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 2020 ACTIVITIES OF THE ELECTRIC PROGRAM INVESTMENT CHARGE PROGRAM

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Dated: **March 1, 2021**

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STATE OF CALIFORNIA

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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 2020. This is SCE's seventh annual report pertaining to its 2012-2014 EPIC Triennial Investment Plan (Application (A.) 12-11-004), after receiving Commission approval on November 14, 2013. Furthermore, this is SCE's fifth annual report pertaining to its 2015-2017 EPIC Triennial Investment Plan (Application (A.) 14-05-005), after receiving Commission approval on April 9, 2015. Lastly, this is SCE's third 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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March 1, 2021

EPIC ADMINISTRATOR ANNUAL REPORT FOR 2020 ACTIVITIES

EPIC ADMINISTRATOR ANNUAL REPORT FOR 2020 ACTIVITIES

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1. Executive Summary

a) Overview of Programs/Plan Highlights

2020 represented SCE's seventh 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 2020 represented almost six 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 2020 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, 2020, SCE expended a total of $880,137 toward project costs and $97,864 toward administrative costs for a grand total of $978,001. SCE's cumulative expenses over the lifespan of its 2012 – 2014 EPIC program amount to $37,345,810. SCE committed $311,188 toward projects and encumbered $498,441 through executed purchase orders during this period. During 2020, SCE finished its final project (Substation Automation, (SA-3) Phase 1) in the EPIC I Portfolio which is now complete.

SCE executed 16 projects from its approved portfolio. Three projects were completed during calendar year 2015, 4 projects were completed in 2016, 4 projects were completed in 2017, 2 projects were completed in 2018, 2 project was completed in 2019 and 1 project was completed in 2020. A list of completed projects is included in the 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

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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.

the Annual Report according to the years completed. The SA-3, Phase 1 Final Project Report completed in 2020 is included in the Appendix of this Annual Report.

(2) 2015-2017 Investment Plan

For the period between January 1 and December 31, 2020, SCE expended a total of $3,201,118 toward project costs and $124,982 toward administrative costs for a grand total of $3,326,110. SCE's cumulative expenses over the lifespan of its 2015 – 2017 EPIC program amount to $31,813,481. SCE committed $3,829,533 toward projects and encumbered $1,861,186 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.[7] Project execution activities continued for the remaining 10 projects. Of those 10 projects, 1 project was completed in 2017, 3 projects were completed in 2018, 2 projects were completed in 2019, and 1 project was completed in 2020. The Dynamic Power Conditioner Final Project Report completed in 2020 is included in the Appendix of this Annual Report. 3 demonstrations remain in execution.

(3) 2018-2020 Investment Plan

For the period between January 1 and December 31, 2020, SCE expended a total of $5,139,969 toward project costs and $999,061 toward administrative costs for a grand total of $6,139,030. SCE's cumulative expenses over the lifespan of its 2018 – 2020 EPIC program amount to $6,082,803. SCE committed $30,533,083 toward projects and encumbered $4,214,909 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 included in the Joint Utilities Research Administration Plan (RAP) Application.[8] During 2020, cancelled 2 projects and began execution of the following 17 projects from its EPIC III Portfolio:

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

b) Status of Programs

(1) 2012-2014 Investment Plan

As of December 31, 2020, SCE has expended $39,678,341[9] on program costs. Table 1 below summarizes the current funding status of SCE's EPIC projects:

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[9] SCE's cumulative project expenses amounted to $36,847,953 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 $1,080,316 for projects and $195,250 for administrative labor. As a result, SCE expended a total of $39,678,341 on program costs.

Table 1: 2012-2014 Triennial Investment Plan: 2020 Projects

1. Energy Resources Integration
• 4 Projects Funded ○ 1 Project Completed in 2016[10] ○ 2 Projects Completed in 2018[11]
2. Grid Modernization and Optimization
• 5 Projects Funded ○ 1 Project Cancelled in Q2, 2014[12] ○ 1 Project Completed in 2015[13] ○ 1 Project Completed in 2016[14] ○ 1 Project Completed in 2017[15] ○ 1 Project Completed in 2020[16]
3. Customer Focused Products and Services
• 3 Projects Funded ○ 1 Project Completed in 2015[17] ○ 1 Project Completed in 2016[18] ○ 1 Project Completed in 2017[19]
4. Cross-Cutting/Foundational Strategies and Technologies
• 4 Projects Funded ○ 1 Project Completed in 2015[20] ○ 1 Project Completed in 2016[21] ○ 2 Projects Completed in 2017[22] ○ 1 Project Completed in 2019.[23]
Total Projects Funded: 16

10 Distribution Planning Tool.

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

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 Outage Management & Customer Voltage Data Analytics.

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.

Total Authorized Project Budget: $37,656,998[24] Total Project Spend: $36,847,369[25] Total Funding Committed: $311,188[26] Total Encumbered: $498,441[27] *Note: Due to intrinsic variability in TD&D /R&D projects, amounts shown are subject to change*

Table 2 below summarizes SCE's 2020 administrative expenses:

Table 2: 2012-2014 Triennial Investment Plan: 2020 Administration

• Program Administration	Total Authorized Budget: $1,855,002[28] Total