Capabilities.

37 DC Fast Charging and Integration of Big Data for Advanced Automated Customer Load Management.

o 1 Project completed in 2019[38]
4. Cross-Cutting/Foundational Strategies and Technologies
• 1 Project Funded o 1 Project completed in 2021[39]
Total Projects Funded: 13 Total Authorized Project Budget: $37,504,200[40] Total Project Spend: $34,268,814[41] Total Funding Committed: $2,210,419[42] Total Encumbered: $1,024,969[43] *Note: Due to intrinsic variability in TD&D /R&D projects, amounts shown are subject to change*

Table 4 below summarizes SCE's 2021 administrative expenses:

Table 4: 2015-2017 Triennial Investment Plan: 2021 Administration

• Program Administration	Total Authorized Budget: $4,190,400[44] Total Cumulative Cost: $2,894,351 Total 2021 Cost: $55,951

(3) 2018-2020 Investment Plan

As of December 31, 2021, SCE has expended $14,660,550[45] on program costs.

Table 4 below summarizes the current funding status of SCE's EPIC projects:

Table 5: 2018-2020 Triennial Investment Plan

1. Energy Resources Integration
• 2 Projects Funded o 2 Projects in execution[46]

[38] Regulatory Mandates: Submetering Enablement Demonstration Phase 2.
[39] Integrated Grid Project II.
[40] D.15-04-020, Ordering Paragraph 1 -- Appendix B, Table-5, p. 7.
[41] For additional details regarding SCE's Committed Funds, please see the attached spreadsheet.
[42] *Ibid.*
[43] *Ibid.*
[44] D.15-04-020, Ordering Paragraph 1 -- Appendix B, Table-5, p. 7
[45] SCE's cumulative project expenses amounted to $11,975,657 based on the project spreadsheet in Appendix A. SCE's cumulative administration expenses amounted to $2,415,586. SCE's accounting system calculates in-house labor and overheads separately, which amounted to $241,834 for projects and $27,474 for program administration. As a result, SCE expended a total of $14,660,550 on program costs.
[46] Distributed Energy Resources Dynamics Integration Demonstration and Smart City Demonstration.

2. Grid Modernization and Optimization
• 6 Projects Funded o 4 Projects in execution[47] o 1 Project canceled in 2020[48] o 1 Project on hold or deferred in 2020[49]
3. Customer Focused Products and Services
• 4 Projects Funded o 4 Projects in execution[50]
4. Cross-Cutting/Foundational Strategies and Technologies
• 7 Projects Funded o 4 Projects in execution[51] o 1 Project canceled in 2019[52] o 1 project on hold or deferred in 2021[53] o 1 Project completed in 2021[54]
Total Projects Funded: 19 Total Authorized Project Budget: $40,830,795[55] Total Project Spend: $11,975,657[56] Total Funding Committed: $22,490,411[57] Total Encumbered: $6,364,488[58] *Note: Due to intrinsic variability in TD&D /R&D projects, amounts shown are subject to change*

[47] Beyond Lithium-ion Energy Storage Demo, SA-3 Phase III Field Demonstrations, Storage-Based Distribution DC Link and Next Generation Distribution Automation III.

[48] Power System Voltage and VAR Control Under High Renewables Penetration.

[49] Distribution Primary & Secondary Line Impedance.

[50] Control and Protection for Microgrids and Virtual Power Plants, Distributed PEV Charging Resource, Service Center of the Future, and Vehicle-to-Grid Integration Using On-Board Inverter.

[51] Advanced Comprehensive Hazards Tool, Advanced Technology for Field Safety (ATFS, Cybersecurity for Industrial Control Systems, and Wildfire Prevention & Resiliency Technology Demonstration.

[52] Energy System Cybersecurity Posturing.

[53] Advanced Data Analytics Technologies (ADAT).

[54] Distributed Cyber Threat Analysis Collaboration (DCTAC).

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

[56] For additional details regarding SCE's Committed Funds, please *see* the attached spreadsheet.

[57] *Ibid.*

[58] *Ibid.*

Table 6 below summarizes SCE's 2021 administrative expenses:

Table 6: 2018-2020 Triennial Investment Plan: 2021 Administration

• Program Administration	Total Authorized Budget: $4,562,100[59] Total Cumulative Cost: $2,415,586 Total 2021 Cost: $931,796

2. Introduction and Overview

a) Background on EPIC (General Description of EPIC)

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 EPIC Program will continue through 2020[60] with an annual budget of $162 million,[61] adjusted for inflation.[62] 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.[63] The IOUs were also limited to only the area of Technology Demonstration and Deployment (TD&D) activities.[64] SCE was allocated 41.1% of the IOU portion of the budget and administrative activities.[65]

The Commission approved SCE's 2012-2014 Investment Plan[66] in D.13-11-025 on November 19, 2013. SCE submitted its 2015-2017 Investment Plan Application[67] 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 2015-2017 and 2018-2020 EPIC Investment Plans.

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59 D.18-01-008, at p. 38.
60 D.12-05-037, OP1.
61 D.12-05-037, OP7.
62 Using the Consumer Price Index.
63 *Id*, OP5.
64 *Id*.
65 D.12-05-037, OP 7, as modified by D.12-07-001.
66 A.12-11-004.
67 A.14-05-005.

The Commission initiated a rulemaking[68] split into 2 phases to determine the future of EPIC. In Phase 1 the Commission determined EPIC would continue for 10 years through 2030 and each investment period would cover 5 years (2021-2025 and 2026-2030). Additionally, the Commission determined in Phase 1 to authorize the CEC to continue being an administrator of EPIC.[69] In Phase 2 of the rulemaking, the Commission determined that Utilities should continue to be EPIC Administrators, along with the CEC.[70] SCE (along with PG&E and SDG&E) will file their respective EPIC 4 Investment Plan, covering 2021-2025 on October 1, 2022.[71] Phase 2C will close-out the EPIC Rulemaking and address such issues as a future program evaluation.

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 and reiterated in D.21-11-028. 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.[72]

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 modernization and optimization, (3) customer-focused products and services, and (4) cross-cutting/foundational strategies and technologies. SCE's 2012-2014, 2015-2017, and 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.

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68 R.19-10-005.
69 D.20-08-042.
70 D.21-11-028.
71 *Id*., OP 6, at p. 47.
72 D.12-05-037, OP3.B.

c) EPIC Program Regulatory Process

The Commission approved SCE's 2012-2014 Application[73] in D.13-11-025 on November 19, 2013. SCE submitted its 2015-2017 Investment Plan Application[74] 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,[75] 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[76] on May 1, 2017, and the Commission approved the Application in D.18-10-52 on October 25, 2018. Within the Commission's decision approving the 2018-2020 Investment Plan Applications, the Commission directed the Utilities to file a joint RAP Application on April 23, 2019, to address recommendations made by in the independent evaluator's report and to provide an opportunity to refresh the portfolio by allowing an opportunity to replace project proposals. The Joint Utilities filed the RAP Application[77] on April 23, 2019, and SCE proposed two replacement project proposals, which was approved by the Commission on February 10, 2020. In 2021, the Commission determined to continue having the Utilities be co-Administrators of EPIC.[78] In compliance with the Commission's requirements for the EPIC Program,[79] SCE submits its 2021 Annual Report to update the Commission and stakeholders on SCE's program implementation.

d) Coordination

The EPIC Administrators have collaborated throughout 2021 on the execution of the 2015-2017 and 2018-2020 Investment Plans. Specific examples of the IOUs coordinating with the CEC include:

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[73] A.12-11-004.
[74] A.14-05-005.
[75] D.15-09-005.
[76] A.17-05-005.
[77] A.19-04-028.
[78] D.21-11-028.
[79] 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.

- The August 12 SCE/CPUC Energy Division Quarterly Check-in;
- The October 20 EPIC 3 Project Initiation Public Workshop where SCE presented on two EPIC 3 projects – Wildfire Prevention & Resilience Technologies and Beyond Lithium-Ion;
- The November 17 Joint Utilities Autumn EPIC Workshop;
- The December 14-15 virtual 2021 EPIC Symposium where SCE presented: Technology Advancements in Long-Duration Storage, Innovative Technologies for Wildfire Risk Reduction and Data Applications to Support a Climate Resilient Electricity Sector;
- SCE continued project coordination on the Electric Access System Enhancement (EASE) project.[80] 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 coordination, the Utility EPIC Administrators met on a near-weekly basis and bi-weekly basis with the CEC 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, 2021, SCE supported the annual EPIC Symposium held virtually again this year due to the corona virus. SCE supported the CEC in a discussion on, and a utility management plenary panel. In addition to the Symposium, the Joint Utilities coordinated with the CEC on a public workshop co-hosted by PG&E and SCE on EPIC III projects.

SCE supported numerous parties applying for CEC EPIC funding in 2021. A total of 24 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

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[80] 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.

bids for CEC projects. These requests consisted of 15 LOSs and 9 LOCs. Of these requests, 5 LOSs and 2 LOC were approved by the CEC. 6 of the 15 LOSs are still being reviewed. 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 view 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: 2012-2014 Authorized EPIC Budget

20212-2014 (Jan 1 - Dec 31)	Administrative	Project Funding	Commission Regulatory Oversight Budget
SCE Program	\$1.3M	\$11.9M	\$0.33M[81]
CEC Program	\$5.3M	\$47.7M	

(2) 2015 – 2017 Investment Plan

Table 6: 2015-2017 Authorized EPIC Budget

2015-2017 (Jan 1 - Dec 31)	Administrative	Project Funding	Commission Regulatory Oversight Budget
SCE Program	\$1.4M	\$12.5M	\$0.35M
CEC Program	\$5.6M	\$50M	

[81] Advice Letter, 2747-E, p. 6.

(3) **2018 – 2020 Investment Plan**

Table 7: 2018-2020 Authorized EPIC Budget

2018-2020 (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, 2021, SCE has committed $436,567 and encumbered $121,241 of its authorized 2012-2014 program budget.

(2) **2015 – 2017 Investment Plan**

As of December 31, 2021, SCE has committed $2,210,419 and encumbered $1,024,969 of its authorized 2015-2017 program budget.

(3) **2018 – 2020 Investment Plan**

As of December 31, 2020, SCE has committed $22,490,411and encumbered $6,364,488 of its authorized 2018-2020 program budget.

(4) **CEC & CPUC Remittances**

For CEC remittances, SCE remitted $7,603,500[82] for program administration, and $80,498,265 for encumbered projects during calendar year 2021.

For CPUC remittances, SCE remitted $273,116 in calendar year 2021.

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

(1) **2012 – 2014 Investment Plan**

As of December 31, 2021, SCE has spent $5,043,471[83] on in-house activities.

82 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.

83 SCE expended a total of $5,043,471 on in-house activities through 2021 based on the project spreadsheet in Appendix A. SCE's accounting system calculates in-house labor overheads separately, which amounted to $1,288,619. As a result, SCE expended a total of $6,332,090 on in-house costs.

(2) 2015 – 2017 Investment Plan

As of December 31, 2021, SCE has spent $2,681,580[84] on in-house activities.

(3) 2018 – 2020 Investment Plan

As of December 31, 2021, SCE has spent $984,160 on in-house activities.

d) Fund Shifting Above 5% between Program Areas

(1) 2012 – 2014 Investment Plan

As of December 31, 2021, SCE does not have any pending fund shifting requests and/or approvals.

(2) 2015 – 2017 Investment Plan

As of December 31, 2021, SCE does not have any pending fund shifting requests and/or approvals.

(3) 2018 – 2020 Investment Plan

As of December 31, 2021, 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, 2021, SCE has $0 in uncommitted/unencumbered funds.

(2) 2015 – 2017 Investment Plan

As of December 31, 2021, SCE has $0 in uncommitted/unencumbered funds.

(3) 2018 – 2020 Investment Plan

As of December 31, 2021, SCE has $0 in uncommitted/unencumbered funds.

f) Joint CEC/SCE Projects

As of December 31, 2021, 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.

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[84] SCE expended a total of $2,681,580 on in-house activities through 2021 based on the project spreadsheet in Appendix A. SCE's accounting systems calculates in-house labor overheads separately, which amounted to $1,043,674. As a result, SCE expended a total of $3,725,254 on in-house costs.

g) Non-Competitive Bidding of Funds

As of December 31, 2021, SCE awarded $0 in direct awards for projects.

h) Match Funding

As noted in last year's EPIC Annual Report, SCE has begun tracking match funding. SCE's EPIC projects did not receive match funding in 2021.

i) High-Level Summary

SCE provides a summary of project funding for SCE's 2012-2014, 2015-2017, and 2018-2020 Investment Plans, please refer to Table 1, Table 3, and Table 5 in Section 1b.

j) Project Status Report

Please refer to Appendix A of this Report for SCE's Project Status Report. The Project Status Report also addressed items k (i) to k (xiv) below.

k) 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)

l) Status Update

The following project descriptions for the objective and scope reflect the proposals filed in the EPIC Investment Plans,[85] while the projects' status information show progress as of December 31, 2020. As a result of corrections made to address preliminary 2020 EPIC audit findings,[86] some dollar values for completed projects have changed.

(1) 2012 – 2014 Triennial Investment Plan Projects

1. Integrated Grid Project – Phase 1

<table>
<tr><td>Investment Plan Period:
1st Triennial Plan (2012-2014)</td><td>Assignment to value Chain:
Grid Operation/Market Design</td></tr>
<tr><td colspan="2">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?</td></tr>
<tr><td colspan="2">Deliverables:
• An IGP cost/benefit analysis and business case
• A systems requirement specification</td></tr>
</table>

[85] 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.

[86] Finding 4 of the draft 2020 EPIC audit performed by Sjoberg Evashenk Consulting, Inc., 455 Capitol Mall, Suite 700, Sacramento, CA 95814 (Sjoberg Consulting). SCE has not yet been provided with a copy of the final report.

• 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:** $17,413,924	
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

<table>
<tr><td colspan="2">Investment Plan Period:
1st Triennial Plan (2012-2014)</td><td colspan="2">Assignment to value Chain:
Demand-Side Management</td></tr>
<tr><td colspan="4">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.</td></tr>
<tr><td colspan="4">Deliverables:
1. Submetering Protocol Report
2. Manual Subtractive Billing Procedure
3. 3PE Final Report and Recommendation</td></tr>
<tr><td colspan="4">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</td></tr>
<tr><td colspan="4">Schedule:
Q1 2014 – Q1 2017</td></tr>
<tr><td colspan="2">EPIC Funds Encumbered:
$0</td><td colspan="2">EPIC Funds Spent:
$1,134,368</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
The final project report is complete, was submitted with the 2016 Annual Report, and is available on SCE's public EPIC web site.</td></tr>
</table>

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 Grid LAB-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:** $1,071,032
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
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)
Schedule: Q3 2014 – Q4 2017

EPIC Funds Encumbered: $0	**EPIC Funds Spent:** $1,471,383

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 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 marketplace (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:** $844,938

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, was submitted with the 2018 Annual Report, and is 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:	**EPIC Funds Spent:**
$0	$10,241

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.
Status Update SCE formally cancelled this project in Q3 2014.

8. State Estimation Using Phasor Measurement Technologies

Investment Plan Period:	**Assignment to value Chain:**
1st Triennial Plan (2012-2014)	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 marketplace (when known)		
Schedule: Q2 2014 – Q4 2017		
EPIC Funds Encumbered: $0	**EPIC Funds Spent:** $816,236	
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: $4,503	**EPIC Funds Spent:** $709,096	
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 2019 Annual Report, and is available on SCE's public EPIC web site.		

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	$72,995

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, was submitted with the 2018 Annual Report, and is posted on SCE's public EPIC web site.

11. Outage Management and Customer Voltage Data Analytics Demonstration

Investment Plan Period: 1st Triennial Plan (2012-2014)	**Assignment to value Chain:** 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:** $1,018,549	
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 marketplace (when known)		
Schedule: Q1 2014 – Q3 2021		
EPIC Funds Encumbered: 116,738	**EPIC Funds Spent:** 5,965,354	
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 and is submitted as part of the 2020 Annual Report and is available on SCE's public EPIC web site.		

13. Next-Generation Distribution Automation

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

Schedule: Q1 2014 – Q4 2017		
EPIC Funds Encumbered: $0	**EPIC Funds Spent:** $4,091,723	
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 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 was submitted with the 2018 Annual Report, and is posted on SCE's public EPIC web site.		

14. Enhanced Infrastructure Technology Evaluation

Investment Plan Period: 1st Triennial Plan (2012-2014)	**Assignment to value Chain:** 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 would not 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 marketplace (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"[87] 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:** $1,193,834

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:

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

The Final Report for the Integration of Big Data for Advanced Automated Customer Load Management is complete, was submitted with the 2018 Annual Report, and is posted on SCE's public EPIC web site.

2. Advanced Grid Capabilities Using Smart Meter Data

Investment Plan Period: 2nd Triennial Plan (2015-2017)		**Assignment to value Chain:** 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:** $178,426	
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

<table>
<tr><td colspan="2">Investment Plan Period:
2nd Triennial Plan (2015-2017)</td><td colspan="2">Assignment to value Chain:
Distribution</td></tr>
<tr><td colspan="4">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.</td></tr>
<tr><td colspan="4">Deliverables:
RFP Package
Requirements / Use Cases
Measurement and Validation Plan
Supplier’s Pilot Report
Technology Transfer Plan
Final project report</td></tr>
<tr><td colspan="4">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 marketplace (when known)</td></tr>
<tr><td colspan="4">Schedule:
Q3 2015 – Q4 2018</td></tr>
<tr><td colspan="2">EPIC Funds Encumbered:
$0</td><td colspan="2">EPIC Funds Spent:
$1,185,899</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>
</table>

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, was submitted with the 2018 Annual Report, and is posted on SCE's public EPIC web site.

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

Investment Plan Period: 2nd Triennial Plan (2015-2017)	**Assignment to value Chain:** 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 Integrated 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 on single-phase unit, final report on single-phase unit, delivery of three-phase unit, three-phase unit standard approval and publication, training on three-phase unit and final report on 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 2022		
EPIC Funds Encumbered: $20,032	**EPIC Funds Spent:** 5,645,101	
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:

Remote Integrated Switch (RIS)
The RIS team demonstrated the Phase 3 advanced features which address system scalability and usability concerns identified by stakeholders. The team also initiated development of the decommissioning plan for installed field devices.

High Impedance Fault Detection
The additional validation test scope was not pursued due to challenges with Cyber Security policy contract negotiations that could not be resolved. As such, data already gathered is in process of being analyzed and learnings documentation is in progress.

Underground/Overhead Remote Fault Indicator (RFI)
The project team completed all installations and hardware/firmware updates for the RFI systems. Documentation and technology transition plans for the technology have started development and are expected to complete in 2022.

5. System Intelligence and Situational Awareness Capabilities

Investment Plan Period: 2nd Triennial Plan (2015-2017)	**Assignment to value Chain:** Distribution	
Objective & Scope: This project will demonstrate system intelligence and situational 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.		
Deliverables: • Intelligent Alarm processing stakeholders lab demonstration • Testing tools lab demonstration and hand-over to production team • Process bus lab demonstration		
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		
Schedule: Q1 2016- Q4 2022		
EPIC Funds Encumbered: $585,095	**EPIC Funds Spent:** $2,872,946	
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:

Process Bus (Mayberry)

The new optical sensing technology demonstration equipment with the IEC-61850 process bus standard was left at the Mayberry Substation after the initial demonstration phase. This equipment was left in the field until July 27, 2021. Leaving the equipment in the field for this extended period allowed the SCE Engineers to identify the possibility of working toward a long-term option of implementing a complete IEC-61850 substation automation system.

Fully Digital Substation (Proof of Concept)

In 2021, the project team created and finalized the testing procedures to be implemented within the lab for testing. These plans were separated into two types of testing: Interface and Scheme. The Interface consists of communications and IEC-61850 compliance testing and the Scheme testing focuses primarily on validating the system protection as well as negative test case scenarios.

Due to Covid restrictions, this project also allowed the team to do some remote testing with one of our contractors. This remote testing proved valuable for the contractor as they were able to work off-site and still provide SCE with testing services. The Lab Testing was conducted remotely and on-site by SCE and contractors. The ability to test remote and on-site was more efficient if both teams were needed in the Lab.

The Proof of Concept for the Fully Digital Substation is nearing completion and concluded in December 2021. This demonstration project will assist with identifying the differences of implementing the lab demonstration versus a traditional substation.

HMI & ePAC Testing

As part of the substation HMI and ePAC testing, the project team was able to identify reconfiguration that were needed with the ePAC in order for the functions to work with new devices in the automation schemes. Testing was successful.

Network Switches

The process bus ethernet network architecture was measured collaboratively with the Project team and the SCE network engineering department. Both teams worked to successfully configure the network devices and validate communications between the devices. Network technology such as VLANs were utilized and validated to segregate network traffic.

6. Regulatory Mandates: Submetering Enablement Demonstration - Phase 2

<table>
<tr><td colspan="2">Investment Plan Period:
2nd Triennial Plan (2015-2017)</td><td colspan="2">Assignment to value Chain:
Demand-Side Management</td></tr>
<tr><td colspan="4">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.</td></tr>
<tr><td colspan="4">Deliverables:
• Manual subtractive billing procedure for multiple customers of record
• 3PE final report
• PEV submetering protocol
• Final project report</td></tr>
<tr><td colspan="4">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 marketplace (when known)</td></tr>
<tr><td colspan="4">Schedule:
Q4 2015 – Q1 2019</td></tr>
<tr><td colspan="2">EPIC Funds Encumbered:
$0</td><td colspan="2">EPIC Funds Spent:
$1,236,402</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>
</table>

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 Regulatory Mandates: Submetering Enablement Demonstration - Phase 2 is complete, was submitted with the 2019 Annual Report, and is posted on SCE's public EPIC web site.

7. Bulk System Restoration Under High Renewables Penetration

Investment Plan Period: 2nd Triennial Plan (2015-2017)	**Assignment to value Chain:** 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 its 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:** $42,225

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 an 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:** $5,683	
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)

<table>
<tr><td colspan="3">Investment Plan Period:
2nd Triennial Plan (2015-2017)</td><td colspan="2">Assignment to value Chain:
Distribution</td></tr>
<tr><td colspan="5">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).</td></tr>
<tr><td colspan="5">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</td></tr>
<tr><td colspan="5">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</td></tr>
<tr><td colspan="5">Schedule:
Q3 2015 – Q1 2019</td></tr>
<tr><td colspan="2">EPIC Funds Encumbered:
$24,476</td><td colspan="3">EPIC Funds Spent:
$1,125,945</td></tr>
<tr><td colspan="5">Partners:
N/A</td></tr>
<tr><td>Match Funding:
N/A</td><td colspan="3">Match Funding split:
N/A</td><td>Funding Mechanism:
N/A</td></tr>
<tr><td colspan="5">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="5">Status Update:
The Final Report for the VAPS is complete, was submitted with the 2019 Annual Report and is posted on SCE's public EPIC website.</td></tr>
</table>

10. Dynamic Power Conditioner

Investment Plan Period:	**Assignment to value Chain:**
2nd Triennial Plan (2015-2017)	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:	**EPIC Funds Spent:**
$1,504	$939,330

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 report is complete, was submitted as part of the 2020 Annual Report, and is available on SCE's public EPIC website.

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:** $139,583	
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:** $15,961	
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, was submitted with the 2018 Annual Report, and is posted on SCE's public EPIC website.		

13. Integrated Grid Project II

Investment Plan Period:	**Assignment to value Chain:**
2nd Triennial Plan (2015-2017)	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 distributed energy resources (DERs) owned by both 3rd parties and the utility. The objectives are to demonstrate the next generation grid infrastructure that manages, operates, and optimizes the DERs 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 – Q4 2021

EPIC Funds Encumbered: $393,862	**EPIC Funds Spent:** $17,830,929

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

Match Funding: $2.3M Cost Share	**Match Funding split:** N/A	**Funding Mechanism:** 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: See Final Project Report in the Appendix for 2021 achievements.

(3) 2018 – 2020 Triennial Investment Plan

1. Cybersecurity for Industrial Control Systems

Investment Plan Period: 3rd Triennial Plan (2018-2020)	**Assignment to value Chain:** Grid Operation/Market Design

Objective & Scope: This project will demonstrate the ability to deploy adaptive security controls and dynamically re-zone operational networks while the Industrial Control System (ICS) is

either under cyberattack or subject to an increased threat level. The concept of dynamic zoning allows for isolation of threats to certain segments of the ICS and could include both vertical (isolating data flows from SCADA masters to substation endpoints) and horizontal (containing data flows between substations, for example, under a state of manual control when the SCADA master cannot be trusted). Adaptive Controls/Dynamic Zoning (AC/DZ) has the potential to benefit the national grid and ratepayers by bolstering a more resilient and secure grid through the ability to identify and isolate core grid operational functions while under a cyber-attack or incident. The benefits are also cross cutting in that AC/DZ will drive grid operations and cybersecurity together for collaboration to address controls for zones to be defined risk impact mitigations.		
Deliverables: 1. Demonstration Environment Design Documentation 2. Independent Use Case Demonstration Guide 3. Demonstration Procurement List 4. Demonstration Physical Lab 5. Unified Use Case Demonstration Guide 6. Final Report		
Metrics: 1. Decrease mean time to completion of disconnecting grid communications in response to a simulated cyber incident 2. Demonstrate the viability of segmenting mesh networks 3. Demonstrate the viability of commercial orchestration and automation tools in a grid control / operational technology environment		
Schedule: Q2 2019 – Q4 2022		
EPIC Funds Encumbered: $1,242,075	**EPIC Funds Spent:** $2,282,542	
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 2021, the team continued to refine individual test cases for inserting cybersecurity controls into operational technology / industrial control systems environments proving viability of actions and automation to change grid threat response based on a higher risk event.

The demonstration development focused on combining individual cybersecurity actions. These actions utilized a defense-in-depth approach creating a series of actions and responses to support the individual use cases.

Complex action demonstrations were completed for all four proposed Use Cases (UC), which are comprised of (1) Cyber Automation for Switching Stations and Substations, (2) PLC and RTU Local Control Isolation, (3) Distribution Automation and Wireless Mesh Zoning, and (4) Energy Management System Workstation Threat Actions and Isolation.

Basic research was completed for UCs (4) Energy Management System Workstation Threat Actions and Isolation, and UC (2) PLC and RTU Local Control Isolation allowing for the ability to demonstration of the threat and subsequent remediation actions to take place. Additionally, a Web Dashboard was created to demonstrate the live status of systems and elements, allowing for clear indication of changes to the environment due to simulated attack, by remediation, and finally system reset.

The team installed, configured, and integrated extended detection and response (XDR) tools for threat simulation and automated response demonstrations. Additional depth and complexity were added to internal substation actions.

Lessons Learned:
The team extended lab research at the consultant's Operational Technology Cyber Fusion Center (OTCFC) lab location in response to on-site restrictions stemming from COVID. This workaround has shown the additional benefit of using a rapid solution prototyping lab for demonstration purposes to gain better access to technologies not available at each utility.

The project researched serial firewall (L7) technology and found the available tools lacking and not production worthy for utility environments. While the concept itself was valid for protecting older technology integration, the lack of need in the industry has led to no commercially viable partners.

2. Advanced Data Analytics Technologies

Investment Plan Period: 3rd Triennial Plan (2018-2020)	**Assignment to value Chain:** Grid Operation/Market Design

Objective & Scope:
This project will demonstrate the possibility of using advanced data analytics technologies for Transmission and Distribution (T&D) and customer maintenance. This project will evaluate pattern recognition technologies that are capable of using new and/or existing data sources such as from sensors, smart meters, supervisory control, and data acquisition (SCADA), for predicting or providing alarms on the incipient failure of distribution system assets. These assets would include connectors, transformers, cables, and smart meters.

Use-case Scope
Use supervised machine learning techniques to train, validate, then demonstrate a time-to-failure model on a subset of SCE's distribution transformer installed base. The models will quantify the probability of failure (at the transformer-level) and estimate the remaining useful life (RUL) of distribution transformers.
 	
Business Objective
1. Inputs to the Transformer Asset Class Strategies
    a. Inform risk buy down calculations based on remaining useful life (RUL)
    b. Inform aggregation of like transformers based on level of RUL for decision making
2. Prevent an In-service Failure
    a. Avoid unplanned outage time (reduced CMI, reduce crew OT expense)
    b. Repair during planned outage (lessen customer impact)
    c. Avoid catastrophic failure and resulting consequences (damage to customer/public property, safety, surrounding equipment, wildfire ignition)
3. Procurement/Inventory Planning
    a. Pre-order replacement transformer if there are none in inventory
    b. Budget planning for future procurement (Inform future GRC Testimony)

Deliverables: • Technical report explaining the modeling process, datasets, and results and evaluating the model's performance on how it provides benefits to the project's business objectives. • Interactive data report for the end-user showcasing the results the Transformer Remaining Useful Life predictive model.
Metrics: 1. Maintain/reduce operation and maintenance costs 2. Reduce number of unplanned outages, frequency, and durations 3. Public safety improvement and hazard exposure reduction
Schedule: Q1 2020 – Q1 2022

EPIC Funds Encumbered: $0	**EPIC Funds Spent:** $281,452

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:
This project was deferred in April 2021 to allow consideration of other projects which may offer greater benefits aligned with California and CPUC objectives.

3. Advanced Technology for Field Safety

<table>
<tr><td colspan="2">Investment Plan Period:
3rd Triennial Plan (2018-2020)</td><td colspan="2">Assignment to value Chain:
Distribution</td></tr>
<tr><td colspan="4">Objective & Scope:
This project will demonstrate the possibility of using new advanced technologies to reduce T&D field crew exposure to customer hazards. The project will evaluate technologies that are capable of using data sources such as field sensors, smart meters, etc. to provide real/near real-time status of faulty equipment. This project will also evaluate technology that is capable of levering recent advancements in the Augmented Reality space.</td></tr>
<tr><td colspan="4">Deliverables:
Software – New or improved software to facilitate a demonstration by hosting AR content on various devices types (non-wearable and wearable)
AR Content – New AR based content targeted at new use-case scenarios for demonstration.
Hardware – AR/Wearable devices which represent current market offerings with the feature sets that meet our business needs to demonstrate the field capabilities.
Final Project Report – A report which provides a summary of project activities and the overall results/observation of the project team.
EPIC Documentation – Any associated EPIC and CPUC filing and presentation material required as part of the EPIC program.</td></tr>
<tr><td colspan="4">Metrics:
2a. Hours worked in California and money spent in California for each project
3a. Maintain / Reduce operations and maintenance costs
5e. Utility worker safety improvement and hazard exposure reduction
8f. Technology transfer</td></tr>
<tr><td colspan="4">Schedule:
Q1 2020 – Q4 2023</td></tr>
<tr><td colspan="2">EPIC Funds Encumbered:
$0</td><td colspan="2">EPIC Funds Spent:
$61,924</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>
</table>

Treatment of Intellectual Property: SCE has no current patents or licensing agreements signed. Future Intellectual Property is to be determined.
Status Update: SCE has focused on initiating other higher-priority projects and has therefore not made progress on this project in 2021. The team anticipates launching this project in 2022.

4. Storage-Based Distribution DC Link

Investment Plan Period: 3rd Triennial Plan (2018-2020)	**Assignment to value Chain:** Distribution
Objective & Scope: This project will examine the benefits of a novel architecture for a distribution-connected energy storage system. Storage systems are typically connected to a single electrical point. This project will demonstrate an architecture will allow the system to connect to two unique distribution circuits, using two power conversion systems tied to a single storage medium. This approach will allow the storage system to support both circuits, individually or simultaneously, and will also provide a means of dynamically exchanging power between the two circuits (DC link).	
Deliverables: • System requirements document and design concept summary • Control system specifications • Final report with recommendations • Provide lessons learned to evaluate future projects • Present project at least one technical conference (ETV requirement)	
Metrics: 1b. Total electricity deliveries from grid-connected distributed generation facilities 1e. Peak load reduction (MW) from summer and winter programs 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 5f. Reduced flicker and other power quality differences 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) 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)	

<table>
<tr><td colspan="3">8b. Number of reports and fact sheets published online</td></tr>
<tr><td colspan="3">Schedule:
Q4 2019 – Q4 2023</td></tr>
<tr><td>EPIC Funds Encumbered:
$830,603</td><td colspan="2">EPIC Funds Spent:
$483,515</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:
SCE has no current patents or licensing agreements signed. Future Intellectual Property is to be determined.</td></tr>
<tr><td colspan="3">Status Update:

The Project began working with the selected vendor officially on 8/9/21, and has made substantial progress to-date. There was a 6-month delay to onboard the vendor due to negotiation on the terms and conditions of the contract.

The project team completed the early design phase involving decision around the cooling system, type of disconnecting switch, nominal voltage, auxiliary power source, and relay model type.

The team evaluated two options for the SCADA communication paths and reviewed various control modes for the Tie Controller. We are continuing to evaluate the proposal to update components and software for the Grid Simulator and have completed a review of the scope of work for the power systems study.

The team has met with internal Distribution Engineer and Construction Methods Specialist to review the overall 12kv system design and initiate a plan of inspections/reviews. The team also met with the with Apparatus Engineer to review the 12kv switch design. The team continues to evaluate the single-line diagram and dimensions of the test pad for equipment layout. Meetings have been scheduled with Protection Manager to review protection schemes of the Storage Based DC Link project.

The team presented a project update to the internal Stakeholders to inform of the latest tasks that have been met and the next steps to meet the objective of the project. We have initiated a PO for grid simulator upgrade and conducting meetings with IT to discuss Firewall rules.

<u>Key Findings and Lessons Learned</u>
During internal discussions with project stakeholders, the team learned that transformer winding configurations were modified to better detect ground fault conditions. Y grounded to Y grounded configurations were chosen for this reason.</td></tr>
</table>

5. Smart City Demonstration

<table>
<tr><td>Investment Plan Period:
3rd Triennial Plan (2018-2020)</td><td>Assignment to value Chain:
Grid Operation/Market Design</td></tr>
<tr><td colspan="2">Objective & Scope:
The project will demonstrate the electric utility role within a Smart City initiative. The demonstration has the following objectives: Increasing coordination between electric system and urban planning, coordinating infrastructure construction activities within a city, streamlining the interconnection process through automated systems between SCE and the city, partnering with cities to engage more customers in renewable resources (e.g. Community Solar PV, Community Storage) and creating more opportunities for electric transportation, working with cities to customize their resource portfolio to meet a Climate Action Plan goal (e.g. “Community Choice Aggregation Lite” or Community Choice Aggregation), leveraging assets (e.g. Telecommunications, Right of Ways), coordinating communication on energy programs (e.g. Energy Efficiency, Demand Response, Charge Ready, Green Rate), and assisting large customers (i.e. the City as an energy customer) in more efficiently utilizing their energy resources and improving resiliency for critical operations center (e.g. emergency command centers).</td></tr>
<tr><td colspan="2">Deliverables:
a. Create criteria and a memorandum of understanding (MOU) for use in potential Smart City partner and site selection (with the city and/or local agency(s)).

b. Final report that documents:
Steady-state network studies and reports, which include load flow, protection coordination and identification of potential updates / upgrades
Technical specifications (IEEE 2030.5 and smart inverter requirements, architecture, etc.)
Development of functional/non-functional requirements and use cases
Test plans to simulate variables in field operations
Integration and system test results in the lab and field
Lessons learned and recommendations for future projects
c. Create training materials and provide microgrid operation training to grid operations.

d. Deliver project findings / lessons learned in conference presentation(s).</td></tr>
</table>

Metrics: 1a. Number and total nameplate capacity of distributed generation facilities 1b. Total electricity deliveries from grid-connected distributed generation facilities 1d. Number and percentage of customers on time variant or dynamic pricing tariffs 1i. Nameplate capacity (MW) of grid-connected energy storage 3e. Non-energy economic benefits 3h. Energy Security (reduced energy and energy-related material imports) 5a. Outage number, frequency, and duration reductions 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 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) 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) 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) 8b. Number of reports and fact sheets published online 8d. Number of information sharing forums held 8e. Stakeholders attendance at workshops 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	
Schedule: Q3 2019 – Q2 2024	
EPIC Funds Encumbered: $1,306,202	**EPIC Funds Spent:** $780,378
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: During 2021, the team accomplished the following: • Initiated procurement for the microgrid controller, which is currently under negotiation. • Began actively performing microgrid technical consultation work with support from the local agency and vendors. • Launched detailed engineering design work, which is underway with the vendor. Identified the field site is identified and began negotiating the customer agreement covering the microgrid system (this remains in progress.)		

6. Next Generation Distribution Automation III

Investment Plan Period: 3rd Triennial Plan (2018-2020)	**Assignment to value Chain:** Distribution
Objective & Scope: This project will leverage lessons learned from the Next Generation Distribution Automation II project. It will integrate new FAN wireless radio to automation devices and continue to improve control functionalities. It will provide greater situational awareness to allow system operators to manage the grid with higher DER penetration and be ready to support Distribution System Operators (DSOs). It will integrate 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. This project will demonstrate technologies that are applicable for both overhead and underground distribution circuits. This project is composed of the following sub-projects: 1) Duct Bank Monitoring will demonstrate the capability to use an accurate duct bank temperature modeling tool and/or scalable real-time monitoring system. This system would allow for the avoidance of excessive duct bank temperature due to circuit overloading which could lead to premature, catastrophic cable failure. Monitoring of the system could provide better situational awareness to proactively manage circuit loading. 2) IEC 61850 to the Edge aims to explore improvements upon legacy DNP communications for DA by testing and assessing a standardized communication	

protocol using IEC 61850 to manage field DA devices for passive activities including commissioning, updates, retirement, and cybersecurity patches. The intent is for the results of the testing in this EPIC project to enable uniform, accelerated configuration and enhanced cybersecurity, extending the protocol used by Substation Automation (SA) to the distribution grid. 3) Standard for GMS Field Connected Devices will provide a lab-only demonstration of next generation DA controller devices, capable of using the DNP v3 SAV5 secure protocol, to communicate with a lab sandbox Field Device Management Platform (FDMP). The intent of the lab test system is to validate the ability of the next generation DA controller devices to send/receive messages required by the SCE DA device management platform.
Deliverables: • Design and Test Plans • Modeling Requirements • Benefits Modeling Tool • Duct Bank System Ready for Demonstrations • System Requirements • Lab Test Results • GMS Capabilities Recommendations • Final Report
Metrics: 2a. Hours worked in California and money spent in California for each project 3a. Maintain / Reduce operations and maintenance costs 3e. Non-energy economic benefits 5i. Increase in the number of nodes in the power system at monitoring points 6a. Increased worker efficiency to setup, maintain and configure field assets 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) 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 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 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 2020 – Q4 2024

EPIC Funds Encumbered: $0		EPIC Funds Spent: $386,178
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:

Duct Bank Monitoring

The Duct Bank Monitoring project was intended to demonstrate the feasibility of utilizing a dynamic modeling tool and real-time temperature monitoring system to improve the ability to manage loading of circuits and better predict the temperature of distribution cables. This could improve upon existing static cable limits used today.

In the early stages of this project, it was assumed that some environmental characteristics involving underground ducts could be accurately recorded. Upon further analysis, it became apparent that data accuracy was not achievable based on the physical conditions of the underground duct bank and the dynamics of the surrounding soils. These variables led to the conclusion that data accuracy concerns limit their ability to improve cable loading calculations. These uncertainties and the complexity of the underground getaway cable configurations made this project's objectives difficult to meet.

SCE also realized that monitoring cable temperatures within a semi-open cable trench area could not accurately represent similar cable temperatures within an underground conduit. Ambient air temperatures within the underground conduit structures do not immediately escape into air like the air within the cable trench. This ambient heated air within the conduit exposes the cables to additional heating that could increase the actual cable temperatures compared to readings at the cable trench. Again, cable air temperature accuracy is an important variable to cable loading models and could lead to false estimations of underground cable loading and temperatures.

This project led to many positive discoveries. First, this project helped SCE determine that monitoring distribution circuit getaway cables should consider following a practice of using a Duct Bank Temperature Monitoring System similar to what is being used for SCE's 500 KV underground system. In fact, SCE's 500KV DTS system is monitoring an important underground cable segment delivering renewable energy into Southern California. A fiber optic based DTS has been proven in industries to be reliable and accurate for monitoring cables in real time.

For the reasons stated above, SCE will close out the Duct Bank Monitoring workstream, of NGDA III and will report findings in the NGDA III Final Report when the entire project is concluded. **IEC 61850 to the Edge** Initiated development of project requirements and released RFI for Intelligent Field Devices to identify market availability and roadmaps for devices capable of communicating via 61850 protocol. Reviewed IEC 61850 configuration tool software from several vendors and down selected three for further demonstration. **Standard for GMS Connected Field Devices** Initiated development of project requirements and released RFI for Intelligent Field Devices to gather intel on features, specifications, and market availability/roadmaps for devices with SAv5 compatibility.

7. SA-3 Phase III Field Demonstrations

Investment Plan Period: 3rd Triennial Plan (2018-2020)	**Assignment to value Chain:** Transmission
Objective & Scope: The objective of this project is to successfully demonstrate a modern substation automation system for use in transmission substations by adopting scalable technology that enables advanced functionality to meet NERC CIP compliance and IT cybersecurity requirements. This project is to provide measurable engineering, operations, and maintenance benefits through improved cybersecurity and reliability for transmission substations. It will also provide interoperability and allow the system to work with relays from multiple vendors, prevent vendor lock-in due to proprietary software and hardware, and assure that SCE has the flexibility to implement the best solution available.	
Deliverables: • Converting a substation feeding two circuits totaling less than thirty miles of length to resonant grounding. • Modeling fault currents to ensure the candidate substation will be able to meet the ignition thresholds with resonant grounding • Addition of an arc suppression coil to the substation, a protection system which is capable of detecting which circuit the fault is on, and replacement of any equipment not rated for the over-voltages such systems experience. • At the conclusion of a high fire season the lessons learned will be published to share the feasibility and applicability of this approach to fire mitigation • All design documents (business requirements, system requirements, test plans, test reports, use cases, etc.) • IEC 61850 PAC capable of controlling other 61850 IEDs for automated load restoration	

- Data driven auto configuration program/method for device
- Complete comprehensive Evaluation and Testing Reports
- Provide lessons learned to evaluate future projects

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
6a. Avoiding technology obsolescence
7a. Description of the issues, project(s), and the results or outcomes

Schedule:
Q4 2019 – Q4 2024

EPIC Funds Encumbered:	**EPIC Funds Spent:**
$10,597	$2,543,766

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:

IEC 61850 Programmable Automation Controller (PAC)
This project has successfully completed and met all the 2021 project milestones, including laboratory testing, all cyber and IT tests, documentation, and a demonstration to stakeholder groups.

- Project team completed IEC61850 PAC client configuration and implemented documentation on system design – including detailed information on best practices for expanding the configuration for future implementation of new IEC61850 IEDs.
- Initial configuration for IEC61850 PAC server configuration was completed. The server configuration involved creation of a unique server model specific to SCE's standard PLC design.
- Project team evaluated advanced cybersecurity features available for some IEDs when used in a fully IEC61850 system. The project team created documentation on the setup of the cybersecurity features and best practices.
- Completed major Cyber/IT tasks, including vulnerability scans, hardware and software analysis, and integration testing against in-scope services, equipment, and technologies associated with the GT-19-0048 61850 Capable PAC Demo project.

- Participated in GTI Showcase meetings to share general project capabilities, relatable project updates, and feedback to other EPIC project leads and stakeholders.

Key Findings and Lessons Learned

- Methods required to retrieve data from IEC61850 IEDs may vary by vendor. Additional logic was implemented in the PAC to account for these differences and to ensure that the PAC was able to obtain data from all devices.
- The project team determined the following items from testing and troubleshooting in the lab environment: (1) software tools such as Wireshark and IED Scout were critical for identifying issues with communications and were useful for simulating controls; (2) IED CID files must be managed, there should be one repository for generated files, and CID files downloaded to an IED must match the CID file used in the PAC configuration.
- The project team was required to quickly adapt to remote working and remote testing. This was accomplished through virtual meetings, screen sharing, and recording via Teams.

Resonant Grounding with an arc suppression coil (ASC)

In 2021 SCE began working on a Resonant Grounding with an arc suppression coil (ASC) demonstration to support advancements in grid infrastructure design and to implement new approaches and strategies to improve the SCE system's overall resilience to wildfire threats. The primary benefit of resonant grounded systems is the reduction in phase-to-ground fault current. In resonant grounded systems the fault current will be no more than 100 amperes on any SCE system an ASC could be installed on and would be under 10 amperes in most distribution systems. The bulk of the evaluation will be done on the equipment installed at Arrowhead substation, but the relays will be installed in the lab for purposes of familiarization with their functions and RTDS testing.

The project completed construction in December 2021.

- Installed high voltage equipment including an Arc Suppression Coil and high accuracy metering.
- Installed low voltage equipment including an arc suppression coil controller and digital fault recorder.
- Developed training for the project and trained SCE internal groups on how the equipment impacts them.
- Published a paper with GE at the Western Protective Relay Conference on parts of the project, "A Proposed Scheme to Protect Transformer Bank and Arc Suppression Coil in Compensated-Grounded Distribution Systems"

Virtual Substation Relays

The team released and RFI to vendors on Virtual Substation Relays. The vendor responses were received and reviewed, and then down-selected to a list of potential vendors to be

included in the RFP in Q1 of 2022. The team is developing requirements based, in part, on the RFI responses.

8. Distributed Cyber Threat Analysis Collaboration

Investment Plan Period: 3rd Triennial Plan (2018-2020)	**Assignment to value Chain:** Grid Operation/Market Design	
Objective & Scope: This project will demonstrate the ability to standardize utility cybersecurity threat analysis by developing a Distributed Cyber Threat Analysis Collaboration framework to conduct local utility collaboration with utility peers and sharing with National analysis centers to support expedient cyber threat feed analysis. This framework will demonstrate the capability to effectively consume internal and external sourcing threat feeds, process them for legitimacy, and identify utility risk impact, and potential response measures through collaboration with utility peers and National analysis centers to validate and verify threats as well as significantly shorten the time needed to respond to a cyber compromise of the electric grid.		
Deliverables: 1. Virtual Demonstration Lab Environment 2. Monthly progress reports for demonstration areas 3. Area of concentration demonstration reports (Quarterly) 4. Final use case demonstration guide 5. Final report		
Metrics: 1. Mean duration of vulnerability response: Shorten the duration from reported grid vulnerability to executing a response or plan. 2. Mean duration of intelligence sharing: Shorten the time from receiving threat intelligence, to sharing with internal affected business units and external vetted partners 3. Mean duration of cybersecurity defense response: Shorten the time between recognition, sharing, and executing a response to a cybersecurity threat on SCE's grid systems or technologies		
Schedule: Q2 2019 – Q1 2022		
EPIC Funds Encumbered: $231,405	**EPIC Funds Spent:** $1,441,512	
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: See Final Project Report in the Appendix for 2021 achievements.

9. Energy System Cybersecurity Posturing (ESCP)

Investment Plan Period: 3rd Triennial Plan (2018-2020)	**Assignment to value Chain:** Grid Operation/Market Design	
Objective & Scope: This project demonstration will automate the ability to probe the Utility's supervisory control and data acquisition system (SCADA), using an automated probing capability which will enable the system to report back on how it is configured. The ESCP project will engineer toolset to demonstrate the capability to execute an automated system posture where cybersecurity and regulatory related system attributes will be collected and analyzed via a toolset. It will then demonstrate enhanced network communications situational awareness through a Software Defined Networking (SDN) interface with the capability to support cross cutting operations and cybersecurity analysis.		
Deliverables: N/A		
Metrics: N/A		
Schedule: N/A		
EPIC Funds Encumbered: $0	**EPIC Funds Spent:** $13,034	
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: During project planning in 2019, the team learned that additional research would be required to complete this project. This research is not currently available, nor allowable for the Utilities to conduct under current EPIC requirements. SCE canceled this EPIC project and is looking into alternative funding sources.		

10. Distribution Primary & Secondary Line Impedance

<table>
<tr><td colspan="2">Investment Plan Period:
3rd Triennial Plan (2018-2020)</td><td colspan="2">Assignment to value Chain:
Distribution</td></tr>
<tr><td colspan="4">Objective & Scope:
This project will examine the possibility of establishing primary and secondary line impedance information for distribution circuits by examining the voltage and power signatures at the meter and transformer levels, leveraging a basic connectivity model of the circuits, and utilizing SCADA data. The availability of complete primary line impedance information can result in accurate load flow / distribution state estimation results, greater real-time management of the distribution grid, and greater utilization of capacity within the existing installed infrastructure before requiring new assets.</td></tr>
<tr><td colspan="4">Deliverables:
The project will provide the following functions in terms of priority:
1. Distribution Network Phasing Validation and Correction Algorithm
2. Meter to Transformer Connectivity Validation and Correction Algorithm
3. Impedance Parameter Validation and Correction Algorithm
4. Data Model for Distribution Network Secondaries</td></tr>
<tr><td colspan="4">Metrics:
3c. Reduction in electrical losses in the transmission and distribution system
3e. Non-energy economic benefits – this project, if successful, will allow SCE to plan and operate the grid</td></tr>
<tr><td colspan="4">Schedule:
TBD</td></tr>
<tr><td colspan="2">EPIC Funds Encumbered:
$0</td><td colspan="2">EPIC Funds Spent:
$68,140</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:
Due to budget constraints SCE put this project on hold in 2020.</td></tr>
</table>

11. Advanced Comprehensive Hazards Tool

<table>
<tr><td>Investment Plan Period:
3rd Triennial Plan (2018-2020)</td><td>Assignment to value Chain:
Grid Operation/Market Design</td></tr>
<tr><td colspan="2">Objective & Scope:
This project will demonstrate a new and innovative approach to integrate emerging and mature hazard assessment tools. This demonstration will use a centralized data architecture that integrates various types of SCE asset data from non-electric, generation, and grid infrastructure. The project aims to identify vulnerabilities across different types of infrastructure to understand the overall risk to the grid. The project will demonstrate hazard scenarios and the impacts of those scenarios to the SCE system.</td></tr>
<tr><td colspan="2">Deliverables:
The Project will develop and demonstrate a comprehensive natural hazard web application with multi-layer mapping capabilities that provide an integrated, holistic view of hazards in the service territory (e.g., earthquake, flood, fire, and extreme weather events)

The application will have the ability to conduct risk analysis that allows for asset data to be referenced with hazard exposure and probability of failure or consequence (fragility) to arrive at risk profiles for assets

It will integrate:
Various types of asset data from non-electric, generation, and grid infrastructure sources, to provide decision-support on hazard impact and mitigation options before, during, and after a significant event (e.g., extreme weather events, wildfires, and earthquakes, etc.).
Hazard risk assessment / severity index capabilities allowing a comprehensive assessment of vulnerability and exposure across the service territory.
A Final Report will be created detailing lessons learned, areas for maturity, potential synergies, with other internal or external efforts

Project Kickoff presentation for CPUC (webinar or workshop) (EPIC Requirement)

Present project at least one technical conference (ETV requirement)</td></tr>
<tr><td colspan="2">Metrics:
5a. Outage number, frequency, and duration reductions
5d. Public safety improvement and hazard exposure reduction
5e. Utility worker safety improvement and hazard exposure reduction
8d. Number of information sharing forums held</td></tr>
<tr><td colspan="2">Schedule: Q4 2019 – Q2 2022</td></tr>
</table>

EPIC Funds Encumbered: $0	**EPIC Funds Spent:** $281,328	
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 team's initial attempt to onboard the Seismic Earthquake Risk Assessment (SERA) developer was unsuccessful due to an inability to agree on terms and conditions. This resulted in prolonged negotiations and overall project schedule delay. The vendor selection and onboarding through a Request for Proposal (RFP) is near completion, and is pending SCE's vendor cybersecurity risk assessment. The agreed upon scope of work will include establishment of electric utility component database of fragilities (based on known fragilities), FEMA P-5, Global Earthquake Model (GEM), and Hazus fragility functions. The Seismic hazard module will use probabilistic and deterministic approaches based on OpenSHA engine and USGS ShakeMap API. The climate hazard module for extreme wind, precipitation, temperature, sea-level rise, and flood hazard events will use SCE's climate models and CAL-ADAPT climate projections.		

12. Vehicle-to-Grid Integration Using On-Board Inverter

Investment Plan Period: 3rd Triennial Plan (2018-2020)	**Assignment to value Chain:** Distribution
Objective & Scope: The project will assess and evaluate new interconnection requirements, Vehicle-to-Grid ("V2G") related technologies and standards, and utility and third-party controls to demonstrate how V2G direct current (V2G-DC) and V2G alternating current (V2G-AC) capable EVs and EV chargers can discharge to the grid and be used to support charging during grid outages. The project will assess and evaluate, in a laboratory environment, the proposed V2G-AC Rule 21 interconnection processes, proposed SAE and UL standards, and the function of automaker OEM battery/inverter systems to support vehicle-grid integration (VGI) services, integration of project 3rd party aggregators with SCE's Grid Management System (GMS)/DER Management System (DERMS), and partner with an existing Rialto Unified School District DOE V2G school bus project (and its Charge Ready Transport application) to	

provide an interconnection pathway by demonstrating functional requirements in the lab; and the field evaluation of deployed systems.
Deliverables: • An evaluation and demonstration plan of bidirectional on-board inverters based on Rule 21 proposed updates, automaker input, SAE, and UL • Report on lab testing of vehicle V2G systems with EVSE infrastructure, with automakers, NREL on V2G implementation • Field implementation and demonstration with Blue Bird school bus, Rialto USD site • Demonstrated technical solution for integration into SCE's Grid Management System and Grid Interconnection Planning Tool (GIPT), which may support interconnection and utilization for grid support purposes such as voltage and frequency management or the integration of other renewable resources • Final report, including above and draft input for new standards updates, Rule 21, SAE, UL, IEEE • Technical presentations: at least one technical conference
Metrics: 1a. Number and total nameplate capacity of distributed generation facilities 1b. Total electricity deliveries from grid-connected distributed generation facilities 1e. Peak load reduction (MW) from summer and winter programs 1h. Customer bill savings (dollars saved) 1i. Nameplate capacity (MW) of grid-connected energy storage 3e. Non-energy economic benefits 3f. Improvements in system operation efficiencies stemming from increased utility dispatchability of customer demand side management 3h. Energy Security (reduced energy and energy-related material imports) 5d. Public safety improvement and hazard exposure reduction 5e. Utility worker safety improvement and hazard exposure reduction 5f. Reduced flicker and other power quality differences 5i. Increase in the number of nodes in the power system at monitoring points 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) 7d. Deployment and integration of cost-effective distributed resources and generation, including renewable resources (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 8e. Stakeholders attendance at workshops 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)		
Schedule: Q3 2019 – Q3 2024		
EPIC Funds Encumbered: $465,196	**EPIC Funds Spent:** $694,156	
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 following is a summary of the key activities performed in 2021: • Updated the Project's Concept of Operation document describing proposed system and components, data flow and interfaces, modes of operation, assumptions and constraints, and high-level business use cases and business requirements. • Updated Project's Detailed Use Case and Requirements document illustrating scope, actors, assumptions, use cases, step by step analysis, and alternative scenarios • Completed Lab design network system • Completed Lab Architecture Briefs (LAB) • Completed CDA with Honda • Completed Nuvve terms and conditions • Completed Kitu SaaS Agreement and SOW		

- Completed Cyber vendor assessments
- Consulted in the Rule 21 OIR process to evolve and understand V2G interconnection requirements
- Participated in SAE J3072 to advance to ballot the updated standard based on Rule 21 developments.
- Consulted with internal regulatory and interconnection process personnel on V2G applications.
- Participated in the new Committee UL 1741 SC for V2G-AC EVSEs supporting SAE J3072 and IEEE 1547
- Participated in the new SunSpec IEEE 2030.5 Profile for SAE J3072 AC EVSE working group
- Completed Cybersecurity Aggregator requirements
- Completed V2G-AC EVSE specification supporting SAE J3072, UL 1741 SC and IEEE 2030.5/CSIP as well as V2H capabilities
- Completed SCE DERMS IEEE 2030.5 Aggregator Requirements to be used for V2G Aggregator demonstrations
- Supported SCE's DERMS IEEE 2030.5 GW design and development
- Led a monthly V2G Technology Advisory Board to share learnings, support the advancement of V2G deployments, and discuss current issues pathways to resolve them
- Consulted with Charge Ready program on prospective V2G applications and coordinated technology advancement through EPIC project
- Coordinated on Interconnection Wholesale and Retail Tariffs
    - Consulted with one set of partners to establish one V2G certified DC charger capable of Rule 21 interconnection to move forward in the project.
    - There are still no EVSE or DC chargers that are configured to support our DERMS communication protocols.
    - The team learned that the electric transit bus prospective V2G partner was not ready to perform V2G, despite public pronouncements.
    - A readily available combined charging & storage platform (incorporating 2nd life batteries) that will allow demonstration of the Project’s Use Cases was not identified in the current marketplace.

13. Distributed Plug-In Electric Vehicle Charging Resources

<table>
<tr><td>Investment Plan Period:
3rd Triennial Plan (2018-2020)</td><td>Assignment to value Chain:
Distribution</td></tr>
<tr><td colspan="2">Objective & Scope:
This project will demonstrate PEV fast charging stations with integrated energy storage that can be used to control the grid system impact of fast charging, allow more of them to be accommodated for a particular cost, and also to respond to grid needs as distributed energy resources when not charging a vehicle. Fast charging units currently demand 25 to 125 kW, and the load cannot be planned or scheduled. This demand is expected to climb to 350 kW or more as advertised by vehicle and charging system suppliers. This intermittent and unpredictable high demand could concern utility planning and could also challenge high deployment of such systems due to their low load factor and potentially alarming bill impact to customers under current tariffs. Combining fast charging systems with energy storage can result in higher load factor, while still providing satisfactory service to customers. The size of such storage systems, along with power components, will determine their effectiveness in a particular duty cycle. This is demonstrated in the demands on the system from customers in the real world, which this project will show; the demands on such energy storage systems may be met by the capabilities of used batteries. These measures increase the likelihood of higher numbers of such stations becoming operational. Integrated energy storage provides reliability in the case of grid events – transient or otherwise – and improves charging service in the evolving modern system of increased renewable and distributed generation. This project will demonstrate the reliability improvement of such systems subject to grid events.</td></tr>
<tr><td colspan="2">Deliverables:

Deliver a Project that includes or addresses:

Sizing of energy storage systems for fast charge and grid asset applications.
Specifying storage parameters for second use batteries.
Using Energy Storage to perform peak shaving in conjunction with fast charging.

Increasing Customer adoption & reducing costs
Reduce risk of oversizing of distribution system
Increase the use of clean renewable energy resources

Respond to Grid Events while minimizing customer impact.
Provide distribution circuit V/VAR control support
Enable/encourage fast charging in remote locations e.g., CA State Parks.

Procure, test, evaluate, and demonstrate, or partner with OEMS to model & evaluate, fast charging systems coupled with energy storage systems that will:

Reduce system impact of high-power charging while reducing customer cost.
Allow Fast EV charging systems which can support increased participation in DR Programs.
Integrate energy storage systems using new or used batteries, with proper communications and controls, so it can be used by a distribution system operator or aggregator as a Distributed Energy Resource (DER).

</td></tr>
</table>

o Use of Charger intelligence to support DR and/or DER capability while minimizing impact to customer and other load management capabilities. o Evaluate uses of ancillary services to charge or discharge instantly to provide frequency regulation, voltage control, and reserve energy that can be used by the grid to help integrate renewable power. • For knowledge transfer, provide a Final Report to the internal/external stakeholder audience that summarizes results and lessons learned. • Develop materials and provide the necessary training to internal/external stakeholders • Technical presentations: at least one technical conference
Metrics: 1a. Number and total nameplate capacity of distributed generation facilities 1b. Total electricity deliveries from grid-connected distributed generation facilities 1e. Peak load reduction (MW) from summer and winter programs 3e. Non-energy economic benefits 3f. Improvements in system operation efficiencies stemming from increased utility dispatchability of customer demand side management 3h. Energy Security (reduced energy and energy-related material imports) 5f. Reduced flicker and other power quality differences 5i. Increase in the number of nodes in the power system at monitoring points 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) 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) 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) 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 8e. Stakeholders attendance at workshops 8f. Technology transfer
Schedule: Q3 2019 – Q1 2023

EPIC Funds Encumbered:	**EPIC Funds Spent:**
$276,274	$380,881

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 project team spent the year trying to identify and collaborate with a partner with which SCE could utilize a trial-use agreement to employ fast-charging equipment with a system that incorporates an Energy Storage System. After searching and communicating with several companies, the project team was unable to find fast charger vendor that was willing to meet all the use cases we envisioned for the system. Therefore, we decided to switch focus and develop an in-house system to demonstrate the project objectives and use in-house and contract resources to develop the integration and control system. The partnership with an OEM experienced a setback as the company is diverting its efforts from second life batteries to recycling. However, they have discussed offering SCE ownership of one of their existing projects, which would save money on equipment. SCE has a partnership with the Ohio State University (OSU) to evaluate the Edison system for the applicability of using Second-life batteries for grid regulation. SCE and OSU have signed a NDA so we can share data that they can use to evaluate the SCE system. The project has initiated a conversation with a vendor to buy a fast charger to integrate with existing energy storage at the Pomona EVTC Microgrid Test Pad to demonstrate the use cases. The vendor is currently being onboarded and the equipment is expected to be procured in the Q1 of 2022. <u>Key Findings and Lessons Learned</u> Second life batteries are still not available in the quantities needed for this project. Some manufacturers are offering integrated energy storage with fast charging, but these systems are larger than our use cases that SCE could use as a demonstration.		

14. Service and Distribution Centers of the Future

Investment Plan Period: 3rd Triennial Plan (2018-2020)	**Assignment to value Chain:** Distribution
Objective & Scope: The project's objective will be to evaluate the ability to fully electrify a fleet service center with building electrification technologies (e.g., space and water heating), EVSEs and employee charging while managing any associated impacts to the local grid system. The	

results could inform future efforts to electrify other service centers, while also supporting commercial customer electric vehicle loads.

This project will demonstrate an advanced SCE service center housing electrified utility crew trucks, together with employee workplace charging, connected to a local service area with high penetration of distributed solar generation and plug-in electric vehicles. The electrification of transportation at the service center will be conducted in a way that not only does not adversely impact the local system, but also interacts with the system using vehicle-grid integration (VGI) technology to ensure reliable and stable service for both the service center and local area. This project will deploy electrified utility trucks and utility and workplace EVSE with advanced VGI communications and controls to receive and respond to both DR (direct) and SCE grid (dynamic) signals to both ensure reliable charging and to support the local grid's stability. The vehicle systems, when not driving, can be used as grid assets and respond directly to support system voltage and stabilize demand. This two-front approach leverages the operating characteristics of both fleet trucks (charge at night) and employee vehicles (charge in the morning).

Deliverables:

- A fleet center or depot within a disadvantaged community that will support:
    - High power, high energy EV charging infrastructure to support light to heavy-duty vehicles
    - Electrified facilities on site
    - Site control system to support V1G and V2G, control of electric space and water heating, cooling, and energy elements such as storage and PV, to manage safety, reliability, and cost
    - Data and control connection to SCE grid management system
- Demonstrated technical solution for integration into SCE's Grid Management System and Grid Interconnection Planning Tool (GIPT), which may support interconnection and utilization for grid support purposes such as voltage and frequency management or the integration of other renewable resources
- Final report showing results and providing recommendations to enable further deployment of such facilities
- Technical presentation: at least one technical conference

Metrics:

1a. Number and total nameplate capacity of distributed generation facilities
1b. Total electricity deliveries from grid-connected distributed generation facilities
1e. Peak load reduction (MW) from summer and winter programs
1f. Avoided customer energy use (kWh saved)
1h. Customer bill savings (dollars saved)
1i. Nameplate capacity (MW) of grid-connected energy storage
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 5d. Public safety improvement and hazard exposure reduction 5e. Utility worker safety improvement and hazard exposure reduction 5f. Reduced flicker and other power quality differences 5i. Increase in the number of nodes in the power system at monitoring points 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) 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 8e. Stakeholders attendance at workshops 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 9c. EPIC project results referenced in regulatory proceedings and policy reports	
Schedule: Q3 2019 – Q3 2024	
EPIC Funds Encumbered: $760,214	**EPIC Funds Spent:** $643,209

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 2021, the team began negotiations with the Microgrid Control System (MCS) vendor. These negotiations remain underway as of year-end. The team also worked on the conceptual design for the microgrid integration with battery storage and building electrification. This work also remains underway. The team also completed site walks and analysis of electric bus EVSE and charge management platform.		

15. Control and Protection for Microgrids and Virtual Power Plants

Investment Plan Period: 3rd Triennial Plan (2018-2020)	**Assignment to value Chain:** Grid Operation/Market Design
Objective & Scope: This project will examine control and protection schemes for safe and reliable operation of distribution systems with customer owned nested microgrids (MGs) and virtual power plants (VPPs). Standardized control and protection schemes and streamlined operation practices will be designed to support the integrity of the grid and to facilitate grid operation in the context of high penetration of renewable resources and highly variable loads.	

Deliverables:
• Network studies and reports, which include load flow and protection evaluation and assessment of a candidate Microgrid project(s).
• Design and implement a Lab based Microgrid Test bed.
• Using the Test bed, provide a Final Report documenting the candidate Microgrid, which will include:
  o Microgrid Control Design, prototypes, and simulations
  o Microgrid design variations, stating advantages, disadvantages, along with some optional basic cost analysis
  o Equipment requirements.
• Create and document the Use Case scenarios, with Microgrid functional and nonfunctional Requirements. Microgrid Cybersecurity protection will be included.
• Create and document the Test plan, which will include lab tests, software and hardware testing, end-to-end testing, and field evaluation leveraging other EPIC III Microgrid Project testing. A final test report with the results will be provided	

- The QA & Field Demonstration learnings will be leveraged from the EPIC III Smart City Demonstration (GT-18-0005) Project's Front of the Meter Microgrid work.

- Provide Microgrid internal and external customers Commissioning technical support
- Provide technical Microgrid Customer and Internal Stakeholder (Grid Operations) Training support.
- Create and provide a standardized Microgrid Control design procedure to SCE internal stakeholders.
- For knowledge transfer, provide a Final Report to the internal/external stakeholder audience that summarizes results and lessons learned.
- Project Kickoff presentation for CPUC (webinar or workshop)
- At least one technical conference presentation about project

Metrics:
1a. Number and total nameplate capacity of distributed generation facilities
1b. Total electricity deliveries from grid-connected distributed generation facilities
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)
1h. Customer bill savings (dollars saved)
3e. Non-energy economic benefits
3f. Improvements in system operation efficiencies stemming from increased utility dispatchability of customer demand side management
3h. Energy Security (reduced energy and energy-related material imports)
5a. Outage number, frequency and duration reduced. Public safety improvement and hazard exposure reduction
5e. Utility worker safety improvement and hazard exposure reduction
5f. Reduced flicker and other power quality differences
5i. Increase in the number of nodes in the power system at monitoring points
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)
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)
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 8e. Stakeholders attendance at workshops 8f. Technology transfer

Schedule: Q3 2019 – Q1 2023	
EPIC Funds Encumbered: $669,427	**EPIC Funds Spent:** $696,841
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 2021, the team initiated negotiations with a vendor to procure the microgrid control system to support design and testing. These negotiations remain in-process as of year-end. The team also began preparing the design of the lab testbed, which also remains underway as of year-end.

16. Distributed Energy Resources (DER) Dynamics Integration Demonstration

Investment Plan Period: 3rd Triennial Plan (2018-2020)	**Assignment to value Chain:** Distribution
Objective & Scope: This project aims to evaluate the two key technical challenges related to high DER penetration—protection system impacts and adverse interactions between multiple types of DERs. The project will be comprised of both hardware and software components: solar PV inverters, a lab testbed, and computer models of inverters, synchronous and induction generators, protective relay and one SCE sample feeder.	

Test smart inverter functional capabilities on SCE distribution feeder with high DER penetration levels, it will be able to establish DER Operating Standards and leverage Smart Inverters for System-wide reliability. Develop interoperable controls capability at SCE to provide flexibility to the operation of the grid.
Deliverables: • PSCAD (Power Systems Computer Aided Design) models (e.g., PV model, single-phase legacy inverter average model, single-phase smart inverter average model, anti-islanding protection algorithm model, SCE's Pronghorn feeder model, etc.). • CA Power Hardware-in-the-Loop (PHIL) testbed for laboratory demonstrations.
Metrics: 1. Description of issues resolved that prevented widespread deployment of technology or strategy and the results or outcomes 2. Effectiveness of information dissemination by the number of reports and fact sheets published online 3. Effectiveness of information dissemination by the number of times reports are cited in scientific journals and trade publications for selected projects
Schedule: Q4 2019 – Q4 2022

EPIC Funds Encumbered:	**EPIC Funds Spent:**
$527,421	$635,799

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 team performed the following key activities in 2021: • Completed numerous models using the PSCAD (Power Systems Computer Aided Design) simulation modeling tool and the CAPE simulation platform (e.g., PV model, single-phase legacy inverter average model, single-phase smart inverter average model, anti-islanding protection algorithm model, SCE's Pronghorn feeder model, etc.). • Started system simulation and corresponding studies. • Completed design of the Power Hardware-in-the-Loop (PHIL) testbed for laboratory demonstration.

- Completed testing and confirmed the functionality of grid simulator, PV simulator, two smart inverters, two legacy inverters, relay, and the relay tester F6150SV equipment.
- Started RTDS (Real-Time Digital Simulator) testing for testbed functional verification for use case demonstration.
- Communicated project objective and deliverables to PG&E, SDG&E, & Rule 21 working group and added as external stakeholders in the project.
- Completed PSCAD and CAPE simulation for PV, smart inverter, legacy inverter, induction generator, synchronous generator, anti-islanding algorithm and Prong Horn feeder.
- Presented as an Industry Speaker in the APEC 2021 conference based on the work of the project. Md Arifujjaman, "Smart Inverter Experiences in Southern California Edison (SCE)," Next Gen Power Electronics: Requirement and Solutions, Applied Power Electronics Conference (APEC), Virtual, June 9 – 17, 2021.

Key Findings and Lessons Learned:

The overall project simulation model using the average model of the smart and legacy inverter can reflect the inverter characteristics. However, when the switching models replace the average models, the simulation time extends over a couple of hours to simulate only one scenario.

The PSCAD simulation platform is capable of adding the internal dynamics of the models, while CAPE simulation is incapable of reflecting the same dynamics; thus, the distribution system modeling should consider modeling system in the PSCAD platform.

17. Power System Voltage and VAR Control Under High Renewables Penetration

Investment Plan Period: 3rd Triennial Plan (2018-2020)	**Assignment to value Chain:** Grid Operation/Market Design
Objective & Scope: This project will demonstrate in a lab setting the effect of a voltage and VAR management and control algorithm that optimizes the operation of the power grid, for both the transmission and distribution systems, by regulating voltage and controlling VAR resources optimally while maintaining the secure operation of the power grid.	
Deliverables: TBD	

Metrics: 1i. Nameplate capacity (MW) of grid-connected energy storage 3a. Maintain / Reduce operations and maintenance costs 4a. GHG emissions reductions (MMTCO2e) 5a. Outage number, frequency, and duration reductions 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)
Schedule: Q4 2019 – Q4 2020 N/A as this project been cancelled.

EPIC Funds Encumbered: $0	**EPIC Funds Spent:** $185,199

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: During project planning, additional research would be required for completion, which is not currently available, nor allowable for the Utilities to conduct under current EPIC requirements. SCE cancelled this EPIC project in 2020 with the intent of looking into alternative funding sources outside of EPIC.

18. Beyond Lithium-ion Energy Storage Demonstration

Investment Plan Period: 3rd Triennial Plan (2018-2020)	**Assignment to value Chain:** Distribution

Objective & Scope: This project will demonstrate the next wave of next-generation, precommercial, “beyond lithium-ion” energy storage technologies that have a high probability of commercial viability but require real world field experience to reduce technology and adoption barriers on the path to commercialization. This project will focus on advanced energy storage technologies that are non-lithium ion based (e.g., advanced electrochemical batteries, flow batteries, thermal storage, etc.). This project will demonstrate non-lithium ion storage systems against a variety of traditional use cases (i.e., in accordance with the CPUC’s energy storage use cases outlined in D.13-10-040), and emerging use cases (e.g., regional/community resiliency, etc.). Lastly, this project will demonstrate a complete energy storage system, including the storage technology, power conditioning system(s), product/systems integration, and grid interconnection. The objectives of this project are

to identify technologies most likely to achieve commercial viability with the next 3-5 years, and opportunities to accelerate the commercialization process.

Deliverables: TBD		
Metrics: TBD		
Schedule: TBD		
EPIC Funds Encumbered: $0	**EPIC Funds Spent:** $24,662	
Partners: TBD		
Match Funding: TBD	**Match Funding split:** TBD	**Funding Mechanism:** TBD
Treatment of Intellectual Property: TBD		
Status Update: This project is in the Planning phase. Once a test article is obtained, the project team will prepare project articles to move the project into execution. The team executed a NDA in October 2021 with a potential vendor to discuss their flow battery technology, and the next step is to obtain test article. The team has also engaged another potential vendor who plans on conceptualizing their demo to SCE.		

19. Wildfire Prevention & Resiliency Technology Demonstration

Investment Plan Period: 3rd Triennial Plan (2018-2020)	**Assignment to value Chain:** Grid Operation/Market Design
Objective & Scope: This project will demonstrate the latest technology advancements in hardware-based solutions (e.g., field devices, sensors, protection devices, etc.) and software-based solutions (e.g., data analytics, climate and fuel regrowth models, etc.) in support of climate adaptation and wildfire prevention, detection, and mitigation at all voltage levels. While SCE has outlined a comprehensive strategy and specific programs to address the year-round wildfire threat via the 2018 Grid Safety & Resiliency Program (GS&RP) application, and 2019 Wildfire Mitigation Plan (WMP), those initiatives are focused on implementing commercial-ready technologies and strategies that are considered "shovel ready". This project is intended to focus on new or emerging wildfire prevention and resiliency-focused technologies that have a high probability of commercial viability but require more in-depth assessment and demonstration within the utility's operating	

environments in order to reduce technology and adoption barriers on the path to commercialization.

In the case of hardware-based technologies, SCE would like to demonstrate the next generation of distribution-level and transmission-level sensing, measurement, protection, and control technologies that are capable of detecting the presence of wildfires, or operational abnormalities that may trigger wildfire ignitions (e.g., broken conductors), with greater speed and accuracy then what is currently available today in the marketplace.

In the case of software-based technologies, SCE would like to demonstrate the latest advancements in data analytics, climate, weather, and fuel growth modeling, etc., in order to enhance and expand the situational awareness and operational practice capabilities that are being implemented today. In addition, software-based technologies that can leverage the new hardware-based tools and technologies and provide improved resiliency, ignition prevention, fuels management, decision-support, automated high-speed control actions, etc. are also contemplated for this project.

Deliverables: TBD

Metrics: TBD

Schedule:
TBD

EPIC Funds Encumbered:	**EPIC Funds Spent:**
$45,074	$91,141

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 team held an EPIC Public Outreach in October 2021.

Distribution Waveform Analytics (DWA)
The team completed the project's Concept of Operation document describing the proposed system and components, data flow and interfaces, modes of operation, assumptions and constraints, and high-level business use cases and business requirements for the evaluation of Distribution Waveform Analytics.

Machine Learning at the Edge
The team began drafting the Concept of Operations and will have similar content as described for DWA above.

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, 2021, SCE expended a total of $169,076 toward project costs and $0 toward administrative costs for a grand total of $169,076. SCE's cumulative expenses over the lifespan of its 2012 – 2014 EPIC program amount to $38,571,263. SCE committed $436,567 toward projects and encumbered $121,241 through executed purchase orders during this period. SCE has no uncommitted EPIC funding for this period. The costs incurred in 2021 include contract labor and expenses to securely relocate and install the SA-3 equipment (racks, relays, etc.) to its final location.

In 2020, SCE completed the final project that was in execution from its approved EPIC I Portfolio. SCE executed 16 projects, cancelled one project, and completed 15 projects. Three of these projects were completed during the calendar year 2015, four projects were completed in 2016, four projects were completed in 2017, two projects were completed in 2018, one project was completed in 2019, and one project was completed in 2020.

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

1. Enhanced Infrastructure Technology Evaluation;
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
14. Wide Area Reliability Management and Control
15. SA-3 Phase III Demonstration

The final project report is included in the Appendix of this annual report.

(2) <u>2015-2017 Investment Plan</u>

For the period between January 1 and December 31, 2021, SCE expended a total of $2,455,330 toward project costs and $55,951 toward administrative costs for a grand total of $2,511,281. SCE's cumulative expenses over the lifespan of its 2015 – 2017 EPIC program amount to $37,163,163. SCE committed $2,210,419 toward projects and encumbered $1,024,969 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. Of the remaining ten projects, one project was completed in 2017, three projects were completed in 2018, two projects were completed in 2019, one project was completed in 2020, and one project was completed in 2021. Two demonstrations remain in execution.

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. Versatile Plug-in Auxiliary Power System

6. Regulatory Mandates: Submetering Enablement Demonstration - Phase 2
7. Dynamic Power Conditioner
8. The Integrated Grid Project

(3) 2018-2020 Investment Plan

For the period between January 1 and December 31, 2021, SCE expended a total of $5,892,855 toward project costs and $931,796 toward administrative costs for a grand total of $6,824,651. SCE's cumulative expenses over the lifespan of its 2018 – 2020 EPIC program amount to $14,391,243. SCE committed $22,490,411 toward projects and encumbered $6,364,488 through executed purchase orders during this period. SCE has no uncommitted EPIC project funding for this period. SCE cancelled two projects and has begun executing 15 projects from its approved portfolio, and one has been completed. SCE's 2018 – 2020 EPIC III program is currently composed of the following 15 projects:

1. Advanced Comprehensive Hazards Tool
2. Advanced Technology for Field Safety (ATFS)
3. Beyond Lithium-ion Energy Storage Demo
4. Control and Protection for Microgrids and Virtual Power Plants
5. Cybersecurity for Industrial Control Systems
6. Distributed Cyber Threat Analysis Collaboration
7. Distributed Energy Resources Dynamics Integration Demonstration
8. Distributed PEV Charging Resource
9. Next Generation Distribution Automation III
10. SA-3 Phase III Field Demonstrations
11. Service Center of the Future
12. Smart City Demonstration
13. Storage-Based Distribution DC Link
14. Vehicle-to-Grid Integration Using On-Board Inverter
15. Wildfire Prevention & Resiliency Technology Demonstration

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

During the calendar year 2022, SCE looks forward to continuing its engagement with the Commission and stakeholders on planning its EPIC 4 Investment Plan Application, as well as finishing up the EPIC successor program rulemaking in Phase 2c. Additionally, SCE will continue to focus on successfully executing the remaining two approved projects as part of its 2015 – 2017 Investment Plan, as well as executing the remaining 16 projects from its 2018 – 2020 Investment Plan. Key program implementation activities will include finalizing requirement specifications, initiating new procurements, continuing technology deployments in SCE's field and lab environments, and executing rigorous testing, measurement, and verification processes.

Furthermore in 2021, SCE actively participated in the Policy Innovation + Coordination Group (PICG's) public workshop and helped to collaborate with the other Administrators and the PICG Coordinator to support developing a database of EPIC projects. SCE looks forward to continue working with the PICG Coordinator on the database and overall programmatic collaboration.

SCE will continue its open dialogue with stakeholders through public engagements in 2022. SCE will be convening workshops to help identify industry gaps and community resource needs. Furthermore, to help ensure all customers have a voice, SCE will be holding targeted disadvantaged communities workshops. In these public workshops, as well as the annual Symposium, SCE and the other EPIC Administrators will hold discussions with stakeholders and the Commission on areas of interest (e.g., long duration energy storage, wildfires, climate change, etc.), including key accomplishments and learnings obtained from the respective EPIC programs.

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

During the upcoming calendar year of 2022, SCE will focus on successfully executing its remaining approved projects as part of its EPIC II Investment Plan. Furthermore, SCE will continue executing its remaining 16 approved projects from its EPIC III Investment Plan. While the corona virus thus far has not materially impacted SCE's progress toward completing EPIC projects, SCE will continue monitoring for project delays, including production and supply chain delays.

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	(A) Encumbered Funding Amount ($)	(B) Committed Funding Amount ($)	(C) Funds Expended to date: Contract/Grant Amount ($)	(D) Funds Expended to date: In house expenditures ($)	(E=C+D) Funds Expended to date: Total Spent to date ($)	Administrative and overhead costs incurred	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.	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	2021 Update	Coordination with CPUC Proceedings or Legislation
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		$-	$15,679,991	$1,733,933	$17,413,924	$476,847	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.	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	N/A	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	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		$-	$1,307,752	$163,631	$1,471,383	$39,896	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.	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);	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		$0	$595,576	$249,362	$844,938	$58,610	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	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).	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	$ 76,905	$ 816,236	$ 19,972	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	N/A; Applicable to CEC only.	Power World Corporation: California-based entity Electric Power Group, LLC: Callifornia-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)	N/A	
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		$-	$7,207	$65,787	$72,994	$15,698	TBD	N/A	N/A	N/A	N/A	SCE has no current patents or licensing agreements signed. Future Intellectual Property is to be determined.	TBD	TBD	TBD	TBD	TBD	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.	N/A	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	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	$69,555	$468,600	$24,160	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	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)	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		$0	$3,175,540	$916,183	$4,091,723	$206,063	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.		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).	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	$-	$-	$985,986	$148,381	$1,134,367	$35,774	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.	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	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	$-	$-	$850,921	$220,110	$1,071,031	$67,337	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	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).	N/A	Distribution Resources Plan, R.14-08-013; A.15-07-003
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	$10,126	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	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).	N/A	
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	$2,266	N/A	SuperPower Inc.; SPX Transformer Solutions	N/A	N/A	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	N/A; Applicable to CEC only.	N/A; Project is cancelled.	N/A; Applicable to CEC only.	N/A; Project is cancelled	N/A	N/A - Cancelled.
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	$4,503	($4,503)	$599,625	$109,470	$709,095	$36,589	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	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	N/A	Not only does this monitoring system assist with stability with the changing generation resource mix to more renewable energy, but it assists with maintaining stability when large generation or load experiences sudden outages. The Commission's Climate Change Adaptation Rulemaking7 requires the Utilities to perform a climate vulnerability assessment for their service territories, which include mitigation options to those vulnerabilities. The applications learned from this EPIC demonstration can assist with understanding electric system vulnerability and possible mitigation to electric system stability issues during extreme climate events that result in large generation or load disruptions. In addition, with increased Public Safety Power Shutoff (PSPS) instances required to maintain public safety during potential wildfire conditions, the system will experience large instantaneous load reduction. Implementing learnings from this demonstration can assist with maintaining stability during wildfire conditions that prompt PSPS scenarios. Considering this project also helps maintain Transmission
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	$305,404	$1,018,549	$62,818	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	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.	N/A	

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	(A) Encumbered Funding Amount ($)	(B) Committed Funding Amount ($)	(C) Funds Expended to date: Contract/Grant Amount ($)	(D) Funds Expended to date: In house expenditures ($)	(E=C+D) Funds Expended to date: Total Spent to date ($)	Administrative and overhead costs incurred	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.	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	2021 Update	Coordination with CPUC Proceedings or Legislation
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	$116,738	$441,070	$5,143,737	$821,617	$5,965,354	$393,611	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	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).	The final project report was complete and submitted with the 2020 EPIC Annual Report. This project continued to incur costs associated with the final disposion of equipment and project closeout. Project closeout is now complete and now additional costs should accrue.	NA
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	$8,284	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): American Restore, Inc.; Rivcomm, Inc.; California Turbo Inc	N/A	N/A	N/A	N/A	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.	N/A	
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-OE0000675) 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	$-	$-	$1,703,953	$105,371	$1,809,324	$17,786	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	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.	N/A	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	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		$ -	$1,175,924	$17,911	$1,193,835	9064	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	1	Kitu, Inc	TBD	TBD	N/A; Applicable to CEC only.	Small Business	N/A; Applicable to CEC only.	Metrics plan TBD	N/A	
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	$167,651	$178,426	77718	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.	TBD	TBD	TBD	N/A - This technology is very new	There are almost no vendors offering technologies in this area	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	N/A	
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		$ -	$1,078,309	$107,589	$1,185,898	59315	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	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)	N/A	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	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		$1	$11,638	$4,324	$15,962	7925	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.	TBD	TBD	TBD	TBD	TBD	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	N/A	
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	No	Distribution	$20,032	$1,320,376	$5,645,101	$955,812	$6,600,913	$305,900	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): 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	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)	Remote Integrated Switch (RIS) The RIS team demonstrated the Phase 3 advanced features which address system scalability and usability concerns identified by stakeholders. The team also initiated development of the decommissioning plan for installed field devices. High Impedance Fault Detection The additional validation test scope was not pursued due to challenges with Cyber Security policy contract negotiations that could not be resolved. As such, data already gathered is in process of being analyzed and learnings documentation is in progress. Underground/Overhead Remote Fault Indicator (RFI) The project team completed all installations and hardware/firmware updates for the RFI systems. Documentation and technology transition plans for the technology have started development and are expected to complete in 2022.	This project supported the Commission's Track 3 Sub-track 2 of the DRP proceeding, which required the Utilities to file a Grid Modernization Plan with their respective GRC applications that provides a 10-year forecast for technologies that increase the grid's ability to safely and reliability connect DERs. Several technologies within this project are part of SCE's Grid Modernization Classification tables and contained within SCE's Grid Modernization Plan submitted with SCE's GRC application. The learnings from these technologies will directly impact SCE's future Grid Modernization Plans. 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	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	$585,095	$659,762	$2,611,622	$261,324	$2,872,946	$139,846	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): GENERAL NETWORKS, TESCO AUTOMATION LTD, MORRIS & WILLNER PARTNERS,	N/A	N/A	N/A	N/A	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	Process Bus (MayBerry) The new optical sensing technology demonstration equipment with the IEC-61850 process bus standard was left at the Mayberry Substation after the initial demonstration phase. This equipment was left in the field until July, 27, 2021. Leaving the equipment in the field for this extended period allowed the SCE Engineers to identify the possibility of working toward a long-term option of implementing a complete IEC-61850 substation automation system. Fully Digital Substation (Proof of Concept) In 2021, the project team created and finalized the testing procedures to be implemented within the lab for testing. These plans were separated into two types of testing: Interface and Scheme. The Interface consists of communications and IEC-61850 compliance testing and the Scheme testing focuses primarily on validating the system protection as well as negative test case scenarios. Due to Covid restrictions, this project also allowed the team to do some remote testing with one of our contractors. This remote testing proved valuable for the contractor as they were able to work off-site and still	NA
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		($5,694)	$1,097,308	$139,094	$1,236,402	$32,682	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.	TBD	TBD	TBD	TBD	TBD	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)	N/A	
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	$33,899	$42,225	6523	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.	Non-Competitive Nayak Corporation Inc	NA	NA	NA	NA	N/A; Applicable to CEC only.	Nayak Corporation - NA	N/A; Applicable to CEC only.	Metrics plan TBD	N/A	
2nd triennial (2015-2017)	SCE	Series Compensation for Load Flow Control (Power Flow Control with TCSC)	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		$1	$ -	$5,683	$5,683	1903	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.	TBD	TBD	TBD	TBD	TBD	N/A; Applicable to CEC only.	TBD	N/A; Applicable to CEC only.	Metrics plan TBD	N/A	
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	$24,476	($24,476)	$1,056,502	$69,442	$1,125,944	55288	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	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	N/A	
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	$1,504	$9,761	$922,511	$16,819	$939,330	9250	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.	TBD	TBD	TBD	TBD	TBD	N/A; Applicable to CEC only.	TBD	N/A; Applicable to CEC only.	Metrics plan TBD	N/A	NA
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	$1,295	$139,584	1222	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.	TBD	TBD	TBD	TBD	TBD	N/A; Applicable to CEC only.	TBD	N/A; Applicable to CEC only.	Metrics plan TBD	N/A	

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	(A) Encumbered Funding Amount ($)	(B) Committed Funding Amount ($)	(C) Funds Expended to date: Contract/Grant Amount ($)	(D) Funds Expended to date: In house expenditures ($)	(E=C+D) Funds Expended to date: Total Spent to date ($)	Administrative and overhead costs incurred	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.	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	2021 Update	Coordination with CPUC Proceedings or Legislation
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	$393,862	$250,688	$17,830,929	$900,737	$18,731,666	$436,052	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.	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	See Final Project Report in the Appendix for 2021 achievements.	The project supports the Commission's DRP proceeding. IGP learnings helped support the DRP Track 2 Demonstrations C, D, and E as well as Track 3, Subtrack 3 Distribution Investment Deferral Framework (DIDF). SCE's GMS is critical to realizing the DRP vision by safely sending communications between the utility and third party DER providers in real time to meet electric system needs.
3rd triennial (2018-2020)	SCE	Advanced Comprehensive Hazards Tool	Cross Cutting Technologies	This project will demonstrate a new and innovative approach to integrate emerging and mature hazard assessment tools. This demonstration will use a centralized data architecture that integrates various types of SCE asset data from non-electric, generation, and grid infrastructure. The project aims to identify vulnerabilities across different types of infrastructure to understand the overall risk to the grid. The project will demonstrate hazard scenarios and the impacts of those scenarios to the SCE system.	8/5/2019	Yes	Distribution	$-	$852,667	$273,421	$7,907	$281,328	$1,382	None	None	N/A	N/A	N/A	Unknown	Competitive bid for technical services	N/A - In progress. Bidders list is not yet created	G&E Engineering	1st	N/A	N/A	N/A	N/A; Applicable to CEC only.	1. Public safety improvement and hazard exposure reduction. 2. Utility worker safety improvement and hazard exposure reduction 3. Reduction in outage durations	The team's initial attempt to onboard the Seismic Earthquake Risk Assessment (SERA) developer was unsuccessful due to an inability to agree on terms and conditions. This resulted in prolonged negotiations and overall project schedule delay. The vendor selection and onboarding through a Request for Proposal (RFP) is near completion, and is pending SCE's vendor cybersecurity risk assessment. The agreed upon scope of work will include establishment of electric utility component database of fragilities (based on known fragilities), FEMA P-5, Global Earthquake Model (GEM), and Hazus fragility functions. The Seismic hazard module will use probabilistic and deterministic approaches based on OpenSHA engine and USGS ShakeMap API. The climate hazard module for extreme wind, precipitation, temperature, sea-level rise, and flood hazard events will use SCE's climate models and CAL-ADAPT climate projections.	This project supports the Commission's Climate Adaptation Rulemaking. As part of the Climate Adaptation Rulemaking, all utilities are required to perform a vulnerability assessment to understand electric system vulnerabilities in the event of hazards brought on by climate change. The tool being demonstrated as part of this project will improve the Commission and SCE's understanding of the electric system's vulnerabilities to natural hazard events by assisting with risk assessments and identifying grid vulnerabilities that can be documented with SCE's future vulnerability assessment filings.
3rd triennial (2018-2020)	SCE	Advanced Data Analytics Technologies (ADAT)	Cross Cutting Technologies	This project will demonstrate the possibility of using advanced data analytics technologies for Transmission and Distribution (T&D) and customer maintenance. This project will evaluate pattern recognition technologies that are capable of using new and/or existing data sources such as from sensors, smart meters, supervisory control and data acquisition (SCADA), for predicting or providing alarms on the incipient failure of distribution system assets. These assets would include connectors, transformers, cables, and smart meters.	10/7/2019	Yes	Distribution	$-	$5,890	$274,244	$7,209	$281,452	$1,271	None	None	N/A	N/A	N/A	UnKnown	Competitive bid for technical services	5	Tagup, Inc.	1st	N/A	N/A	Small Business (20 employees)	Not applicable	1. Maintain/reduce operation and maintenance costs 2. Reduce number of unplanned outages, frequency and durations 3. Public safety improvement and hazard exposure reduction	This project was deferred in April 2021 to allow consideration of other projects which may offer greater benefits aligned with California and CPUC objectives.	Commission proceedings to support will be determined through the course of the project.
3rd triennial (2018-2020)	SCE	Advanced Technology for Field Safety (ATFS)	Cross Cutting Technologies	This project will demonstrate the possibility of using new advanced technologies to reduce T&D field crew to customer hazards. The project will evaluate technologies that are capable of using data sources such as field sensors, smart meters, etc. to provide real/near real-time status of faulty equipment. Another area that this project will evaluate are the technologies that are capable of levering recent advancements in the Augmented Reality space.	12/18/2019	Yes	Distribution	$-	$837,695	$59,476	$2,448	$61,924	$422	None	TBD	N/A	N/A	TBD	Unknown	TBD	TBD	TBD	TBD	TBD	N/A	TBD	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 5e. Utility worker safety improvement and hazard exposure reduction 8f. Technology transfer	SCE has focused on initiating other higher-priority projects and has therefore not made progress on this project in 2021. The team anticipates launching this project in 2022.	
3rd triennial (2018-2020)	SCE	Beyond Lithium-ion Energy Storage Demo	Grid Modernization and Optimization	This project will demonstrate the next wave of next-generation, precommercial, "beyond lithium-ion" energy storage technologies that have a high probability of commercial viability, but require real world field experience to reduce technology and adoption barriers on the path to commercialization. This project will focus on advanced energy storage technologies that are non-lithium ion based (e.g., advanced electrochemical batteries, flow batteries, thermal storage, etc.). This project will demonstrate non-lithium ion storage systems against a variety of traditional use cases (i.e., in accordance with the CPUC's energy storage use cases outlined in D13-10-040), and emerging use cases (e.g., regional/community resiliency, etc.). Lastly, this project will demonstrate a complete energy storage system, including the storage technology, power conditioning system(s), product/systems integration, and grid interconnection. The objectives of this project are to identify technologies most likely to achieve commercial viability with the next 3-5 years, and opportunities to accelerate the commercialization process.	2/10/2020	No	Grid Operation/Market Design	$-	$475,338	$8,827	$15,835	$24,662	$2,841	None	TBD	N/A	N/A	TBD	TBD	TBD	TBD	TBD	TBD	TBD	TBD	TBD	N/A; Applicable to CEC only.	TBD	This project is in the Planning phase. Once a test article is obtained, the project team will prepare project articles to move the project into execution. The team executed a NDA in October 2021 with a potential vendor to discuss their flow battery technology, and the next step is to obtain test article. The team has also engaged another potential vendor who plans on conceptualizing their demo to SCE.	
3rd triennial (2018-2020)	SCE	Control and Protection for Microgrids and Virtual Power Plants	Customer Focused Products and Services	This project will examine control and protection schemes for safe and reliable operation of distribution systems with customer owned nested microgrids (MGs) and virtual power plants (VPPs). Standardized control and protection schemes and streamlined operation practices will be designed to support the integrity of the grid and to facilitate grid operation in the new context with high penetration of renewable resources and highly variable loads.	7/8/2019	Yes	Distribution	$669,427	$1,103,732	$619,562	$77,279	$696,841	$14,057	None	TBD	N/A	N/A	TBD	TBD	TBD	TBD	TBD	TBD	TBD	TBD	TBD	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 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) 1h. Customer bill savings (dollars saved) 3e. Non-energy economic benefits 3f. Improvements in system operation efficiencies stemming from increased utility dispatchability of customer demand side management 3h. Energy Security (reduced energy and energy-related material imports) 5a. Outage number, frequency and duration reduced. Public safety improvement and hazard exposure reduction 5e. Utility worker safety improvement and hazard exposure reduction 5f. Reduced flicker and other power quality differences 5i. Increase in the number of nodes in the power system at monitoring points 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) 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) 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) 8h. Number of reports and fact sheets published online	In 2021, the team initiated negotiations with a vendor to procure the microgrid control system to support design and testing. These negotiations remain in-process as of year-end. The team also began preparing the design of the lab testbed, which also remains underway as of year end.	This demonstration will identify challenges and protection requirements to enable safe microgrid operation, supporting the Commission's Microgrid rulemaking. The learnings fromthis demonstration will assist with future standards modifications required to enable microgrid operation on SCE's electric grid.
3rd triennial (2018-2020)	SCE	Cybersecurity for Industrial Control Systems	Cross Cutting Technologies	This project will demonstrate the ability to deploy adaptive security controls and dynamically re-zone operational networks while the Industrial Control System (ICS) is either under cyberattack or subject to an increased threat level. The concept of dynamic zoning allows for isolation of threats to certain segments of the ICS and could include both vertical (isolating data flows from SCADA masters to substation endpoints) and horizontal (containing data flows between substations, for example, under a state of manual control when the SCADA master cannot be trusted).	12/13/2018	No	Distribution	$1,242,075	$425,383	$2,240,500	$42,043	$2,282,542	$7,613	None	None	N/A	N/A	N/A	Unknown	Competitive bid for technical services	3	Bidder is not selected at this time	N/A	N/A	N/A	N/A	N/A; Applicable to CEC only.	1. Decrease mean time to completion of disconnecting grid communications in response to a simulated cyber incident 2. Demonstrate the viability of segmenting mesh networks 3. Demonstrate the viability of commercial orchestration and automation tools in a grid control / operational technology environment	In 2021, the team continued to refine individual test cases for inserting cybersecurity controls into operational technology / industrial control systems environments proving viability of actions and automation to change grid threat response based on a higher risk event. The demonstration development focused on combining individual cybersecurity actions. These actions utilized a defense-in-depth approach creating a series of actions and responses to support the individual use cases. Complex action demonstrations were completed for all four proposed Use Cases (UC), which are comprised of (1) Cyber Automation for Switching Stations and Substations, (2) PLC and RTU Local Control Isolation, (3) Distribution Automation and Wireless Mesh Zoning, and (4) Energy Management System Workstation Threat Actions and Isolation. Basic research was completed for UCs (4) Energy Management System Workstation Threat Actions and Isolation, and UC (2) PLC and RTU Local Control Isolation allowing for the ability to demonstration of the threat and subsequent remediation actions to take place. Additionally, a Web Dashboard was created to demonstrate the live status of systems and elements, allowing for clear indication of changes to the	As the grid continues to rely on more third party generation to supply customers and maintain grid stability, cybersecurity becomes increasingly crucial to ensure all grid resources are safe from cyber threats that can destabilize grid conditions. This is even more apparent during microgrid conditions when customers are disconnected from the more stable bulk system and being served solely from local generation. Learning from this demonstration can help to support and inform the Commission of cybersecurity protocols for future microgrids. Moreover, the project will help support the Commission's Microgrid Rulemaking, which is developing these standards.
3rd triennial (2018-2020)	SCE	Distributed Cyber Threat Analysis Collaboration	Cross Cutting Technologies	This project will demonstrate the ability to standardize utility cybersecurity threat analysis by developing a Distributed Cyber Threat Analysis Collaboration framework to conduct local utility, collaboration with utility peers and sharing with National analysis centers to support expedient cyber threat feed analysis. This framework will demonstrate the capability to effectively consume internal and external sourcing threat feeds, process them for legitimacy, and identify utility risk impact, potential response measures through collaboration with utility peers and National analysis centers to validate and verify threats as well as significantly shorten the time needed to respond to a cyber compromise of the electric grid.	12/13/2018	No	Distribution	$231,405	$227,083	$1,381,948	$59,564	$1,441,512	$10,813	None	None	N/A	N/A	N/A	Unknown	Competitive bid for technical services	3	Bidder is not selected at this time	N/A	N/A	N/A	N/A	N/A; Applicable to CEC only.	1. Mean duration of vulnerability response: Shorten the duration from reported grid vulnerability to executing a response or plan. 2. Mean duration of intelligence sharing: Shorten the time from receiving threat intelligence, to sharing with internal affected business units and external vetted partners 3. Mean duration of cybersecurity defense response: Shorten the time between recognition, sharing, and executing a response to a cybersecurity threat on SCE's grid systems or technologies	See Final Project Report in the Appendix for 2021 achievements.	This demonstration could potentially inform the Commission's Rule 21 and the DRP proceedings. Rule 21 has investigated the ability to use smart inverters to provide certain grid services through utility communication. Similarly, the DRP has continued to investigate how DERs can meet electric system needs on an annual basis. Topics within both proceedings require the ability for utilities to communicate with customer DERs and DER providers. In order to maintain a cyber-secure grid, information exchange must be protected, and threats consistently analyzed. This demonstration will better inform protocols for communicating with DERs to meet real-time grid needs.
3rd triennial (2018-2020)	SCE	Distributed Energy Resources Dynamics Integration Demonstration	Energy Resources Integration	This project aims to evaluate the two key technical challenges related to high DER penetration namely protection system impacts and adverse interactions between multiple types of DERs. •The project will be comprised of both hardware and software components: solar PV inverters, a lab testbed, and computer models of: inverters, synchronous and induction generators, protective relay and one SCE sample feeder. •Test smart inverter functional capabilities on SCE distribution feeder with high DER penetration levels, it will be able to establish DER Operating Standards and leverage Smart Inverters for System-wide reliability. •Develop interoperable controls capability at SCE to provide flexibility to the operation of the grid.	7/8/2019	Yes	Distribution	$527,421	$67,616	$607,400	$28,399	$635,799	$5,226	None	None	N/A	N/A		Unknown	Competitive bid for technical services	5	Bidder is not selected at this time	N/A	N/A	N/A	N/A	N/A; Applicable to CEC only.	1. Description of issues resolved that prevented widespread deployment of technology or strategy and the results or outcomes 2. Effectiveness of information dissemination by the number of reports and fact sheets published online 3. Effectiveness of information dissemination by the number of times reports are cited in scientific journals and trade publications for selected projects	The team performed the following key activities in 2021: Completed numerous models using the PSCAD (Power Systems Computer Aided Design) simulation modeling tool and the CAPE simulation platform (e.g., PV model, single-phase legacy inverter average model, single-phase smart inverter average model, anti-islanding protection algorithm model, SCE's Pronghorn feeder model, etc.). Started system simulation and corresponding studies. Completed design of the Power Hardware-in-the-Loop (PHIL) testbed for laboratory demonstration. Completed testing and confirmed the functionality of grid simulator, PV simulator, two smart inverters, two legacy inverters, relay, and the relay tester F6150SV equipment. Started RTDS (Real-Time Digital Simulator) testing for testbed functional verification for use case demonstration. Communicated project objective and deliverables to PG&E, SDG&E, & Rule 21 working group and added as external stakeholders in the project. Completed PSCAD and CAPE simulation for PV, smart	This demonstration assists with the DRP proceeding's goal of ensuring the grid can accommodate a seamless interconnection of DERs and utilize them to meet grid needs by understanding the protection requirements on feeders with various types of generation. This could enable potential capabilities to enable increased amounts of generation on distribution feeders. Learnings from this demonstration may also inform future Grid Modernization Plans required to be filed in conjunction with each of the Utilities' GRCs.

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	(A) Encumbered Funding Amount ($)	(B) Committed Funding Amount ($)	(C) Funds Expended to date: Contract/Grant Amount ($)	(D) Funds Expended to date: In house expenditures ($)	(E=C+D) Funds Expended to date: Total Spent to date ($)	Administrative and overhead costs incurred	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.	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	2021 Update	Coordination with CPUC Proceedings or Legislation
3rd triennial (2018-2020)	SCE	Distributed PE V Charging Resource	Customer Focused Products and Services	This project will demonstrate PEV fast charging stations with integrated energy storage that can be used to control the grid system impact of fast charging, allowing more of them to be accommodated for a particular cost, and also to respond to grid needs as distributed energy resources when not in use to charge a vehicle. Fast charging units currently demand 25 to 125 kW, and the load cannot be planned or scheduled. This demand is expected to climb to 350 kW or more as advertised by vehicle and charging system suppliers. This intermittent and unpredictable high demand could concern utility planning and could also challenge high deployment of such systems due to their low load factor and potentially alarming bill impact to customers under current tariffs. Combining fast charging systems with energy storage can result in higher load factor, while still providing satisfactory service to customers. The size of such storage systems, along with power components, will determine their effectiveness in a particular duty cycle. This is demonstrated in the demands on the system from customers in the real world, which this project will show; the demands on such energy storage systems may be met by the capabilities of used batteries. These measures increase the likelihood of higher numbers of such stations operational. Integrated energy storage provides reliability in the case of grid events – transient or otherwise – and improves charging service in the evolving modern system of increased renewable and distributed generation. This project will demonstrate the reliability improvement of such systems subject to grid events.	7/8/2019	Yes	Distribution	$276,274	$715,845	$352,179	$28,702	$380,881	$5,242	None	TBD	N/A	N/A	TBD	TBD	TBD	TBD	TBD	TBD	TBD	TBD	TBD	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 1e. Peak load reduction (MW) from summer and winter programs 3e. Non-energy economic benefits 3f. Improvements in system operation efficiencies stemming from increased utility dispatchability of customer demand side management 3h. Energy Security (reduced energy and energy-related material imports) 5f. Reduced flicker and other power quality differences 5i. Increase in the number of nodes in the power system at monitoring points 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) 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) 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) 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 8e. Stakeholders attendance at workshops 8f. Technology transfer	The project team spent the year trying to identify and collaborate with a partner with which SCE could utilize a trial-use agreement to employ fast-charging equipment with a system that incorporates an Energy Storage System. After searching and communicating with several companies, the project team was unable to find fast charger vendor that was willing to meet all the use cases we envisioned for the system. Therefore, we decided to switch focus and develop an in-house system to demonstrate the project objectives and use in-house and contract resources to develop the integration and control system. The partnership with an OEM experienced a setback as the company is diverting its efforts from second life batteries to recycling. However, they have discussed offering SCE ownership of one of their existing projects, which would save money on equipment. SCE has a partnership with the Ohio State University (OSU) to evaluate the Edison system for the applicability of using Second-life batteries for grid regulation. SCE and OSU have signed a NDA so we can share data that they can use to evaluate the SCE system. The project has initiated a conversation with a vendor to buy a fast charger to integrate with existing energy	This project supports the Commission's DRIVE Rulemaking, Transportation Electrification Framework, and DRP proceedings by providing crucial information on the integration of fast chargers with energy storage and the potential use of second-life batteries.
3rd triennial (2018-2020)	SCE	Distribution Primary & Secondary Line Impedance	Grid Modernization and Optimization	This project will examine the possibility of establishing primary and secondary line impedance information for distribution circuits, by examining the voltage and power signatures at the meter and transformer level, by leveraging a basic connectivity model of the circuits and utilizing SCADA data. The availability of complete primary line impedance information can result in accurate load flow / distribution state estimation results and greater real time management of the distribution grid and greater utilization of capacity within the existing installed infrastructure before new assets deemed to be required.	12/18/2019	Yes	Distribution	$-	$0	$66,233	$1,907	$68,140	$330	None	None	N/A	N/A		None	TBD	TBD	TBD	TBD	TBD	TBD	TBD	N/A; Applicable to CEC only.	3c. Reduction in electrical losses in the transmission and distribution system 3e. Non-energy economic benefits – this project, if successful, will allow SCE to plan and operate the grid	Due to budget constraints SCE put this project on hold in 2020.	
3rd triennial (2018-2020)	SCE	Power System Voltage and VAR Control Under High Renewables Penetration	Grid Modernization and Optimization	This project will demonstrate in a lab setting the effect of a Voltage & VAR management and control algorithm that optimizes the operation of the power grid, for both the transmission and distribution systems, by regulating voltage and controlling VAR resources optimally while maintaining the secure operation of the power grid.	12/18/2019	Yes	Distribution	$-	$8,718	$179,107	$6,092	$185,199	$1,086	None	None	N/A	N/A	TBD	TBD	TBD	TBD	TBD	TBD	TBD	TBD	TBD	N/A; Applicable to CEC only.	1i. Nameplate capacity (MW) of grid-connected energy storage 3a. Maintain / Reduce operations and maintenance costs 4a. GHG emissions reductions (MMTCO2e) 5a. Outage number, frequency and duration reductions 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)	During project planning, additional research would be required for completion, which is not currently available, nor allowable for the Utilities to conduct under current EPIC requirements. SCE cancelled this EPIC project in 2020 with the intent of looking into alternative funding sources outside of EPIC.	This project supports the Commission's Climate Adaption Rulemaking. The Climate Adaptation Rulemaking requires the Utilities to identify vulnerabilities to infrastructure, operations, and services and also provide mitigation options to those vulnerabilities. One of those vulnerabilities could result in large blackouts and limitations to operations or services due to blackstart limitations. This demonstration could display the feasibility of leveraging inverter technology as a mitigation to the challenges of blackstart conditions brought on by climate hazards.
3rd triennial (2018-2020)	SCE	SA-3 Phase III Field Demonstrations	Grid Modernization and Optimization	The Project is to successfully demonstrate a modern substation automation systems for transmission substation by adopting scalable technology that enables advanced functionality to meet NERC CIP compliance and IT cybersecurity requirements. This project is to provide measurable engineering, operations, and maintenance benefits through improved cybersecurity and reliability for transmission substations. It will also provide interoperability and allows the system to work with relays from multiple vendors. Prevent vendor lock-in due to proprietary software and hardware and assure that SCE have the flexibility to implement the best solution available	12/18/2019	Yes	Distribution	$10,597	$3,514,820	$2,128,384	$415,382	$2,543,766	$138,185	None	TBD	N/A	N/A	TBD	Unknown	TBD	TBD	TBD	TBD	TBD	N/A	TBD	N/A; Applicable to CEC only.	2a. Hours worked in California and money spent in California for each project X 3a. Maintain / Reduce operations and maintenance costs X 3b. Maintain / Reduce capital costs X 6a. Avoiding technology obsolescence 7a. Description of the issues, project(s), and the results or outcomes	IEC 61850 Programmable Automation Controller (PAC) This project has successfully completed and met all the 2021 project milestones, including laboratory testing, all cyber and IT tests, documentation, and a demonstration to stakeholder groups. Project team completed IEC61850 PAC client configuration and implemented documentation on system design – including detailed information on best practices for expanding the configuration for future implementation of new IEC61850 IEDs. Initial configuration for IEC61850 PAC server configuration was completed. The server configuration involved creation of a unique server model specific to SCE's standard PLC design. Project team evaluated advanced cybersecurity features available for some IEDs when used in a fully IEC61850 system. The project team created documentation on the setup of the cybersecurity features and best practices. Completed major Cyber/IT tasks, including vulnerability scans, hardware and software analysis, and integration testing against in-scope services, equipment, and technologies associated with the GT-19-0048 61850	CPUC proceedings to support will be determined through the course of the project.
3rd triennial (2018-2020)	SCE	Service and Distribution Centers of the Future	Customer Focused Products and Services	This project will demonstrate an advanced SCE service center housing electrified utility crew trucks, together with employee workplace charging, connected to a local service area with high penetration of distributed solar generation and plug-in electric vehicles. The electrification of transportation at the service center will be conducted in a way that not only does not adversely impact the local system, but interacts with the system using vehicle-grid integration (VGI) technology to ensure reliable and stable service at both the service center and local area. This project will deploy electrified utility trucks and utility and workplace EVSE with advanced VGI communications and controls to receive and respond to both DR (direct) and SCE grid (dynamic) signals to both ensure reliable charging and to support the local grid's stability. The vehicle systems, when not driving, can be used as grid assets and respond directly to support system voltage and stabilize demand. The two-front approach presented leverages the operating characteristics of both fleet trucks (charge during p.m.) and employee vehicles (charge in a.m.). The Project's objective will be to evaluate the ability to fully electrify a fleet service center with building electrification technologies (e.g., space and water heating), EVSEs and employee charging while managing any associated impacts to the local grid system. The results could inform future efforts to electrify other service centers, while also supporting commercial customer electric vehicle loads.	7/8/2019	Yes	Distribution	$760,214	$2,156,577	$598,043	$45,166	$643,209	$8,222	None	TBD	N/A	N/A	TBD	TBD	TBD	TBD	TBD	TBD	TBD	TBD	TBD	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 1e. Peak load reduction (MW) from summer and winter programs 1f. Avoided customer energy use (kWh saved) 1h. Customer bill savings (dollars saved) 1i. Nameplate capacity (MW) of grid-connected energy storage 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 5d. Public safety improvement and hazard exposure reduction 5e. Utility worker safety improvement and hazard exposure reduction 5f. Reduced flicker and other power quality differences 5i. Increase in the number of nodes in the power system at monitoring points 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) 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)	In 2021, the team began negotiations with the Microgrid Control System (MCS) vendor. These negotiations remain underway as of year-end. The team also worked on the conceptual design for the microgrid integration with battery storage and building electrification. This work also remains underway. The team also completed site walks and analysis of electric bus EVSE and charge management platform.	This project will support the Commission's Transportation Electrification Framework, DRIVE Rulemaking, DRP proceeding, and Microgrid proceeding by providing crucial data on improving the value of fleet electrification, while maintain safe and reliable grid operations.
3rd triennial (2018-2020)	SCE	Smart City Demonstration	Energy Resources Integration	The project will demonstrate the electric utility role within a Smart City initiative. The demonstration would seek to meet the following objectives: Increasing coordination between electric system and urban planning, Coordinating infrastructure construction activities within a City, Streamlining the interconnection process through automated systems between SCE and the City, Partnering with cities to engage more customers in renewable resources (e.g. Community Solar PV, Community Storage) and creating more opportunities for electric transportation, Working with cities to customize their resource portfolio to meet a Climate Action Plan goal (e.g. "Community Choice Aggregation Lite" or Community Choice Aggregation), Leveraging assets (e.g. Telecommunications, Right of Ways), Coordinating communication on energy programs (e.g. Energy Efficiency, Demand Response, Charge Ready, Green Rate), and Assisting large customers (i.e. the City as an energy customer) in more efficiently utilizing their energy resources and improving resiliency for critical operations center (e.g. emergency command centers)	7/8/2019	Yes	Distribution	$1,306,202	$2,113,420	$705,350	$75,028	$780,378	$13,664	None	TBD	N/A	N/A	TBD	TBD	TBD	TBD	TBD	TBD	TBD	TBD	TBD	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 1d. Number and percentage of customers on time variant or dynamic pricing tariffs 1i. Nameplate capacity (MW) of grid-connected energy storage 3e. Non-energy economic benefits 3h. Energy Security (reduced energy and energy-related material imports) 5a. Outage number, frequency and duration reductions 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 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) 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) 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) 8b. Number of reports and fact sheets published online 8d. Number of information sharing forums held 8e. Stakeholders attendance at workshops 8f. Technology transfer 9a. Description/documentation of projects that progress deployment, such as	During 2021, the team accomplished the following: Initiated procurement for the microgrid controller, which is currently under negotiation. Began actively performing microgrid technical consultation work with support from the local agency and vendors. Launched detailed engineering design work, which is underway with the vendor. Identified the field site is identified and began negotiating the customer agreement covering the microgrid system (this remains in progress.)	This demonstration will support the Commission's Microgrid Rulemaking by providing technical learnings on limitations currently creating barriers to microgrid deployment. The Microgrid Rulemaking has continued to identify barriers and modifications to existing rules to support microgrid deployment. Not only will this demonstration understand the technical requirements for an MCS, but also identify additional standards and requirements that could be used to support the Commission's within the Microgrid Rulemaking, in order to assist with future microgrid operation and deployment.
3rd triennial (2018-2020)	SCE	Storage-Based Distribution DC Link	Grid Modernization and Optimization	This project will examine the benefits of a novel architecture for a distribution-connected energy storage system. Where typically storage systems are connected to a single electrical point, this architecture will allow the system to connect to two unique distribution circuits, through the use of two power conversion systems, tied to a single storage medium. This approach will allow the storage system to support both circuits, individually or simultaneously, and will also provide a means of dynamically exchanging power between the two circuits (DC link).	12/9/2019	Yes	Distribution	$830,603	$690,758	$439,397	$44,118	$483,515	$7,991	None	TBD	N/A	N/A	TBD	Unknown	TBD	TBD	TBD	TBD	TBD	N/A	TBD	N/A; Applicable to CEC only.	1b. Total electricity deliveries from grid-connected distributed generation facilities 1e. Peak load reduction (MW) from summer and winter programs 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 5f. Reduced flicker and other power quality differences 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) 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) 8b. Number of reports and fact sheets published online	The Project began working with the selected vendor officially on 8/9/21, and has made substantial progress to-date. There was a 6-month delay to onboard the vendor due to negotiation on the terms and conditions of the contract. The project team completed the early design phase involving decision around the cooling system, type of disconnecting switch, nominal voltage, auxiliary power source, and relay model type. The team evaluated two options for the SCADA communication paths and reviewed various control modes for the Tie Controller. We are continuing to evaluate the proposal to update components and software for the Grid Simulator and have completed a review of the scope of work for the power systems study. The team has met with internal Distribution Engineer and Construction Methods Specialist to review the overall 12kv system design and initiate a plan of inspections/reviews. The team also met with the with Apparatus Engineer to review the 12kv switch design. The team continues to evaluate the single-line diagram and dimensions of the test pad for equipment layout. Meetings have been scheduled with Protection Manager to review protection schemes of the Storage Based DC Link project. The team presented a project update to the internal Stakeholders to inform of the latest tasks that have	This project supports the Commission's DRP proceeding by attempting to identify reliability needs and projects that can be met by DER services. This demonstration could further DERs as a viable grid solution compared to traditional wires solutions. Eventually, this could be integrated into possible DER projects included in the annual Distribution Infrastructure Deferral Framework.
3rd triennial (2018-2020)	SCE	Vehicle-to-Grid Integration Using On-Board Inverter	Customer Focused Products and Services	The Project will assess and evaluate new interconnection requirements, Vehicle-to-Grid ("V2G") -related technologies and standards, and utility and third party controls to demonstrate how V2G direct current (V2G-DC) and V2G alternating current (V2G-AC) capable EVs and EV chargers can discharge to the grid and be used to support charging when there's an outage on the grid. It will assess and evaluate, in a laboratory environment, the proposed V2G-AC Rule 21 interconnection processes, proposed SAE and UL standards, and the function of automaker OEM battery/inverter systems to support vehicle-grid integration (VGI) services, integration of project 3rd party aggregators with SCE's Grid Management System (GMS)/DER Management Systems (DERMS), and partner with an existing Rialto Unified School District DOE V2G school bus project (and its Charge Ready Transport application) to provide an interconnection pathway by demonstrating functional requirements in the lab; and the field evaluation of deployed systems.	7/8/2019	Yes	Distribution	$465,196	$1,694,648	$657,308	$36,848	$694,156	$6,628	None	TBD	N/A	N/A	TBD	TBD	TBD	TBD	TBD	TBD	TBD	TBD	TBD	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 1d. Number and percentage of customers on time variant or dynamic pricing tariffs 1e. Peak load reduction (MW) from summer and winter programs 1h. Customer bill savings (dollars saved) 1i. Nameplate capacity (MW) of grid-connected energy storage 3e. Non-energy economic benefits 3f. Improvements in system operation efficiencies stemming from increased utility dispatchability of customer demand side management 3h. Energy Security (reduced energy and energy-related material imports) 5d. Public safety improvement and hazard exposure reduction 5e. Utility worker safety improvement and hazard exposure reduction 5f. Reduced flicker and other power quality differences 5i. Increase in the number of nodes in the power system at monitoring points 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) 7d. Deployment and integration of cost-effective distributed resources and generation, including renewable resources (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 8e. Stakeholders attendance at workshops 8f. Technology transfer	The following is a summary of the key activities performed in 2021: Updated the Project's Concept of Operation document describing proposed system and components, data flow and interfaces, modes of operation, assumptions and constraints, and high-level business use cases and business requirements. Updated Project's Detailed Use Case and Requirements document illustrating scope, actors, assumptions, use cases, step by step analysis, and alternative scenarios Completed Lab design network system Completed Lab Architecture Briefs (LAB) Completed CDA with Honda Completed Nuvve terms and conditions Completed Kitu SaaS Agreement and SOW	Since this project helps to support the DRP's goal of having electric vehicles be identified as DERs to be analyzed as grid solutions. Technology does not currently exist to utilize EVs as generating resources to meet customer or grid needs. To date, EVs have only been considered a load on the grid consuming energy and contributing to increasing demand. This demonstration will provide the needed learnings for the industry and Commission to understand how EVs could finally be used similar to energy storage by discharging to meet grid needs as the DRP previously identified. This project also supports the Commission's DRIVE Rulemaking, Rule 21 proceedings, and the Transportation Electrification Framework.
3rd triennial (2018-2020)	SCE	Energy System Cybersecurity Posturing	Cross Cutting Technologies	This project demonstration will automate the ability to probe the Utility's supervisory control and data acquisition system (SCADA), using an automated probing capability which will enable the system to report back on how it is configured. The ESCP project will engineer toolset to first demonstrate the capability to execute an automated system posture where cybersecurity and regulatory related system attributes will be collected and analyzed via a toolset. It will then demonstrate enhanced network communications situational awareness through a Software Defined Networking (SDN) interface with the capability to support cross cutting operations and cybersecurity analysis.	12/13/2018	No	Distribution	$-	$0	$ -	$13,034	$13,034	$2,274	None	None	N/A	N/A	N/A	Unknown	Project not advanced (Cancelled)	N/A	N/A	N/A	N/A	N/A	N/A	N/A; Applicable to CEC only.	N/A - Project was cancelled	During project planning in 2019, the team learned that additional research would be required to complete this project. This research is not currently available, nor allowable for the Utilities to conduct under current EPIC requirements. SCE canceled this EPIC project and is looking into alternative funding	

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	(A) Encumbered Funding Amount ($)	(B) Committed Funding Amount ($)	(C) Funds Expended to date: Contract/Grant Amount ($)	(D) Funds Expended to date: In house expenditures ($)	(E=C+D) Funds Expended to date: Total Spent to date ($)	Administrative and overhead costs incurred	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.	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	2021 Update	Coordination with CPUC Proceedings or Legislation
3rd triennial (2018-2020)	SCE	Wildfire Prevention & Resiliency Technology Demonstration	Cross Cutting Technologies	This project will demonstrate the latest technology advancements in hardware-based solutions (e.g., field devices, sensors, protection devices, etc.) and software-based solutions (e.g., data analytics, climate and fuel regrowth models, etc.) in support of climate adaptation and wildfire prevention, detection, and mitigation at all voltage levels. While SCE has outlined a comprehensive strategy and specific programs to address the year-round wildfire threat via the 2018 Grid Safety & Resiliency Program (GS&RP) application, and 2019 Wildfire Mitigation Plan (WMP), those initiatives are focused on implementing commercial-ready technologies and strategies that are considered "shovel ready". This project is intended to focus on new or emerging wildfire prevention and resiliency-focused technologies that have a high probability of commercial viability, but require more in-depth assessment and demonstration within the utility's operating environments in order to reduce technology and adoption barriers on the path to commercialization. In the case of hardware-based technologies, SCE would like to demonstrate the next generation of distribution-level and transmission-level sensing, measurement, protection, and control technologies that are capable of detecting the presence of wildfires, or operational abnormalities that may trigger wildfire ignitions (e.g., broken conductors), with greater speed and accuracy then what is currently available today in the marketplace. In the case of software-based technologies, SCE would like to demonstrate the latest advancements in data analytics, climate, weather, and fuel growth modeling, etc., in order to enhance/expand the situational awareness and operational practices capabilities that are being implemented today. In addition, software-based technologies that can leverage the new hardwarebased tools and technologies and provide improved resiliency, ignition prevention, fuels management, decision-support, automated high-speed control actions, etc. are also contemplated in this project.				$45,074	$5,770,414	$78,231	$12,910	$91,141	$2,747															TBD	The team held an EPIC Public Outreach in October 2021. Distribution Waveform Analytics (DWA) The team completed the project's Concept of Operation document describing the proposed system and components, data flow and interfaces, modes of operation, assumptions and constraints, and high-level business use cases and business requirements for the evaluation of Distribution Waveform Analytics. Machine Learning at the Edge The team began drafting the Concept of Operations and will have similar content as described for DWA above.	
3rd triennial (2018-2020)	SCE	Next Generation Distribution Automation III	Grid Modernization and Optimization	This project will leverage lessons learned from the Next Generation Distribution Automation II project. It will integrate new FAN wireless radio to automation devices and continue to improve control functionalities. It will provide greater situation awareness to allow system operators to manage the grid with higher DER penetration and ready to support Distribution System Operators (DSOs). It will integrate 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. This project will demonstrate technologies that are applicable for both overhead and underground distribution circuits. This project is composed of the following subprojects: 1) Remote Integrated Switch – An Advanced Automation Scheme for distribution circuit fault detection, automatic load restoration and circuit reconfiguration. Distribution circuit fault detection, isolation, and automatic load restoration and circuit reconfiguration, providing greater levels of telemetry, and providing support for Distributed Energy Resources interconnected to the grid. Improve control functionalities using high speed low latency FAN radio. Improve system reliability. 2) Overhead & Underground Remote Fault Indicator - Integrate Overhead & Underground Remote Fault Indicators on distribution circuits with the new FAN communication network that is most effective for fault detection applications. Improve functionalities such as reduce the minimum current requirement of RFI to facilitate selection of RI locations. Improve system reliability.			Distribution	$-	$1,829,808	$321,889	$64,289	$386,178	$11,843															TBD	Duct Bank Monitoring The Duct Bank Monitoring project was intended to demonstrate the feasibility of utilizing a dynamic modeling tool and real-time temperature monitoring system to improve the ability to manage loading of circuits and better predict the temperature of distribution cables. This could improve upon existing static cable limits used today. In the early stages of this project, it was assumed that some environmental characteristics involving underground ducts could be accurately recorded. Upon further analysis, it became apparent that data accuracy was not achievable based on the physical conditions of the underground duct bank and the	

Appendix B

Integrated Grid Project EPIC 2

Final Project Report

Grid Technology Innovation
ID# IIM-15-0008
Integrated Grid Project (IGP)
Final Project Report

28 February 2022

Developed by

Southern California Edison (SCE) Asset & Engineering Strategy

Grid Technology Innovation

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Disclaimer

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Project Overview

There are increasing amounts of distributed energy resources (DER) being installed on Southern California Edison's (SCE) distribution system, which support federal, state and SCE corporate goals to reduce carbon emissions. A previous project conducted by SCE called the Irvine Smart Grid Demonstration[1] showed how managed DER could be a useful tool to help optimize the distribution grid and increase operational flexibility. The Integrated Grid Project (IGP) was created to build on the previous learnings of the Irvine Smart Grid Demonstration, in order to define, develop and demonstrate the next generation of local distribution grid infrastructure (field and back office) to optimally manage increasing DER adoption.

This report summarizes the final phase of the IGP project, conducted as part of SCE's Electric Program Investment Charge (EPIC) II Portfolio, which includes a field demonstration of concepts developed and laboratory tested as part of earlier project phases. Several subprojects were included as part of this project. Additional funding for the scope of the field demonstration was obtained from the DOE-funded Electric Access System Enhancement (EASE) project. Additional project scope was obtained via DOE's Advanced Research Projects Agency – Energy (ARPA-E)-funded Network Optimized Distributed Energy Systems (NODES) projects, as well as through California Energy Commission (CEC) Project Opportunity Notices (PON)[2].

Linkage to Previous Phases of IGP

Two prior CPUC filed reports describe earlier phases of the IGP project. The first is the EPIC I Final Project Report[3]. This report covers the initial project design, control development and the first phase of the laboratory demonstration. Workshops were held with key SCE internal stakeholders to establish the basis for the project design. A review of control system vendors was performed, and vendors were selected for the project. The control systems were then tested in SCE's laboratory test environment utilizing a real-time simulator system assembled for the project. This phase of the project ended with the completion of the initial factory acceptance testing conducted in SCE's research labs.

The second report was the Distribution Resources Plan Demonstration D Final Status Report, which was completed using EPIC II funds under IGP (see Attachment 11 for full report). This report describes the scope of the Demo D project, which called for SCE to plan, design, and deploy the next generation grid infrastructure capable of enabling advanced operational functions such as bi-directional power flow, thereby allowing for higher DER penetration. The Distribution Resources Plan (DRP) Report covers work performed to take the limited laboratory demonstration done under EPIC I funding and integrate it with

1 Yinger, Robert, and Irwin, Mark. "Irvine Smart Grid Demonstration, a Regional Smart Grid Demonstration Project", 2015, https://www.osti.gov/biblio/1234553-irvine-smart-grid-demonstration-regional-smart-grid-demonstration-project

2 For more details on these projects, *see* Attachments 1 through 10 at the back of this report.

3 "Deep Grid Coordination (aka Integrated Grid Project (IGP), EPIC I Final Report", February 15, 2018, https://www.sce.com/sites/default/files/inline-files/EPIC_SCE2017AnnualReport.pdf , Report starts on page 64 of the file

production SCE equipment and control systems. System acceptance testing was conducted to confirm this integration utilizing SCE's production system test environment called the Alhambra Quality Assurance System. Unfortunately, a field demonstration was not possible at the time due to cybersecurity challenges associated with communicating to large numbers of customer owned DERs controlled by aggregators. After completing the Demo D project, these cybersecurity capabilities advanced to the point where this field demonstration was feasible and conducted as part of the EASE subproject. As the cybersecurity landscape continues to evolve, additional cybersecurity grid demonstrations will be critical to maintain grid system security for future field implementations.

Support of Federal, State and SCE Priorities

Federal and state policy objectives and SCE strategic priorities all encourage increasing renewable resources to support the reduction of carbon emissions that are contributing to global warming. In the White House fact sheet, "President Biden Sets 2030 Greenhouse Gas Pollution Reduction Target Aimed at Creating Good-Paying Union Jobs and Securing U.S. Leadership on Clean Energy Technology,"[4] the United States has set a goal to reach 100 percent carbon pollution-free electricity by 2035. The fact sheet says this goal will be achieved through deploying carbon pollution-free electricity generating resources, transmission, and energy storage. Many of these resources will be connected to the SCE distribution system and their coordinated operation is a goal of the IGP project work.

In California, Senate Bill 100[5] requires renewable and zero-carbon energy resources supply 100 percent of electric retail sales to customers by 2045. California is expected to roughly triple its current electric grid capacity while electrifying other sectors of its economy. This increase in electric grid capacity and electrification of industries increases the need to implement optimization and control systems, such as the IGP to meet this growth in electric demand.

In the "Pathway 2045" white paper[6], SCE shares its vision for achieving Federal and California energy and environmental goals. A reduction in carbon dioxide emissions can be met through the electrification of transportation and buildings, decarbonization of electricity generation, and increasing grid capacity and resilience. The IGP project tested methods to control generation, storage, and load resources on the distribution system to increase the economic efficiency of future investments in grid infrastructure.

4 "Fact Sheet: President Biden Sets 2030 Greenhouse Gas Pollution Reduction Target Aimed at Creating Good-Paying Union Jobs and Securing U.S. Leadership on Clean Energy Technologies," April 22, 2021, https://www.whitehouse.gov/briefing-room/statements-releases/2021/12/08/fact-sheet-president-biden-signs-executive-order-catalyzing-americas-clean-energy-economy-through-federal-sustainability/

5 Details and FAQ's for Senate Bill 100 can be found at: https://focus.senate.ca.gov/sb100/faqs

6 "Pathway 2045: Update to the Clean Power and Electrification Pathway", November 2019, https://newsroom.edison.com/_gallery/get_file/?file_id=5dc0be0b2cfac24b300fe4ca&ir=1

Project Scope

Several subprojects were assembled to achieve the objectives of IGP, Phase 2. Each subproject contributed to the final field demonstration, which was conducted under EASE. A short summary of each subproject that describes its contribution to the overall project is provided below. For additional details on each subproject, see the subproject attachments at the end of this document.

- **DOE – EASE**: Conducted a field demonstration of a scalable, interoperable, and cost-effective means of integrating and optimizing a high penetration of solar photovoltaic (PV) and battery energy storage on the distribution grid. This demonstration showed ways to streamline the DER interconnection process between key interconnection parties, established standards-based infrastructure and communications protocols for DERs, defined and field tested the value of energy services that controllable DER can provide, and showed how to incorporate these services into local distribution grid planning and operations. This field test was the final step in the IGP program and demonstrated how controllable DER can be of value to the grid and assist with allowing higher penetrations of DER on local distribution circuits. This capability has the potential to lead to deferrals of wires-only distribution system upgrades, which was analyzed in the project's cost-benefit analysis. Local distribution upgrades in theory can be deferred, but in most cases today it is not cost-competitive to rely on DER for deferring distribution capacity upgrades. Note that SCE has a process to identify distribution deferral opportunities and does so for each distribution capacity upgrade project annually in its Grid Needs Assessment (GNA) and Distribution Deferral Opportunity Report (DDOR).[7]
- **Adaptive Protection**: Performed a lab demonstration of an adaptive protection system designed to analyze the current state of the distribution protection settings and automatically adjust device settings to maintain or improve system protection. Increased amounts of varying loads, variable renewable generation, and changing circuit configurations can cause protection systems to behave improperly. This subproject shows how to overcome these protection problems as amounts of DER increase by adjusting device protection settings dynamically.
- **Integrated Grid Analytics**: Evaluated and tested models of the distribution system to provide granular disaggregated solar PV and demand response forecasts to allow improved grid peak load management. While these forecasts were used primarily for grid operations, the enhanced data could also allow better distribution grid planning. These improved models allow integration of increasing amounts of DER.
- **Integration of Big Data**: Demonstrated the use of the IEEE 2030.5 (national standard for communicating with DER aggregators) and the Common Smart Inverter Profile (CSIP) (California-required inverter communications and control capability specifications) to evaluate their effectiveness in controlling DER from SCE's back office computer control systems. This

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[7] *See* Appendix D for 2021 LNBA Calculations, accessed Dec. 2021
https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M400/K580/400580035.PDF
Also *see* Appendix D for 2020 LNBA Calculations, accessed Dec. 2021
https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M345/K926/345926397.PDF

subproject supported integration with aggregators utilizing IEEE 2030.5 and enabled monitoring and control of customer DER devices.

- **ARPA-E – ProsumerGrid DSO**: Used the ProsumerGrid Simulation Studio software tool to evaluate DER impacts at the physical, information, coordination, and market levels. This tool was used to explore candidate distribution system operator (DSO) market concepts, what they might look like, and how they would be operated.
- **ARPA-E NODES – National Renewable Energy Laboratory Grid Services**: Created a hardware-in-the-loop test bed of a SCE circuit to evaluate the operation of the National Renewable Energy Laboratory's (NREL) frequency and voltage regulation optimization algorithm. The control algorithm can be embedded on low-cost microcontrollers at each inverter or group of inverters allowing control decisions to be made quickly enough to match the dynamics of distribution systems with high renewable penetration. This subproject tested a less centralized method of optimization and dispatch of DER.
- **ARPA-E NODES – GE Grid Services**: Worked with project partners to develop and test models that establish the ability of loads to provide flexibility in responding to grid generation variations. Lack of flexibility is driving costly battery installations and delaying retirement of CO_2-emitting generation units. This subproject helped prove the ability of loads to provide generation flexibility, although load flexibility was not used in the final EASE demonstration.
- **ARPA-E NODES – Pacific Northwest National Laboratory Grid Services:** Worked with the Pacific Northwest National Laboratory (PNNL) to validate incentive-based control strategies across multiple timescales designed to provide flexibility services to the grid. This validation was done through simulation of a SCE distribution feeder through hardware in-the-loop testing. This subproject verified that the PNNL hierarchical control system can operate at large scale and provide the needed flexibility services.
- **CEC PON** Grant EPC-14-036 **– SunSpec Alliance**: Worked with the SunSpec Alliance to test and validate the ability of aggregators to control and monitor residential DER systems through communications with smart inverters using IEEE 2030.5 and CSIP. This communications path allows residential DER to provide grid services, thereby supporting increased DER penetration. This subproject helped resolve issues with the IEEE 2030.5 protocol so it could be used by the final EASE field demonstration.
- **CEC PON** Grant EPC-14-079 **– Electric Power Research Institute (EPRI)**: Provided testing at SCE's laboratories of the functionality of smart inverters conforming to California's CSIP. Conforming inverters will enable the coordinated control of inverters to provide grid support. These conforming inverters were needed for the EASE field demonstration.

Project Results Summary and Conclusions

This phase of the IGP project brought together several complementary subprojects, built on an earlier phase of IGP, and assembled a field demonstration that produced a scalable, interoperable, and cost-effective means of integrating high penetration of DERs. The project identified and demonstrated a non-production online information-sharing portal to streamline the customer DER interconnection process to the grid through cooperation with the local jurisdiction and SCE. The goal was to demonstrate a way to automate the provisioning process of up to 1,000 fast-tracked DER applicants in the Distributed Energy Resource Management System (DERMS) and DSO systems, since the number of DER interconnection applicants is expected to grow. A second part of the demonstration project performed a simulation of high DER penetration using a "digital twin" of SCE's Camden substation. This simulation included 10,000 DERs (30 MW PV and 40 MW/80 MWh storage) with a gross customer load of 20 to 40 MW. The project's optimization and control software was used to control this system using real-time modeling. The last part of the demonstration was an actual field installation of the software utilizing real customers with DER installations (24 customers with 167 kW of PV and 24 kW/56 kWh of storage). Both the simulation and field demonstrations showed how having controllable DER could enable increases in the amount of DER that could be interconnected to the Camden substation system, while preventing grid voltage and load violations.

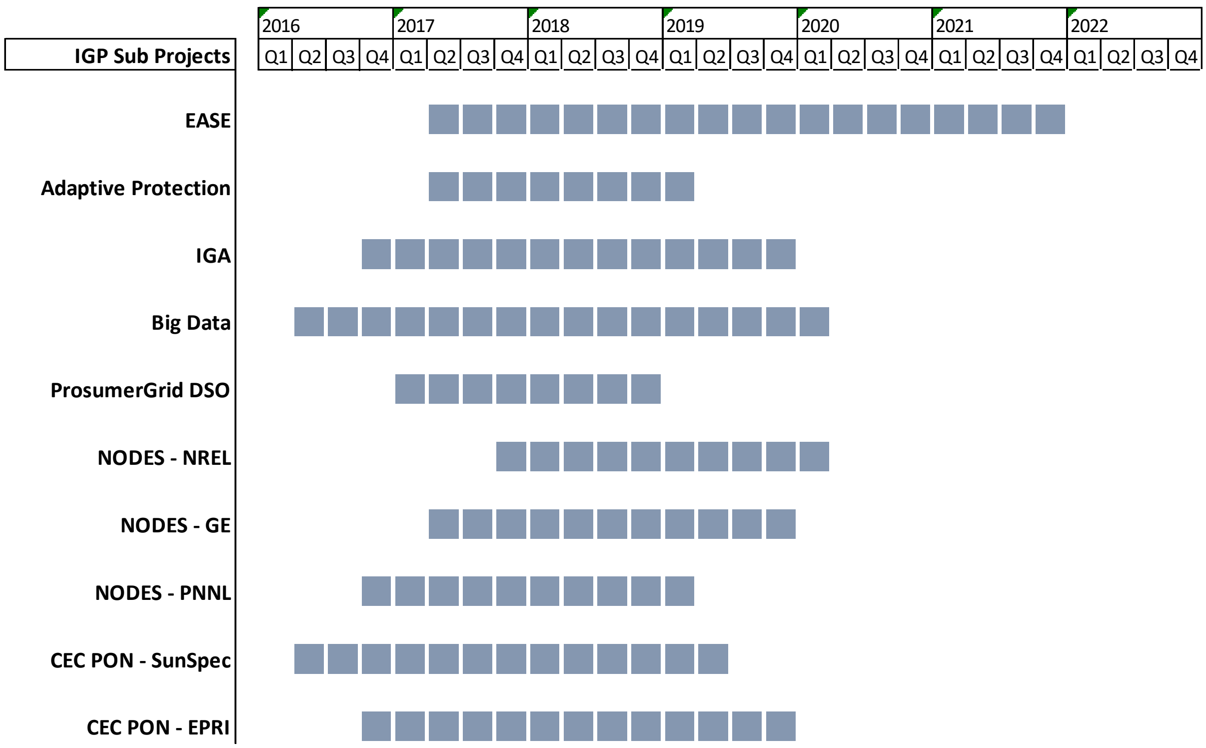
The implementation of the optimization and control software was a significant challenge, due to obtaining information in real time, which required integrating several inputs, such as the locational marginal price (LMP) for Camden substation, SCE system load forecast, weather forecast, substation load forecast per circuit using AMI data, SCE system applications, and a DER aggregator in a cyber-secure manner. The optimization output used the data to make decisions of how to prevent voltage and current violations, while optimizing battery charge, discharge, and PV output. Control commands were then issued to accomplish the needed DER dispatch. LMP had a big impact on dispatches and forecasting was critical for planning the generation and storage dispatch. These learnings can be used to mold future DER integration and planning of DER markets.

Obtaining customers willing to share control of their DER for the field demonstration was difficult for this project. This challenge stemmed in part from the COVID pandemic, but it also appeared the incentives presented to customers were insufficient to make them willing to turn over control of their generation and storage resources to the utility. Customer education and the construction of attractive customer rates and incentives will be necessary, if controllable DER will increase DER penetration without increasing distribution infrastructure costs.

Leverage

The IGP project leveraged Federal, California, and partner resources to increase the depth of the EPIC II-funded work. SCE utilized IGP EPIC dollars as cost match to participate in six projects managed by other outside entities that contributed to the IGP work. The contract value of these projects, including cost match by others plus the DOE-funded EASE work that SCE managed, resulted in a total of $2.3 for each $1 of EPIC funding. The combined value of the EPIC dollars and this other funding was approximately $48 million. Collaborating with this diverse group of partners expanded the scope of the work and helped increase the sharing of ideas between utilities, national labs, and vendors.

Schedule



Benefits

- Substation and line upgrades could potentially be deferred on feeders with sufficiently high penetrations of DER—assuming that the necessary combination of controllable DERs is available. This increased DER hosting capacity could lead to cost-savings by deferring certain wires-only capital projects. SCE could potentially recover the more than $400 million in planned Grid Modernization investments for the Grid Management System (GMS) and engineering and planning software tools by 2040 through distribution deferrals. This could potentially provide an additional $300 million in savings by 2045, assuming that SCE could continue to defer projects using the necessary combination of controllable DERs.[8]

[8] Note that these are high-level estimates are based on a simple analysis of potential savings and should not be interpreted as distribution deferral targets for SCE. Cost data was leveraged from Table 11 of A1908013-SCE-Various-Grid Modernization, Grid Technology, Energy Storage-SCE02V4P1 https://docs.cpuc.ca.gov/PublishedDocs/SupDoc/A1908013/2237/312075231.pdf, 2020 and 2021 GNA and DDOR, along with SCE's Pathway 2045 targets for DER concentrations on the distribution systems. Only existing capacity upgrades to primary feeders and substations of <16 MW were considered in this study since SCE cannot defer new infrastructure to newly developed areas. These targets are also aligned with the state of California's goals for reducing greenhouse gases (GHGs).

- Additional controllable DER on the SCE grid reduces the need for additional fossil fueled conventional generation for flexibility and reserves, which would lead to reduced greenhouse gas emissions. DER management capabilities will support SCE's goal in reaching carbon neutrality by 2045, which requires the management of DER on both the bulk system and distribution system. Combining SCE's distribution and bulk-system investments in clean generation and storage, by 2045 we expect to see a 339 MMT reduction in greenhouse gases. Another 108 MMT will need to be sequestered for SCE to reach its goal of carbon neutrality by 2045.[8]
- Replacing spinning reserve with flexible loads and controllable DER saves costs and reduces greenhouse gas emissions.
- Simplifying the customer DER interconnection process through cooperation with the local jurisdiction through an information sharing web site reduces the delays for customers to implement PV and storage systems.
- DER dispatch can be cost-optimized through optimal power flow, saving money for customers and utilities.
- SCE forecasts its GMS Fault Location Isolation Service Restoration system will help SCE customers avoid approximately 300 million customer minutes of interruption by 2030, an estimated value to customers of $471 million. SCE also forecasts that the Distributed Energy Resource Management System will provide $134 million in reliability benefits by 2030 based on its ability to help resolve "masked load" concerns associated with DERs. IGP contributed to the development and deployment of these systems.
- The work done with testing inverter communications and control protocols (IEEE 2030.5, CSIP, Rule 21) helped deliver inverters that use standards and eases coordinated DER control on the grid. These communications standards are necessary to increase DER system penetration of the grid, and are needed for the implementation of SCE's GMS system
- The project testing work identified cybersecurity issues and proved-out methods needed to securely communicate between SCE systems and 3rd party DER aggregators and other external support services (i.e., weather services). This work improves standards and accelerates the implementation of commercial systems being implemented by utilities in California and other states.
- Customer and workforce safety can be improved by reducing the number of customers impacted by outages, reducing outage frequency, and outage duration. This is made possible using the system architecture developed as part of the IGP project, which was then applied to the development of SCE's GMS system.
- SCE's GMS will include DER management capabilities that enable integration of DERs into SCE's grid and enable them to provide grid services. This supports California's clean energy policy targets and empowers customers to realize the benefits of their investments more fully. To the extent this project allows an increased penetration of renewable generation on distribution circuits, there would be a corresponding reduction in greenhouse gasses. There would also be a

reduction in fossil fuel usage by conventional generation units displaced by this increase in renewable generation.

Lessons Learned

Cybersecurity

- All project applications (utilities and 3rd-party vendors) need to be prepared to have their software and hardware products undergo and tolerate regular patching, penetration testing, source code scanning, and network vulnerability scanning to maintain a Zero Trust[9] secure deployment. Not all project software vendors were prepared to go through the tests outlined above and could have cost the project a three month implementation delay had the deployed system not been fully sandboxed from company systems. This resulted in some vendors having to upgrade their code-scanning tools and patching processes, which in some cases posed a significant capital investment in the tens of thousands of dollars.
- Concise project cyber requirements need to be provided to project personnel, vendors, and for all associated testing environments as early in the project design as possible. This will prevent delays and allow ample time for mitigating unforeseen costs by all parties.
- The continually changing landscape of cyber threats and the required development of cyber tools had a critical impact on project requirements, timing, and cost. Recommendations are being prepared for a more permanent and stabilized testing environment (both Lab and Grid Data Center). To mitigate this challenge, utilities need to have risk-assessment processes in place to manage cybersecurity risks that arise during the development or operation phase of a project. There also needs to be a phased approach to updating cyber tools as such tools become available. Operating system and patching standardization have a significant impact on ensuring that these changes could be implemented at scale, while improving software compatibility.

Customer Acquisition for DER Field Testing

- There were significant difficulties recruiting customers with DERs to help demonstrate grid reliability services, which points to problems with the programs used to incentivize customers to cooperate.
    - Novel grid reliability services often required the latest inverter equipment, which meant that most participating customers were either new buyers of solar PV and potentially storage, or they had to upgrade their existing systems. Significant incentives are required to persuade new buyer customers to 1) adopt solar and storage and 2) compensate them for allowing SCE to utilize their resources. EASE acquired 24 customers to participate by designing its incentives such that buyers would recover 80% of their installation costs, but still fell short of its target of acquiring 100 customers. This

[9] Zero Trust deployment means that all users, whether inside or outside the organization's network, need to be authenticated, authorized, and continuously validated for security before being granted or keeping access to applications and data.

was likely due to this demonstration's limitation to a 4-square mile area in Santa Ana, CA. Future incentives could be designed to be more equitable to all residents within the community to increase customer adoption and participation.

- Targeting a broad area of customers increases the likelihood of reaching acquisition targets, but is challenging to balance if DER reliability services require high DER penetrations in small geographical areas. Areas that offer the flexibility to allow a larger number of customers to participate are more likely to be successful in acquiring customers. Demonstration goals should consider these acquisition challenges and tailor their goals to what can be realistically demonstrated. If external risks to acquiring customers in a given area cannot be easily mitigated based on technology or socio-economic barriers, then a lab-only demonstration can offer a better value to model and predict use-case outcomes.

- Partnering with solar installers and manufacturers in acquiring customers reduces the burden of acquisition on the utility. Utilities could also support installers and manufacturers by marketing and branding their sponsorship of demonstration programs to gain consumer trust.
- The proposed programs to use customer DERs for grid services can conflict with existing customer warranty provisions, energy production contracts, and demand charge reduction goals. Partnering with solar installers and manufacturers in acquiring customers could potentially mitigate these challenges.

Technology Architecture and Execution

- DER aggregators had a difficult time implementing the IEEE 2030.5 standard due to the limited number of suppliers who had full protocol support available at the time the project was executed. Since this protocol would soon be required in California, the project wanted to demonstrate this IEEE standard. More time would have been beneficial to work out problems with the protocol. To ensure a workable standard, SCE was an active participant in the IEEE committees that were developing and refining the standard. Implementation issues with this standard will lessen as more commercial products that support the mature IEEE 2030.5 standard become available.
- Implementation of the IEEE 2030.5 protocol introduced security threats that required a new network architecture and cyber tools to isolate aggregator communications from SCE's main grid control system. Knowing the newness of the protocol, more time and funding would have been advantageous to work through the challenges.
- Control system vendors used various versions of system software (operating system, databases, etc.) that were not easily portable to SCE's standard software and operating systems. This required software updates by SCE and vendors. Specific system software requirements need to be established as early in the project design phase as possible and communicated to vendors to avoid delays and extra cost.
- Some practical field issues, not necessarily encountered in the laboratory setting, needed to be overcome. These issues included cybersecurity concerns, interactions with many stakeholders,

legacy system issues, and interaction with existing SCE software solutions. While this was a demonstration project, more up-front efforts need to be made in the future to identify issues and draft plans to overcome them. These include cybersecurity analyses, application integration investigations, field recruitment planning, and contracting with vendors.

Effectiveness of Cross-Organization Project Support

- The project encountered significant challenges associated with SCE IT infrastructure and cybersecurity tool upgrades as the team migrated the setup from the lab to the Quality Assurance System (QAS) test environment for field trials. The QAS test environment allows software testing on a duplicate of the production grid control system to work out problems before putting software into use by system operators.
- Support organizations underestimated the cost and level of effort required to support these tasks. While this project was a demonstration of new technology, more efforts need to be made by all parties involved to identify issues and plans to resolve them as early in the project as possible.

Compliance / Contracts

- There were significant contractual complexities around business rules, information access and exchange, and commercial agreements, including the on-boarding and billing of vendors which impacted project timing. With first-time demonstration projects it is difficult to foresee many of these problems, but efforts to mitigate these issues as soon as possible, such as the creation of standard contract terms could help reduce these challenges.

Next Steps

The project demonstrated ways in which customer DERs could be used to increase DER penetration on SCE's distribution circuits—namely by managing multiple DERs (typically solar PV and energy storage) and optimizing their operations. Significant steps also were taken to integrate the control and optimization systems with SCE's production control and monitoring systems. The following conditions still need to be met to fully implement these systems:

- The project demonstrated a centralized way to dispatch DERs to provide grid services and reduce the need to upgrade grid infrastructure. More work needs to be done to choose the right market structure and control strategy for service territory-wide implementation.
- The field-testing phase of the project identified significant gaps between modeled inverter capabilities and what was actually available when using real residential customer DERs. Actual inverter controls need to be improved to be more useful in providing grid support. This highlights the need to work with manufacturers to improve controllability and refinement of inverter control standards.
- Customer participation was difficult to obtain in the field test program. Better methods need to be identified to sign up customers to allow the utility to manage their DERs. Cost incentives either are unclear or insufficient to motivate customer participation. There are still challenges

with this program's requirements conflicting with existing SCE rates and programs, customer warranties, and manufacturer energy production contracts.

- Flexible loads need to be integrated with broader efforts to enable DER management and optimization. The NODES work has shown the value of flexible loads in reducing the need for energy storage and fossil fueled generation. The growth of electric vehicle charging will provide additional sources of flexible load.

Attachment 1 – Electric Access System Enhancement (EASE)

Summary

The EASE project demonstrated a scalable, interoperable, and cost-effective means of integrating high penetration of DERs with the distribution grid. The project identified ways to enhance the customer interconnection process and improve utility access to information from DERs. This was done by simulation of 1000 DER interconnections that were dynamically provisioned into the EASE Distributed Energy Resource Management System (DERMS) system per day for 10-days. A second part of the demonstration performed a simulation of high DER penetration using a "digital twin" of SCE's Camden substation. This simulation included 10,000 DERs (30 MW PV and 40 MW/80 MWh storage) with a gross customer load of 20 to 40 MW. The project's optimization and control software was used to control this system using real-time modeling. The last part of the demonstration was an actual field installation of the software utilizing real customers with DER installations (24 customers with 167 kW of PV and 56 kWh of storage). Both the simulation and field demonstrations showed controllable DER would be able to increase the amount of DER that could be interconnected to the Camden substation system by preventing grid voltage and load violations. Expansion of this monitoring and control software throughout the SCE service territory would help support future system demand growth.

Benefits

- **Enhanced customer interconnection** – An enhanced interconnection portal was demonstrated to allow up to 1,000 fast-tracked DER interconnection requests daily to be provisioned into the DERMS and DSO systems. Provisioning between SCE and the 3rd party DER aggregator was also established within this timeframe for IEEE 2030.5-compliant DERs. Once provisioned DER were immediately available for the DERMS to use. This enhancement was demonstrated to gain insights as to how DERMS and DSO systems could be automatically updated with registration information from a large number of newly interconnected customer DERs each day.
- **Improved distribution system operator (DSO) situational awareness and power flow optimization** – Simulated how improved sensing throughout each major branch in the Camden Substation 12 kV network (~100 voltage and current sensors) could be used for detecting constraint violations. The DERMS simulated voltage maintenance (like SCE's low-voltage management system) and demand response to correct thermal violations without the need for using capacitors or tap-changers.
- **DER optimization with network and electricity price data** – DSO simulation optimized the dispatch of 10,000 DER in Camden substation's 12 kV network while maintaining nominal voltage and current levels throughout the network. DER dispatches were cost-optimized daily through AC optimal power flow simulations that solved hourly, 24-hours a day. Input data for the DSO's cost-optimized DER dispatches included CAISO electricity price and system load information (locational marginal prices), PV generation forecasts using weather data, and network load forecasts per transformer (~1000 total on Camden) or via feeder-load allocation.

- **Increased DER hosting capacity territory-wide to supply demand growth** – The EASE architecture was designed to be scalable at the medium-voltage distribution substation level and would allow SCE to actively observe and control interconnected DER capacity via software to host more DER than traditionally possible. This will help SCE meet its targets for interconnecting 30 GW of generation and 10 MW of customer-sited storage on the distribution network by 2045.
- The EASE team performed a cost-benefit analysis to determine how increasing territory-wide DER hosting capacity could lead to cost-saving. A simple analysis provided a high-level estimate of potential savings through distribution capacity deferrals—assuming that the necessary combination of controllable DERs is available. The analysis estimated SCE could potentially recover the more than $400 million in planned Grid Modernization investments for the GMS and engineering and planning software tools by 2040 through distribution deferrals. This could potentially provide an additional $300 million in savings by 2045, assuming that SCE could continue to defer projects using the necessary combination of controllable DERs.[8]
- **Greenhouse gas reduction** - Combining SCE's distribution and bulk-system investments in clean generation and storage, by 2045 we expect to see a 339 MMT reduction in greenhouse gases. Another 108 MMT will need to be sequestered for SCE to reach its goal of carbon neutrality by 2045.[8]

Lessons Learned for This Sub-Project

EASE's core use-cases are being developed for SCE's GMS DERMS Optimization Engine and DERMS Short-Term Forecasting Engine. These production systems will allow SCE to optimize and forecast DER generation territory wide and will follow a similar process utilized by EASE. Insights from the project were used in developing the system requirements for both production DERMS engines to unlock new dynamic hosting capacity capabilities. These high-level insights are listed below:

- The EASE DSO could manage interconnected DER capacity via software that calculates their cost-optimized dispatch schedule to host more DER than traditionally possible on a substation system while remaining within the voltage and line-loading limits network-wide. Currently, SCE does not have enough distribution-level DER to support this capability but is making investments in its technology platforms and applications to handle more DER when it appears in the future. SCE continues to track DER eligibility in deferring wires-only capital projects through SCE's Grid Needs Assessment (GNA) and Distribution Deferral Opportunity Report (DDOR).
- The EASE DERMS could mitigate (within several minutes) short-term voltage and load-flow violations on the network using customer DER if voltage and power data were available from more locations. This added data could be obtained from SCE distribution sensors and customer DERs. The use of customer energy storage put a heavy burden on these systems since the control software rapidly charged and discharged the customer batteries.

- Capacitors and tap changers are better suited to handle slow voltage fluctuations but aggregated DER at scale could be used in certain peak loading and rapidly changing grid situations.

Partners

- Smarter Grid Solutions (SGS): DERMS platform
- Opus One Solutions: Transactive Energy Platform
- Kitu Systems Inc: DER Aggregator Platform
- Clean Power Research, Inc: Interconnection Portal
- NREL: Solar PV forecasting expertise
- City of Santa Ana: DER permitting linkage
- Pandora Consulting Associates

Attachment 2 – Adaptive Protection

Summary

The objective of the Adaptive Protection System (APS) was to adaptively (in real-time) adjust the settings of protective devices such as relays and remote automatic reclosers (RAR), and to understand how to better coordinate with reliability devices such as remote intelligent switches (RIS) based on the dynamically changing configuration of the feeder, DER status, and loading. The project was a lab demonstration focused on two activities:

- Model Degradation Analysis: Determined the impact of inaccuracies in the feeder model on calculated short-circuit fault duties. Since the calculation of protective device settings depends on the results of the short-circuit studies, the settings calculated with faulty short-circuit data might not satisfy the objectives of the protection system to clear hazardous short-circuit fault conditions from the grid in the least amount of time possible, with the least amount of service outage as possible. This task also considered the presence of DER on the feeder, and their impact on the calculated short-circuit currents.
- Protection Security Assessment (PSA) Tool Evaluation: The PSA tool is the heart of the APS system. It evaluates the protection deployed on the feeder for its ability to meet the protection objectives. In the event the objective is not met, the tool attempts to adjust the settings of the devices on the feeder such that an adequate coordination margin is maintained between upstream and downstream devices.

The results of the project were:

- The model degradation analysis found that incorrect conductor types or incorrect source impedance results in significant variations in the fault current when compared to a base-line model. The analysis also found that the presence of large DERs on the feeder, either modeled in an aggregated manner, or distributed along the feeder at different locations, caused significant changes in the currents measured at the feeder source. As such, there is a case to be made for an application or tool that adaptively adjusts protective relay settings, based on actual system changes.
- Within the PSA tool, a function was implemented to adaptively adjust protective device settings to maintain 0.5 second operating margin between devices that have a primary and backup relationship with each other.

With the successful completion of these activities, SCE is well positioned to advance the APS project to the next step, which is the implementation of the APS functionality within the framework of an Advanced Distribution Management System. The detailed functional specification developed for this project was used as the basis for the commercial GMS version of the APS.

Benefits

- Improved feeder protective device coordination and sensitivity where there are significant DERs or following feeder reconfiguration will improve the safety and reliability of the distribution grid.

Lessons Learned for This Sub-Project

- Model Degradation Analysis: Determined the impact of inaccuracies in feeder models on calculated short circuit duty. Work still needs to be done to determine the level of sensitivity needed for adequate feeder protection.
- Protection Security Assessment: Determined the functional scope for an adaptive protection system. Work still needs to be done to validate existing business requirements.
- The small batch of test circuits did not encompass other factors such as rural circuits that are typically longer. A more representative cluster of test circuits needs to be evaluated.

Partners

- Subcontract to Siemens to deliver the pilot demonstration

Attachment 3 – Integrated Grid Analytics (IGA)

Summary

Increasing bulk PV system and behind-the-meter intermittent and variable resources are increasing the complexity of planning and operating the grid. Today's grid operators are 'flying blind' with PV, grid susceptibility to loss of generation due cloud cover, and grid issues that impact solar PV generation resulting in 44 scenarios impacting grid normal and emergency operating scenarios. These impacts exemplify the need for new grid planning and management systems.

The purpose of this proof-of-concept project was to better inform future grid infrastructure deployments using data integration and test four new grid concepts to enable higher levels of PV penetration. The four concepts that were tested seek to allow higher PV penetration without a reduction in reliability, safety, or affordability. They were:

- Integrate data from AMI, 3rd parties, and distribution network topology to improve PV situational awareness and determine PV susceptibility.
- Improve the distribution system model fidelity through access to data at a more granular level using load blocks.
- Advance new short term 14-day and peak forecasting to support grid managements systems.
- Improve peak load management using an optimized portfolio of DERs.

The project was able to advance and enhance system fidelity with data, IT/OT and modeled data-driven capabilities which can improve peak load management and was demonstrated in four new ways:

- Provide higher fidelity insight into the grid loading at many more locations (using calculated data from circuit load blocks instead of only a single measured data point from the head of the circuit at the substation).
- Inform grid infrastructure deployments through a better understanding of the net impact of DER on the load shape using temperature and cloud cover forecast.
- Provide access to peak demand forecasts within 1 to 3% of the actual observed peak.
- Show how to dispatch DR and energy storage more surgically through an optimized DER plan for peak load management.

Benefits

- Provide decision support for operations engineers, system operators, planners, and distribution engineers.
- Improve SAIDI (System Average Interruption Duration Index) and CAIDI (Customer Average Interruption Duration Index) by avoiding unanticipated outages due to improper forecasting of DER generation output.

- AMI, 3rd party solar data, and distribution network topology information were temporally and spatially combined to improve DER situational awareness and to help solve the PV susceptibility issue.
- Project data analyses can be used to write better switching plans that take into account PV output, detailed load forecasts, and unexpected overloads. This input data helps with pre-planning (2 weeks out), plan verification (1 to 3 days out) and on the day of plan execution.
- Produced learnings and insights that supported the specification of the Grid Management System

Lessons Learned for This Sub-Project

- Better distribution system modeling fidelity improved the distribution system model by enabling access to and being able to observe the system operations at a more granular level, which can improve operational efficiency, reliability, and safety.
- Discrepancies of between 10% and 90% were found between SCADA readings at the head of a circuit and aggregated AMI load data from that same circuit. This points to database problems that need to be resolved.
- There also seems to be significant discrepancies between different data sources (1079 units) in the number of PV system attached to the grid in the test area.
- The use of 3rd party estimated solar output data may have significant errors when compared to actual inverter output data.
- Demand response capacity (e.g., summer discount program) can be calculated and integrated all the way down to the switch (load block) level on a circuit where load switching occurs for peak management.

Partners

- mPrest
- SLAC
- PREDICT

Attachment 4 – Integration of Big Data for Advanced Automated Customer Load Management

Summary

The purpose of this project was to showcase an IEEE (Institute of Electrical and Electronics Engineers) 2030.5 Distributed Energy Resource Management System (DERMS) that interfaced with customer DERs, DER systems, and DER aggregators. Within the Integrated Grid Project (IGP) back-office environment, the DERMS executed registration, grouping, monitoring, and targeting of customer DERs in aggregate.

This project used an IEEE 2030.5-compliant DERMS to:

- Demonstrate CSIP (Common Smart Inverter Profile) use cases for IEEE 2030.5 (i.e., grouping, monitoring, controls, and registration) that investor-owned utilities (IOU) are developing.
- Evaluate the IEEE 2030.5 DER function set for effectiveness and completeness, with results guiding future revisions of the standard.
- Define and demonstrate integration with SCE's back-office systems to securely exchange data, as well as implement open and closed looped controls.

The project was able to successfully demonstrate how new smart inverter capabilities can use IEEE 2030.5 as defined by CSIP. Other project results included:

- Supported the design and related testing for the secure integration of IEEE 2030.5 services into SCE's production environment.
- Worked with standards committees to update IEEE 2030.5 and CSIP based on the project work.
- Identified possible inverter integration and customer communication issues.
- 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.

The project has demonstrated the use of IEEE 2030.5 as a useful protocol for communications with large numbers of customer DERs.

Benefits

- Enable 2030.5 service integration requirements with SCE's back-office systems.
- Determine Rule 21, Phase 2, CSIP 2030.5 server and end-to-end interactions' effectiveness (i.e., latency, functionality, security, etc.) through actual testing.
- Develop architectures and requirements to implement internet-based controls from SCE's back office securely.
- Support IEEE 2030.5 CSIP certification needed to validate customer DER interconnections.

Lessons Learned for This Sub-Project

The project inverters' modification of generation curves and dispatch of real power based on external controls was challenging. 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 brief 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-owned communications (e.g., cellular) should be used.

The project was unable to define cybersecurity requirements for the systems and communications beyond its aggregator interfaces. The DER industry, vendor alliances, vendors, and standard development organizations should work with the utility industry to develop and implement strong cybersecurity requirements.

Partners:

The project engineers supported the development and revisions to CSIP, the Smart Inverter Working Group and California Rule 21 proceedings.

Attachment 5 – ARPA-E – Distribution System Operator Simulation Studio (ProsumerGrid DSO)

Summary

The purpose of this DOE ARPA-E project was to develop a simulation tool capable of evaluating the operation of emerging distribution system operator (DSO) models. The tool needed to account for physical and market constraints, as well as information and coordination requirements. The software provided a more customer-oriented design studio environment in which various DSO design concepts could be assessed.

ProsumerGrid Simulation Studio is a software tool based on an interactive and multi-agent framework that merges T&D system analysis capabilities with markets and other algorithms. This software can simulate DER impacts at the physical, information, coordination, and market levels.

The project demonstrated DSO Simulation Studio, which included three core capabilities:

1. DER Scheduling and Decentralized Optimization - determines schedules for sets of DERs based on various scenarios. DER decision variables include curtailable photovoltaic (PV) generation, schedulable storage, electric vehicles, and customer demand elasticity. The DER dispatch schedules are optimized for distribution locational marginal prices (DLMP), given various physical constraints.
2. Locational Value Analysis **-** models, assesses, and potentially recommends DERs as non-wire alternatives to transmission or distribution infrastructure investments.
3. Advanced Visualization - presents DLMP information in a GIS format through a web-based interface.

The project demonstrated the conversion of Cymdist models to Gridlab-D and ran a large DSO simulation with over 2000 transmission busses and 20 feeders with about 100 DERs each, showing the scalability of joint transmission and DSO studies. Visualization of the results using the software showed multiple layers of information such as geographical location of loads and DERs, market components, and interaction with other regions (DSO-DSO and DSO-independent system operator). Overall, the software appeared to be a valuable tool to simulate and evaluate future DSO models.

Benefits

- Computer code was developed in Python to convert Cymdist models to Gridlab-D and made available to others to use.
- The project software facilitated DSO conceptual design testing and help develop DSO functional requirements.

Lessons Learned for This Sub-Project

- The software had advanced visualization capabilities that would be useful to grid planners and operators. These included visualizations of geographical location of loads and DERs, electrical solutions of grid power flow, market behavior, and interactions with other markets.
- The existing software to convert Cymdist models to Gridlab-D did not function well and needed to be rewritten by the project before it could be used.
- The Advanced Decentralized Optimization module was able to schedule sets of DERs based on the desired DSO objectives as planned.
- The software was able to model and recommend DERs as non-wire alternatives to transmission or distribution infrastructure investments.

Partners

- ProsumerGrid (Lead)
- National Rural Electric Cooperative Association
- New York State Smart Grid Consortium
- Newport Consulting Group
- Southern California Edison

Attachment 6 – ARPA-E NODES – NREL – Real-Time Optimization and Control of Next-Generation Distribution Infrastructure

Summary

The NODES program is intended to enable renewable penetration at the 50% level or greater using load flexibility and DERs while reducing costs, CO_2 emissions, and improving grid resilience. The National Renewable Energy Laboratory (NREL) team developed a comprehensive distribution network management framework that unifies real-time voltage and frequency control at the home or DER controller-level with network-wide energy management performed at the utility or aggregator level. The distributed control architecture continuously optimizes the operating points of DERs, while dynamically procuring and dispatching synthetic reserves (synthetic frequency control - Category 1 and regulation reserves - Category 2 ancillary services) based on the current system state and forecasts of load conditions. The control algorithms invoke simple mathematical operations that can be embedded on low-cost microcontrollers, and enable distributed decision making on time scales that match the dynamics of distribution systems with high renewable integration.

Southern California Edison's role in this project was to work with NREL to:

- Develop the hardware in-the-loop (HIL) test plan.
- Provide a multi-phase feeder model with hundreds of real and simulated DERs in three and single-phase points of interconnection.
- Utilize a detailed PowerFactory network model to implement a frequency and voltage regulation optimization algorithm.
- Perform HIL testing and large-scale simulation testing with 100 DERs.

Benefits

- Increase the distribution system capacity through load following utilizing DER control.
- Mitigate costly peak demand periods and reduce energy waste.
- Use DERs to provide frequency control and regulation ancillary services to the grid.
- If implemented across the country, reduce CO_2 emissions by 290 million metric tons nationally (US) each year.
- If implemented across the country, replace 4.5 GW of spinning reserves, saving customers $3.3 billion nationally (US) each year.

Lessons Learned for This Sub-Project

- Flexible loads and DERs can contribute to offsetting thermal generation and reduce CO_2 emissions.

- Control of flexible loads and DERs can contribute to a reduction of the need for spinning reserves.

Partners

- NREL (prime)
- Harvard University
- Solar City
- Southern California Edison
- California Institute of Technology
- University of Minnesota

Attachment 7 – ARPA-E NODES – GE Grid Services

Summary

The NODES program is intended to enable renewable penetration at the 50% level or greater using load flexibility and DERs while reducing costs, CO_2 emissions, and improving grid resilience. The objective of this project was to explore the potential for load flexibility to provide ancillary services (regulation and ramping), reduce solar/wind curtailment, and reduce greenhouse gas emissions and costs. The project developed a system to aggregate loads and DERs to deliver grid services. There were four main tasks:

- Quantify available flexibility of loads
- Calculate its value to the power system at 50% renewable energy penetration
- Enumerate the expected cost of enabling this flexibility
- Design, implement, and demonstrate a scalable control system to provide operational flexibility

Using aggregated SCE customer data and key load types identified as having flexibility, models were developed to establish regulation and ramping load flexibility supply curves. Using these curves, it was determined that the Category 2 California regulation reserves (1,715 MW) could be met using load flexibility for 8453 of the 8760 annual hours. It was also determined that all but two hours of the Category 3 California ramping requirement (4,258 MW) could be met with load flexibility. Additional flexibility resources such as electric vehicle charging and energy storage systems could be used to meet 100% of the requirements.

Additional steps need to be taken to determine the best way to work with customers to implement load flexibility. This includes the establishment of the signaling technology and determination of customer compensation for use of their loads.

SCE's role was:

- Provided aggregated customer data for modeling of customer load flexibility
- Helped quantify available flexibility of loads
- Assisted with benefits quantification for the WECC system

Benefits

- Provided flexibility supply curves.
- Determined the value that distributed flexibility resource (DFR) brings in terms of avoided costs to be in the range of $1 – 7 per MWh of DFR depending on the scenario.
- Determined the value of DFR to provide spinning and regulation reserves to be $2.95 per MWh.
- If implemented across the country, this technology could use load and DER flexibility to offset 3.3 quads of thermal generation and displace 290 million tons of CO_2 emissions each year.

- If implemented across the country, this technology could use integration of flexible loads and DERs to replace 4.5 gigawatts of spinning reserves at a value of $3.3 billion each year.

Lessons Learned for This Sub-Project

- Loads can provide significant flexibility to satisfy grid ancillary service needs.
- Seven key load types that could provide flexibility were identified (central HVAC, large-packaged HVAC, chiller plants, commercial refrigeration, lighting, behind the meter storage, and EV charging).
- Significant cost and CO_2 emission reductions are possible using flexible loads.
- PV and wind generation curtailment can be reduced using flexible loads.

Partners:

- GE Global Research (Prime)
- GE Energy Consulting
- Southern California Edison
- LBNL

Attachment 8 – ARPA-E NODES – PNNL – Multi-Scale Incentive-Based Control of Distributed Assets

Summary

The NODES program is intended to enable renewable penetration at the 50% level or greater using load flexibility and DERs while reducing costs, CO_2 emissions, and improving grid resilience. PNNL (Pacific Northwest National Laboratory) developed and tested a hierarchical control framework for coordinating the flexibility of a full range of DERs, including flexible building loads, to supply reserves to the electric power grid. The hierarchical control framework consisted of incentive-based control strategies across multiple timescales. The system used a slower incentive-based approach to acquire flexible assets that provide services, combined with faster device-level controls that use minimal communication to provide desired responses to the grid. Each DER that participated in the project communicated its ability to provide flexibility and the timescale over which it could provide the service. A distribution reliability coordinator acted as an interface between the DERs and the bulk system, coordinating the resources in an economic and reliable manner. The performance of the resulting hierarchical control system was tested at scale in a co-simulation environment spanning transmission, distribution, ancillary markets, and communication systems.

SCE's role was:

- Applied a synthetic ramping capability (developed by PNNL) to a simulation of one of its distribution feeders through hardware in-the-loop testing in SCE's Controls Testbed.
- Evaluated the synthetic ramp control's capability to operate the distribution feeder as virtual energy storage by controlling the DERs on the feeder to maintain targeted levels of real and reactive power.

Benefits

- The project provided technology and capabilities required for the grid to use flexible loads and DERs.
- If implemented across the country, this technology could contribute to offsetting thermal generation and reducing CO_2 emissions by 290 million metric tons nationally each year.
- If implemented across the country, this technology could contribute to replacing 4.5 GW of spinning reserves, saving customers $3.3 billion annually (national basis).

Lessons Learned for This Sub-Project

- Demonstrated a method to integrate DERs into dynamic system operations.

- Characterized various DER types to quantify the maximum flexibility that can be extracted from a collection of DERs in aggregate. This characterization was used to show how service level guarantees could be delivered to the bulk energy market operator.
- Showed that the PNNL hierarchical control system could perform at scale in a co-simulation environment spanning transmission, distribution, ancillary services market, and communications systems.

Partners:

- PNNL (Prime)
- United Technologies Research Center
- Alstom Grid
- Southern California Edison

Attachment 9 – CEC PON – SunSpec Alliance

Summary

California Energy Commission (CEC) Grant EPC-14-036 was awarded to the SunSpec Alliance and project partners to develop, demonstrate and evaluate standardized third-party DER systems that will address key barriers impeding the progress toward high DER penetration while maintaining reliability. The CEC-funded project aimed to:

- Enable high penetration of cost-effective solar photovoltaic (PV)-based DER beyond current Institute of Electrical and Electronics Engineers (IEEE) limits
- Enable the availability of well-tested, "plug-and-play," communications-capable smart inverters
- Provide sufficient data to evaluate the grid impacts of solar PV

This project relied on aggregated resources, and therefore supported the development of a California Public Utilities Commission Rule 21 utility-to-aggregator communication interface, evaluated the use of an aggregator to target specific DER functionality, and demonstrated the integration of aggregated DER management into available IGP control systems.

SCE's role in this project was to support the field demonstration with SCE's IEEE 2030.5 Application (from the Big Data project) which included the monitoring and control of residential DER systems owned by a 3rd party aggregator. The project tasks included:

- Integrate the complete DER ecosystem and confirm interoperability.
- Confirm ability to operate DER assets without violating utility operating procedures including safety and compliance.
- Configure and test monitoring and control interface systems.
- Demonstrate that aggregated DER systems respond correctly to CA Rule 21 mode changes.

Benefits

- Provided a standards-ready test and certification framework.
- Demonstrated how DER assets provided ancillary grid services.
- Identified revenue models for DER investors and operators.
- Enabled availability of well-tested plug and play communications-capable smart inverters.
- Provided financial analysis of using smart inverters showing an annual savings of $640 million to $1.4 billion.
- Knowledge gained from the project was made available via the SunSpec Alliance distribution channels including its website, newsletters, educational events, media outreach, and promotional events.

Lessons Learned for This Sub-Project

- The developing grid connection and inverter standards need to be aligned and end-to-end functional testing and certification procedures need to be established.
- Strong communications commissioning, monitoring, and related performance requirements need to be developed and included within interconnection and program requirements.
- The DER industry, vendor alliances, and vendors should work with the utility to develop and implement strong cybersecurity requirements.
- Customers need to be educated about how connections are set up at their site, so they do not inadvertently modify inverter modes.
- Stakeholders need to account for the fact that at any time a certain percentage of residential customer inverter systems cannot be relied upon to provide data or grid support due to communications failures.

Partners

- SunSpec Alliance (Prime)
- Southern California Edison
- Kitu Systems

Attachment 10 – CEC PON - EPRI

Summary

California Energy Commission (CEC) Grant EPC-14-079 was awarded to the Electric Power Research Institute (EPRI) and project partners to assess the ability of smart inverters and smart consumer devices to enable more residential solar energy. The project was specifically focused on the local PV hosting limitations that occur when multiple PV systems are installed on the same residential transformer. Smart inverters can help mitigate these issues. It is not known whether multiple inverters can operate side-by-side in stable conditions when each one is performing smart inverter functions.

SCE developed laboratory smart inverter testing methods to identify how the functions identified in California Public Utilities Commission's Rule 21 on interconnections (Rule 21) can be used and configured so that multiple smart inverters work in harmony (supporting one another's actions). SCE used these testing methods to evaluate some of the smart inverters on the market.

While working on these tests, inconsistencies among Rule 21 specifications of the California utilities led to questions about the proper configuration of currently installed inverters. The new test procedures developed by the project will help investigate these issues and may also provide improved data for modeling advanced function inverters.

Benefits

- Provided experience with inverters operating with the new smart inverter communications and controls required by Rule 21.
- Evaluated the strengths and weaknesses of these smart inverters to determine how they can help increase penetration levels of DER on distribution circuits.
- Results from this project help regulators and grid operators evaluate regulatory changes needed to scale deployment of Rule 21-compliant inverters and assess the outcomes that are relevant to their DR programs and reliable grid operations.

Lessons Learned for This Sub-Project

- Some inconsistencies were revealed in how Rule 21 specifications are implemented by utilities through the testing conducted by this project. These inconsistencies can be corrected to safely allow high penetration of PV systems on distribution feeders.
- It was difficult to setup and performing field tests for the new smart inverters since there was an absence of Rule 21 compliant inverters from manufacturers.

Partners

- EPRI (Prime)
- Underwriter Labs

- Southern California Edison
- Intwine Connect
- ClipperCreek
- Sacramento Municipal Utility District
- Pentair
- Emerson Climate Technologies
- A. O. Smith Corporate Technology Center

Attachment 11 – DRP Demonstration D Final Status Report

DRP Demonstration D

Final Status Report

Dated 30 July 2019

SOUTHERN CALIFORNIA EDISON®
Energy for What's Ahead℠

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1. Executive Summary

1.1 Introduction

Consistent with Decision (D.)17-02-007, SCE is providing the following report for Distribution Resource Plan Demonstration D (Demo D), and includes a summary of learnings relating to project planning, control software design/implementation, and laboratory testing of these controls using a real-time simulator.[10]

SCE's DRP Demo D project was designed to develop, test and demonstrate a system that could monitor and operate multiple DERs under various ownership and control arrangements (including SCE-owned, customer-owned, aggregator-managed and third-party-owned) and how the distribution system can be managed with high penetrations of DERs.[11]

The value and learnings SCE has obtained from Demo D tasks are significant, as they include the design, development and testing of new control and communication systems for the grid and their first-time integration into SCE's existing supervisory control and data acquisition system (SCADA).[12]

The output from these activities could improve SCE's capability to more accurately assess how high penetration of DERs will influence distribution planning operations. For example, these learnings are helping SCE move forward with the new Grid Management System (GMS) that enables management of the electrical system with high penetrations of distributed energy resources.[13]

SCE has determined that Demo D cannot not be completed because actual field testing cannot be performed due to the following cybersecurity challenges:

As SCE designed the solutions for the EPIC Integrated Grid Project (IGP) / Demo D - including the associated DRP demonstration projects, SCE conducted periodic cyber security assessments to ensure our solutions do not create greater cybersecurity expose our production grid systems.

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10 D.17-02-007, at Ordering Paragraph No. 9 ("Southern California Edison Company's Demonstration Project D is approved."); R.14-08-013, COMMENTS OF SOUTHERN CALIFORNIA EDISON COMPANY (U 338-E) PROPOSING DEMONSTRATION PROJECTS, filed June 17, 2016, at p. 32-33 ("To keep the Commission informed on the progress of Demonstration D, SCE proposes to submit an annual status report depicting all the achievements, issues, budget, and schedule updates. . . . SCE also proposes to submit a final report … [which] will outline the project, findings, and lessons learned.").

11 D.17-02-007 at p. 11 ("Demonstrate Distribution Operations and High Penetrations of DERs. This project calls for the utilities to integrate high penetrations of DER into their distribution planning operations. The utilities must: a) assess locational benefits and values of DER at the substation level using ICA and LNBA across multiple circuits; b) demonstrate the operations of multiple DER in concert; c) coordinate operations with third parties and customers; d) develop and explain the methodology for selection of DER types used in the project; and e) utilize both third-party-owned and utility-owned resources.") (Quoting Scoping Memo).

12 A complete list of the key lessons learned for this demonstration project is presented in Section 1.5.

13 Demo D learnings will also inform the development of DER control systems, communications protocols, cybersecurity, Field Area Network (FAN) communications, and methods to work with customers and aggregators.

The threat environment these demonstration projects are slated to operate in has evolved, necessitating additional cybersecurity controls. As such, in order to protect grid systems and deploy field demonstrations that are secure, SCE concluded that it must delay deployment until it can integrate and deploy the appropriate cybersecurity controls with the demonstration technologies to minimize the risks to our grid production systems. This delay is estimated to prevent deployment until at least 2021.

Following the identification of this security issue, the Demo D project team worked extensively with the teams from SCE's Information Technology (IT) organization and particularly with SCE's Cybersecurity organization to identify alternative approaches and architectures that would enable SCE to conduct the field demonstration activities without waiting until the new recommended security tools were in place.

The Transmission and Distribution (T&D) team met with key SCE stakeholders to determine an appropriate decision on how to proceed with Demo D and meet the DRP objectives and perform a Field Demonstration.

Following this analysis, SCE concluded, that Demo D should be concluded at the end of the current System Acceptance Testing (SAT) testing period. This decision was based on the anticipated length of the cybersecurity delay and the substantial learnings already achieved from the program.

Because SCE is not completing field testing, this demonstration will not provide additional learnings regarding operational activities. But this operational experience can now be gained during the testing phase of SCE's GMS project.

1.2 Demo D Project Objectives and Overview

This project called for SCE to determine how to plan, design and deploy the next generation grid infrastructure capable of enabling advanced operational functions such as bi-directional power flow, thereby allowing for higher penetrations of distributed energy resources (DERs).

These DER would include DER under various ownership and control arrangements (including SCE-owned, customer-owned, aggregator-managed and third party-owned). Specifically, high penetrations for this project was developed to demonstrate reliable operation of the grid with DER penetration levels in excess of 15%.

The output from the following activities would improve SCE's capability to more accurately assess how high penetration of DERs will influence distribution planning and investments:

a) Assess locational benefits and values of DER at the substation level using ICA and LNBA across multiple circuits;

b) Demonstrate the operations of multiple DER in concert;

c) Coordinate operations with third parties and customers;

d) Develop and explain the methodology for selection of DER types used in the project; and

e) Utilize both third-party-owned and utility-owned resources.

The results of Demonstration Project D would inform SCE, the Commission, and stakeholders on alternatives for operational processes, control systems and integration equipment to safely and reliably manage high penetration circuits on the distribution grid.

More specifically, this demonstration project would provide knowledge, experience and requirements to develop the following capabilities:

Develop the next generation of distribution grid control systems and algorithms.

Monitor and validate the DER performance for voltage and power flow control.

Improve methods for gathering DER field data and properly displaying it to grid operators.

Standardize the interface requirements between third party DER resources and the utility's operating systems.

Ultimately, Demo D would inform the industry grid standardization processes as well as inform selection of future distribution grid upgrades needed to provide safe, reliable, and affordable service to SCE's customers. Demo D would also demonstrate the back office and cybersecurity systems needed to manage large penetrations of DER in a scalable manner.

1.3 Level of Completion of Key Activities

Below, SCE lists key activities that were identified to accomplish the objectives, listed above in Section 1.2, and the level of completion that was accomplished for each.

Provide a demonstration test bed for systems, equipment, and concepts for future modernization efforts.

Level of Completion:

Assembled a demonstration test bed which allowed laboratory testing as well as testing with production SCE systems in the Alhambra Control Center Quality Assurance System (QAS). The control systems were not demonstrated in the field.

Verify technology readiness and potential architectures for production systems such as GMS and Distributed Energy Resource Management System (DERMS).

Level of Completion:

Verified the system architecture and technology readiness via testing through SAT in the QAS environment. The control system architecture was not verified in the field.

Test new communications technologies and standards such as the Field Area Network (FAN) radio communications system and the IEEE 2030.5 standard for communications to aggregators for smart inverters.

Level of Completion:

Tested new FAN communication technologies, and their integration, via laboratory and production system testing in the SAT / QAS environment. These systems were not verified in the field.

1.4 Key Accomplishments

Demo D contributed learnings to various distribution planning operations tools and technologies as follows:

Grid Management System (GMS)

GMS utilized Demo D learnings for GMS DERMS development and associated supplier selection

GMS utilized certain Demo D use cases as a foundation for the development of selected GMS use cases

The Demo D Operational Service Bus (OSB) served as a demonstration of an efficient architecture for the GMS, allowing the management of interfaces between multiple applications.

GMS utilized Demo D requirements as a starting point for the requirements gathering exercise for control systems and related architectures, FAN requirements, and communication with 3rd parties.

Factory Acceptance Testing (FAT)/ Laboratory Testing

Designed and tested an IEEE 2030.5 implementation with controllers that met SCE cybersecurity requirements

Designed and tested an IEEE 2030.5 implementation with controllers to be used by a DERMS

Successfully evaluated the use of the IEEE 2030.5 standard for end-to-end communications and control of new smart inverter capabilities as defined by the Common Smart Inverter Profile (CSIP) and demonstrated integration with SCE's back office systems (as part of SAT).

Tested volt/VAR and power flow optimizations for high penetrations of DERs. This activity assisted the development of the request for proposal requirements for the Advanced Distribution Management System (ADMS)

Assessed and tested control application integration through an OSB architecture

Completed the development of detailed Interface Service Definitions for the GE Predix OSB, which are now reusable for the DERMS and ADMS implementations

Assessment of field messaging bus technologies and their practical maturity level

Demonstration of Agile methodologies and their benefits for DERMS and ADMS implementations through the laboratory and FAT testing

Site Acceptance Testing (SAT)

Connected an IP based device to the lab copy of the production distribution management system (DMS); findings informed connection of the first IP based devices (battery energy storage systems) to the production DMS.

Integrated and tested the DESI-2 battery system simulator with the control system in QAS/SAT; lessons learned are now informing the Energy Storage Integration Program (ESIP) measurement and validation (M&V) testing.

Integrated and tested IntelliCAP Plus (serial based programmable capacitor controller) and IntelliCAP 2000 (Ethernet based programmable capacitor controller) with the control system using the FAN network's edge computing capability.

- Identified bugs informed hardening of FAN application hardware/software
- Identified process improvement and training needs
- Improved requirements and documentation for the future FAN work

Successfully ran the control system 24/7 for two weeks in the QAS test environment (Alhambra).

Developed a hardware and software-in-loop test bed that can now be utilized for testing of GMS/DERMS production applications

<u>**Field Area Network**</u>

Assisted the development and integration of the new FAN technical design and specifications

Assisted the development of detailed system requirements for the FAN RFP

Conducted FAN vendor product assessment in SCE's Grid Technology & Modernization (GT&M) lab and in the QAS environment

Implemented new comprehensive FAN testing equipment setup and procedures in GT&M lab

Completed a radio frequency model for the FAN radios derived using automated testing processes

Integrated the new FAN with the Common Substation Platform (CSP)

Designed and delivered an IPv4/IPv6 dual stack solution that increased flexibility of the FAN solution and integration with SCE back-office software applications (e.g. ADMS)

Enabled a FAN testing platform for DERMS and ADMS by integrating the new FAN into back-office systems including common shared and security services

Documented new business process flows needed for FAN field deployment

Developed an edge compute implementation in the FAN radios for cap controllers

Discovered and corrected errors with the FAN radio's internal network address translation (NGT&M) functionality preventing communication between the FAN network and IP based devices

Other Accomplishments

Identified the demonstration site for the DESI-2 utility-owned storage system on the test circuit

Developed system requirements and completed the system design for high penetration DER control systems

Developed a high-level integration path for aggregators of DERs using IEEE 2030.5

Integrated the distributed control systems with the DMS through the integration platform in the lab setting

Assembled a laboratory test environment based on the DigSILENT PowerFactory simulation system to allow more comprehensive testing of the control systems

Completed FAT testing in the GT&M lab and SAT testing in the QAS environment of the control systems and the OSB. This activity included system and integration testing with four FAN radios and lab-based edge devices

1.5 Key Lessons Learned

The learnings from Demo D are being used by SCE to provide the requirements for future grid modernization investments and activities. For example, while conducting a major system upgrade (such as Grid Modernization), it is critical that early in the process new technologies, and their integration, are thoroughly tested to confirm architecture assumptions and technical requirements. Demo D conducted this early stage testing, including the development of DER control systems, communications protocols, cybersecurity, FAN communications, and methods to work with customers and aggregators.

Ultimately, the Demo D learnings provide a smoother, better-defined transition to a smarter grid that can operate reliably and safely with high penetrations of DERs. These lessons will continue to inform future modernization efforts.

A complete list of the lessons learned for this demonstration project is presented below:

General

DERMS is needed in the future to optimally manage and dispatch DERs to provide grid services, facilitate non-wires alternatives, and enable DERs to participate in markets when not needed for grid services.

DERMS provides capabilities that current utility DMS does not provide. A DERMS-like system is also required to complete the Distribution Resource Plan Demonstration projects (Demos C, D, and E), as these projects require control and dispatch of DERs to realize net locational benefits, circuit optimization, and microgrid controls.

Significant difficulties recruiting customers with DERs to help demonstrate grid reliability services point to problems with the programs used to incentivize customers to cooperate

Proposed programs to use customer DERs for grid services can conflict with their existing warranty provisions, energy production contracts, and demand charge reduction goals

Behind the meter (BTM) DER resources will be extremely valuable to the reliability of the future grid

Individual, not aggregated, DER measurements are critical to modeling grid behavior and providing better situational awareness to grid operators

Constraint management on distribution circuits can be implemented by both charging and discharging of battery systems

Field Area Network

FAN radio technology can provide higher speed communications that enables quicker, and potentially automatic, response to an outage which reduces restoration times

Results from lab testing of various FAN vendors has established which criteria are most important in selecting a final FAN vendor

The FAN radios are IP based and contain edge computing capabilities that allow control actions to take place locally, avoiding the need and delay for messages to go all the way to the Alhambra Grid Control Center and back to a device

The FAN radios currently do not support the required communication for high speed generic object oriented substation event (GOOSE) communication (part of the IEC 61850 standard)

The GOOSE testing experience demonstrates the routable-GOOSE testing effort will take longer than originally forecasted

To successfully prepare future IP based devices for the FAN system, IT needs to finalize system architect well in advance of the required operational date

Cybersecurity

Cybersecurity threats are continually changing and thus pose significant challenges in regard to determining preventative tools and the timing associated with developing and validating them

Cybersecurity challenges with IEEE 2030.5 protocol, caused by interfacing Internet communications with SCE grid control systems, has been difficult to resolve

The project team needed to get cybersecurity input to system design in the earliest phases of the project to mitigate downstream delays

IEEE 2030.5

The IEEE 2030.5 communications protocol is in the early stages of implementation in the industry

Aggregators have had a difficult time implementing the IEEE 2030.5 standard due to the limited number of suppliers who have full protocol support packages available at this time

Piloting

Lab testing in an environment that mirrors production provides valuable insight to validate capabilities on the distribution system

A lab development environment provides the following key benefits:

Allows testing of multiple applications, hardware configurations and communications infrastructure

Allows testing of both centralized and distributed controls, optimization routines, and simulation of hypothetical DER adoption or load growth scenarios

Hardware-in-the-loop testing allows the utility to gain confidence in the outcome of deploying advanced control schemes into production

Lab testing has demonstrated that it may be viable to establish “temporary” microgrids with DER to support isolated load, which likely requires in front of the meter energy storage devices and a change in existing tariffs

Customer Participation

Signing up DER resources as only demand response resources limits the scope of services available for grid management

Need tariffs or standard contracts for customers to provide services from their DERs

The primary challenge in effectively obtaining customer participation is creating clearly defined measurable incentives and contract protections for them

A significant issue with customer participation is that existing DER customers do not have the ability to change their existing tariffs or contract terms. In addition, DER service contracts need to be structured to allow resource dispatch both at an individual and utility defined group levels and not define DER services to a specific circuit, as distribution grid topology is highly dynamic.

<u>Technology Architecture</u>

The current state of the industry for publish and subscribe services is immature and should be introduced in a phased approach. An OSB should be confined to the back office and not pushed down to the edge at this time.

The concept of a field message bus is in its infancy and not ready for prime time.

Forecasting and dispatching strategies require individual, not aggregated measurements.

Implementation of the IEEE 2030.5 protocol introduces security threats that require a new network architecture and cyber tools to isolate communications.

<u>Overall Project Lessons Learned</u>

Lab testing with a real-time simulation approach allows examination of a broad range of conditions before field deployment

Edge computing capability in the FAN field device is vital to allowing network adaptability and future implementation of new applications and capabilities

Integration of multiple applications through the OSB is key to easing future integration efforts, but needs to mature for production deployments

Recruiting customers for the demonstration requires establishing value for their efforts/equipment use

Software vendors need to improve the user Human Machine Interface (HMI) for a better user experience, situation awareness, and control capabilities

Vendors need to develop the capability for auto-discovery and auto-registration of field devices

Control system vendors use various versions of system software (operating system, databases, etc..) that are not easily portable to SCE's standard software and operating systems

1.6 Challenges Encountered

The following provides a summary of the critical challenges encountered:

The requirement to develop and integrate technologies that were new and previously unproven resulted in an extremely challenging efforts. This included the following:

- A stable communication path between the Demo D controllers and the Operational Service Bus
- A stable communication path between the Demo D controllers and the new FAN radio

The recruitment of DER customers utilizing current incentive programs was very difficult and yielded significantly less sign ups than anticipated

The ability to maintain a stable and consistent schedule due to the following:

- Anticipating and managing the significant technical challenges mentioned above
- Estimating the timing to for approval and set up of test environments for brand new technologies within SCE

The degree of new cyber threats and their impact on project progress via the need for and timing of new technologies and their respective test environments (Please see prior discussion concerning cybersecurity challenges in Section 1.1).

1.7 Funding

The Demonstration D project is part of the Integrated Grid Project which utilizes EPIC funding.

There was no incremental funding requested for non-procurement expenses under the Distribution Resource Plan Track 2 proceeding, which is consistent with the approval obtained in CPUC Decision 17-02-007, dated February 9, 2017.

2. Project Summary

2.1 Objectives

SCE's Demonstration D project primary goal was to analyze the potential benefits and locational values associated with high penetration DER at the substation level for up to five circuits, to serve as a prototype model that is scalable upon completion.

To accomplish this, the project pursued to explicitly demonstrate the operations of multiple DERs in concert with customers and third-party owners, operators or aggregators. Thus, a central part of this project was to monitor and control resources under various ownership and control arrangements, including SCE-owned resources, customer-owned resources, aggregator-managed resources, and third party-owned resources.

The field portion of the project was intended to be in the Santa Ana/ Costa Mesa portion of Orange County (*see* Section 2.4) and aimed to control DER owned by SCE, customers, and third-party aggregators in a coordinated manner.

2.2 Scope

To achieve the stated goals for Demo D, the following tasks were pursued to demonstrate distribution operations of high penetration DERs:

Assess the locational benefits and values of DERs at the substation level using the established ICA and LNBA for up to five circuits.

In collaboration with third party owners, operators or aggregators, construct a DER portfolio and the associated control system. This portfolio will include existing DER resources in the area as well as new resources being installed.

Once deployed, the DERs will operate in concert with each other and with existing infrastructure to demonstrate operation of multiple DERs. These operations will show how DERs can be used for volt/VAR optimization and power flow optimization. In addition, systems will be put in place to improve DER visualization for grid system operators. - 20 –

The impacted region will be analyzed before and after DER deployment to validate the DERs' ability to achieve the previously identified net benefits.

2.3 Project Approval

SCE DRP Demonstration D was approved by CPUC Decision 17-02-007, dated February 9, 2017.

2.4 Demo D Location

Determining the Demo D location took several key considerations into account. Key criteria included the system topology, the ability to install field equipment, meeting the DRP Demonstration requirements, but most importantly, enough existing and planned PV and storage installations to qualify as high penetration of DER.

The location, as proposed by SCE and approved in D.17-02-007, was a combination of the adjacent Camden and Johanna Jr substations (Figure 1.).

These systems consisted of a mix of overhead and underground circuits with both residential and commercial customers. In addition, the Camden substation area offered several large PV installations already in place with more installations under way to help meet the definition of high penetration of DER.

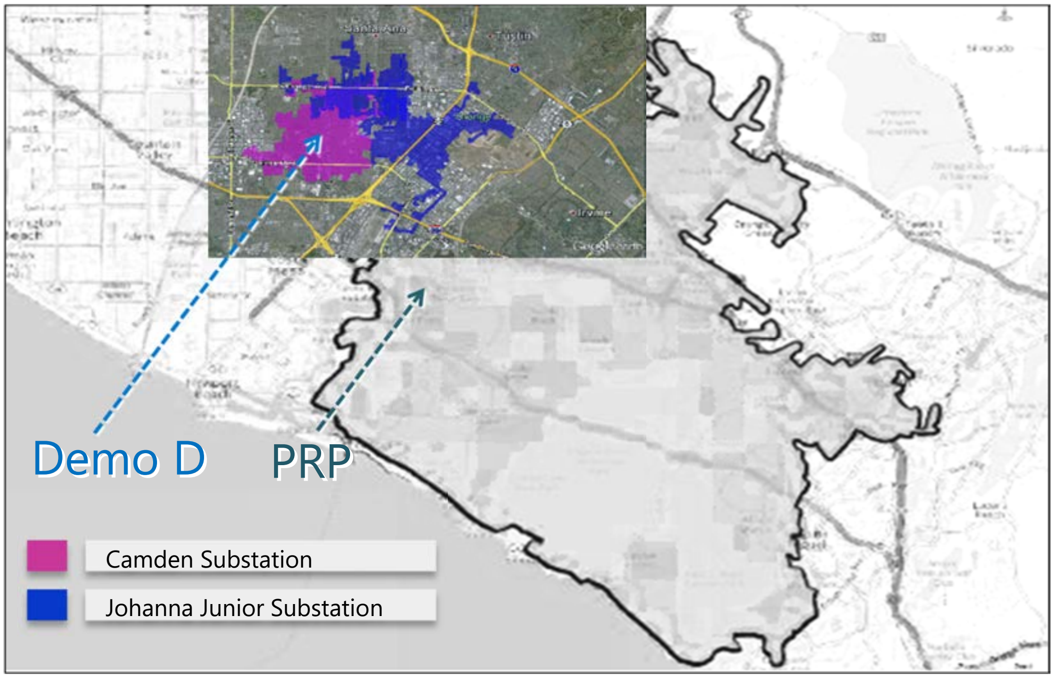

Figure 1: Demo D and Preferred Resource Pilot (PRP) Demonstration Location

3. System Design

3.1 Approach

In order to fulfill Demo D's objectives and accommodate its requirements, a hybrid design approach was adopted that combined existing systems and assets already in production with a set of new systems and assets.

Examples of existing systems and assets included the XA-21 DMS, the NetComm radio network, and edge devices such as Remote Fault Indicators (RFI), and Remote Integrated Switches (RIS) already configured for operation over the existing NetComm radio network.

Examples of the new Demo D systems and assets included optimization and control applications, the OSB, the CSP, the new FAN, and the set of edge devices that will be configured for operation over the new FAN.

The design approach intended to leverage SCE's various test facilities to test each Demo D element in a controlled lab environment prior to field deployment.

The completed system design was documented and communicated through a series of design artifacts, including a Systems Requirements Document (SRD), a System Design Document (SDD), a System Interface Catalog, and eight individual service design interface documents.

3.2 System Requirements / Use Cases

Requirements Definition

The SRD provided the business context for the project, a high-level system description, and listed the system requirements obtained from the Demo D use cases. The requirements were divided into five logical categories: general, communications, control, security, and integration.

Use Cases

Use cases were assembled to help determine how the control systems would operate and to derive the functional and non-functional requirements for the system design. A short summary of each of the applicable Demo D use cases is included in the following section with more detailed descriptions found in Appendix 10.4.

Use Case 2-1: Voltage Optimization with DER

The substation-level volt/VAR optimization (VVO) controller optimizes circuit voltage using capacitors and DERs (generation and storage devices) equipped with smart inverters. The Demo D/ Integrated Grid Project (IGP) control application optimizes circuit voltage by lowering and flattening the voltage profile along the circuit so it remains in the lower portion of the 114 to 120 volt range for commercial and residential customers.

Use Case 3-3: DERs Managed to Shape Circuit Load

At the circuit level, the Demo D/ 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. The OPF controller maintains circuit demand below a user defined threshold and minimizes circuit operating cost.

Use Case 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 circuit for a pre-determined period.

3.3 Design Considerations

The scope of Demo D presented sizable complexities and potential operational risks for the intended field deployment. As such, key design decisions were undertaken to mitigate such risks and minimize integration complexities during the planned implementation.

Based on lessons learned from the Irvine Smart Grid Demonstration (ISGD), the setup and operational maintenance of a separate pilot-production environment for Demo D was deemed too burdensome on SCE's grid operations. As such, the new Demo D systems were integrated into existing systems and assets wherever possible. Notable examples of these production assets include DMS and common/shared enterprise cybersecurity services such as Active Directory, RSA, and Radius.

Known that Demo D was intended only as a demonstration, the Demo D systems did not require redundancy. Therefore, the design is such that, if all the new Demo D systems were to go offline or become unavailable, the normal existing production operations would be unaffected. The result is that, in the event of failure, Grid Operations would see the same conditions they have known and managed prior to the introduction of the new Demo D components.

Given the lack of experience with such control operations, the Demo D design provided the ability to maintain operational safety using a battery energy storage system disconnect switch controlled over an alternate communication channel. This capability would provide grid operators the ability to override the testing environment, should a need arise. Grid operators could disable all automated functions introduced by the new Demo D applications.

3.4 Cybersecurity

The overarching goal of the cybersecurity requirements for Demo D was to demonstrate an end-to-end cybersecurity system. These cybersecurity measures utilized industry standards as much as possible (e.g. IEEE C37-240, IEEE 1686, IEC 62351, IEC 61850 90-5). To accomplish these goals, nine cybersecurity measures were investigated and/or tested as part of the laboratory phase of Demo D. These measures included:

Advanced application-level firewalls

Multi-factor authentication for user access

Centralized system log collection and aggregation from applications and devices

Application whitelisting

Application password vault

Vulnerability scanning

Web application firewall to link SCE control systems to third party DER partners over the Internet

Public key encryption services

Network access control, visibility, and system profiling capabilities

A cybersecurity risk assessment was performed on Demo D technologies in the lab test environment. This assessment was repeated as the control systems moved into the SCE QAS test environment. These efforts have helped resolve issues relating to the proper application of cybersecurity requirements and what methods were needed to securely interact with DER aggregators over the internet. This testing has helped lay the groundwork and expose additional requirements for implementation of cybersecurity tools for SCE's grid modernization applications.

As addressed earlier in this report, they cyber delay that prevented field testing is formally described as follows:

As SCE designed the solutions for the EPIC Integrated Grid Project (IGP) / Demo D - including the associated DRP demonstration projects, SCE conducted periodic cyber security assessments to ensure our solutions do not create greater cybersecurity expose our production grid systems. The threat environment these demonstration projects are slated to operate in has evolved necessitating additional cybersecurity controls. As such, in order to protect grid systems and deploy field demonstrations that are secure, SCE concluded that it cannot complete deployment until it can integrate and deploy the appropriate cybersecurity controls with the demonstration technologies to minimize the risks to grid production systems.

4. Laboratory Design / Setup / Testing

4.1 Control System Test Lab Design

Demo D used the Grid Technology & Modernization (GT&M) Laboratory and Alhambra QAS testing environment to validate functionality and performance capabilities of the control systems prior to intended field deployment. The benefits of this approach were that testing was performed in a controlled environment without adversely affecting the service provided to customers (e.g., creating actual faults on a circuit for testing is not permissible given the presence of customers).

Demo D systems were tested utilizing the following:

(1) Substation Automation Laboratory (for CSP),

(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).

The testing setup is depicted in Figure 2 below.

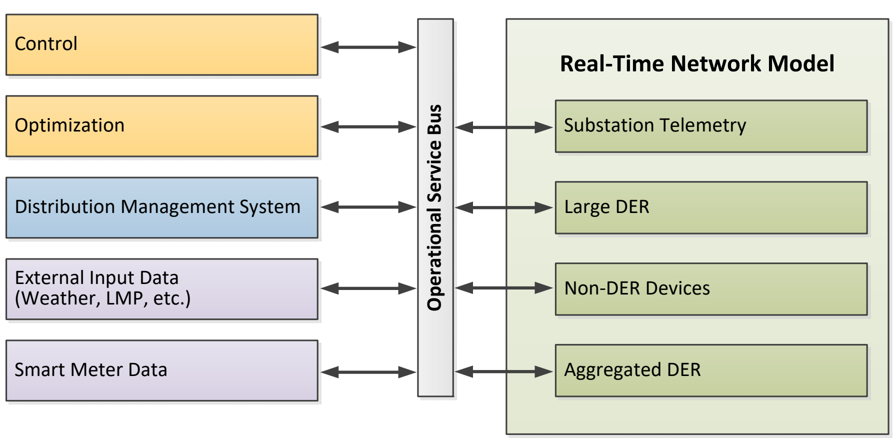

Figure 2: Demo D Control System Test Lab Setup

4.2 Top Level Approach to FAT Control System Testing

Demo D testing was divided into several stages as illustrated in Figure 3. Initial unit testing of the system components was conducted at both the GT&M 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, the testing moved to the system integration testing at the GT&M 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 controls team was satisfied that the applications were working properly and controls were being properly executed in the GT&M lab environment, all software systems were transferred to the SCE QAS environment for SAT. This environment is setup just like the formal production environment, but is isolated so the actual production system is not disturbed.

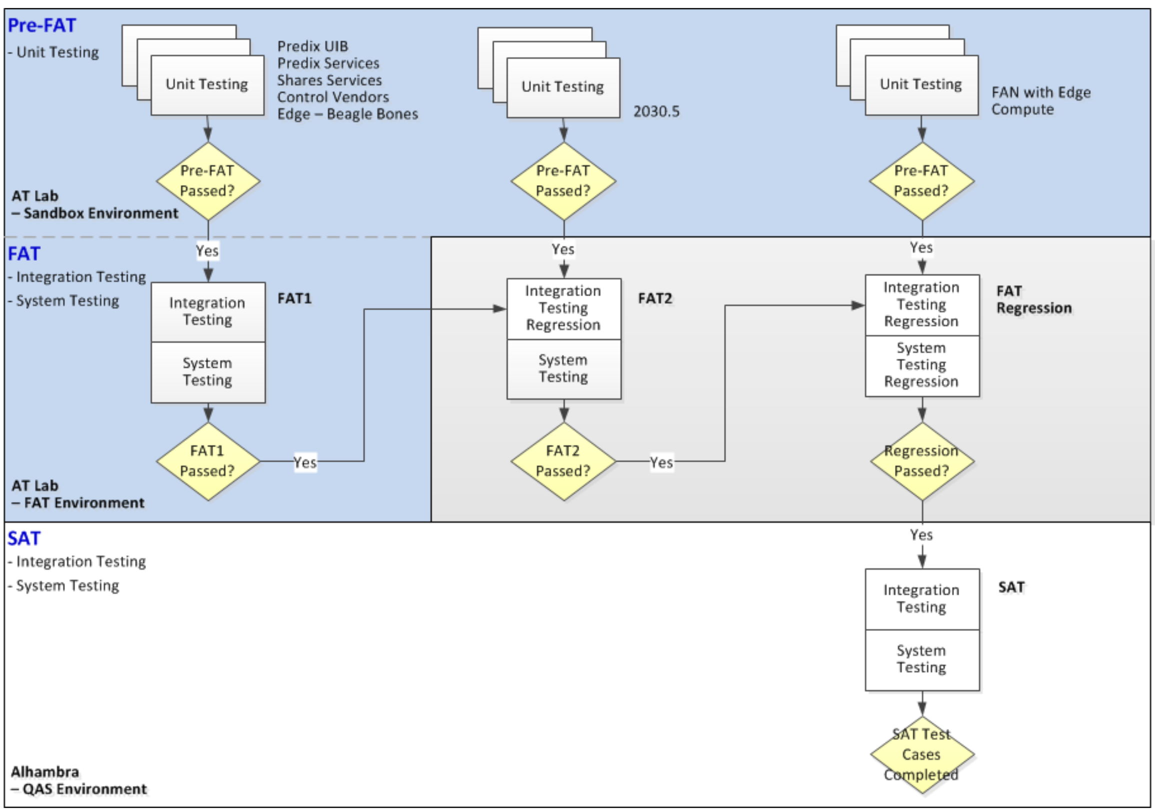

Figure 3: Overall Demo D Test Approach

4.3 Control System Testing Overview

Testing was performed to ensure/determine the following:

Show hardware and software operates according to Demo D and manufacturer specifications.

Verify field devices could be monitored and controlled by remote command through the control systems.

Determine if the controller is capable of controlling capacitors and DER to meet circuit voltage requirements.

Determine if the 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 DESI 2 battery 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.

Demo D tested the Optimal Power Flow, Volt/VAR optimization and Microgrid applications using a controller-in-the-loop test environment.

This test environment used 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 circuits.

The test bed implemented a detailed distribution system model of SCE's Camden substation and two of its circuits (Titanium and Aluminum). This model included cables, conductors, switches, capacitors, and realistic PV and energy storage functionality. The control applications and integration bus then interacted with the modeling environment in real-time to investigate their performance.

4.4 Grid Technology & Modernization (GT&M) Laboratory Environment

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 OSB, the DMS, and the IGP optimization and control applications being tested.

The controller was comprised of a planning engine and a real-time control engine. The planning engine provided day-ahead optimization results (DER control commands and set-points in 15-minute intervals) based on load and generation forecasts, weather, ISO price data, network topology, and business rules. The real-time control engine performed autonomous deterministic control of grid edge devices (such as capacitors and DERs) to support and maintain circuit operational constraints.

The decentralized edge compute application was hosted on BeagleBones. The control system monitored circuit conditions and dispatched controls both centrally and locally to ensure the circuit operated in its desired operating range. Other external data sources (weather data, CAISO data, and AMI meter data) were also connected to the integration bus and shared with all the applications.

The testing was primarily conducted for the steady state/long term dynamics behavior of the network model, so simulations were run with a one second time step. The test system performed the translation between data types and control commands from different protocols (OPC, DNP3, Modbus, and IEEE 2030.5). The lab environment design mimicked the production system as closely as possible to catch potential production issues as soon as possible.

The GT&M laboratory was set up for the Demo D FAT testing and used a Distributed Control Architecture (DCA), as shown in Figure 4, to demonstrate that all integrated systems were able to successfully communicate via DNP3 and IEEE 2030.5 communication protocols.

The system architecture established and tested links from the DER control platform to individual DER and aggregators. The power system model included dynamic models for Battery Energy Storage Systems (four BESS units), solar photovoltaics (four PV units) and capacitor banks (four programmable capacitor control units) as controllable DERs distributed on the Titanium and Aluminum circuits out of Camden substation.

Control commands signals were sent to all 12 DERs, nine via DNP3 and three via IEEE 2030.5. Measurements and commands were exchanged between the control system and DNP3 DERs via BeagleBones hosting the edge compute application. IEEE 2030.5 measurements and commands were exchanged between the IEEE 2030.5 server and virtual DERs via IEEE 2030.5 clients hosted on Raspberry Pi platforms demonstrating closed-loop controls. FAT testing was conducted in the GT&M laboratory environment with and without using the IEEE 2030.5 communication protocol to communicate with DERs.

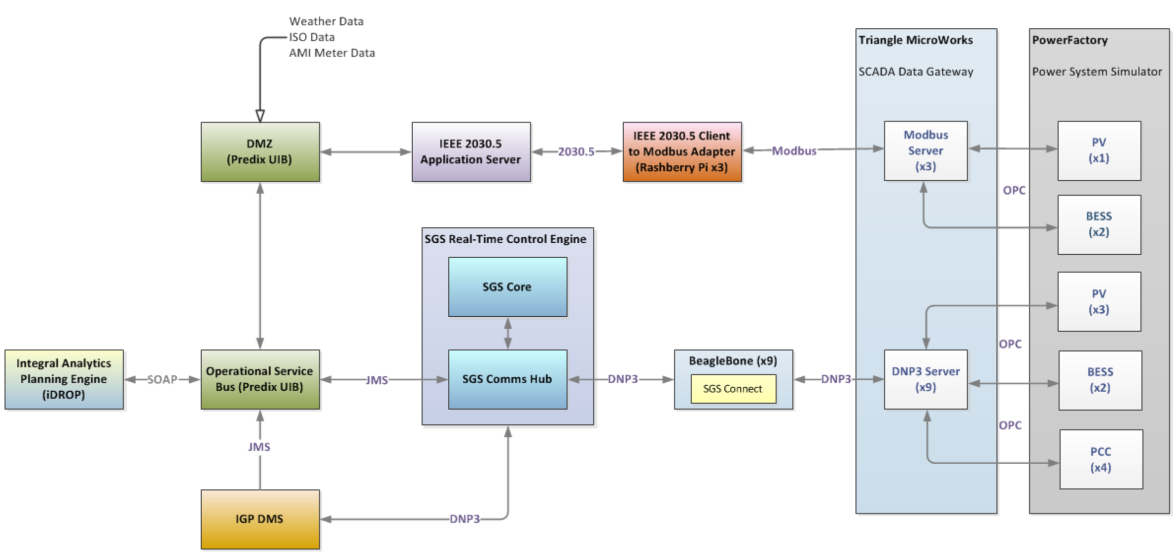

Figure 4: Demo D FAT (GT&M Lab Configuration)

4.5 Alhambra QAS – SAT Environment

Alhambra QAS Demo D SAT testing was setup just like the formal production environment but was isolated, so the actual production system was not disturbed. The QAS/SAT environment (Figure 5) used the same distributed control architecture (DCA) as discussed in GT&M lab FAT environment with the following changes:

Updated the architecture and network model to represent devices and circuits that are in the field for the IGP demonstration.

Programmable Capacitor Controllers (PCCs) from SCE's current deployment were used in the QAS setup for SAT testing. These included three S&C IntelliCAP Plus units and one IntelliCAP 2000 unit connected to FAN radios hosting the edge compute application.

A vendor supplied DESI-2 BESS hardware simulator replaced the PowerFactory energy storage simulation with the edge compute application hosted in SEL RTAC

Software and hardware were deployed in an isolated and secured environment with limited connectivity including two-factor authentication in SCE's grid data center.

Architecture, software, and firewall rules were vetted by SCE's IT teams representing: Cybersecurity, firewall rule administration, system architecture, and Power System Controls.

Firewall rules were implemented between different system components deployed in grid data center to allow or deny flow of traffic for measurements and controls.

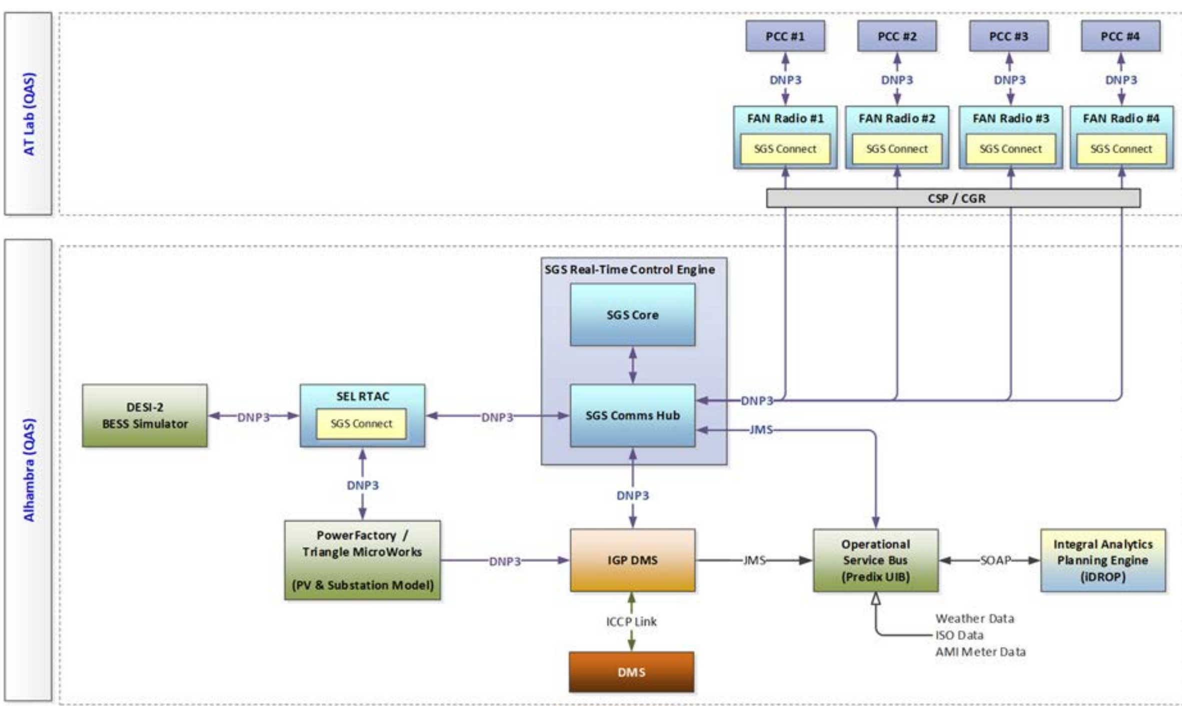

Figure 5: Demo D SAT (QAS Configuration)

5. FAT Test Results

5.1 FAT: GT&M Lab Test Results

The EPIC I Final Report for IGP (previously submitted) has already covered GT&M lab test results and lessons learned during unit/integration testing and FAT testing solely using DNP3 integration with DERs.

This section covers the following FAT testing scenarios: 1) addition of IEEE 2030.5 compliant DERs, and 2) transition to Release 1 testing that represents the DERs actually in the field which can be directly controlled by SCE.

IEEE 2030.5 Testing

Integration testing between the control system and IEEE 2030.5 compliant DERs was conducted using an IEEE 2030.5 application server and the Raspberry Pi clients. The end-to-end integration testing identified several communication and control issues that were resolved by the respective vendors.

Once the integration testing was completed, system test cases were conducted as part of 2030.5 FAT test cycle. This sub-set of the system testing was a set of regression test cases that validated the control application, including thermal limits, voltage limits, and priorities in all automated modes of operation (OPF, VVO, microgrid, and power smoothing).

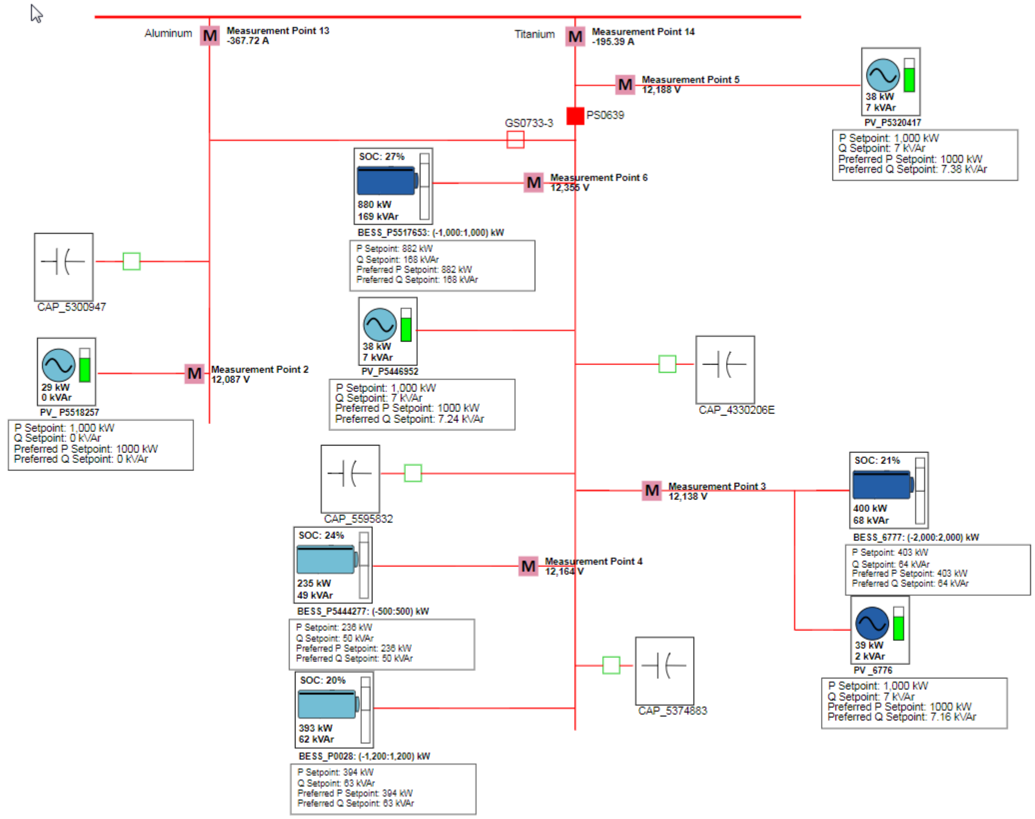

Figure 6: 2030.5 - Controller HMI Demonstrating DER's Set points and Measurements

In the test setup, three out of 12 DERs were supporting IEEE 2030.5 communication. The control system HMI screen shown in figure 6 listed the DER's active and reactive power set points from the planning engine and real-time control engine as well as their actual measurements.

The active and reactive power set points dispatched to BESS (P5517653 and 6777) and PV (6776) were translated to activate power set point and power factor set point using the IEEE 2030.5 objects "opModFixedFlow" (in percentage) and "opModFixedPF" respectively. For the measurements, IEEE 2030.5 objects were available for Real Power Output, Reactive Power Output and Voltage. The "State of Charge" 2030.5 object was not available for the BESS, thus it was mapped to a different measurement object.

The set points were successfully dispatched to all BESS units as intended with either DNP3 or 2030.5 protocol. An issue was observed when dispatching reactive power set point to PV units while using the 2030.5 protocol. The actual active power production of a PV unit depends on the solar irradiance and will be equal to or less than the active power reference set point requested. The real-time control engine was computing the PF set point based on a set point profile subscribed to every 15 minutes from the planning engine, thus creating a mismatch between the reactive power "set point" and the "measured" value. It is recommended that the "reference power factor set point" be frequently updated based on "actual active power measurement" to deliver the "planned reactive power set point".

Release 1 Testing

As compared to other cycles of FAT testing, Release 1 testing transitioned from fictitious high penetration to a limited DER scenario representing the real field production environment. Release 1 testing was performed in the GT&M lab FAT environment using DNP3 communication protocol for DER integration. There were four controllable capacitor banks and one controllable BESS unit available on the Titanium circuit.

Since there was only one controllable BESS unit in the circuit, the virtual microgrid monitoring point was moved to RCS0028 instead of the head of the Titanium circuit. Addressing circuit reconfiguration as well as addition/subtraction of DERs was not a simple process and required several manual configuration changes in several components of the control system. Auto-discovery and registration of field devices into the integration platform was recommended for future production projects.

The Release 1 system testing began with seven regression test cases that validated the control system still maintained the systems objectives of thermal and voltage limits in all modes of operation. While tests were successfully passed for optimal power flow, microgrid, and power smoothing modes, the optimization (planning engine) did not provide a feasible solution for volt-var mode. Upon further investigation by the vendor, it was concluded that the convergence issue was persistent and related to use of a virtual machine for the optimization controller.

Two possibilities were identified to solve the problem: resolve the performance issues on the virtual machine, or replace the virtual machine with a physical server. In the interest of time, all Volt-Var optimization related test cases (~20) were ignored for the Release1 test cycle. Additionally, nine test cases were removed from the test cycle as they were related to high DER penetration and business rules that no longer were practical for the field implementation of the controls.

A total of 17 system test cases were executed and passed successfully. Note that system test cases were performed using seven scenarios from the year 2015 representing a variety of load, weather and CAISO profiles. These profiles represented sunny/cloudy day, moderate/peak/low load, weekday/weekend/holiday, low/high temperatures, and various days of the year. The load forecasting algorithm was independently verified for proper load forecasts results at the structure and circuit level using actual meter data. Lastly, a system test was performed in "Live Mode" by setting the planning engine to run continuously 24x7 and utilizing current weather, CAISO pricing, and AMI meter data from actual sources available from the Demo D field area instead of the fixed seven scenarios/profiles.

Based on these tests, various system test procedures were updated. As an example, thermal constraints at the head of the circuit were not being violated due to limited controllable DER resources, thus a dummy load was added at the end of the circuit in the PowerFactory model and manually switched on in order to meet the test case requirement.

Figure 7, below, demonstrated the reduced network model with limited controllable devices, where BESS (P0028) provided the control system-requested active and reactive power outputs. Two PV units on the circuit were not controllable, thus could not be controlled.

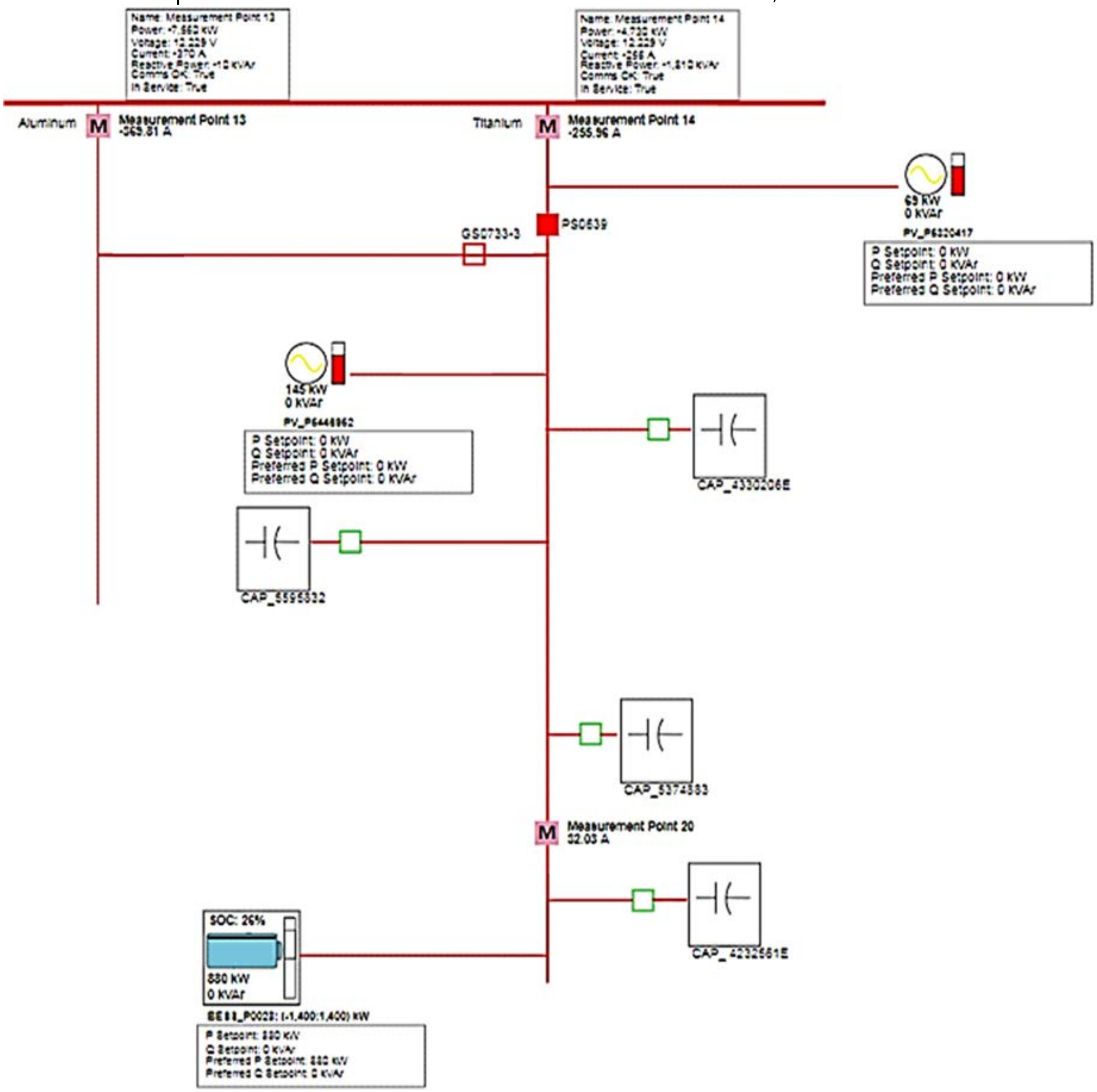

Figure 7: Release 1 - Controller HMI Demonstrating DER's Set Points and Measurements

Load and generation forecasts are essential for reliable and effective optimization solutions. The control system received over 30 days of AMI meter and circuit load data as an input to the forecasting engine. The load forecasting validation was executed for the Titanium circuit and a few structures along the circuit. Figure 8 shows load forecast results versus metered load on the Titanium circuit sampled every 15 minutes for 04/05/2018. Similarly, Figures 9 and 10 show forecasted versus actual load sampled every hour on two structures #P5497746 and #P5320417. These structures had load as well as generation at the same node thus complicating the load forecasting engine's job.

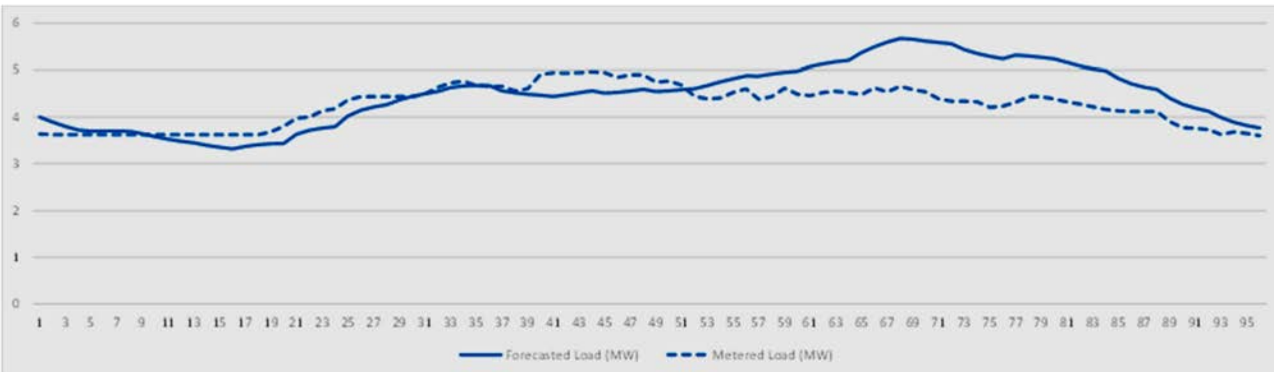

Figure 8: Forecasted and Metered Load on Titanium Circuit

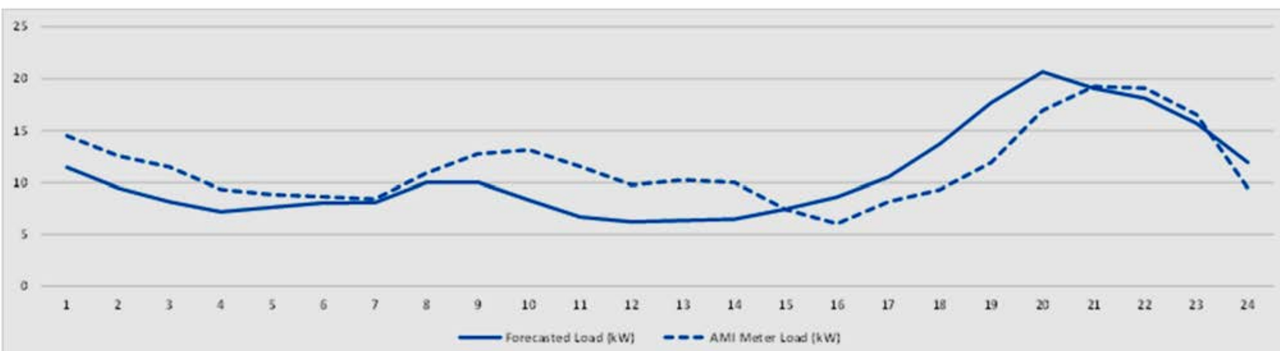

Figure 9: Forecasted and Metered Load on Structure #P5497746

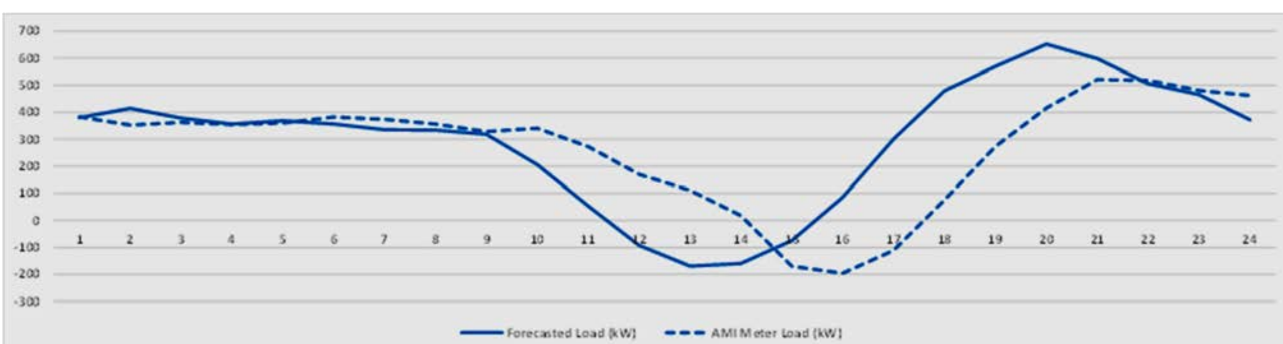

Figure 10: Forecasted and Metered Load on Structure #P5320417

The endurance testing was performed leveraging IGP controls "Live Mode", where the system was evaluated over a week running 24x7 to analyze the performance under sustained use. The energy storage system (BESS PS0028) autonomously received control set points from the control system and produced the demanded power for five uninterrupted days while executing optimal power flow optimization as depicted in Figure 11.

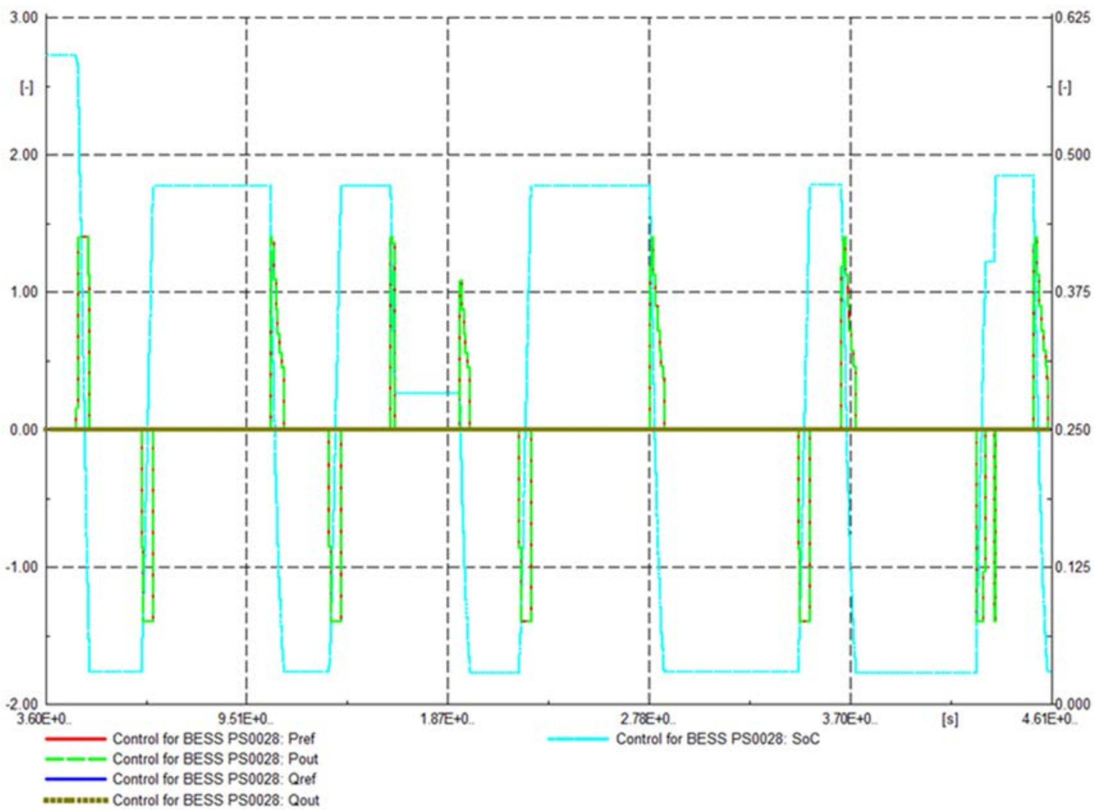

Figure 11: Energy Storage Dispatching in Live Mode OPF

Fifteen issues were identified and mostly resolved in the Release1 test cycle with most related to Live Mode testing using OPF. Various ad hoc tests, negative tests, and long run tests were conducted apart from the well documented system tests to identify issues with the control systems. The lab environment provided flexibility to perform these tests in a low risk environment as compared to the production environment.

Identified forecasting issues were mostly related to time stamps on the data (e.g. UTC vs local, start time), and interpretation of AMI data when load and generation were present in the same node. Live mode produced some issues also including: an infeasible optimization solution, incorrect set point/commands, time stamp issues, and a service failing to run for multiple days. The power smoothing algorithm was revised to resolve issues uncovered when the system transitioned from other modes to the power smoothing mode.

While testing the peak load reduction control option, it was observed that the planning engine was correctly responding to the user defined thermal threshold at the head of the circuit, however, the real-time control engine was allowing the real-time thermal constraint to be violated. After discussing this issue with the vendor, it was concluded that the user limit should be manually configured in an additional configuration system. To do this, the software would have to be redeployed - not an option for the production environment. It was recommended the vendor develop a configuration window to allow the user to modify these set points. They also needed to develop a common service that allows update of configuration parameters so changes can be without shutting the control system down.

6. FAT to QAS Transition

After the SCE team was satisfied that the applications were working properly and the controls were being properly executed in the GT&M lab environment, all software systems were migrated to the SCE production QAS environment for SAT. The ISGD project demonstrated that laboratory testing had significant limitations. It was therefore important to test the control systems with real field apparatus (e.g. capacitor controllers, automated switches, DERs) that would be deployed or real simulators that closely imitated a physical device in the field. These tests would help identify issues that cannot generally be replicated in a laboratory environment.

The capacitor bank controllers and the FAN radios were deployed in GT&M's Grid Edge Solution lab connected to the QAS network. The rest of the hardware and software were deployed in SCE's Grid Data Center (GDC) in Alhambra. The DESI-2 BESS hardware simulator was also housed in Alhambra. Once the back office installation and integration into the QAS was completed, the availability of the external data sources (weather data, CAISO data, and AMI meter data) at the integration bus were verified.

Communication between the various sub-systems (including the communication bus, planning engine, real-time control engine, DMS, and PowerFactory) were also confirmed. Finally, communication and controls were tested with field devices (e.g. remote-controlled switch, solar PV, energy storage system, and capacitor bank controller) using the control system and DMS. The following highlights the major activities performed during QAS Integration testing:

6.1 FAN Radio Integration with Programmable Capacitor Controls

The QAS environment transitioned the PCC edge compute application (SGS Connect) from a BeagleBone, which is not a production grade device, to the Cisco IR510 FAN radio in preparation for field deployment.

This process presented several challenges. The PCCs used in the QAS environment included three legacy PCCs - S&C IntelliCAP Plus with serial DNP3 connection and one S&C IntelliCAP 2000 with TCP/IP Ethernet connection to FAN radios. The DNP3 mapping of IntelliCAP 2000 was different, but configurable, thus was modified to match with IntelliCAP Plus points list for uniformity and reduce the effort for mapping to the control system.

The Cisco IR510 FAN radio device has a proprietary operating system. It is managed and configured by several proprietary tools, with little documentation. Figure 12 shows the layered model of the software systems in the FAN radio.

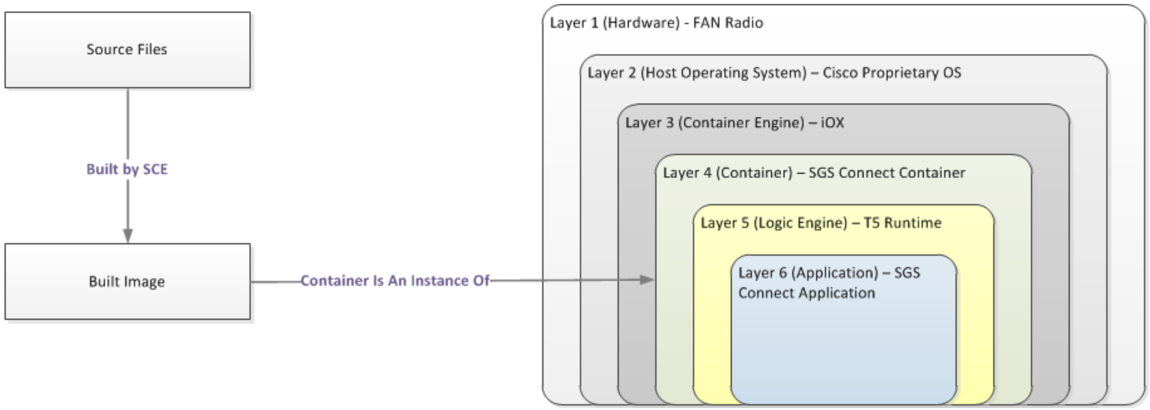

Figure 12: SGS Connect Hosted on CISCO IR510 FAN Radio

Figure 13 shows the QAS lab setup for testing IR510 FAN radios to monitor and control PCCs. The IR510 provides enterprise class RF mesh connectivity to the controls of Ethernet and serial-enabled IoT devices such as reclosers, capacitor banks, voltage regulators, and Remote Terminal Units (RTUs). These platforms are purposely built to withstand harsh environments and are ideal for pad-mount and pole-mount cabinet installations. CGR 1000 routers are the FAN aggregation device used to collect FAN traffic and forward it to the control network.

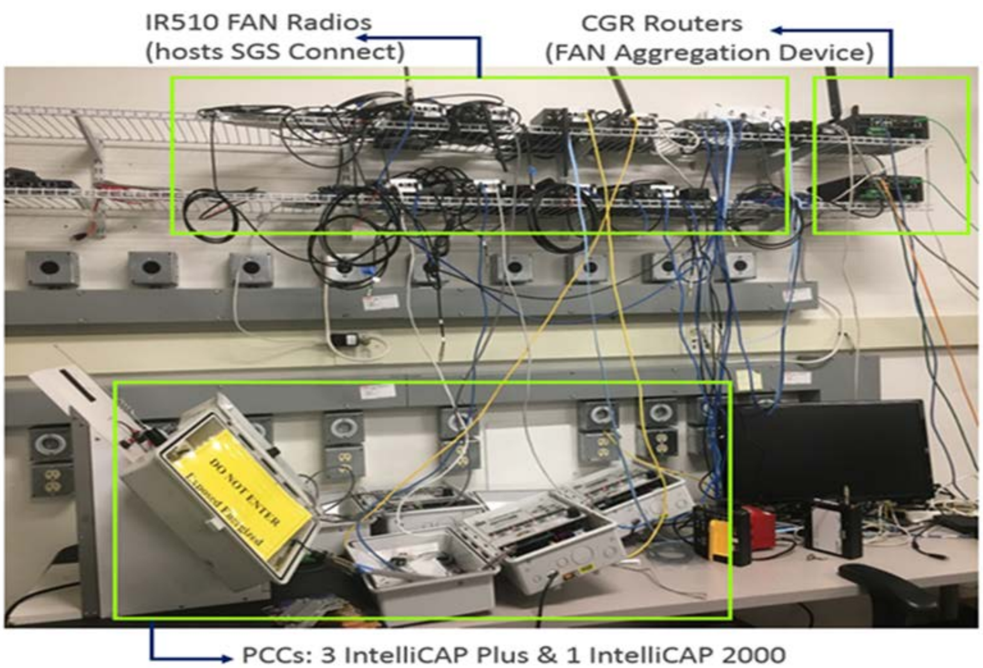

Figure 13: PCCs Connection to IR510 FAN Radios during SAT Testing

Several issues were identified in the process of integrating the SGS Connect edge compute application with the IR510 FAN radio. Many of these issues were due to the early stage of development of the product.

- Reliability of the FAN radio and its configuration software
  - Field Network Director and Fog Director software used to configure the radios in the SCE's back office system was the biggest challenge for testing PCCs communication and controls and took nearly eight months to become a stable test bed.
  - The numerous issues discovered during testing of the PCCs assisted in developing improved requirements and documentation for the FAN radios. This allowed identifying several process improvements and helped determine training needs. The result was better FAN application software and hardware.
  - The project team set up daily standup calls to discuss test results or issues identified during testing. Through active contribution from all stakeholders, the team was able to promptly resolve issues quickly and allow tests to be re-run smoothly.
  - Once the FAN test bed was stable, communications and control between the SGS control system and PCCs was tested via FAN radio. The open and close commands were sent using Integral Analytics dashboard and were observed in the control system HMI and IGP DMS screens. The DNP3 points (binary input, binary output, analog input, analog output and counters) were tested on all four PCCs. The test bed ran reliably for over a month providing an opportunity to test the FAN radios with controls. This provided for better preparation for QAS system testing, and for large scale production projects.

6.2 DESI-2 Energy Storage Simulator Integration

The DESI-2 simulator was a vendor supplied hardware simulator whose behavior closely resembled the production DESI-2 system. DNP3 points, based on the production system's point list, were mapped to the control system. Initial plans were to integrate DESI-2 directly with a FAN radio hosting the SGS Connect application. However, the Cybersecurity team rejected this proposal since it could bridge the FAN network with an LTE network (also connected to DESI-2 for vendor monitoring of the battery system). The DESI-2 QAS setup with the FAN radio was thus abandoned.

An alternative communication architecture was developed that connected to the DESI-2 battery control system using only the LTE network. The design was revised to host the SGS Connect edge compute application on an SEL RTAC 3505/3535 connected between the LTE radio and the DESI-2 controller. This required modification of the SGS Connect code to run properly on the SEL RTAC. Significant delays were encountered due to the processes involved in opening firewalls for this new configuration.

Figure 14 demonstrates the DESI-2 simulator setup for QAS testing. The control system receives the state of charge (SOC), active power, reactive power and status information from the DESI-2 simulator. DESI-2 voltage and other circuit information is obtained from the PowerFactory simulation. The DESI-2 simulator does not emulate varying voltage behavior, so this information is obtained from the PowerFactory simulation. Once the setup was complete, communications and controls between the control systems, the DESI-2 simulator, and PowerFactory were verified.

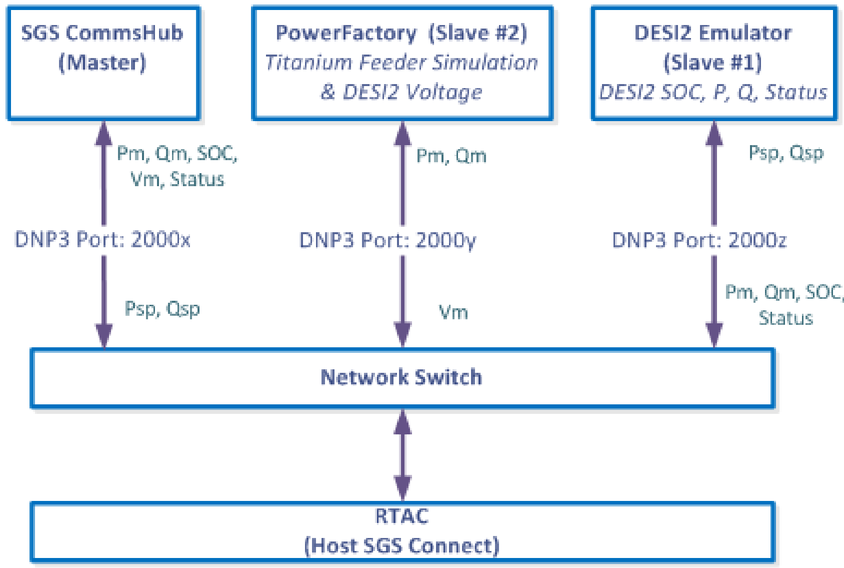

Figure 14: DESI-2 Simulator Setup for QAS

6.3 DNP3 Points List

Five controllable devices were used for the demonstration: The DESI-2 battery system and four PCCs. Monitoring data was provided from a PV array, remote controlled switch (RCS0028), and the circuit breakers for the Titanium and Aluminum circuit.

The DNP3 points mapping between the field devices and control system included binary input, binary output, analog input, analog output, and counters.

To save configuration time for the planned Production Acceptance Test (PAT), the DNP3 points list was chosen to match the existing device points lists already installed in the field.

6.4 Volt-Var Optimization Testing in FAT

Volt-Var optimization related test cases were not conducted in the Release 1 testing. The expectation was to transition into the QAS environment and then resolve the issues previously noted relating to the need to run the optimization engine on an actual physical machine instead of a virtual machine.

SCE coordinated a meeting with optimization vendor (Integral Analytics) and the virtual machine vendor (VMWare) to investigate and resolve performance issues on the virtual machine. The issue was identified only on the Volt-Var optimization between a virtual machine and physical server. VMWare could not resolve the problem without access to Integral Analytics' source code. This request was not acceptable to Integral Analytics, so the SCE team decided to purchase a hardware server for optimization.

A physical server was setup in the GT&M lab environment to run VVO algorithms. Better performance in terms of convergence and speed of solution was observed with the physical server.

The transition from FAT to the QAS environment and then QAS integration testing took a prolonged time to obtain a stable and reliable test bed for SAT testing in the QAS environment. The completion of QAS integration testing was delayed significantly due to following constraints: 1) needed modifications for the FAN radio software to allow for proper communications with the control system and edge devices, 2) a scope change altering the communications to the DESI-2 battery control system from the FAN radio to an LTE radio/ SEL RTAC hosting the SGS Connect application, and 3) need to change the location where the VVO optimization code was run from a virtual machine to a physical machine.

7. QAS Test Results

After the migration of the test environment to the QAS system, completion of FAN radio integration, and DESI-2 controller testing was completed, official QAS testing began. System test procedures were updated to reflect SAT environment changes, DER hardware alterations (e.g. FAN radio, DESI-2 BESS), updates to IGP control system and IGP DMS, and lessons learned from previous FAT test cycles.

The QAS testing began with evaluation of the control system in “Live Mode” followed by standard QAS system test cases. Sample system test procedures and test case reports are provided in Appendix 10.3.

A total of 22 system test cases were executed including several volt-var optimization test cases that were bypassed during the Release 1 FAT test cycle. Several test cases were removed from the test cycle as they were no longer valuable and were already covered or combined with other test cases.

The system test cases were performed using the seven scenarios from 2015 representing a variety of load, weather and CAISO profiles (see section 5.1 – Release 1 Testing). These QAS system test cases were successful in validating that the control system maintained the systems objectives, including thermal and voltage limits in all modes of operation. Most tests cases successfully passed including optimal power flow, volt-var, microgrid, and power smoothing modes.

7.1 Live Mode

“Live Mode” testing was accomplished by setting the planning engine to run continuously 24x7 utilizing weather data, CAISO data and AMI meter data from live services. Live mode was successfully tested for two weeks. The energy storage system (BESS PS0028) autonomously received control set points from the control system and produced the commanded power continually while executing optimal power flow optimization as shown in Figure 15.

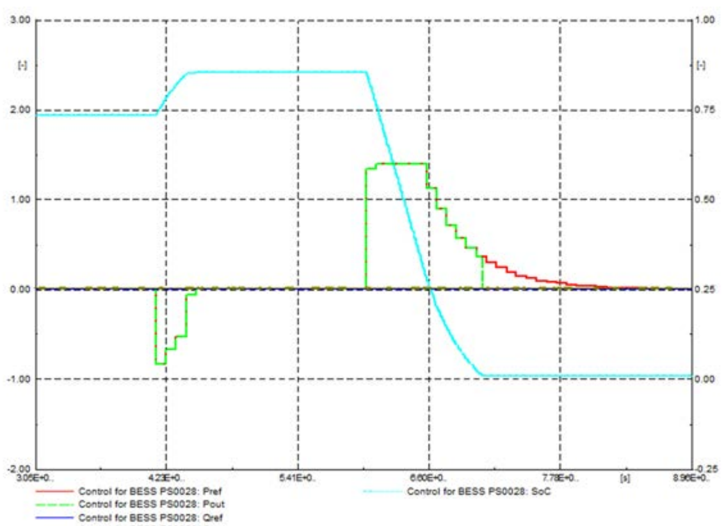

Figure 15: Energy Storage Dispatching in Live Mode OPF for one day

7.2 Optimal Power Flow

The OPF controller maintains circuit demand below a user defined threshold and minimizes circuit operating cost. Some of the key test scenarios evaluated during the QAS test cycle are addressed below.

Minimize Circuit Operating Cost:

The objective of this scenario is to minimize the cost of power (kW) supplied by the grid as compared to the cost of power generated from the DERs. The planning engine thus compares the day-ahead locational marginal prices (LMP) at the LMP node and computes optimal dispatch set points for the energy storage over the next 24 hour period in 15 minute interval to minimize circuit operating cost as shown in the Figure 16.

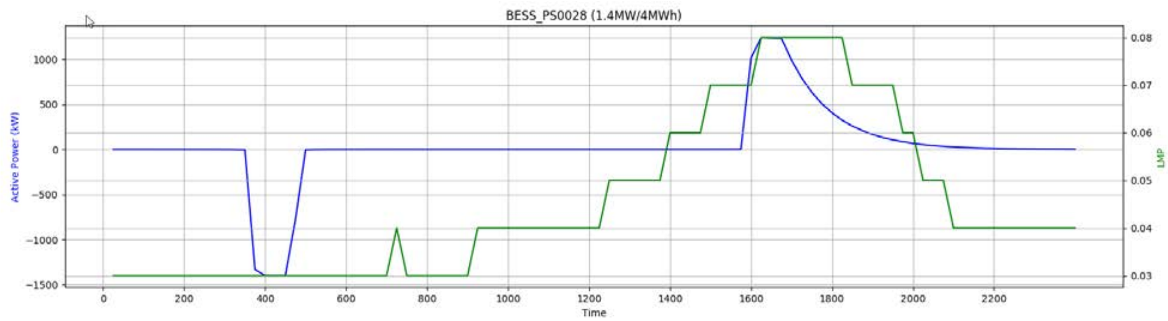

Figure 16: Energy Storage Dispatching Active Power based on Day-Ahead LMP Price

Peak Reduction:

The objective of this scenario is to use DER output to reduce peak load conditions on a circuit. The thermal limit at the head of the Titanium circuit set by SCE is 473 A. Since the load on the circuit generally did not hit this limit, the target loading at the head of the circuit was reset to 300 A for this test. The planning engine then successfully capped the loading at the head of the circuit at 300 A and followed the desired target loading as shown in Figure 17.

The real-time control engine, however, was allowing violation of the thermal constraint. After discussing this issue with the vendor, it was concluded that the loading limit needed to be manually configured in a different configuration system for the real-time control engine to act properly. This would require redeployment of the control software with the new limit. This was not done due to the significant testing delays this would cause.

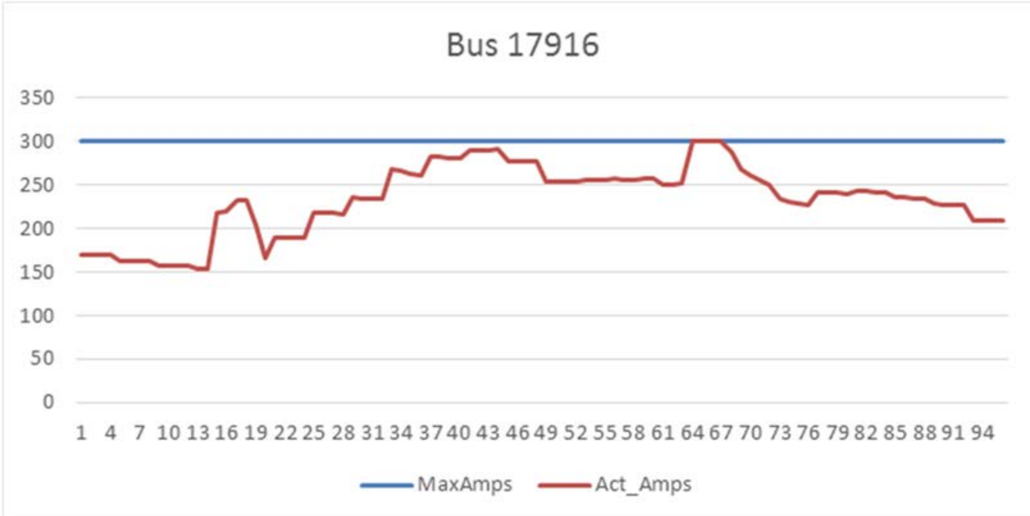

Figure 17: Planning Engine Managing Requested Current Limit at the Circuit Head

Topology Detection/Circuit Reconfiguration:

In this scenario, the real-time control engine responds to circuit topology changes and loss of voltage in the distribution circuit by de-energizing DERs. Figure 18 shows the real-time control engine recognized null voltage at the head of the Titanium circuit and sent zero active and reactive power set point to BESS_PS0028 within 15 seconds.

The energy storage status was updated to “Out of Service” on the HMI. Once the nominal voltage was re-established at the DER terminal through circuit reconfiguration (by closing switch GS0733-3), the real-time control engine brought BESS_PS0028 back to “Online” state and began dispatching the commanded set points.

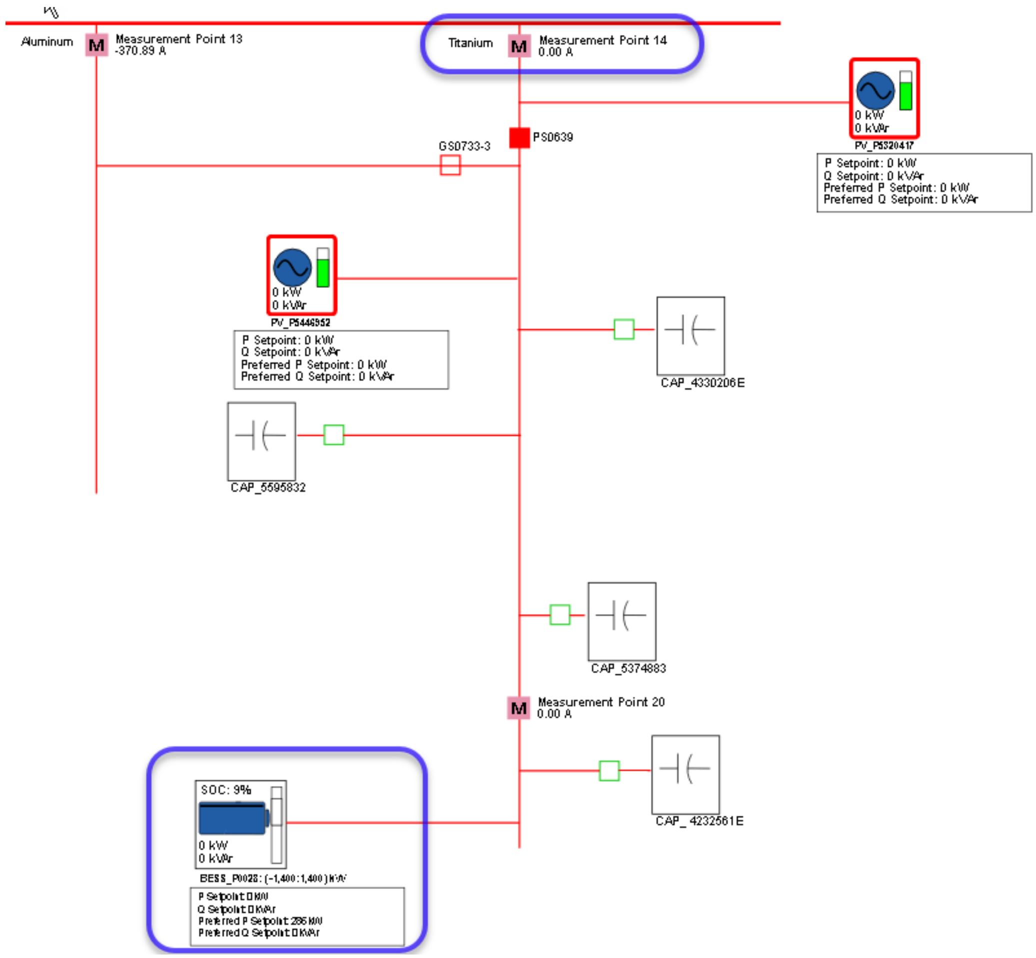

Figure 18: Real-Time Control Engine Responding to Topology Change and Null Voltage

Maintain Thermal Limits:

In this scenario, the real-time control engine maintains operation within thermal limits. The system receives input from the circuit's substation breaker that indicates the ampacity limits are being exceeded. The real-time control engine then manages the DER to mitigate any circuit overload condition.

In this test, the loading on the Titanium circuit was increased by transferring load from the Aluminum circuit. BESS_PS0028 was then dispatched at the full charging rate by the planning engine, thus loading the Titanium circuit over its thermal limits to 496 A. Within a minute of thermal constraint violation, the real-time control engine ignored the planning engine dispatch set points and recalculated set points for the energy storage system to maintain ampacity below the thermal limits of 473 A at the head of the circuit as shown in Figure 21. This thermal limit violation test scenario was repeated three times. The current at the Titanium circuit was maintained below the set thermal limit (473 A) for the complete test period (>2 hours) as shown in Figures 19 and 20.

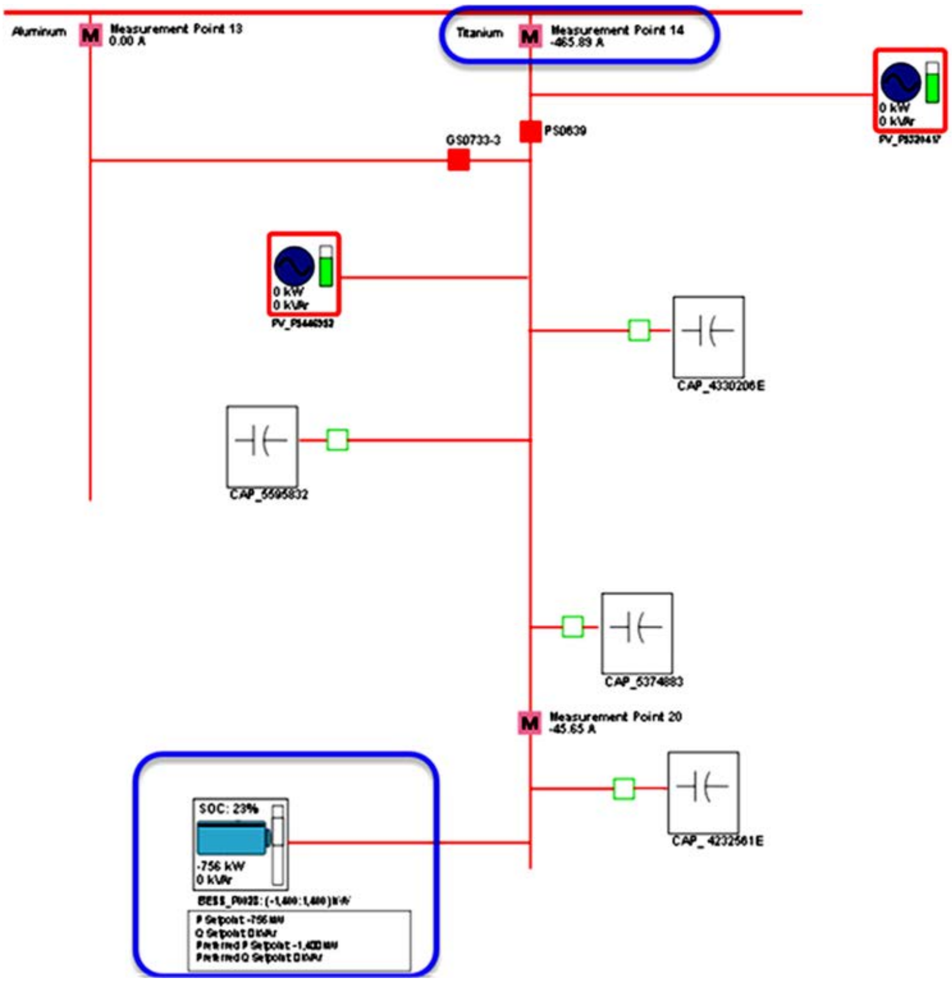

Figure 19: Real-Time Control Engine Responding to Thermal Limit Violation at the Circuit

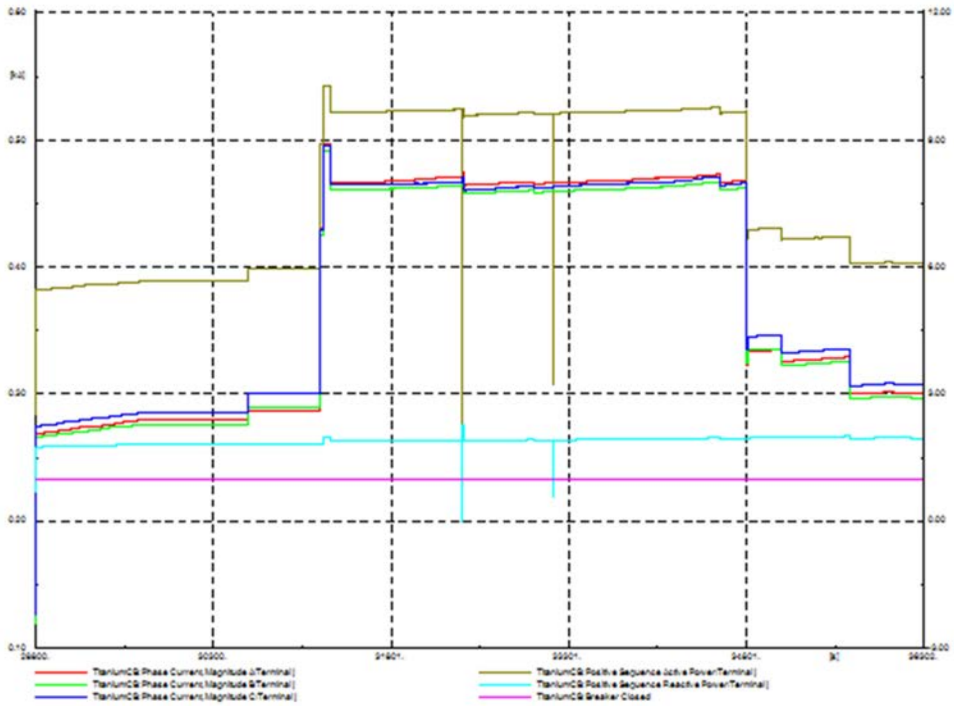

Figure 20: Thermal Limits Maintained below Set Value (473 A) at the Circuit

Circuit Faults:

This test scenario validated the response of the controller under different faults conditions applied at three locations along the circuit, with the faults lasting one second, one minute, and permanently.

- When the fault was applied at a node along the Titanium circuit lasting for only one second, the real-time control engine did not detect the faulted condition and the BESS_PS0028 set points remained unchanged with it continuing to discharge.
- When a fault was applied lasting for one minute at a node along the Titanium circuit, high fault current (~1423 A) was observed at the Titanium circuit breaker. The real-time control engine detected the abnormal condition within 10 seconds of the fault and re-dispatched BESS_PS0028 to manage thermal constraint violation at Titanium circuit by increasing active power of 1400 kW, thus lowering the thermal overload to 1364 A as shown in Figure 21. The real-time control engine did not provide any reactive power support to improve the system voltage. After the fault was cleared and current at the Titanium circuit dropped below the normal ampacity rating, the real-time control engine followed planning engine set points and re-dispatched the energy storage system. Figure 22 shows Titanium circuit and energy storage measurements before, during and after the one minute fault.
- Finally, a permanent fault was applied leading to opening of the Titanium circuit breaker to simulate a protection action. The real-time control engine recognized a null voltage at

the head of the Titanium circuit and sent zero active and reactive power set points to energy storage system. The energy storage status was updated to "Out of Service".

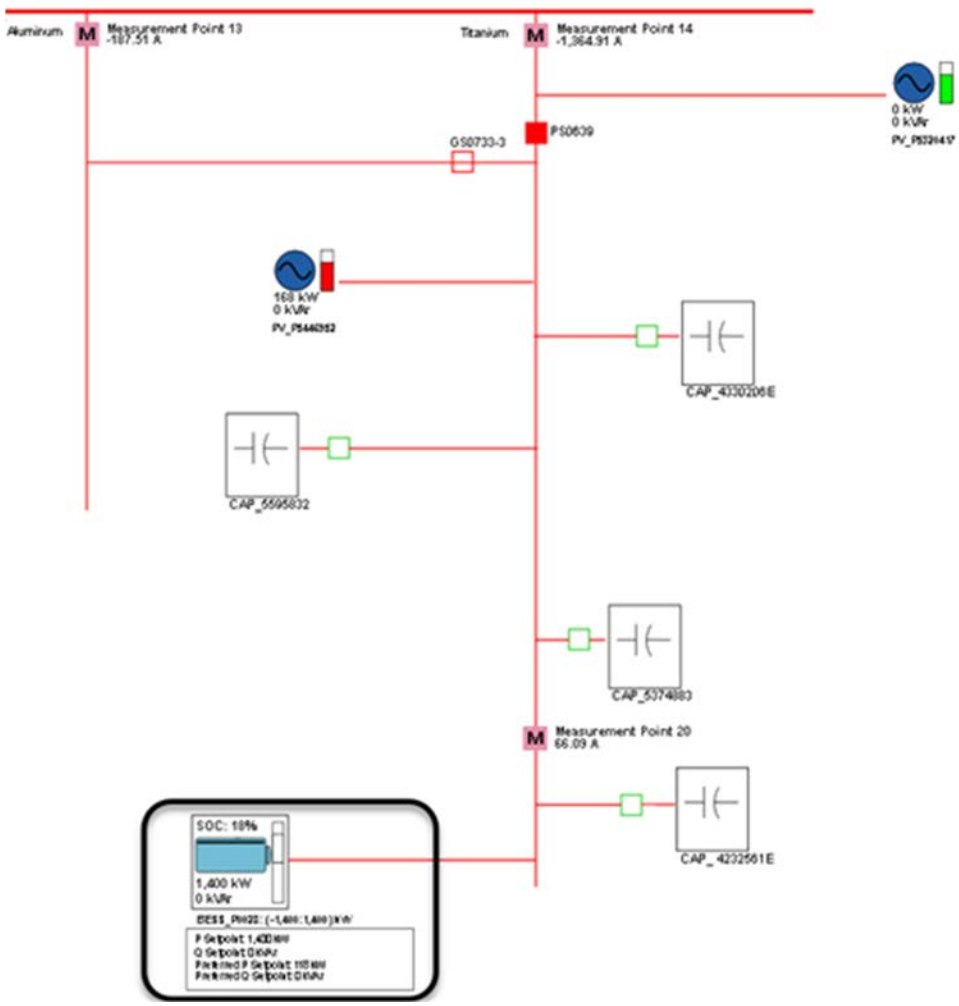

Figure 21: Real-Time Control Engine Responding to 'One Minute' Circuit Fault Scenario

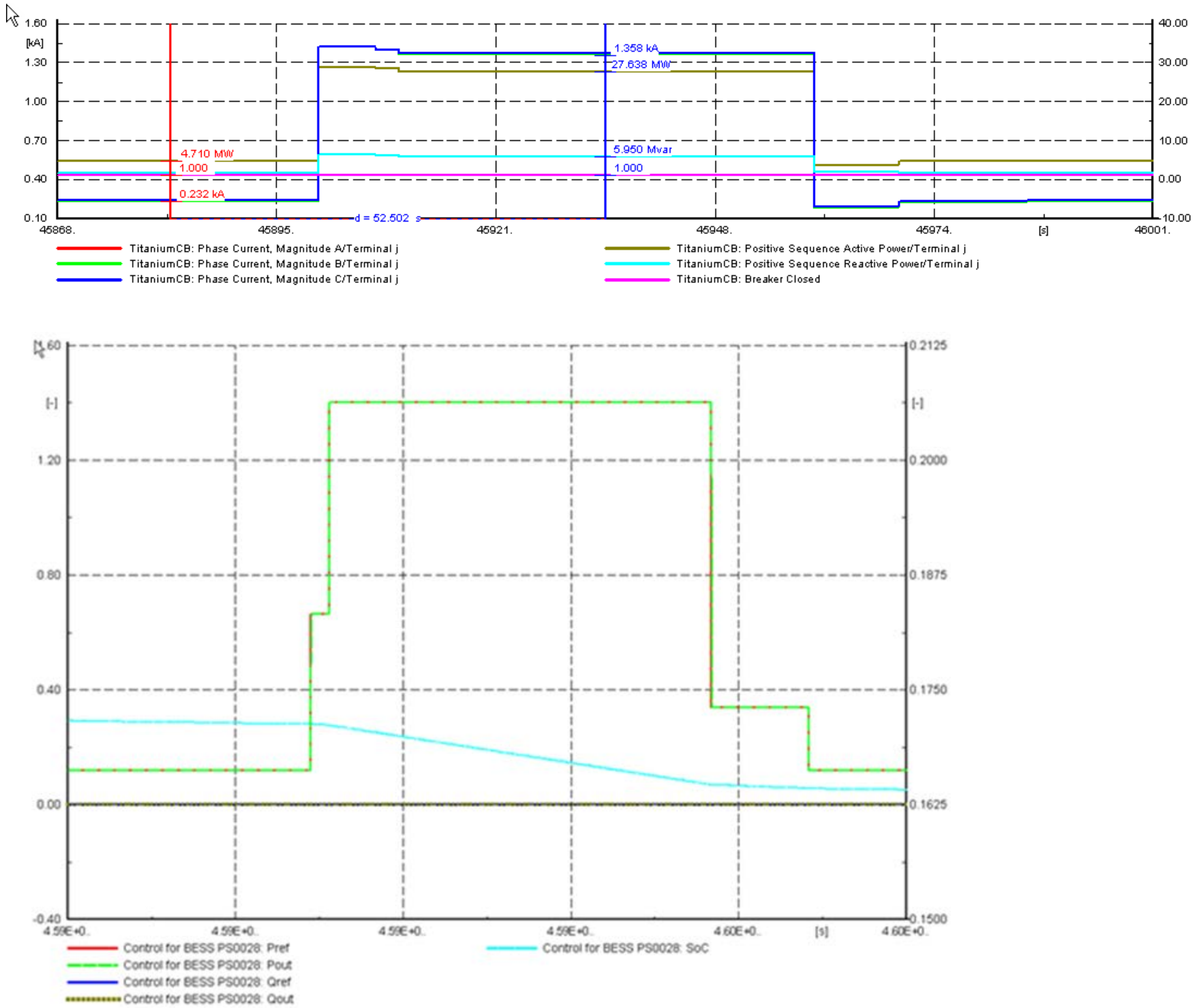

Figure 22: Response of Energy Storage and Circuit Measurements during 'One Minute' Fault

Communication Failure:

This test scenario validates the control system behavior when there is a loss of communications to the field devices in a manner that does not damage or cause instability in the electrical distribution system. The test case was modified to reflect QAS test environment and validate additional test scenarios that were likely be experienced in the production environment during the field measurement and verification tests.

The scenarios verified proper system behavior with disconnection and reconnection of 1) the energy storage simulator, 2) the SEL RTAC, 3) PCCs, and 4) the FAN radio connected to the test system. The real-time control engine responded to most of the communication failure scenarios within a few seconds by sending an alarm and indicating a communication failure on the control system HMI. However, a few test scenarios were not recognized by the control system. These scenarios were not in the original control system specifications, so the control system was unable to handle them properly.

Planning Engine Re-Optimization:

The planning engine is designed to generate an optimization solution at 15-minute intervals for 24 hours every midnight (12 AM). However, a new optimization solution can be triggered when a significant difference in forecasted results and actual readings are observed.

The test scenario used was a case where the measured state of charge of the BESS differed from the forecast value by more than 10%. In this scenario, the planning engine should have triggered a new optimization solution but did not. The vendor investigated the issue and identified a couple of issues with the planning engine optimization routine that needed fixing. Again, this new software update was not implemented due to testing delays it would have caused.

7.3 Virtual Microgrid

The virtual microgrid function controls the available DER to reduce real and reactive power flow to near zero at a defined (microgrid) reference point. Since there was only one energy storage DER in the circuit, the virtual microgrid monitoring point was placed at RCS0028. In the microgrid mode of operation, the real-time control engine ignored the planning engine's preferred set points and maintained active and reactive power flow at near zero at RCS0028/MP20 as shown in Figure 23.

The test case additionally evaluated the response characteristic in terms of speed of response by starting a 50 hp induction motor during the simulation as shown in Figure 24. This impacted the power flow at the microgrid monitoring point. The real-time control engine recalculated the real and reactive power set points of the BESS to mitigate the change caused by the motor.

However, due to delays in the communication between the real-time control engine, SEL RTAC, energy storage simulator, and PowerFactory, it took about a minute for the BESS to respond. This is an expected scenario in the QAS test environment due to the presence of the PowerFactory tool, which will not occur in the production environment when connected to the production DESI-2 energy storage site. When the control engine did respond, real and reactive power flow was maintained at near zero at MP20. The detailed test procedure and test case report are covered in Appendix 10.3.

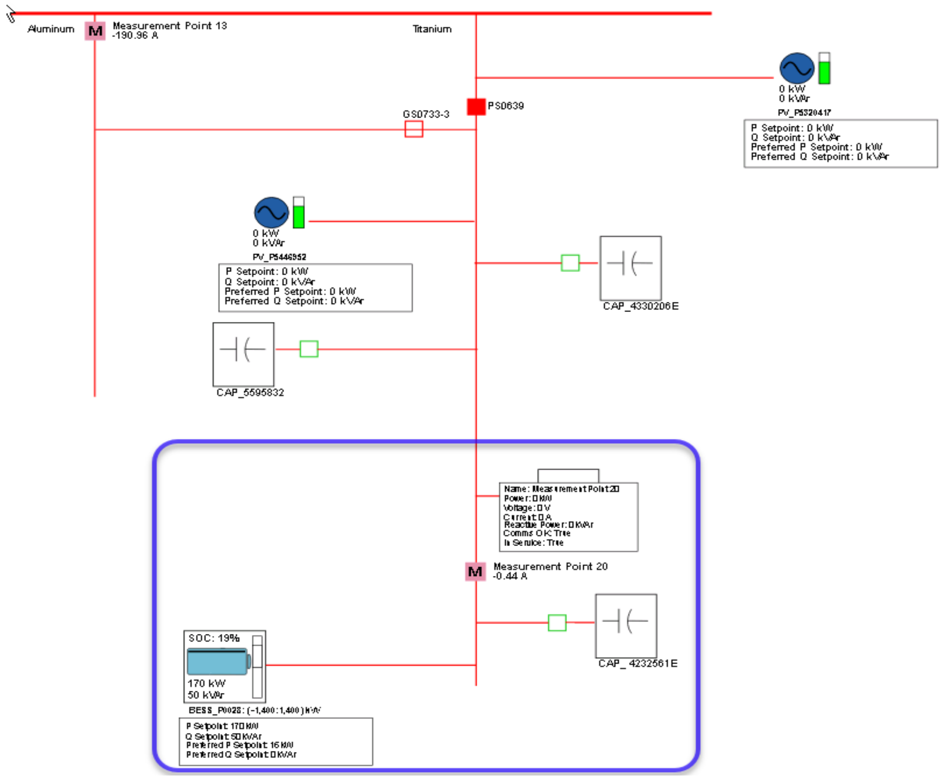

Figure 23: Real-Time Control Engine Maintaining near Zero Power Flow at MP20

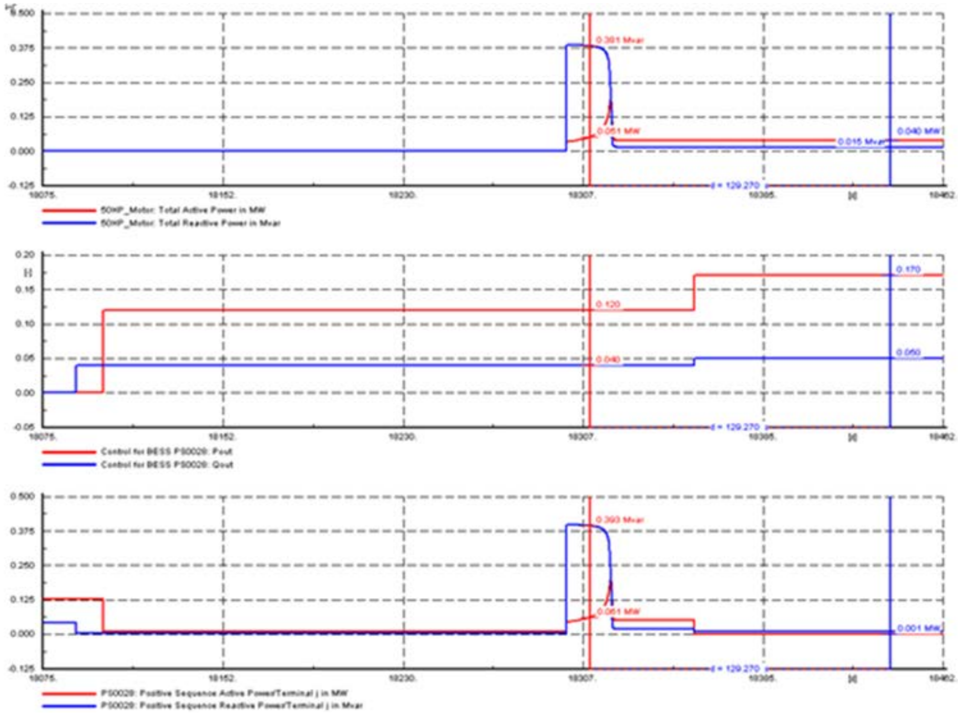

Figure 24: Power Flow and Control Setpoint during Microgrid Motor Starting Test

7.4 Power Smoothing

In this mode of operation, the BESS output is controlled to reduce variations in power at the head of the circuit. Energy storage helps minimize the impacts of changes in the PV output. Figure 25 demonstrates that the BESS provided ramp rate control to smooth the circuit load profile during a day with intermittent PV generation. The first plot shows the BESS output in MW and the second plot shows the Titanium circuit profile in MW during the two-hour simulation.

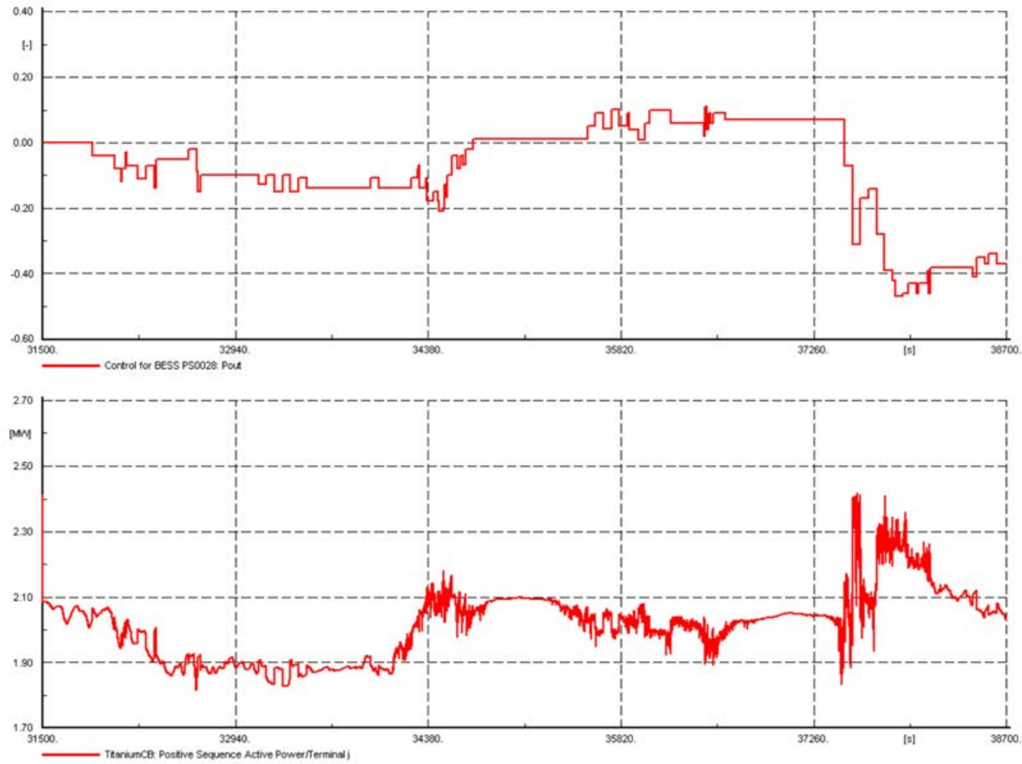

Figure 25: Real-Time Control System Managing Circuit Load Profile using Energy Storage

7.5 Volt-Var Optimization

This control application optimizes circuit voltage by lowering and flattening the voltage profile along the circuit using capacitors and DERs (generation and storage devices) equipped with smart inverters. Mathematically, the objective of VVO is to keep the voltage at all points along the circuit at the lower end of the permitted voltage range. Many of the same key test scenarios used in the optimal power flow section (see section 5.1 – Release 1 Testing) were used for the volt-var optimization test cases. Several volt-var modes of operation and settings were validated in the QAS test cycle.

The tests include the following cases:

Enable/disable autonomous operation using IGP DMS

Validate the operation rules and constraints (e.g. maximum number of allowable capacitor operations in a day)

Check minimum time between capacitor operations

Change the time interval when optimizations are to be run (e.g. at 10-minute time intervals)

Change the secondary voltage range for the optimization (e.g. Vmax = 1.05 pu and Vmin = 1.00 pu)

Enable/disable control over different resources (e.g. capacitors, BESS) used during optimization calculations

Selected test scenarios are presented below. Many of them had convergence issues as experienced in the Release1 (FAT) test cycle.

Maintain Statutory Voltage Limits:

> This test was developed to verify the planning engine maintains the voltage along the circuit within the statutory voltage limits during extreme low/high-load conditions. The test was conducted for high voltage and low voltage scenarios by setting the Titanium circuit voltage to 1.05 pu and 0.95 pu respectively.
>
> The test passed for high voltage scenario where the voltage was maintained at 1.05 pu or below, however, the planning engine failed to converge to a feasible solution at 0.98 pu or less at the head of the circuit.

Conservation Voltage Reduction:

> In this scenario, the test case verified that the planning engine can reduce the voltage along the circuit and consequently lower energy consumption as shown in Figure 26. The test was repeated by changing the Titanium circuit voltage (1.02 pu, to 0.95 pu at 0.01 pu intervals) and running VVO optimization. The test was successful for voltages >0.99 pu but failed for voltages lower than this.

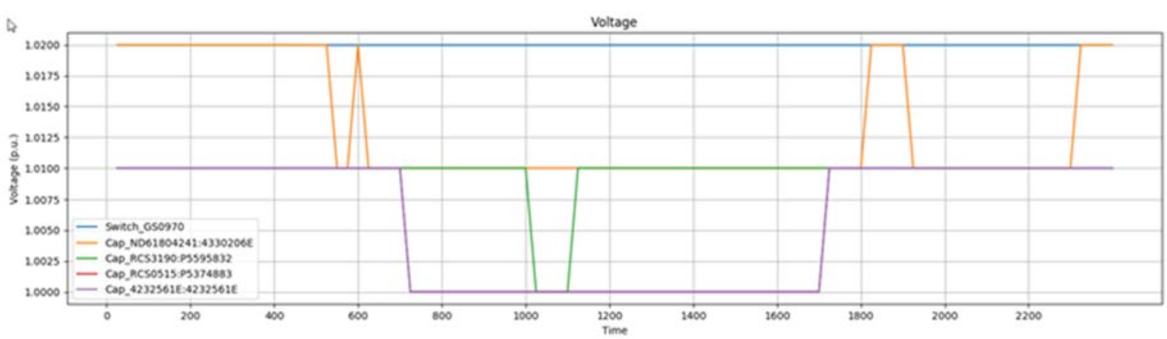

Figure 26: Planning Engine Reducing Voltage along the Titanium Circuit

Distribution Limits Outside of Statutory Voltage Limits:

In this scenario, the real-time control engine is expected to maintain the system operation within statutory voltage limits using energy storage. The test case evaluates the performance of the real-time control engine to mitigate voltage constraint violations (<0.95 pu or >1.05 pu) at the head of the Titanium circuit.

The test case was modified to validate system voltage behavior during the peak load cloudy day profile with the addition of three load change events (switching dummy loads and motor load). These loads were added to trigger high voltage or low voltage constraints violation. During the test, the real-time control engine did not dispatch the BESS even when the voltage dipped below 0.95 pu or above 1.05 pu at head of the Titanium circuit.

Figure 27 shows the DER voltage profiles lowered below 0.95 pu voltage, but no corrective actions were performed by the real-time control engine to mitigate the voltage issue.

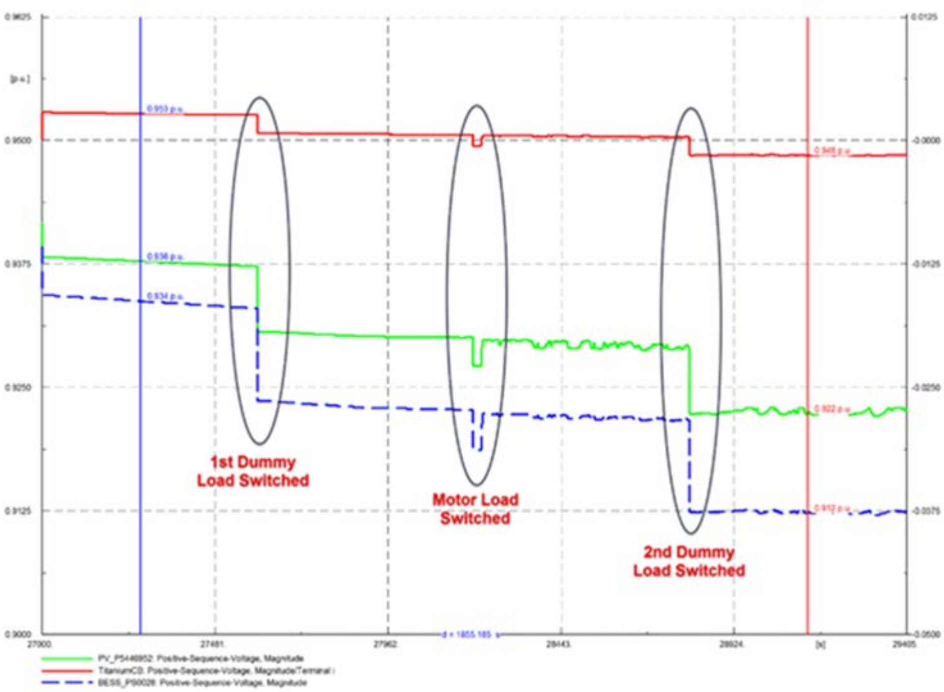

Figure 27: Real-Time Control Engine Unable to Maintain Voltage Limits

7.6 Issues and Recommendations

Several issues were identified during the QAS test cycle. Some of the key issues, and their recommendations are discussed below.

Issue:

The BESS integration included a vendor supplied hardware simulator as well as a PowerFactory model to emulate voltage behavior. State of charge logic exists in both the BESS simulator and the PowerFactory model, but they have different characteristics, thus the state of charge measurements can be out of sync. The PowerFactory model reached the low state of charge limit sooner than the BESS simulator. This triggering a zero active power output from the energy storage model in PowerFactory causing the BESS to stop following the reference set point sooner than indicated by the BESS simulator.

Recommendation:

For future testing, state of charge indication must be synchronized between the two systems to perform closed loop control testing. The best solution might be to disable the state of charge logic in PowerFactory.

Issue:

The control system was reading capacitor bank voltages from actual PCCs installed in the GT&M lab QAS environment. Capacitor bank models were also present in PowerFactory to model the impact of reactive power injection on distribution system voltage. When switching capacitors on and off, these two systems indicated different voltages. This created a mismatch in voltages which caused problems with the VVO control system. This mismatch made testing of low and high voltage cases difficult.

Recommendation:

Sync the PCC measurements (e.g. voltage) and status between the IntelliCAP PCCs and the PowerFactory capacitor bank models to perform closed loop control testing.

Issue:

Updating common configuration parameters in the planning engine as well as the real-time control engine was troublesome and required restarting software services to make the change. As an example, if an operator wishes to update the thermal limit at the head of the Titanium circuit, this would require update of the Amp Capacity value in the planning engine and the real-time control engine independently; and services then needed to be restarted or new software deployment. This would not be an option in the Production environment.

Recommendation:

Utilize a common service definition to make these setting changes and allow implementation without restarting or redeploying services.

Issue:

In live mode, the planning engine optimized over the entire day starting at midnight, even when the optimizer was restarted later in the day (e.g. 10 am). This issue resulted in a mismatch between the forecasted and the actual state of charge for the BESS.

Recommendation:

The optimizer should optimize the rest of the day with the first time-slice being the current time. A way should also be developed to query the state-of-charge of the BESS when restarting the optimizer to avoid errors.

Issue:

The planning engine failed to generate a new optimization solution when significant differences (>10% state-of-charge error) in the forecasted result and the actual reading were observed when in live mode.

Recommendation:

The vendor investigated the issue and identified that the planning engine was not checking out of sync status correctly. This problem can be corrected by the vendor.

Issue:

The control system did not respond to a loss of communication with the DESI-2 simulator.

Recommendation:

Utilize a heartbeat signal, which is already integrated between the real-time control engine and the simulator, to detect and report communication failures.

Issue:

The control system detected and reported a communication failure with the SEL RTAC, when the Ethernet cable to the DESI-2 simulator was disconnected, but it did not respond correctly after the cable was plugged back in. The vendor identified that the real-time control engine is trying to operate the DESI-2 circuit breaker which was not available for control during the communications failure.

Recommendation:

Ignore the circuit breaker control and read the circuit breaker status (Online Offline Status) to report the communication status.

Issue:

The control system detected and reported a communication failure when a FAN radio was turned off, but it did not respond correctly when the FAN radio was turned back on. The vendor determined that following a power outage, the FAN radio requires re-granting root permission to the edge compute application in the radio by manually logging into it.

Recommendation:

In future tests or deployments, the edge compute application will need a script to symbolically link and grant permission to start the edge compute application from the correct directory.

Issue:

The planning engine optimizer failed to converge at or below 0.98 pu voltage at the head of the circuit. A similar issue was observed during the Release1 testing. The vendor suggested use of a physical server instead of a virtual machine to solve this problem. When this was done as part of the QAS testing, the optimizer inputs still did not converge or generate a feasible solution.

Recommendation:

The planning engine needs to be re-evaluated to run volt-var optimization prior to field deployment.

Issue:

When voltage constraints were violated on the circuit, the real-time control engine failed to use the BESS to maintain the voltage within limits. One of the PV devices was monitored to report a voltage violation during the FAT testing, however, no voltage constraint was being monitored in the QAS set up.

Recommendation:

Either use the voltage at the head of the circuit or the controllable DER voltage for managing voltage constraint.

Issue:

The real-time control engine and the planning engine are two separate parts of the control system. These two engines are configured and controlled separately using different user interface screens, creating confusion when the grid operators need to enable or disable DERs or PCCs.

Recommendation:

Develop a common user interface for the control system.

8. Measurement and Validation (M&V)

The next steps for the project was to move the control applications to PGT&M when QAS testing was successfully completed. As part of the PGT&M testing, the control systems were to be connected to real field apparatus (e.g. capacitor controllers, automated switches, DER) and the production DMS. The production environment uses real system measurements and issues commands to real distribution equipment in the field. It does not allow use of simulated or modified grid parameters. Since some software modifications were made by the vendors to correct issues identified in QAS testing, retesting of certain functions in QAS would be required. After these re-tests in the QAS system are successfully completed, the control software would then be ready for field testing. As a result of the software modifications, new or modified test cases would be required to meet the PGT&M and M&V requirements.

Final QAS test cases were developed for Demo D that documented the necessary procedures/steps for the following:

Testing the use cases developed for Demo D,

Methods to transition from one test case to another,

Transition of control between various SCE's stakeholders (Demo D Demonstration team, Energy Storage team, Distribution Engineering, and Grid Operations) impacted by the Demo D testing.

9. Technology / Knowledge Transfer

Technology and knowledge transfer were divided into two areas. The first was transfer within SCE. The second was transfer of SCE's lessons to the industry, including other utilities.

SCE is deploying new grid technologies and systems across the entire company. Demo D, funded through EPIC, and is meant to demonstrate how these technologies could be deployed and to identify lessons that can resolve issues before full-scale deployment begins. Technology and knowledge are transferred to the teams and organizations working on production systems by sharing staff between the groups and regular inter-departmental review of progress and findings.

For those outside of SCE, the Demo D team has made numerous presentations at industry conferences and published articles in trade and professional magazines discussing technologies and their development within Demo D.

Examples include the following:

'Integrated Grid Project' (which includes Demo D) presentation briefed at the 2018 EPIC Winter Symposium.

'SCE's Integrated Grid Project: Demonstrating Coordinated Operations of High-Penetration DERs' presentation briefed at the 2017 DistribuTECH conference

‘Advanced Distribution Controls & Optimization Testbed at SCE’ presentation briefed at the 2017 DistribuTECH conference

‘Modernizing The California Grid’ published in the March/April 2017 edition of the IEEE power & energy magazine

‘Modern Grid, Modern Capabilities’ presentation briefed at the 2016 DistribuTECH conference

10. Appendix

10.1 Demo D Diagrams

10.2 Test Execution Material

10.3 Test Cases / Procedures

10.4 Use Cases

10.5 Metrics Overview

10.1 Demo D Diagrams

Architecture Diagrams

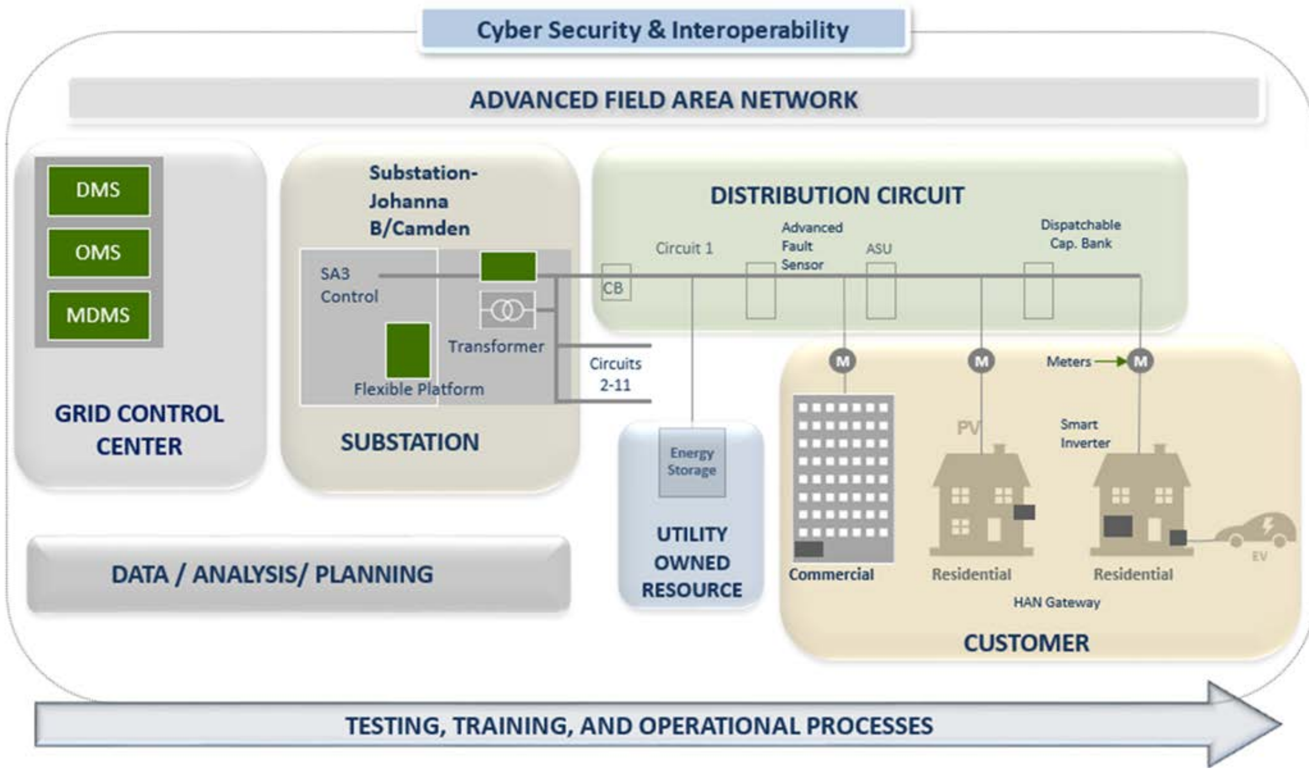

Figure 28: Demo D Structure Diagram

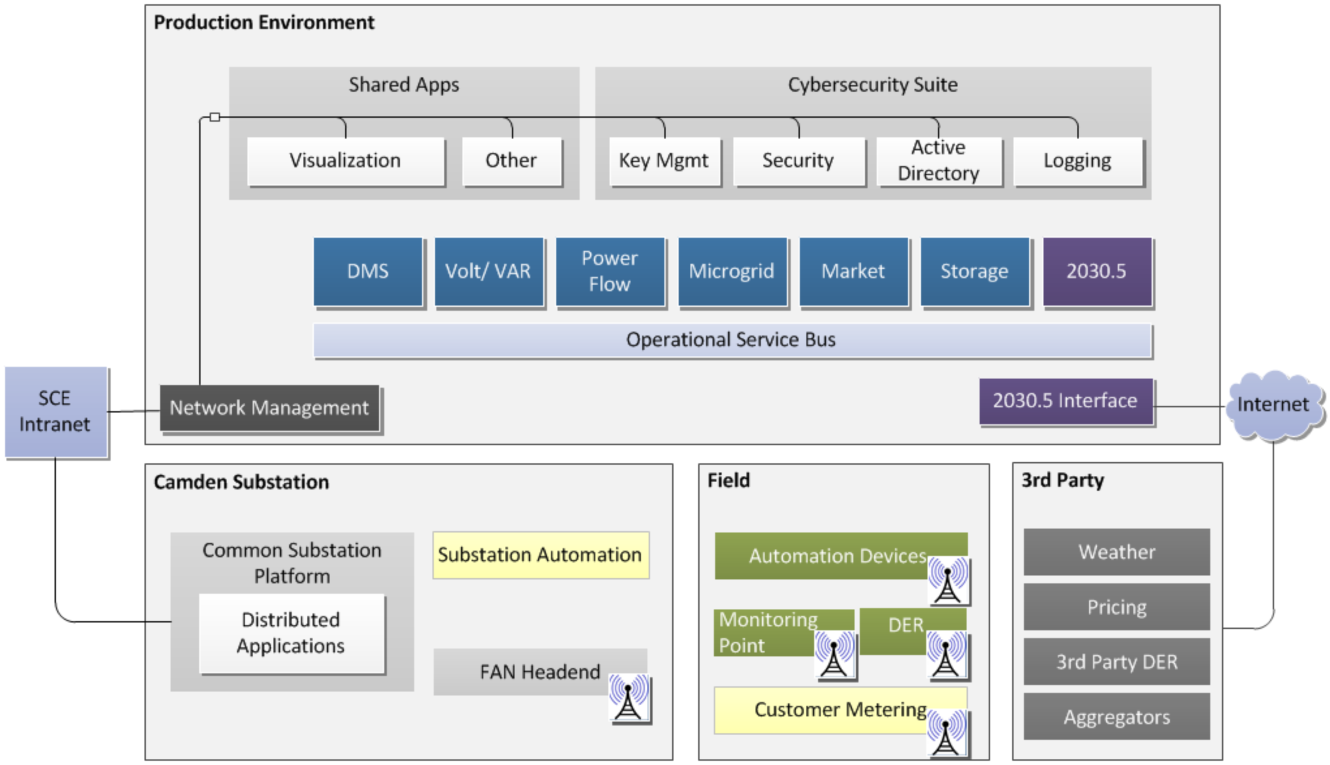

FIGURE 29: TOP LEVEL DEMO D ARCHITECTURE DIAGRAM

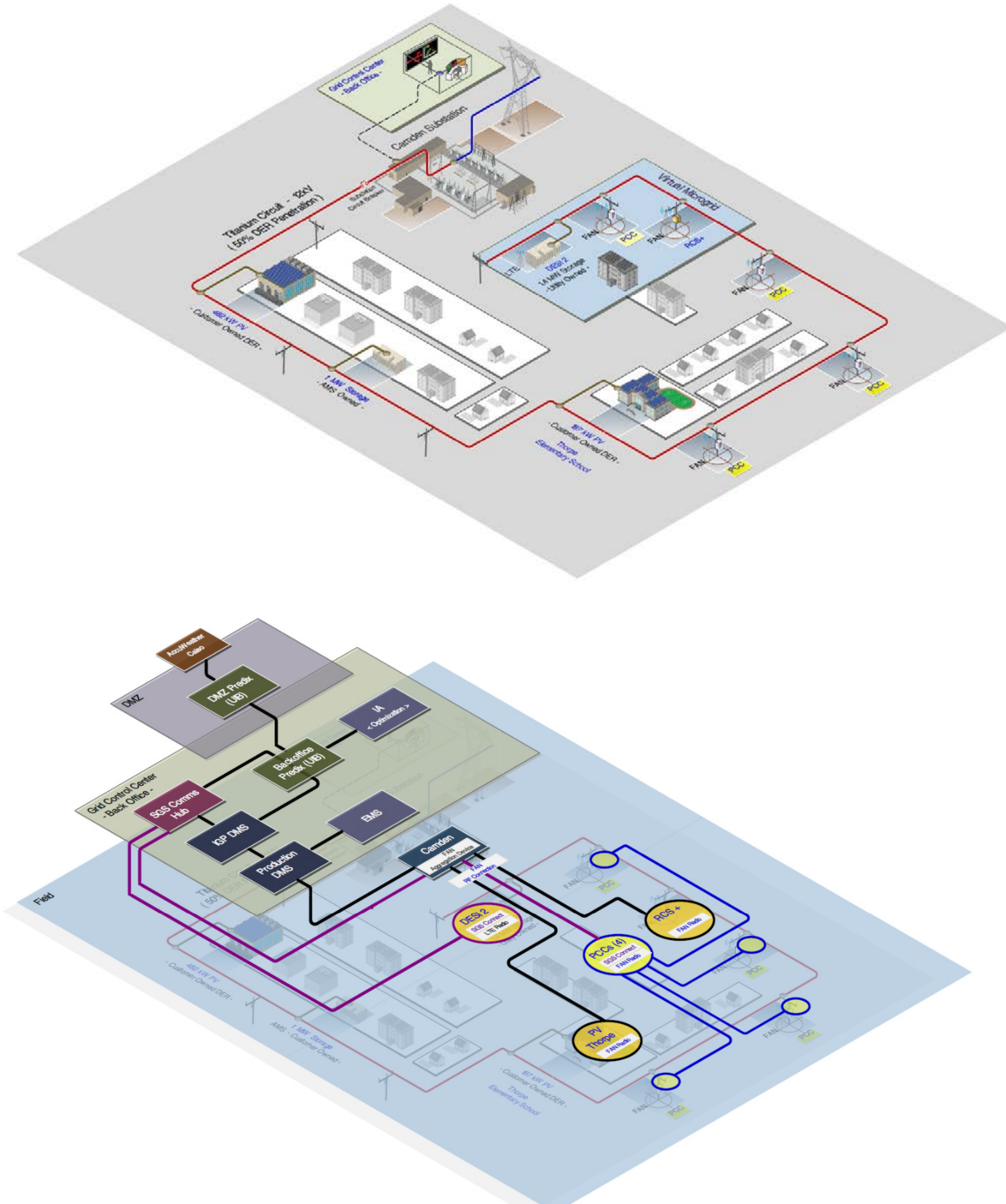

FIGURE 30: TOP LEVEL DEMO D LAYOUT & COMMUNICATION DIAGRAM

10.2 Test Execution

QAS Test Report Material / Diagrams

Utilized JIRA for daily status tracking of testing progress, issues, mitigation, and resolution

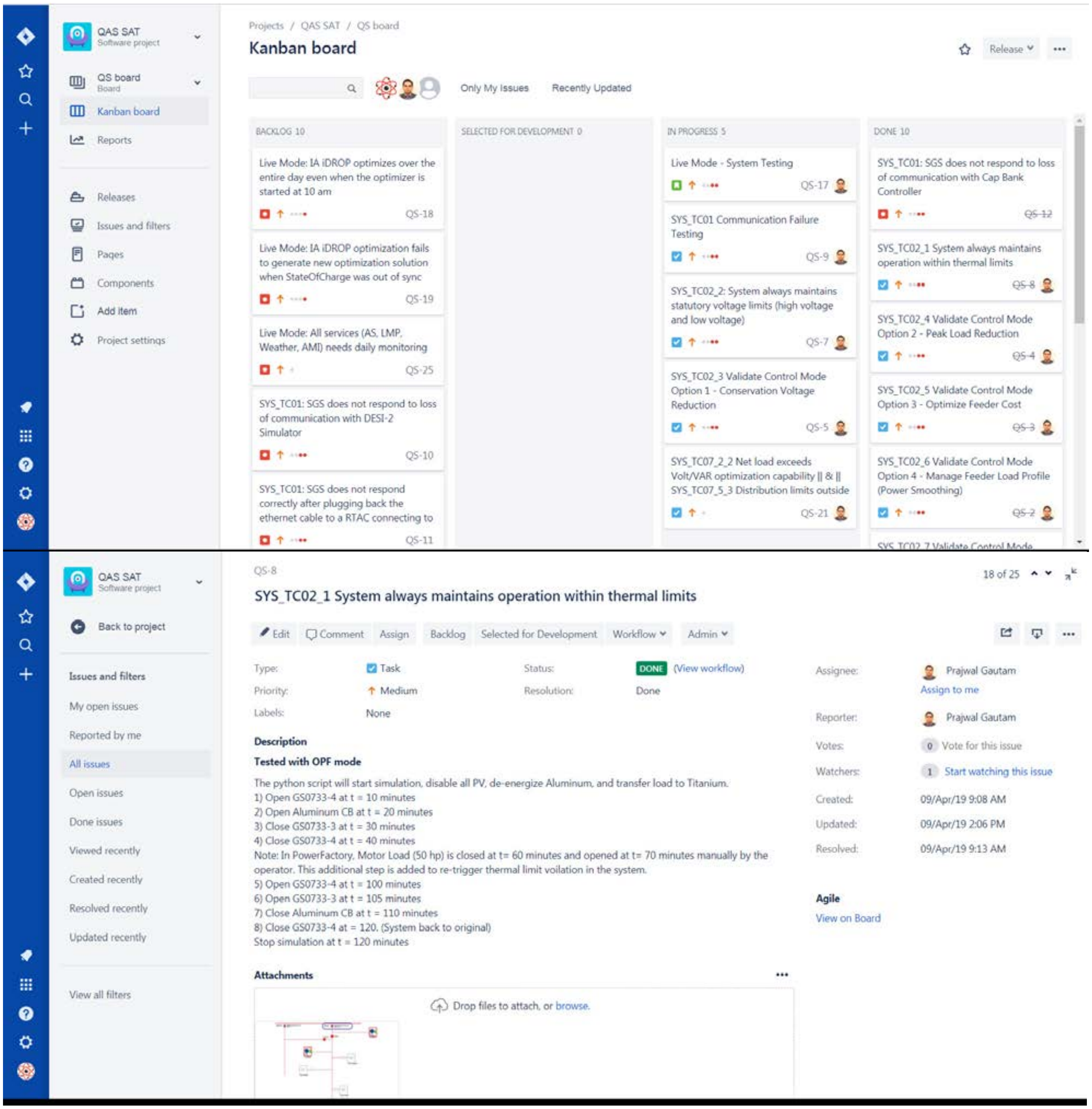

Figure 31: Sample JIRA Test Tracking Screens (SAT)

10.3 Test Cases / Procedures

QAS Test Case Execution and Reporting Material (2 Examples)

Test Case / Example 1: SYS_TC02_4 Peak Load Reduction

Description: In this mode of operation, the DER output is optimized so as to reduce peak load conditions on a circuit. Thermal limit at Titanium circuit head set by distribution system operator (DSO) is 473 A. In this test, grid operator resets desired target loading at Titanium circuit to 300 A and runs the OPF optimization mode.

Scenario: Peak_Load_Sunny

Time: 9:00-11:30

Mode: OPF

Test Results:

Planning Engine (Integral Analytics - iDROP) Optimization Results

Utilization of Energy storage: BESS PS0028 (4000kWh) = 3998.88kWh --> 100.0%

SOC (%) for Time Slice 36 and P/Q (kw/kVAR) for Time Slice 37

BESS PS0028 (4000kWh): 60.5 %: -0.1 kW: 0.0 kVAR

CAP Bank Switch Status for Time Slice 37

Cap_ND61804241:4330206E (1200kVAR) = 0.00

Cap_RCS3190:P5595832 (1800kVAR) = 0.00

Cap_RCS0515:P5374883 (1800kVAR) = 0.00

Cap_4232561E:4232561E (1200kVAR) = 0.00

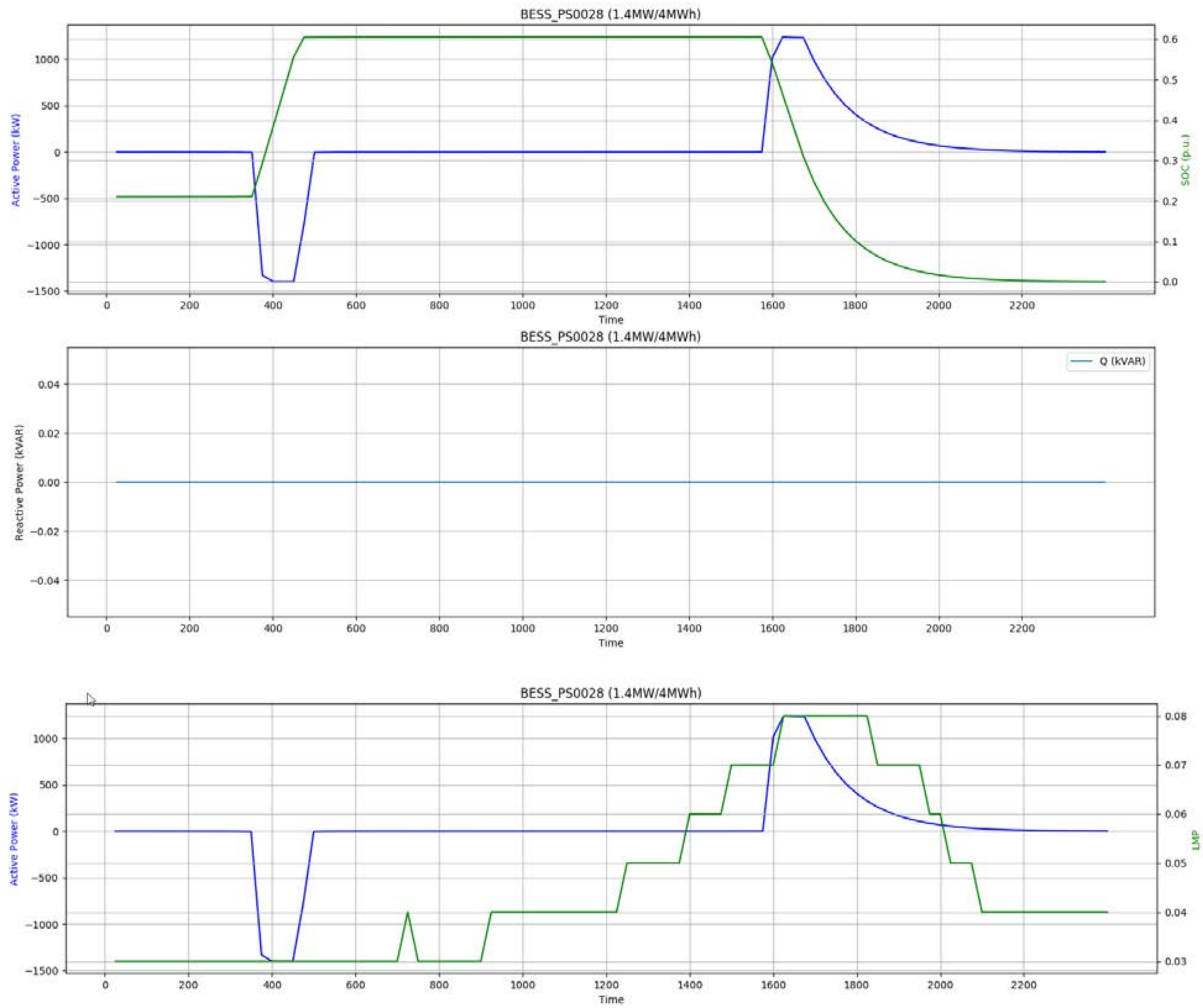

FIGURE 32: PLANNING ENGINE'S FORECASTED RESULT FOR BESS PS0028

Current at Bus 17916 (Titanium circuit head) was successfully capped to 300 A (previously 473 A) by the IA iDROP optimization/planning engine. IA iDROP followed the desired target loading set by the grid control operator in Step 2 of the test procedure.

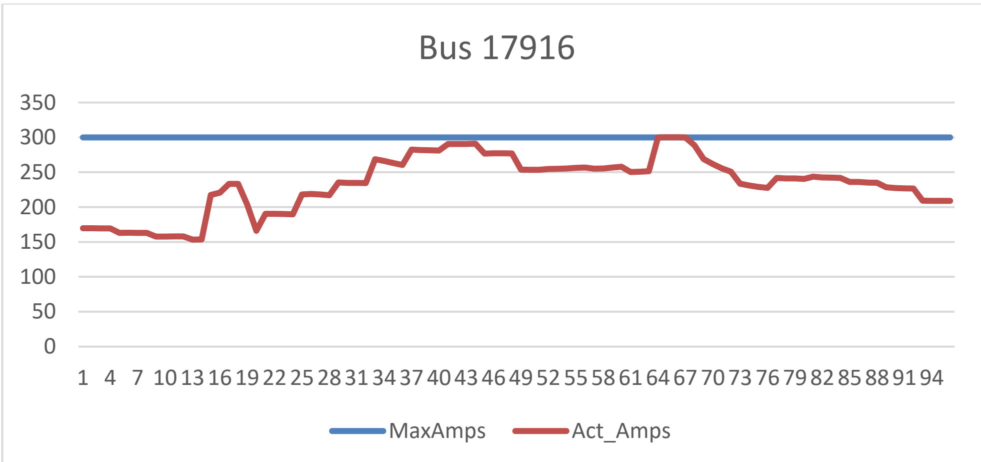

Figure 33: Current at Bus 17916 Maintained below 300 A

At t = 0: SGS ANM controller set to OPF/VVO, thus follows IA iDROP Preferred Setpoints.

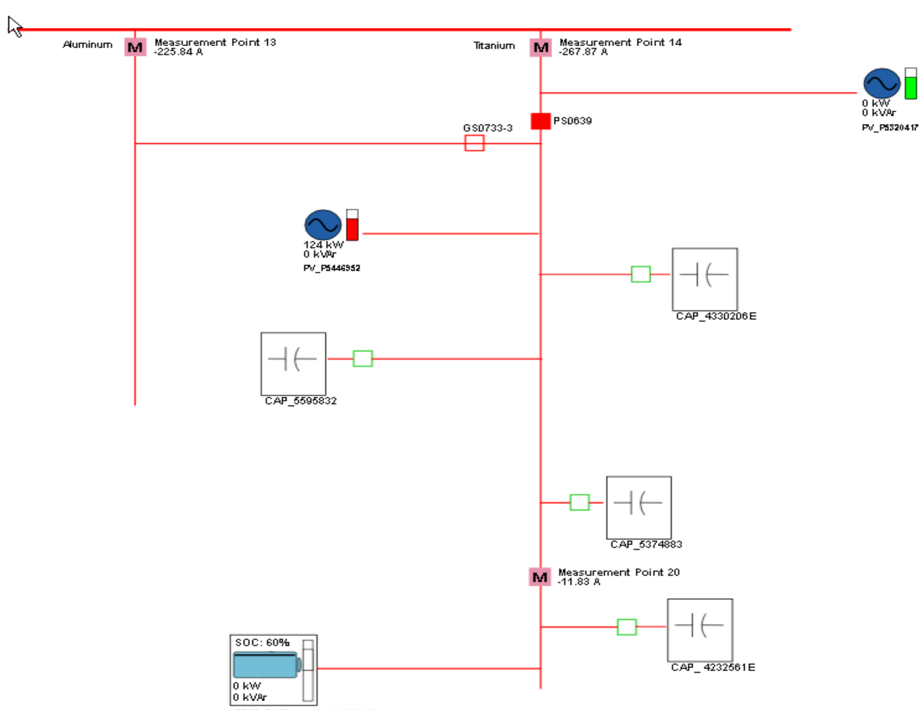

FIGURE 34: TITANIUM CIRCUIT (SINGLE LINE DIAGRAM) - IDROP SETPOINTS AT T = 0

Based on the IA Optimization results, it is recommended to run the test between 1500 to 1800 hours to observe DER loading (BESS discharging).

Thermal Constraint Management Issue

IA iDROP planning engine managed to keep the thermal limits to 300 A, however, the system was still loaded higher than 300 A at 10:30 am simulation time. SGS ANM controller (a real-time control engine) violated the thermal limits threshold set on the IA iDROP. Based on the feedback from SGS, thermal limit threshold (300 A) needs to also be set in SGS ANM configuration. In the past, “according to Chris”, the thermal limits were only tested for iDROP in TC02-4. Test case SYS_TC02_1 covers thermal limits management by SGS ANM controller during real-time simulation.

Thermal limits violated by the SGS ANM controller at Titanium circuit head:

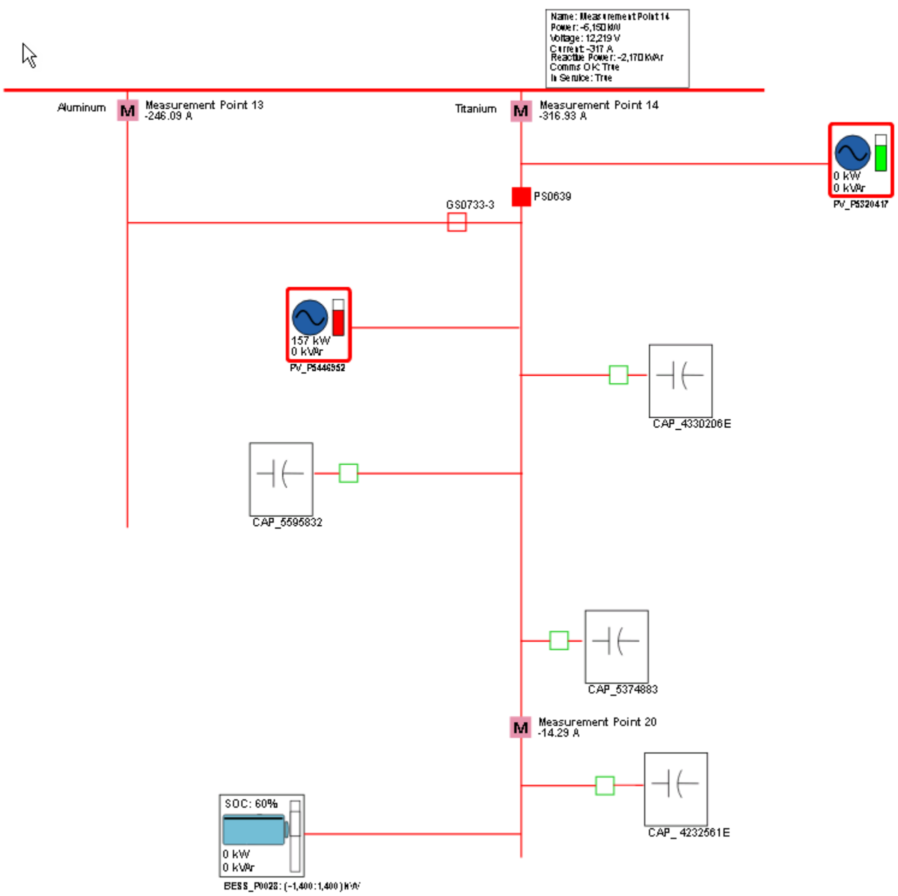

FIGURE 35: TITANIUM CIRCUIT (SINGLE LINE DIAGRAM) - THERMAL LIMITS VIOLATION

All 3 phases IA, IB and IC at Titanium circuit is greater than the thermal limits threshold of 300 A set on IA iDROP.

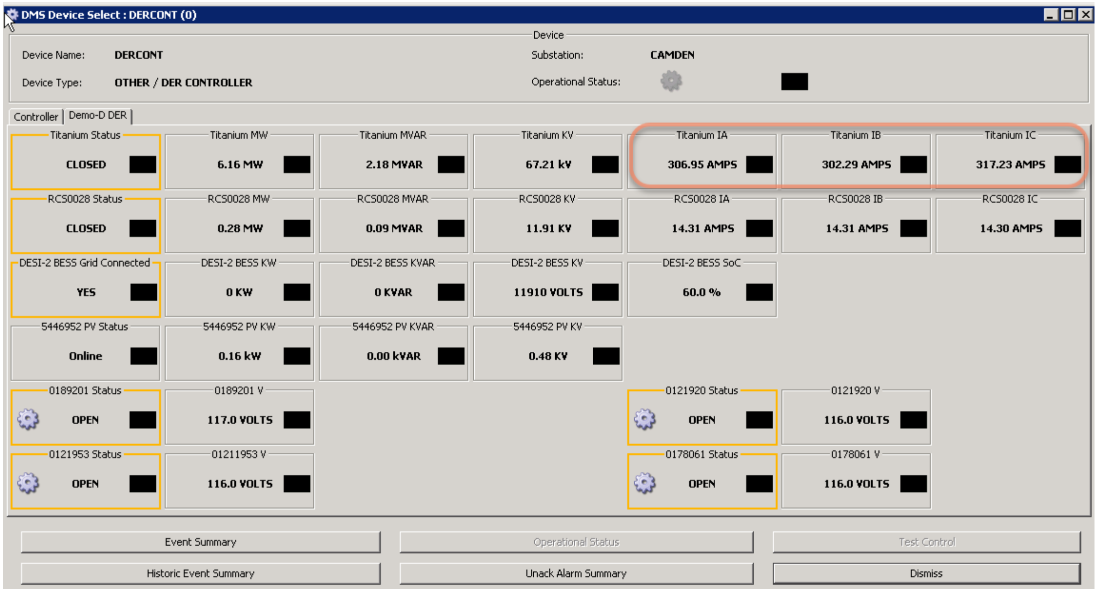

FIGURE 36: TITANIUM CIRCUIT (DMS SCREEN) – THERMAL LIMITS VIOLATION

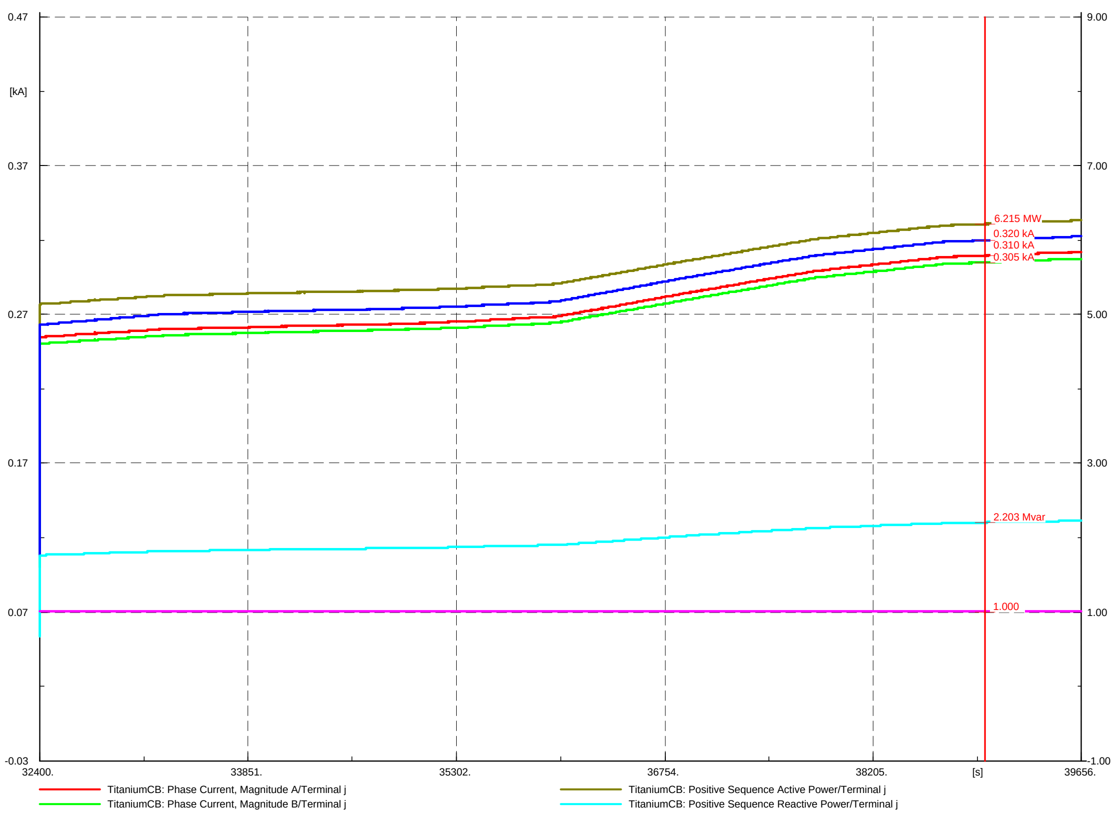

FIGURE 37: TITANIUM CIRCUIT – OUTPUT CURRENT AND POWER CHARTING

Test Case / Example 2: SYS_TC17 Virtual Microgrid

Description: The virtual microgrid function controls the available DER to reduce real and reactive power flow to near zero at a defined (microgrid) reference point, whereby the current is controlled to a low value. Proposes to evaluate this response characteristic in terms of speed of response by starting an induction motor during simulation.

Scenario: Peak_Load_Sunny

Time: 5:00-6:00

Mode: Microgrid

Test Results:

At t = 0: SGS ANM controller set to OPF/VVO, thus follows IA iDROP Preferred Setpoints.

At t = 1 min: Microgrid mode started. SGS ANM controller ignored IA iDROP Preferred Setpoints and maintained power flow to 0 kW/kVAR at microgrid monitoring point.

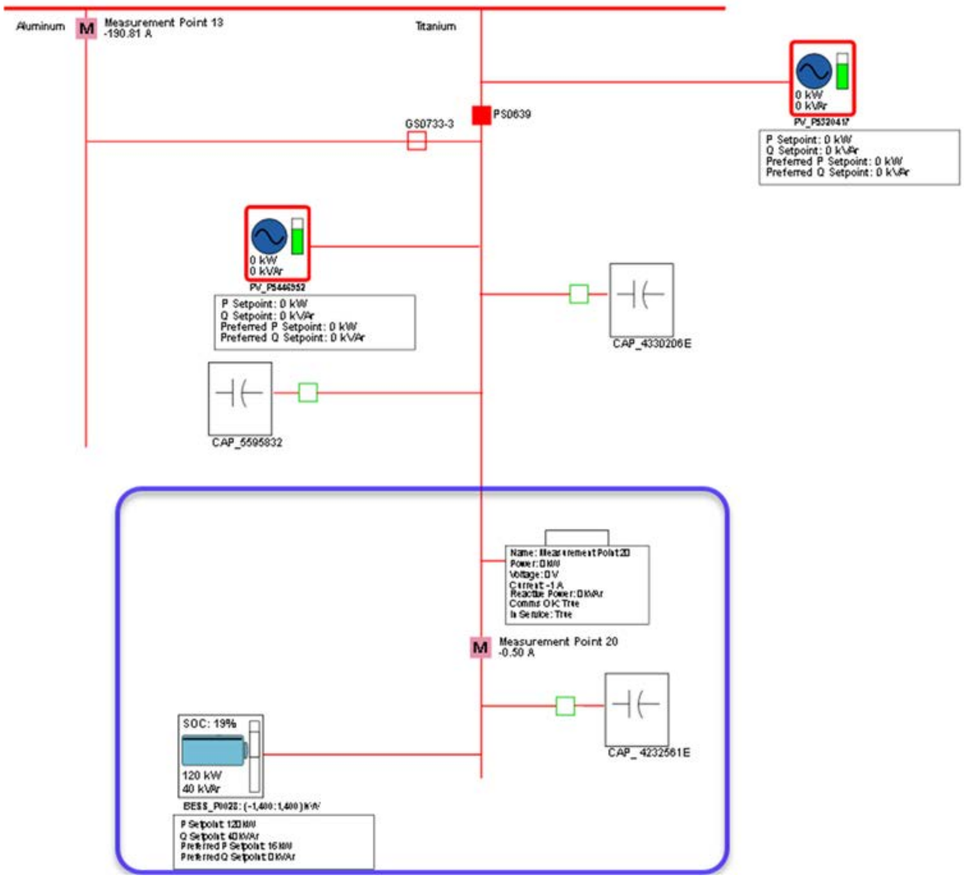

FIGURE 38: TITANIUM CIRCUIT (SINGLE LINE DIAGRAM) - IDROP SETPOINTS AT T = 1 MIN

At t = 5 min: A 50hp induction motor started that impacted power flow at microgrid monitoring point. SGS ANM controller sent the command to mitigate reactive power transient injected by the motor during starting. However, due to delay in communication between SGS to RTAC to DESI-2 simulator *(as P/Q set points)* to RTAC to PowerFactory *(as P/Q measurement)*, the intermittent command (e.g. 430 kVAR) in the figure below did not reach out to PowerFactory.

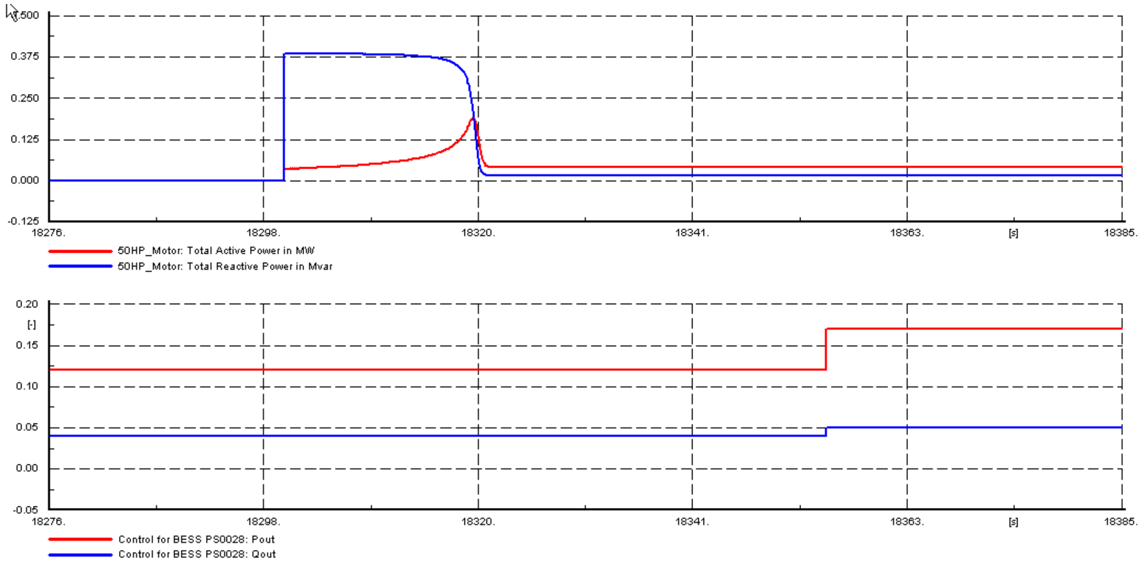

FIGURE 39: TITANIUM CIRCUIT – 50HP MOTOR IMPACT ON POWER FLOW AT T = 5 MIN

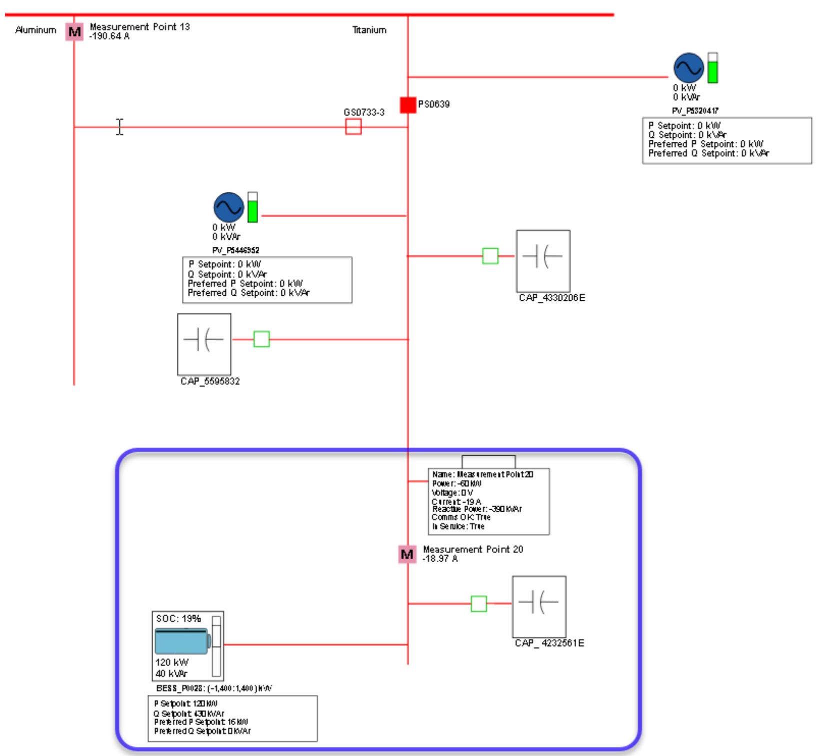

FIGURE 40: TITANIUM CIRCUIT (SINGLE LINE DIAGRAM) – IDROP SETPOINTS AT T = 5 MIN

At t = 6 min: About a minute after an induction motor was started and the motor starting transient settled down, SGS ANM controller maintained PCC's power flow to zero. A total of 40 kW and 0.15 kVAR was injected by a 50 hp induction motor.

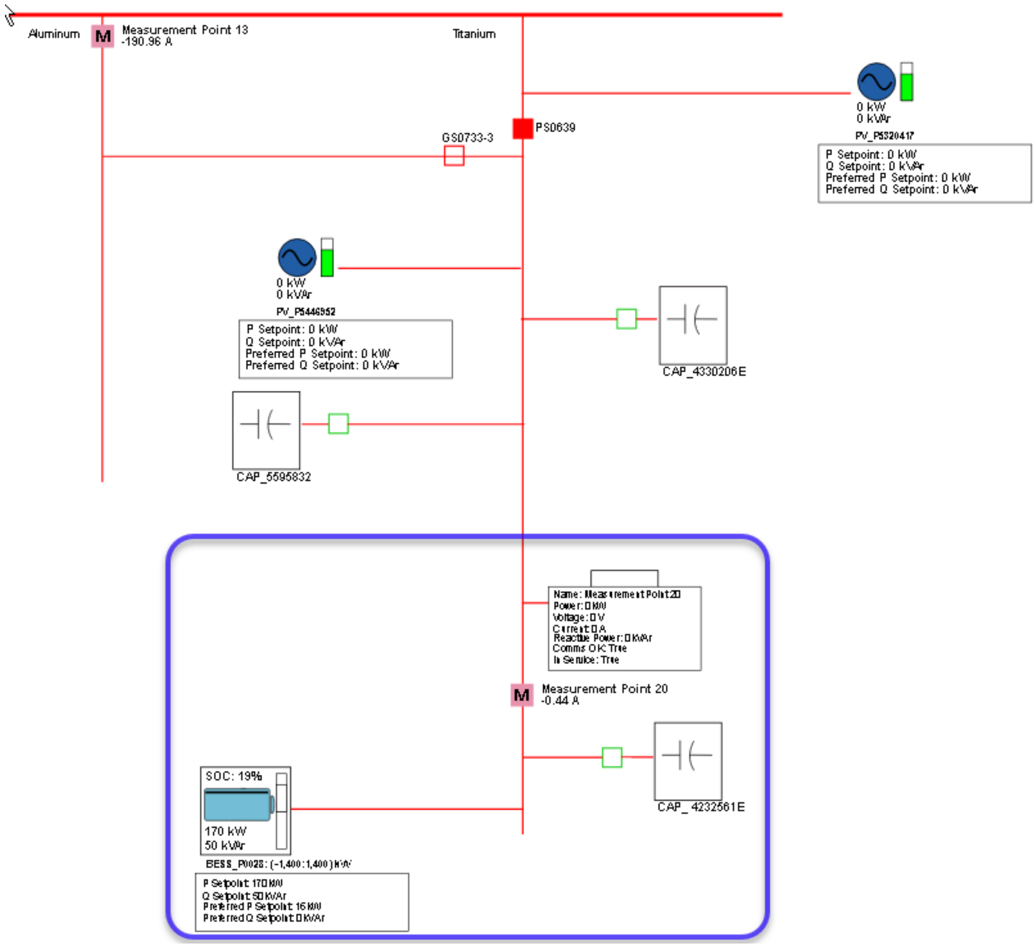

FIGURE 41: TITANIUM CIRCUIT (SINGLE LINE DIAGRAM) – IDROP SETPOINT AT T = 6 MIN

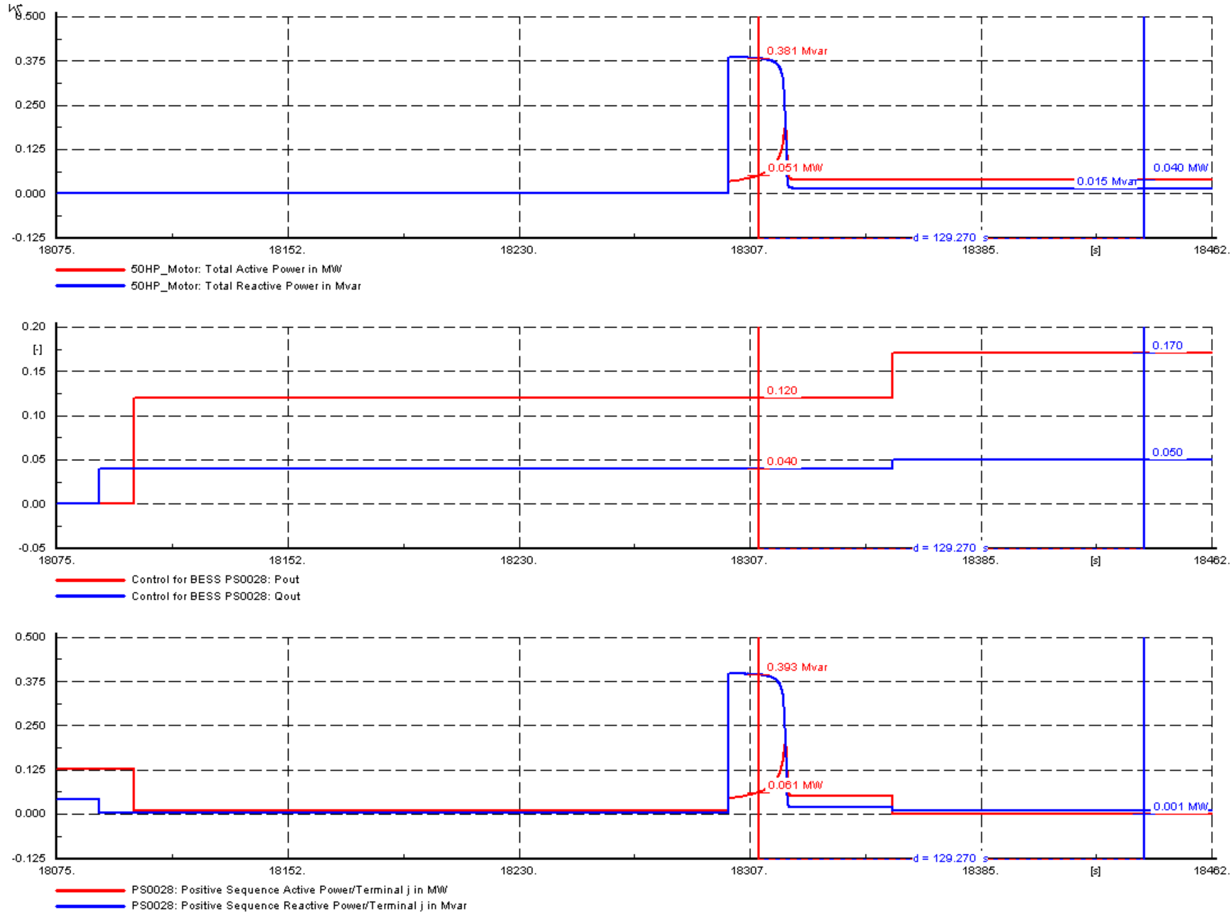

FIGURE 42: TITANIUM CIRCUIT - 50HP MOTOR IMPACT ON POWER FLOW AT T = 6 MIN

Notes:

Microgrid Point-of-Common-Coupling (PCC), also known as Microgrid Monitoring Point, is set up at the RCS+ downstream of PS0028.

SGS ANM Controller ignores IA iDROP Preferred Setpoints while on Microgrid mode.

Test Procedures (2 Examples)

Test Procedure SYS-IASGS-TC02-4 v4.0_2019_04_08_QAS1 - Validate Control Mode Option 2 - Peak Load Reduction

Procedure Number:	**SYS-IASGS-TC02-4 v4.0_2019_04_08_QAS1**	**Tested By:**		**No. of steps**	11
Prepared By:	Prajwal K Gautam	**Test Execution Date:**			
Test Case Name:	**Validate Control Mode Option 2 - Peak Load Reduction**				
Description:	In this mode of operation, the DER output is optimized so as to reduce peak load conditions on a circuit. Thermal limit at Titanium feeder head set by distribution system operator (DSO) is 473 A. In this test, grid operator resets desired target loading at Titanium feeder to 300 A and runs the OPF optimization.				
Tests Functional/Nonfunctional Requirement(s):	**FR-OPF15** **FR-OPF17** **FR-OPF20** **FR-OPF22**				
Test Scenario Overview:	This test will verify the controllers can reduce the loading supplied by the substation, by shifting the loading to the DER devices. The test will start with the base load (approx 2.9 MW) and will be increased to approx 8 MW in two stages (switching procedure implemented by the python script). The Power coming from the substation will be controlled by the thermal limits, and rest should be provided by the DER resources. The data analysis and plotting will also be implemented with a python script. PVs will be offline. BESS systems and cap banks will be under active control at all times.				

	Test Environment	Test Environment Comments
Hardware Requirements (Including Part Numbers):	Power Factory Test Hardware v1.0	
Software Requirements (Including Version):	Predix Integration Bus 2.0.1 configured and running	
	IGP Lab DMS XA-21 17.1.30 configured and running	
	IA iDROP / SGS ANM Control System configured and running	
	Power Factory(PF)v2016 SP3 configured and running PF sim model: IGP_QAS1_v0	
	Triangle Microworks Gateway 3.03.0046 configured and running	

Step	Action	Expected Results	Actual Results	Pass / Fail (plus Severity of Failure)	Iterations
1	Verify the controller is active and configured for OPF. Please refer to "IGP Controls System Testing Procedure.docx" for details to select OPF mode using IGP DMS.	IA iDROP / SGS ANM Control System configured for OPF	SGS ANM HMI shows operating mode as OPF/VVO and IA iDROP shows mode as OPF	Pass	
2	Set desired target loading to 300 Amps (for Titanium) by changing iDrop configuration file (bus_Line_17916.txt) for bus no. 17916. The AmpCap will be set from 472 A to 300 A. Note: Please remember to close iDROP dashboard and restart iDROP service after configuration parameters such as AmpCap is changed. Additionally, reset 300 A to orginial AmpCap of 472 A after the test is complete.	This setting to be implemented in the iDROP configuration file (bus_Line_17916.txt) on bus no. 17916.	Desired target loading of 300 Amps was set and verified on optimization Input Files generated at IA01 server	Pass	
3	Verify DER device setup and external measurement setup defined in the "Initial Conditions" tab	Setup external measurement nodes in Power Factory according to the Initial Conditions tab, plus the Initial state of charge for the BESS'	Configured	Pass	
4	Verify plots for all BESS, PV, Caps, Feeder CB, tie switches, selected load nodes (P5076413, P5506438, P5468243, 50Hp Motor), and selected points along the feeder (2134546E, 4471502E, 4797915E)	The plots exist	Verified	Pass	
5	Verify the OPC link between TMW and Power Factory is active	The link is active	Active	Pass	
6	Run "TC02_4" script in Power Factory		Script executed		
7	Simulation stops at t = 100 minutes		Stopped	Pass	
8	Save output files.	The TC02_4 script will save all external control events, plots, and the raw data to generate the plots on the Power Factory Server	Saved	Pass	
9	Take a snap shot of the plots and paste them to the respective tabs of this excel file		Pasted	Pass	
10	Verify the loading was maintained at the Titanium getaway under 300 A	The load was under 300 A at the getaway	IA iDROP planning engine managed to keep the thermal limits to 300 A at the Titanium feeder, however, SGS ANM controller violated the thermal limits threshold set on the IA iDROP. Based on the feedback from SGS, thermal limit threshold (300 A) needs to also be set in SGS ANM configuration. Test case SYS_TC02_1 covers thermal limits management by SGS ANM controller.	Pass	
11	Verify the new loading setpoints were commanded by the controller.	The DER followed the setpoints	Verified	Pass	
	End of Test - Finalize test results				

Figure 43: SAT Testing – Example Test Procedure (TC 02-4)

Test Procedure SYS-IASGS-TC17 v4.0_2019_04_08_QAS1 – Virtual Microgrid

Procedure Number:	**Test Procedure SYS_TC17 v4.0_2019_04_08_QAS1**	**Tested By:**		**No. of steps**	12
Prepared By:	Prajwal K Gautam	**Test Execution Date:**			
Test Case Name:	**Virtual Microgrid**				
Description:	The virtual microgrid function controls the available DER to reduce real and reactive power flow to near zero at a defined (microgrid) reference point, whereby the current is controlled to a low value. Proposes to evaluate this response characteristic in terms of speed of response by starting an induction motor during simulation.				
Tests Functional/Nonfunctional Requirement(s):	**FR-MG15,FR-MG16,FR-MG18,FR-MG19, FR-MG25** **NFR-MG1 to 8**				
Test Scenario Overview:	Replay a scenario of a virtual microgrid maintaining zero power flow through the PCC				

Test Environment		**Test Environment Comments**
Hardware Requirements (Including Part Numbers):		
	Power Factory Test Hardware v1.0	
Software Requirements (Including Version):	Predix Integration Bus 2.0.1 configured and running	
	IGP Lab DMS XA-21 17.1.30 configured and running	
	IA iDROP / SGS ANM Control System configured and running	
	Power Factory(PF)v2016 SP3 configured and running PF sim model: IGP_QAS1_v0	
	Triangle Microworks Gateway 3.03.0046 configured and running	

Step	Action	Expected Results	Actual Results	Pass / Fail (plus Severity of Failure)	Iterations
1	Verify SGS ANM Controller is active and configured for the microgrid mode. Please refer to "IGP Controls System Testing Procedure.docx" for details to select microgrid mode using IGP DMS. Note: Microgrid Point-of-Common-Coupling (PCC), also known as Microgrid Monitoring Point, is set up at the RCS+ downstream of PS0028. Note: SGS ANM Controller ignores IA iDROP Preferred Setpoints while on Microgrid mode.	SGS ANM Controller configured for microgrid mode	SGS ANM HMI shows operating mode as Microgrid	Pass	
2	Verify DER device setup and external measurement setup defined in the "Initial Conditions" tab	Setup external measurement nodes in Power Factory according to the Initial Conditions tab, plus the Initial state of charge for the BESS'	Configured	Pass	
3	Verify plots for all BESS, PV, Caps, Feeder CB, tie switches, selected load nodes (P5076413, P5506438, P5468243, 50Hp Motor), and selected points along the feeder (2134546E, 4471502E, 4797915E)	The plots exist	Verified	Pass	
4	Verify the OPC link between TMW and Power Factory is active	The link is active	Active	Pass	
5	Run "TC17" script in Power Factory	The script will 1) Start a 50hp induction motor t=5minutes	Script executed Increased in load after starting a 50 hp induction motor was	Pass	
6	Simulation stops.		Stopped	Pass	
7	Save output files.	Go to the PF output file directory, and copy the file to an outside folder for further processing.	Saved	Pass	
8	Take a snap shot of the plots and paste them to the respective tabs of this excel file and analyze the controller performance	Note any violations	Pasted	Pass	
9	Verify the loading at the microgrid virtual node is maintained near 0 MW and 0 MVAR	The flow was maintained within +/- 20kW/kVAR and response within 10 seconds	The power flow was maintained within +/-20kW/kVAR	Pass	
10	Verify the new loading setpoints were commanded by the controller.	Verify on the plot that the commands were sent and received by the devices	New commands were sent to BESS_PS0028 when PCC measurements were beyond +/- 20kW/kVAR	Pass	
11	Verify that voltage stayed within 5% at the nodes specified	There were no voltage violations	No voilations observed	Pass	
12	Disable autonomous control of the microgrid	Autonomous control of the microgrid is disabled	Disabled	Pass	
	End of Test - Finalize test results				

FIGURE 44: SAT TESTING – EXAMPLE TEST PROCEDURE (TC 17)

10.4 Use Cases

Use Case 2-1

Title: Voltage Optimization with DER

Summary: The substation-level volt/VAR controller optimizes circuit voltage using capacitors and Distributed Energy Resources (DER) generation and storage devices equipped with smart inverters. The Grid Management System (GMS) optimizes circuit voltage by lowering and flattening the voltage profile along the circuit 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 DERs, including photovoltaics (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 (RCS). 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 inverters installed by the Distributed Energy Storage Integration (DESI) project, 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 Circuit Load

Summary: At the circuit level, the Grid Management System (GMS) and its Optimal Power Flow (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 photovoltaic (PV) output reduction, Distributed Storage (DS) discharge, and/or load control. The monitoring data will be communicated to the GMS, which manages the OPF). Monitoring will be provided by RFIs, RISs, and RCSs, and the DERs themselves. Interfaces will be implemented to allow the 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 FAN). The communication path for the 3rd party-owned DERs will be either through the Internet, cell data connection or Field Area Network (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 circuit for a pre-determined period.

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. photovoltaics (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 monitoring data will be communicated using the SCE 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.

10.5 Metrics Overview

Metrics Overview

CPUC Demo D Metrics (Reference Appendix B, Decision 17-02-007, dated February 9, 2017)

Background:

The Demo D metrics were intended to assess the performance of DER devices in the field (M&V).

As described at the beginning of this report, the project has been terminated prior to field testing and operations.

The below charts (Figures 45 and 46) provide a top level description of each metric and progress towards its completion (with the understanding that the metrics were to be conducted / completed during M&V, which now will not be conducted)

Performance Measure	Description	Status	Notes
DER Capacity Output	Measure the DER capacity output for one year or greater, to compare to the forecasted output prior to procurement	Partial Completion	Measured during FAT and SAT Testing Period (in Lab and QAS Environment respectively)
DER Energy Output	Measure the DER energy output for one year or greater, to compared to forecasted energy output prior to procurement	Partial Completion	Measured during FAT and SAT Testing Period (in Lab and QAS Environment respectively)
Local Utility System Voltage	Measure the utility system voltage for one year or greater, at a point in proximity to the DER installation and compare to a year prior to DER installation	Partial Completion	Measured during FAT and SAT Testing Period (in Lab and QAS Environment respectively)
Utility Circuit Load	Measure the utility circuit load for the circuit which hosts the DER, for one year or greater, and compare to a year prior to DER installation	Partial Completion	Measured during FAT and SAT Testing Period (in Lab and QAS Environment respectively)
Utility Circuit Energy	Measure the utility circuit energy delivery for the circuit which hosts the DER, for one year or greater, and compare to a year prior to DER installation	Partial Completion	Measured during FAT and SAT Testing Period (in Lab and QAS Environment respectively)
Utility to DER Dispatch Request	Measure the ability of the DER to respond to utility requests when called upon to provide distribution services and solve a local grid/system need.	Partial Completion	Measured during FAT and SAT Testing Period (in Lab and QAS Environment respectively)
Utility System Energy Mix	Measure the utility's energy delivery mix, such that appropriate GHG emission offsets can be evaluated and compared with the DER, while the DER is in service	Not Conducted	n/a
DER Project Capacity Factor	Measure the ratio of the actual output power to its full nameplate capacity over a period of time (usually one year).	Partial Completion	Measured during FAT and SAT Testing Period (in Lab and QAS Environment respectively)
DER Project Capacity Cost	Unitize the actual cost of a DER to provide capacity per unit of time	Not Conducted	n/a
DER Project Energy Cost	Unitize the actual cost of a DER to provide energy per unit of time.	Not Conducted	n/a
DER Reactive Power Output	Measure the DER reactive power output for one year or greater, to study the ability of the resource to supply reactive power	Partial Completion	Measured during FAT and SAT Testing Period (in Lab and QAS Environment respectively)
Distribution Capacity and Hosting Capacity Service Effectiveness	Measure the technical effectiveness of DER dispatch with mitigating projected equipment overloads. Comparative analysis will be performed evaluating projected equipment loading levels against actual equipment loading levels and conditions when sourced DER portfolio is dispatched	Partial Completion	Measured during FAT and SAT Testing Period (in Lab and QAS Environment respectively)
DER Readiness & Assurance	Measuring the time between contract award to operation to ensure timeliness in meeting the locational needs. owneequipment.	Not Conducted	n/a
Process Evaluation	(Demo C Metric)	Not Applicable For Demo D	

FIGURE 45: DEMO D METRIC STATUS (TABLE 1 OF 2)

Performance Measure	Description	Status	Notes
Point of Common Coupling Voltage Support	Measure the voltage increase/decrease seen at the PCC due to the DER operation.	Partial Completion	Measured during FAT and SAT Testing Period (in Lab and QAS Environment respectively)
Turn Around Efficiency	Measure the overall energy lost (%) from storage and utilization of energy.	Not Conducted	n/a
DER Operational Mode Validation	Verify the DER solution modes of operation, such as peak shaving, operate as expected.	Partial Completion	Measured during FAT and SAT Testing Period (in Lab and QAS Environment respectively)
DER Real Power Output	Measure the real power (kW) output of the DER solution compared to the nameplate rating	Partial Completion	Measured during FAT and SAT Testing Period (in Lab and QAS Environment respectively)
DER Reactive Power Output	Measure the reactive power (kVAR) output of the DER solution compared to the nameplate rating.	Partial Completion	Measured during FAT and SAT Testing Period (in Lab and QAS Environment respectively)
Communication Latency	Latency between issued command to actual operation will be measured.	Partial Completion	Measured during FAT and SAT Testing Period (in Lab and QAS Environment respectively)
Communication Resiliency	Communication failures and signal loss will be measured	Partial Completion	Measured during FAT and SAT Testing Period (in Lab and QAS Environment respectively)
Point of Common Coupling Voltage Support	Measure the voltage increase/decrease seen at the PCC due to the DER operation.	Repeat of 15.	
Effectiveness of Proposed Autonomous Operations	Proposed autonomous solutions effectiveness such as automated Volt/VAR operations should be compared to simulated results. No autonomous operations were planned for the DER devices in Demo D	Not Applicable For Demo D	
DER Penetration	Measure of the amount of DER generation (power) divided by the peak circuit or area demand expressed as a percentage	Not Conducted	n/a
Voltage Controllability	Comparison between the voltage setpoint and local utility system voltage measurement	Partial Completion	Measured during FAT and SAT Testing Period (in Lab and QAS Environment respectively)
Power Flow Controllability	Comparison between the power flow setpoint and utility circuit load measurement	Partial Completion	Measured during FAT and SAT Testing Period (in Lab and QAS Environment respectively)
Control and Data Management	Measure the time it takes to gather, process, make recommendation to operator and execute on a command.	Partial Completion	Measured during FAT and SAT Testing Period (in Lab and QAS Environment respectively)

FIGURE 46: DEMO D METRIC STATUS (TABLE 2 OF 2)

Appendix C

Distributed Cyber Threat Analysis and Collaboration

Final Project Report

Project GT-18-0008:
Distributed Cyber Threat Analysis and Collaboration (DCTAC)
Final Project Report

Submittal Date: February 28, 2022

Developed by
Southern California Edison (SCE) Cybersecurity Operations
with support from
Asset & Engineering Strategy, Grid Technology Innovation

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The following individuals were instrumental in the delivery of this project.

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Executive Summary

The Electric Program Investment Charge (EPIC) III Distributed Cybersecurity Threat Analysis Collaboration (DCTAC) project was selected as an EPIC III portfolio because of the industry cross cutting cybersecurity capabilities DCTAC can provide utilities, regulators and U.S. government critical infrastructure agencies through sharing vetted vulnerability and or threat intelligence by the California Public Utilities Commission (CPUC). The DCTAC project was designed to provide a proof-of-concept demonstration for improving and standardizing cybersecurity intelligence information sharing across electric utilities or other critical infrastructure industries. While all utilities likely collect *data* on cybersecurity vulnerabilities, threats, and indicators of compromise from many different sources, it is difficult to take actionable without significant effort to determine the accuracy, validity, and applicability of the information. There are very few reliable sources of *intelligence*, that is, data presented in a way that's meaningful, interpretable and actionable by utility decision makers and stakeholders.

DCTAC's aim was to build on the lessons learned from the California Energy Systems for the 21stCentury (CES21) project's Machine-to-Machine Automated Threat Response (MMATR) concept by demonstrating the ability to standardize electric utility cybersecurity intelligence, threat analysis, and information exchanges and to:

- Demonstrate how cybersecurity threats can be shared between vetted members
- Demonstrate how grid cybersecurity defense can be strengthened through a collaborative threat intelligence sharing process
- Demonstrate the capability to standardize utility threat analysis work products
- Exercise the need for intelligence data classification and handling between members.

The duration of cyber-attacks varies in time, and significant attacks usually involve multiple organizations, which can extend the duration of the attacks. This requires quick response times, which are needed by utilities to react and defend before a compromise can occur. The current cyber practice is for individual Security Operations Centers (SOCs) to gather data and perform the analyses within their own systems, with very little external collaboration. Each organization's processes and documentation requirements vary greatly, and there is no standardized way to share physical evidence directly between partners or vendors. Most intelligence is shared in a non-centralized, distributed fashion with little to no prior communications, and is dependent on each vendor's release channel. The data is commonly delivered in vendor-proprietary formats as there is a lack of a common language or format to support utility-to-utility analysis and information sharing, which negatively affects the time to resolve a threat. In addition, intelligence information is provided by many sources both internal and external to the organization. The information is often duplicative, and intelligence that is potentially applicable—sometimes urgently— to the operation is mixed in with information that has no bearing on the organization at all. Analysts must wade through a sea of data to locate the information that could indicate a potential vulnerability and or threat and provide actionable intelligence.

To address this, the DCTAC framework leverages grid-based addendums to the Structured Threat Information eXpression (STIX™) v2 standard for sharing between utility partners. Our finding is that the DCTAC framework can enhance collaboration among various internal and external stakeholder groups by:

- Demonstrating the capability to standardize utility threat analysis work products by creating a standard format and processes for addressing incoming threat intelligence
- Demonstrating how cybersecurity threats can be shared between vetted members by defining a method to communicate legitimacy and threat impact of intelligence for outgoing intelligence

- Demonstrating how grid cybersecurity defense can be strengthened through a collaborative threat intelligence sharing process by reducing time spent analyzing threat intelligence and creating a risk aware package of sharable intelligence.

The results provide standardized information intake processes and the creation of consistent information packages; a methodology for how information should be shared within the organization and what risk it presents; and recommended standards and automation for intelligence to be shared outside of the organization.

The use of a standard, open format and open source back-end software allows DCTAC to be implemented at minimal cost to the organization and facilitates an information sharing community among all participating partners and dissuade dependance on any particular vendor's intelligence solution.

Project Summary

The DCTAC project demonstrates the ability to standardize electric utility cybersecurity intelligence, threat analysis, and information exchanges to share cybersecurity threat and vulnerability information internally and between members of a sharing community, thereby strengthening grid cybersecurity defenses. The project demonstrates that utility threat analysis workproducts can be standardized and shared, as well as highlights the need for intelligence data classification and handling between members.

DCTAC supports EPIC Cross Cutting/Foundational Strategies and Technologies between Cybersecurity and Grid Operations by facilitating internal information sharing to support greater grid reliability, as shown in Figure 1 below:

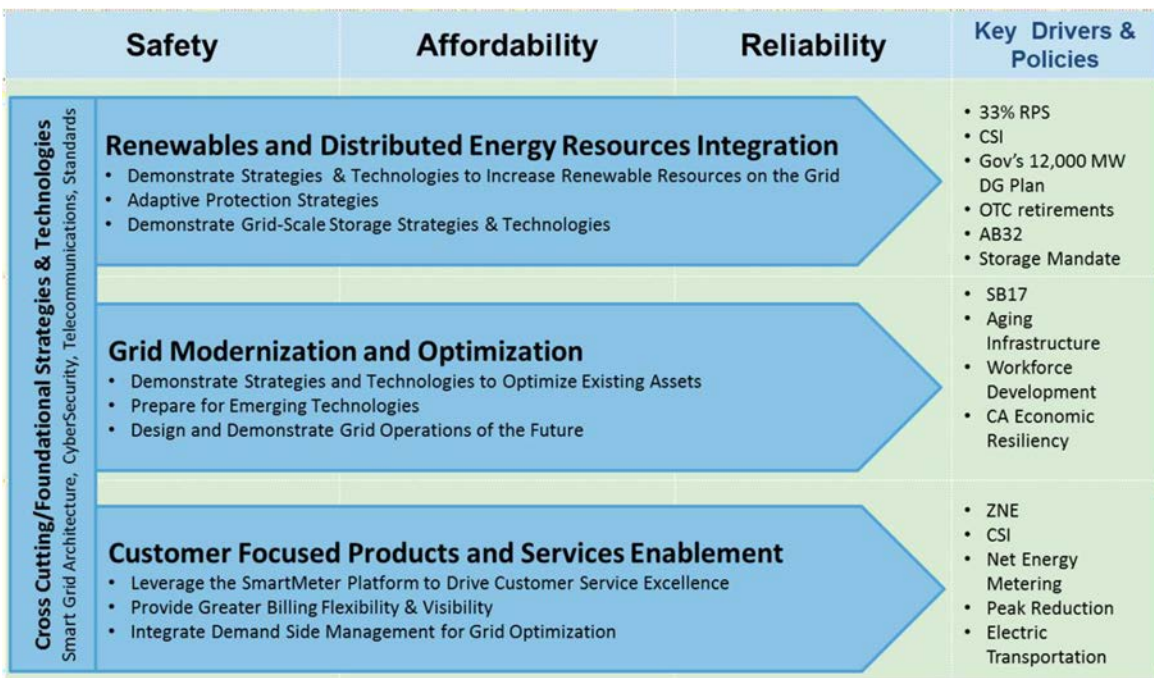

Figure 1: EPIC Investment Framework for Utilities

Project Objectives

The EPIC III DCTAC project was selected as an EPIC III project given the industry cross cutting cybersecurity capabilities that DCTAC can provide utilities, regulators and U.S. government critical infrastructure agencies through sharing vetted vulnerability and or threat intelligence by the California Public Utilities Commission (CPUC). The DCTAC project was designed to provide a proof-of-concept demonstration for improving and standardizing cybersecurity intelligence information sharing across electric utilities or other critical infrastructure industries. While all utilities likely collect *data* on cybersecurity vulnerabilities, threats, and indicators of compromise from many different sources, it is rarely useable or actionable without significant effort to determine the accuracy, validity, and applicability of the information. There arevery few reliable sources of *intelligence* -- data presented in a way that is meaningful to and interpretable and actionable by decision makers and stakeholders.

DCTAC's aim was to build on the lessons learned from the California Energy Systems for the 21st Century (CES21) project's Machine-to-Machine Automated Threat Response (MMATR) concept by demonstrating the ability to standardize electric utility cybersecurity intelligence, threat analysis, and information exchanges and to:

- Demonstrate how cybersecurity threats can be shared between vetted members
- Demonstrate how grid cybersecurity defense can be strengthened through a collaborative threat intelligence sharing process
- Demonstrate the capability to standardize utility threat analysis work products
- Exercise the need for intelligence data classification and handling between members

Problem Statement

The duration of cyber-attacks varies in time, and significant attacks usually involve multiple organizations, which can extend the attack duration. This conflicts with the quick response time needed by utilities to react and defend before a compromise can occur. Current cyber practice is for individual SecurityOperations Centers (SOCs) to gather data and perform the analyses within their own systems, with very little external collaboration. Each organization's processes and documentation requirements vary greatly, and there is no standardized way to share physical evidence directly between partners or vendors. Most intelligence is shared in a non-centralized, distributed fashion with little to no prior communications, and are dependent on each organization's release channel. The data is commonly delivered in vendor-proprietary formats as there is a lack of common language or format to support utility-to-utility analysis and information sharing, which negatively affects the time to resolution for a threat. In addition, intelligence information is provided by many sources both internal and external to the organization. The information is often duplicative, and intelligence that is potentially applicable—sometimes urgently— to the operation is mixed in with information that has no bearing on the organization at all. Analysts must wade through a sea of data to locate the information that could indicate a potential vulnerability and or threat and provide actionable intelligence.

Scope

DCTAC was built on findings from the CES21 project to demonstrate the ability to standardize electric utility cybersecurity threat analysis and information exchanges to shorten the response time to cyber compromise of the grid. The project focused on documenting and refining intelligence workflows (both incoming and outgoing), standardizing and automating data processes, and feeding back enhancements to the governing body.

DCTAC's goal was for the framework to enhance collaboration among various utility and government internal and external stakeholder groups by:

- Demonstrating the capability to standardize utility threat analysis work products by creating a standard format and processes for addressing incoming threat intelligence

- Demonstrating how cybersecurity threats can be shared between vetted members by defining a method to communicate legitimacy and threat impact of intelligence for outgoing intelligence
- Demonstrating how grid cybersecurity defense can be strengthened through a collaborative threat intelligence sharing process by reducing time spent analyzing threat intelligence and creating a risk aware package of sharable intelligence.

The results are standardized information intake processes and the creation of consistent information packages; a methodology for how information should be shared within the organization and what risk it presents; and recommended standards and automation for intelligence to be shared outside of the organization.

Schedule

The DCTAC schedule and timeline is illustrated below.

Figure 2: DCTAC timeline

Milestones/Deliverables

The DCTAC project was delivered on time and on budget. The DCTAC development project was broken into phases, as detailed in the table below. The phased approach was linear in this project, with each independent use case as a distinct phase. Adjustments were made to the work descriptions and milestones as development activities progressed.

Phase	Milestone Description	Deliverables	Planned Date	Completed Date
0	**Project Kickoff and Ongoing Project Management:** This work area was to ensure successful kickoff and execution of DCTAC, managing its budget, goals, schedule, and resources. This work included the communication and resolution of issues as they arise, managing the project and working with the SCE Project Management Office (PMO), as well as regular status updates and reporting.	• Updated Project Schedule • Stakeholder Awareness Presentation • SCE SME Resource List • Project Communications Plan • Initial Approved Vendors List	6/23/20	6/23/20
0.1	**Virtualized Environment Creation:** The virtualized environment build phase established the project's physical equipment and software needs, defined the environment for program demonstrations, and created the infrastructure requiredfor framework development.	• Virtual Environment Description	6/23/20	6/23/20
1	**Use Case #1 – Information Technology (IT) Threat Feed Integration:** In Use Case 1, existing industry IT threat feeds were investigated. Information sharing best practices were identified, and the result translated to a STIX data feed. Once risk and priority elements were added, the industry IT feed was integrated into the DCTAC framework. Concurrently, work began to investigate current industry information sharing practices and procedures.	• Industry IT Threat Feed Opportunities • Information Sharing Processes • DCTAC STIX Mapping • Workshop Presentation • Risk and Prioritization Framework • Industry IT Threat Feed Integration Presentation	9/29/20	9/29/20

Phase	Milestone Description	Deliverables	Planned Date	Completed Date
2	**Use Case #2 – Operational Technology (OT) Threat Feed Integration:** In Use Case 2, existing industry OT threat feeds were investigated. Best practices were identified, and the results were translated to a STIX data feed. Once risk and priority elements were added, the industry OT feeds identified were integrated into the DCTAC framework. The existing process results were analyzed to identify existing best practices and identify processes that may benefit the most from automation.	• Industry OT Feed Opportunities • Information Sharing Processes Best Practices • STIX OT Transformation Mapping • Information Sharing Automation Proposal • Industry OT Threat Feed Integration Presentation	12/22/20	12/22/20
3	**Use Case #3 – Grid Generated Threat Feed Integration:** In Use Case 3, data that was generated by technology-enabled grid equipment was analyzed. A recommendation of which data may provide the most relevant security indicators was provided, and a representative dataset created for integration use. Risk and priority elements were added to the representative data set and the grid feed was integrated into the DCTAC framework. The targeted process automation (PA) practicesidentified in Use Case #2 were analyzed, and a proposal for recommended automation was submitted for review.	• Grid Threat Intelligence presentation • DCTAC Automation Proposal • DCTAC Grid Threat Intelligence • STIX threat feed mapping Updates	3/29/21	3/29/21
4	**Use Case #4 – Integration, Collaboration, and Campaign Design:** In Use Case 4, threat feeds between the completed input areas were combined into a standardized intelligence feed for framework integration. Risk inputs were applied across feeds, and data access restrictions employed. An intelligence campaign was proposed for the final demonstration. Feedback from the PA playbook recommendations were incorporated into a final PA playbook recommendation and tasks for automating the playbook were defined.	• DCTAC Collaboration Campaign Definition • DCTAC STIX Transformation Mapping • Internal Risk Normalization • Process Automation Task List	6/21/21	6/21/21

Phase	Milestone Description	Deliverables	Planned Date	Completed Date
5	**Use Case #5 – External Data Sharing:** In Use Case 5, combined data feeds with risk information were used to create sharable data packages. Three levels of packages were created based on a balance of risk to the utility, overall systemic risk, and partner trust level. Once external groups were defined, the data was packaged and demonstrated as a STIX readable dataset. As a part of identifying external groups, potential partners were identified and provided to project personnel for potential invitations to the final demonstration.	• External Sharing Groups • DCTAC Sharing Risk Controls • STIX External Format Mapping Documents • External Intelligence Sharing Presentation • DCTAX STIX Internal Risk Normalization	9/13/21	9/13/21
6	**Use Case #6 – Unknown Event Type:** This use case initially covered processes to address a new type of threat that had not been experienced before. However, based on recent cyber events including the directives from the Transportation Safety Administration (TSA) and White House on Industrial Control System (ICS) cybersecurity, the team adjusted this use case to provide more detail on information needed for effective intelligence generation from within utility networks. This was broken down into two main foci – defining a trust model that must exist for secure intelligence sharing and creating a definition of the information that must be provided about an ICS device to allow for quicker intelligence sorting and assessment within the utility environment.	• Process Automation Playbook • DCTAC Intelligence Information Trust Model Recommendations • DCTAC Device Specific Information Import Definition	11/4/2021	11/4/2021

Phase	Milestone Description	Deliverables	Planned Date	Completed Date
7	**Use Case #7 – Final Demonstration and Project Wrap-up:** The final phase focused on demonstrating the ability of the DCTAC framework to enhance the ability to share risk aware information and reduce the time needed to process this information. The final report was delivered and included all findings and suggestions for further development and improvements based on industry specific processes.	• Final report covering the DCTAC project and Lessons Learned • Final playbook for technical implementers on how to stand up a DCTAC instance • Presentation and supporting materials for external socialization of DCTAC	3/12/22	3/12/22

Table 1: DCTAC milestones and deliverables

The concepts introduced were grouped throughout the phases as illustrated below and can be carried forward for future DCTAC development.

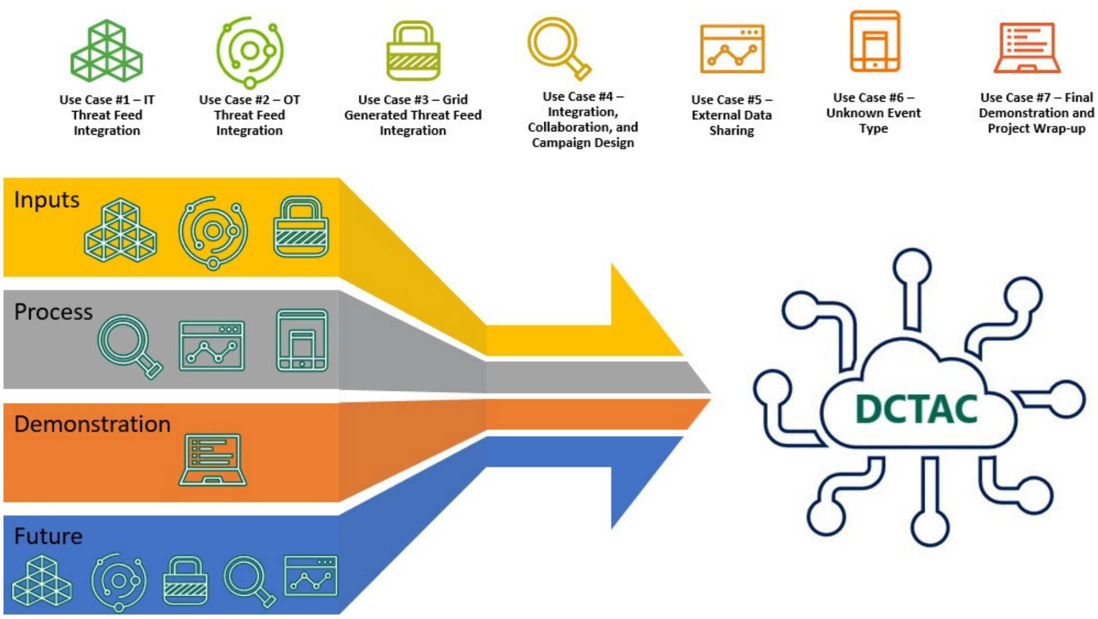

Figure 3: DCTAC phase groupings

Project Results

DCTAC supports EPIC Cross Cutting/Foundational Strategies and Technologies between Cybersecurity and Grid Operations by facilitating internal information sharing to support greater grid reliability and promoting information sharing between utilities and standardization for communicating threat and vulnerability information with respective stake holders.

The DCTAC framework enhances collaboration among various internal and external stakeholder groups by:

- Providing a standardized utility threat analysis product in a standard format with processes for addressing incoming threat intelligence quickly
- Providing the ability to share cybersecurity threat and vulnerability information and indicators of compromise between sharing group members and a method to communicate legitimacy and threat impact for outgoing intelligence
- Strengthening grid cybersecurity defenses through a collaborative threat intelligence sharing process and significantly reducing the time spent analyzing threat intelligence and creating risk-aware packages of sharable intelligence.

DCTAC provides an excellent opportunity to open a dialogue with intelligence information providers and vendors to standardize the content of threat and vulnerability notifications and information, and to identify authoritative repositories of that information to make it easier for information sharing communities to ingest and act on the intelligence and to reduce duplicative or false information.

The results are standardized information intake processes and the creation of consistent information packages; a methodology for how information should be shared within the organization and what risk it presents; and recommended standards and automation for intelligence to be shared outside of the organization.

Technical Results

The DCTAC framework consists of the DCTAC application, which is an automation-driven overlay for an existing cyber threat intelligence (CTI) platform that parses incoming intelligence information to pinpoint relevant and applicable intelligence information, and recommended information sharing program decisions and processes that promote information sharing both within and outside of the organization.

The back-end cyber threat intelligence platform used for the DCTAC proof of concept was the open source OpenCTI platform, which was selected to visually demonstrate the concepts for information sharing; however, the DCTAC framework was built to be platform agnostic. The use of a back-end CTI platform was a necessity to demonstrate how the DCTAC scripts changed the structure and/or content of a STIX bundle—cyber threat information exchanged using a standardized language and serialization format. It also provided a mechanism to create custom STIX bundles from internal data, modify bundles for demonstration purposes, or enhance intelligence content with internal information.

The proposed workflow for DCTAC went through several iterations during the project; however, the general workflow for DCTAC is illustrated below.

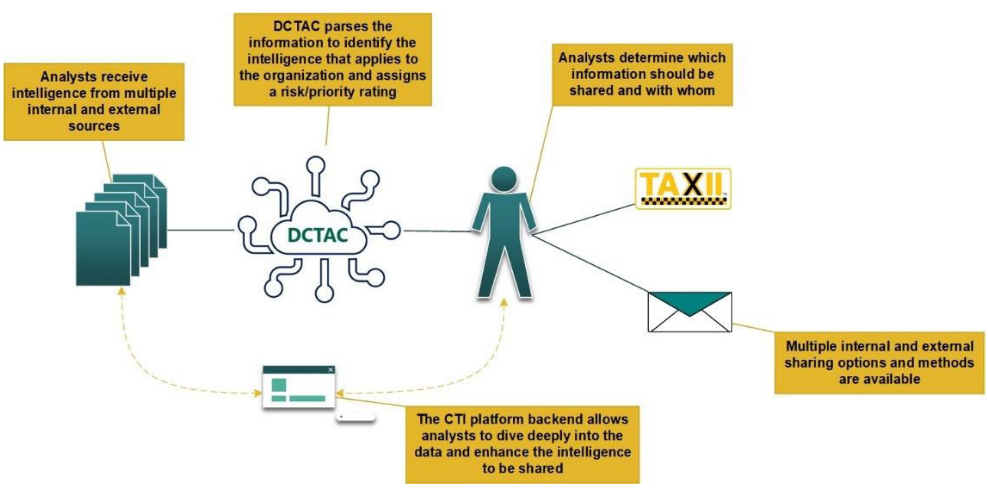

Figure 4: DCTAC high-level workflow

When a STIX bundle is ingested into DCTAC a series of instructions (“scripts”) are run against the data to parse the information for industry, target asset (asset type, vendor, software, or firmware) and to assign a risk and priority rating to the information. The scripts also determine the traffic light protocol (TLP) rating[1] for the intelligence and assigns a recommended sharing group and method that the analyst may accept or override.

The analyst provides a ‘human-in-the-loop’ to review and confirm the validity of the parsed information and its applicability to the organization, and to make the decision whether to share the information, how to share it and with whom, whether to enhance the bundle with additional information (if available), to save the bundle for later decision or review, or to reject the bundle for sharing.

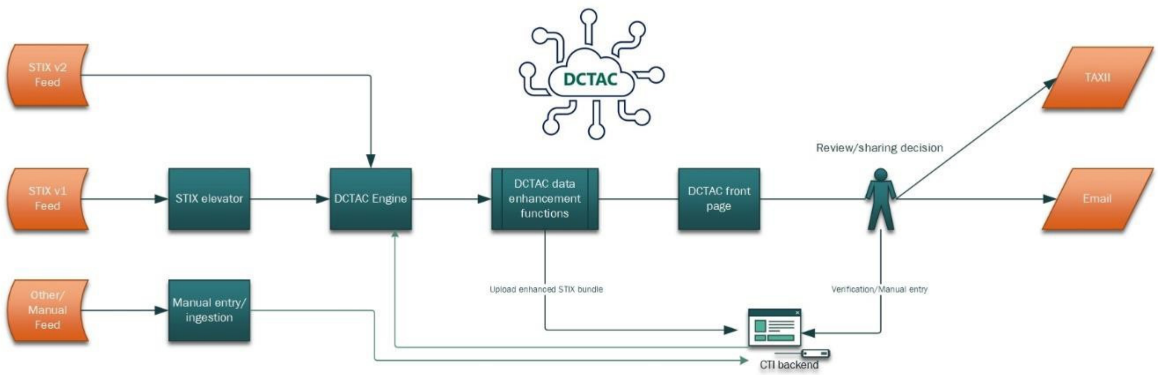

Figure 5: DCTAC workflow

The evolution of the DCTAC framework transpired in six use cases, with a seventh being the final demonstration, playbook, outreach materials and project report. The following sections describe the evolution of the DCTAC framework and proof of concept into its final, demonstrated form.

Use Case #1 – Information Technology (IT) Threat Feed Integration

In Use Case 1, the system-of-systems model from the Risk Framework for Systems Engineering, developed by The MITRE Corporation was used as the basis for risk determination and the ATT&CK (Adversarial Tactics, Techniques and Common Knowledge) framework was chosen as the underlying model for DCTAC risk and prioritization. DCTAC’s focus was to address risks for organizations that may be geographically dispersed withthe accompanying diversity in system managers, subsystems, and stakeholders. Criteria for determining the appropriate levels of risk, impact, and prioritization to be used in the DCTAC riskand prioritization algorithms were developed and codified.

An analysis was conducted of various cyber threat intelligence platforms for DCTAC, including both proprietary and open-source solutions. Due to the prototypical considerations of the DCTAC project, it was determined that an open-source solution would be best due to cost, documentation, and ease of procurement; however, the ability to migrate the framework to a proprietary solution upon completion and determination of success was an additional factor that was integrated into the final solution. It was decided to leverage grid-based addendums to the Structured Threat Information eXpression (STIX™) v2 standard for sharing between utility partners.

The data was structured using a knowledge schema based on the STIX2 standard. DCTAC was originally designed as a web application including a GraphQL application programming interface

[1] Traffic Light Protocol (TLP) Definitions and Usage | CISA

(API) and a user eXperience (UX)-oriented front-end. The environment utilized two data feeds thatprovided prototypical utility IT threat feed data: AlienVault and the National Vulnerability Database's (NVD's) Common Vulnerabilities and Exposures (CVE) database, along with two worker threads that enable communication between the various microservices required by the environment.

DCTAC was developed in a self-contained Ubuntu virtual machine hosted in the Microsoft Azure cloud. During the development lifecycle, the environment and associated configurations were documented with continual consideration towards portability. The result is a system that can be easily relocated into a production environment with few changes. Additionally, the development of the DCTAC framework on the STIX/Trusted Automated eXchange of Indicator Information (TAXII) standard on the OpenCTI platform will allow it to be migrated to a commercial product thatuses STIX/TAXII protocol and incorporate the framework during installation and configuration in a production environment.

Additional industry IT threat feeds were researched and tested for compatibility with the DCTAC framework. The Industrial Control System Computer Emergency Readiness Team (ICS-CERT) feed integration to OpenCTI was implemented. The integration uses the STIX elevator to convert ICS-CERT's STIXv1 formatted threat intel to STIXv2. It was found during the conversion that various STIX objects such as the kill chain phases, name, and even sometimes identity were dropped during the process. The integration resulted in incomplete or otherwise unactionable STIX data. Human intervention or review of the newly formatted STIX intel was required after every conversion. As a result of this process, recommendations were outlined during this sprint to unify and standardize different formats that will be accepted into the CTI platform going forward, and that STIX 2.0 and STIX 2.1 (or any format that can be successfully converted) should be the only accepted formats.

The DCTAC team performed an initial analysis of the risk and prioritization factors that are present in the IT feeds integrated into the OpenCTI platform. Common factors were observed and deemed appropriate to begin initial framework design. Best practices were identified, and the results translated to a STIX data feed. Once risk and priority elements were added, the IT feeds were integrated into the DCTAC framework.

Use Case #2 – Operational Technology (OT) Threat Feed Integration

In Use Case 2, existing Industry OT threat feeds were investigated. An initial trial license was obtained from Crowdstrike, and the OT threat feed intelligence provided was evaluated for use with DCTAC. Subscriptions to AlienVault "pulses" were added to incorporate more OT threat feed intelligence. Subscriptions were searched based on key words (e.g., Energy industry, OT, Operational Technology, ICS, Industrial Control Systems, Critical Infrastructure). Using information from ICS Cert, the existing NVD feed was filtered for OT vulnerabilities. The asset scope was created to limit search criteria and selected vulnerabilities were tagged with "OT" or "ICS" for easy searching.

An import module was created for ICS-CERT Really Simple Syndication (RSS) feeds, and an RSS to STIX v.2 elevator was analyzed. It was found that, as in the previous use case, when RSS information is elevated to STIX v.2 there isn't always an appropriate 1:1 mapping between the RSS specification and the 2.x specification, and that normalization of data ingested will need to be done for automation to be successful.

During this phase, we modified documents used for use case 1 such as the preliminary asset inventory, STIX transformation mapping document and the risk and prioritization schema to create a process for understanding risk using OT threat intelligence received within an organization. Common utility OT assets were selected along with the most cited in the NVD.

Risk and priority ratings were added to the DCTAC algorithm and calculated based on keyword matches within the intelligence bundle for industry, grid, asset vendor, and asset type. The ratings were added based on the following risk and priority scale.

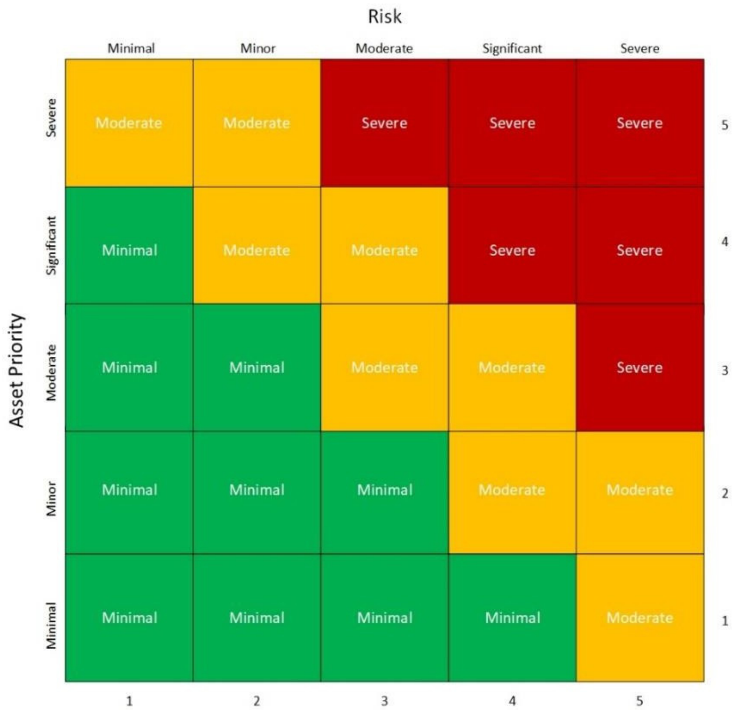

Figure 6: DCTAC risk/priority matrix

Once risk and priority elements were added, the OT feeds were integrated into the DCTAC framework. Process results were analyzed to identify existing best practices and identify processes that may benefit the most from automation.

Use Case #3 – Grid-generated Threat Feed Integration

In Use Case 3, data that is generated by technology-enabled grid equipment were analyzed. A recommendation of which data may provide the most relevant security indicators was provided, and a representative dataset was created for integration use. Risk and priority elements are added to the representative data set, and the grid-related feeds were integrated into the DCTAC framework.

The threat feeds ingested from use case 2 (AlienVault, NVD, Crowdstrike, etc.) were evaluated for intelligence pertaining to the grid. No data feeds were identified that provide grid threat intelligence exclusively. One report (AlienVault) was identified as possibly providing some grid threat intelligence.

The “Grid” tag was added to the DCTAC algorithm to parse all threat intelligence for easy identification and classification of grid-impacting information. When all ingested information was parsed using DCTAC, many CVEs were identified using the “Grid” tag. Because there are many vendors for grid equipment, the key to identifying specific grid threat intelligence that applies to a particular organization was to also determine the asset type. As such, an asset type search was also added to the DCTAC algorithm.

To develop new intelligence based on current internal grid information, monitoring platforms suchas an intrusion detection system (IDS) or human-machine interface (HMI) could send any baseline deviations or indicators to a grid network Security Incident and Event Management (SIEM) solution, which could be configured to send an alert to the CTI analyst. By leveraging STIXv2.1 objects an analyst would be able to create a threat intelligence bundle and import it into DCTAC, enhance or redact the indicators of compromise (IOCs) in the report, and share the information either within the organization or to identified sharing partners.

The grid-related information mapped into STIX objects is outlined in Table 2 below.

STIX Objects	Context
Malware, Vulnerability, Domain_Name, Email_Address, File, IPv4_Address, IPv6_Address, URL	Directly actionable data, can be used to pinpoint potential/active threats
Identity, Grouping, Email_Message, Report	Used in the creation of campaigns and construction of larger threat intelligence bundles, not directly actionable.

Table 2: Grid-related STIX objects

Threat feed data and processes from all sources (IT, OT, and Grid) were analyzed to determine potential automation enhancements to DCTAC, and recommended process automation tasks were provided to project sponsors.

Use Case #4 – Integration, Collaboration, and Campaign Design

In Use Case 4, IT, OT, and grid-related threat feeds were combined into a standardized intelligence feed and integrated into the DCTAC framework. Risk ratings and data access restriction categories were applied to feed data bundles. The proposed elements for an intelligence campaign were defined, as illustrated in Figure 7 below. In the final proof of concept product, theticket option was replaced by the interface being updated to display the current bundle state.

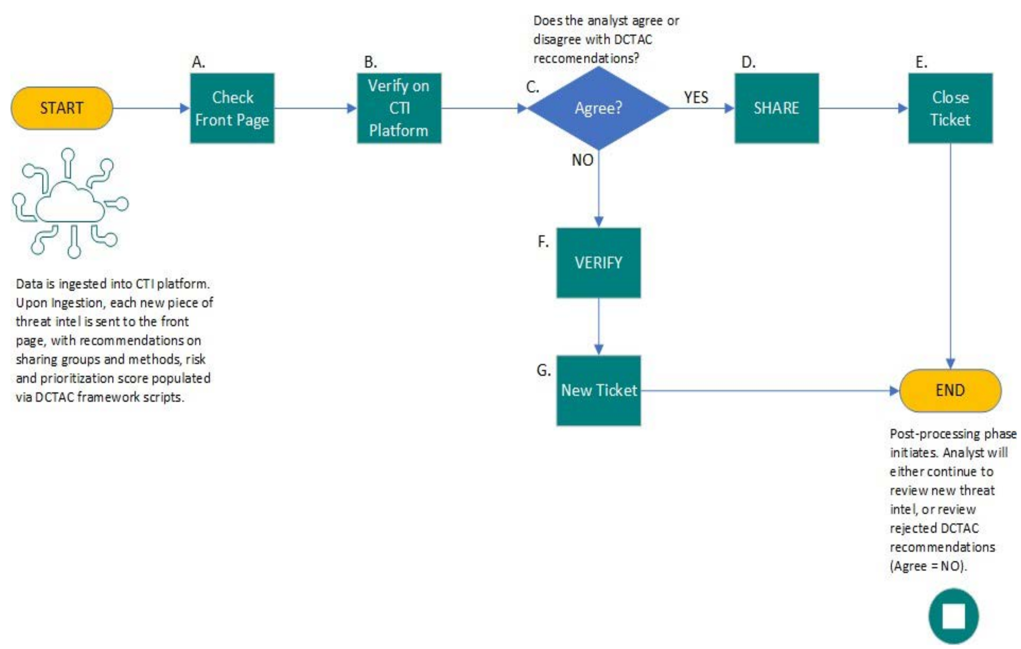

Figure 7: UC4 proposed DCTAC campaign workflow

During Use Case 4, the tasks for automating the playbook were defined and developed. The DCTAC development team designed DCTAC scripts to parse and enhance the intelligence received from external and internal sources so that security intelligence analysts were provided with actionable information that could be used to make quick and informed sharing decisions. Automation tasks were divided into three stages: **ingestion**, **data enhancement**, and **sharing**.

Threat feeds ingested into DCTAC were identified as external, internal intelligence derived from security monitoring appliances, or developed in house. In general, threat information from external sources was provided in one of three forms: as a STIX version 2 or above feed which can be directly ingested into the DCTAC process, or as a STIX version 1 or other type of feed that must be transformed into STIX v2 for processing. For feeds that do not have readily available ways to upgrade the data, customized scripts can be developed that can read the data and put it into the STIX v2 format. Scripts were developed to identify the STIX version of the intelligence, and to run a STIX elevator library to raise the version of the bundle to STIX v2 if the bundle provided was v1. If the intelligence was provided in another format, the system ran a converter that was custom designed to transform the feed to STIX v2. The analyst also had the option to enter non-STIX intelligence information into the CTI back-end manually and export the resulting STIX v2 bundle into DCTAC for enhancement.

Data enhancement scripts were developed to parse the data to ensure that the intelligence was relevant to the operation, risk levels assigned, and recommended sharing groups determined. Once the data was ingested, the scripts parsed the bundle for Industry, Sector, Location, Asset, and Vendor and assigned a risk level and added recommended sharing group(s) and method(s). The processes for determining risk and applying a risk/priority rating were defined and implemented. The scripts were also enhanced to add the Location, Sector, Industry, and TLP level if these were not called out in the original bundle, and tags for display in the CTI backend applied.

The DCTAC web interface was improved and re-designed using a Flask interface. The front page was updated to list each DCTAC-enhanced bundle by title, risk/priority rating, and to note whether the information was new, had been shared, had been reviewed but not shared, or if it had been rejected for sharing by the analyst. The intelligence analyst was provided the option to review the information and, if desired, adjust the risk level and sharing group and method. They also were provided the option to access the raw STIX data using the CTI backend if further review and redactions were necessary. At this point, they could decide to share the information orreject the sharing option for the bundle. If they reviewed or changed the information and chose to wait to make the sharing decision, the bundle would be marked as reviewed. Sharing options included sending the enhanced STIX bundle to a shared TAXII server, emailing the bundle to a predetermined sharing group, or sharing the bundle internally via email.

Use Case #5 – External Data Sharing

In Use Case 5, data feeds were combined with risk information to create sharable data packages.Packages were created based on a balance of risk and partner trust level. Once the packages were defined, the datasets were packaged and demonstrated as a STIX readable bundle. The security of the information shared to analysts, internal and external partners, or others, which is largely dependent on the risk appetite of the sharing organization, was examined and recommendations for sharing partner trust levels, risk calculations, and sharing groups were made based on general security best practices (although they may be tailored to the implementing organization as needed).

Program-level recommendations for organizations to consider when establishing a cyber security intelligence information sharing program and when using DCTAC's intelligence sharing capability with internal and external sharing partners were also developed during Use Case 5. The steps forsetting up an information sharing program were defined as illustrated in Figure 8 below.

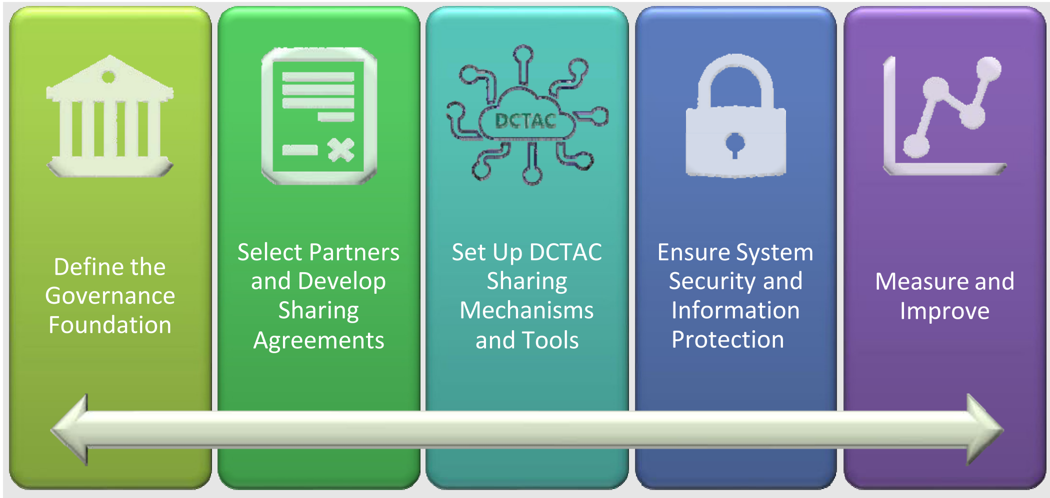

Figure 8: Steps for establishing a sharing program

Recommended sharing risk controls and program and technical cybersecurity controls were established for utilities to consider when implementing DCTAC in a production environment and as part of a secure information sharing program.

Finally, demonstration scenarios were established as part of planning for the DCTAC final demonstration.

Use Case #6 – Unknown Event Type

Use case 6 included the final development sprints for the DCTAC proof of concept and resulted in the demonstrated proof of concept application and process automation playbook for DCTAC. At the beginning of this use case, the deliverables were adjusted based on the results of previous use cases. The changes included updating and refreshing the technology focus in DCTAC to be more in line with current available technology and vendor offerings and to enhance DCTAC's ability to provide actionable, applicable intelligence.

Software/driver/firmware filters were added to the DCTAC scripts to add more depth to the filtering functions and target specific versions of OT software, device drivers, and firmware. This provided more granular targeting for intelligence information. Risk normalization documentation was updated to include the new data fields and information. Deep inventory information and data fields were defined so that implementers could work with vendors to collect improved inventory information, which in turn would provide more granular targeting for intelligence information and more supply chain transparency. Deeper definition of the contents of the STIX bundle and the data transformation (ingested bundle versus shared bundle) for the final demonstration product were defined, providing a better understanding of the fields needed for custom bundles and more clarity on the information being shared.

Recommendations for managing trust between partners, data protection mechanisms for different TLP levels, and options for securing information at different levels were refined and provided for future consideration.

Finally, the process automation playbook was developed with step-by-step instructions on how to set up DCTAC in a production environment. The playbook provided a four-step process for implementing DCTAC, as follows:

- Plan – How to plan the implementation from both a business process and technical standpoint
- Install – Instructions for installing the DCTAC scripts and any other support technologies

- Customize – Ways to customize the DTAC scripts to ensure its relevance to the operation
- Implement and Improve – Recommendations for rolling out the intelligence sharing process and improving the process and technology to provide maximum value

The source code for DCTAC was packaged and provided for future development and implementation.

Use Case #7 – Final Demonstration and Project Wrap-up

The final phase focused on a demonstration to showcase the DCTAC framework's capability to enhance the ability to share risk aware information and reduce the time needed to process this information. The final report (this document) recaps project progression and lessons learned. External outreach materials were also provided to support future DCTAC evaluation and implementation proposals, as well as information sharing discussions.

The DCTAC proof of concept demonstrated the time needed for an analyst to review all incoming intelligence notifications and alerts to determine their applicability to the operation, assign a potential risk rating to each, determine or assign TLP ratings, prepare the information forinternal or external sharing, and share the information appropriately based on its TLP level was significantly reduced using DCTAC (from minutes to seconds). It is projected that further enhancements to customize DCTAC to a particular operation could lower the time from the receipt of intelligence information and sharing that information with internal or external sharing partners for action even more. The use of a standard, open format and open source back-end software allows DCTAC to be implemented at minimal cost to the organization and facilitates an information sharing community among all participating partners.

Technical Lessons Learned

DCTAC team personnel noted the following technical lessons learned for consideration for future DCTAC implementations and enhancements.

- Many IT threat intelligence feeds offer duplicative information and, prior to implementation, sharing groups should agree upon the authoritative sources for intelligence information. A formal way to differentiate and identify duplicates also needs to be developed and implemented in DCTAC.
- The information sharing group must understand and manage the process for selecting which information is shared – every participant cannot just forward all information to everyone in the group since most receive the same intelligence. This will cause a 'sharing storm' and reduce the quality of information provided by the sharing community.
- Transformation/conversions from formats that are not STIX v.2 have issues, for example:
  - During STIX v.1 to v.2 conversions, various STIX objects are dropped during the process. The transformation may result in incomplete or otherwise unactionable STIX data. Human intervention or review of the newly formatted STIX intelligence is required after every conversion.
  - When RSS information is elevated to STIX v.2, there isn't always an appropriate 1:1 mapping between the RSS specification and the 2.x specification, and the data ingested will need to be normalized for DCTAC automation to be successful.
- Be aware of the objects the TAXII server needs to ingest the information being pushed. Different TAXII instantiations may utilize different protocols. For example, the TAXII server used in the demonstration that was packaged along with the open-source CTI platform was under development and unfinished. A GraphQL mutation query was used instead of traditional TAXII protocol to simulate pushing data to TAXII.
- The DCTAC front-end provides the analyst with the option to create or enrich a STIX bundle with additional or local information, or to change recommended risk/priority levels, TLP, or sharing options. Once the changed information is saved, the new information

doesn't write back to the bundle—the analyst must run the new bundle through the DCTAC process again or add it to the DCTAC database manually. No code was developed to automatically add user-modified information to the STIX bundle.

- There is no standardization between intelligence information providers for the content of intelligence feeds. In the future, it would be ideal to work with intelligence feed providers to create a standard of additional STIX objects that must be utilized for a bundle to be posted on a public feed.
- Information posted on public feeds is not vetted prior to being made available for consumption/action. The onus is on the consumer to determine whether the information provided is valid.

Program Lessons Learned

There were several program-level lessons learned noted throughout project execution. These lessons learned include the following:

- The success of any information sharing effort is dependent on the commitment of the sharing group at-large. All members—including the technical personnel responsible for generating and analyzing threat intelligence and vulnerability information—must make a firm agreement to participate openly for the greater good.
- Information sharing outside of Security Operations Centers (internally or externally) is still in its infancy. While several security vendors are beginning to offer information sharing services, there is still little or no ability to provide the specific OT and grid context that a production DCTAC instance could provide to utilities.
- Because intelligence sharing is nascent, there are very few (if any) industry standards and metrics on information sharing capabilities and outcomes.
- Each utility has their own intelligence sharing processes and structure for how they share information, and it will be critical to the success of any information sharing program to agree upon the concept of operations, technologies, formats, and security/information protection schema and mechanisms.

Procurement

The DCTAC project was delivered on time and within budget. The project did not require the procurement of supporting technologies, as free and open-source technologies were utilized to demonstrate the DCTAC proof of concept (thereby avoiding the estimated materials costs).

Stakeholder Engagement

Project progression was marked by the on-time delivery of each deliverable, which detailed the progression of DCTAC development from start to finish.

Stakeholders were provided weekly update reports on the progress of the DCTAC project, any issues or items of note, and the progress of the sprints and project timeline. Monthly technical update meetings were held with DCTAC stakeholders to provide more in-depth information regarding project activities and to highlight DCTAC's development milestones and progress. Project management personnel met with stakeholders weekly to discuss progress, to review and revise the plan and deliverables as needed, and to ensure that project expectations were being met throughout project performance.

Benefits

DCTAC helps promote grid stability and avoid potential outages/safety concerns by enabling quicker response times for identifying threats to and vulnerabilities in OT assets. It also promotes cross-utility security by providing a means for quickly communicating vulnerability information and indicators of compromise to partner entities.

Using DCTAC as part of a larger intelligence sharing community promotes communication and enables each organization to leverage the collective knowledge, experience, and analytic capabilities of their sharing partners. As a result, all sharing partners are better informed and can rapidly detect and respond to threats, reducing the likelihood of a successful attack.

DCTAC's value in freeing up valuable security resources' time has been clearly demonstrated during the proof-of-concept phase of development. The development team provided a detailed DCTAC process automation playbook to transfer architecture and installation knowledge and files, which will help enable future development to commence at the same point that the team finalized the proof-of-concept development.

Next Steps

Based on the work completed, we recommended the following next steps:

- Further refine DCTAC and prepare it to be used in a production environment.
- Establish an information sharing community of grid operators committed to promoting collaboration and mutual protection principles.

Further refinements to DCTAC could yield even more value to the organization, and to the sharing community at large. Examples of potential improvements include:

- DCTAC scripts can be tailored to reflect local risk and priority levels, trigger on specific industry and operations keywords, and select specific sharing partners and methods, providing targeted intelligence that applies specifically to the organization.
- Internal intelligence feeds and both internal and external sharing options can be added and controlled locally.
- Integration with local asset and vendor databases and allowing automated escalation for intelligence information associated with the specific vendors and assets in operation could further tailor the intelligence and pinpoint areas of vulnerability.
- DCTAC could automatically adjust risk and escalate when matches are found, further reducing response times.
- Automation of the initiation of process scripts to provide 'touchless' ingestion of internal and external intelligence feeds would reduce the need for human intervention.
- Integration with internal feeds from IDSs, security incident and event management (SIEM) systems, firewall rulesets, etc. to provide immediately actionable intelligence to internal customers as well as external sharing partners would facilitate faster response times andreduce the impact of multi-pronged attacks.
- Integration with the local ticketing system to automatically create tickets for actionable intelligence would get the right information to the right people for quick action.

Additionally, intelligence information is a key input to a zero-trust architecture, and DCTAC could potentially be used as a resource to provide targeted information from internal or external sources to help the DCTAC scripts make access decisions. It could be programmed to consolidate multiple services that take data from internal and/or multiple external sources and provide information about newly discovered attacks or vulnerabilities. This also includes newly discovered flaws in software, newly identified malware, and reported attacks to other assets that the organization will want to deny access to from enterprise assets.[2]

[2] https://doi.org/10.6028/NIST.SP.800-207

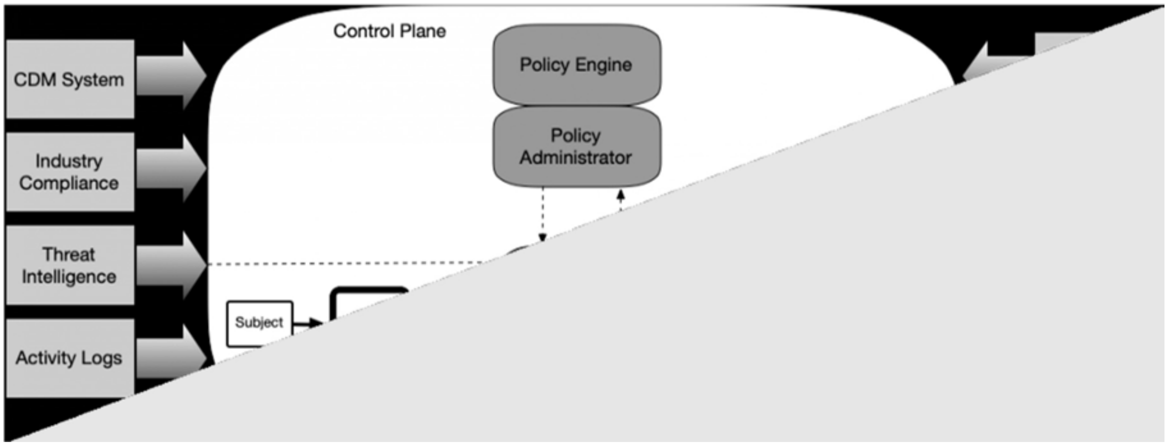

Figure 9: Zero trust architecture

The use of a standard, open format and open source back-end software allows DCTAC to be implemented at minimal cost to the organization and facilitates an information sharing community among all participating partners.

The development team provided a detailed DCTAC process automation playbook to transfer architecture and installation knowledge and files, therefore future development can commence at the same point that the team finalized proof of concept development.

Appendix A: List of Acronyms

Acronym	Definition
API	Application Programming Interface
ATT&CK	Adversarial Tactics, Techniques and Common Knowledge
CERT	Computer Emergency Readiness Team
CES21	California Energy Systems for the 21st Century
CPUC	California Public Utilities Commission
CTI	Cyber Threat intelligence
CVE	Common Vulnerabilities and Exposures
DCTAC	Distributed Cybersecurity Threat Analysis and Collaboration
EPIC	Electric Program Investment Charge
HMI	Human-Machine Interface
ICS	Industrial Control System
IDS	Intrusion Detection System
IOCs	Indicators of Compromise
IT	Information Technology
MMATR	Machine-to-Machine Automated Threat Response
NVD	National Vulnerability Database
OT	Operational Technology
PA	Process Automation
PMO	Project Management Office
RevSec	Revolutionary Security
RSS	Really Simple Syndication
SIEM	Security Incident and Event Management
SOW	Statement of Work
STIX	Structured Threat Information eXpression
SCE	Southern California Edison
SOC	Security Operations Center
TAXII	Trusted Automated eXchange of Indicator Information
TLP	Traffic Light Protocol
TSA	Transportation Safety Administration
UX	User eXperience

Appendix B: Glossary

Term	Definition
Intelligence	Data that is presented in a way that's meaningful to and interpretable and actionable by decision makers and stakeholders.
Scripts	A series of computer instructions.
Threat	Validated adversarial activity that can successfully execute an attack on a network, system or component vulnerability.
Vulnerability	The potential for a compromise to be attempted against a network, system and or component weakness.
Zero trust architecture	An enterprise cybersecurity architecture that is based on the principle that all users, systems, and networks are untrusted and is designed to prevent data breaches and limit internal lateral movement.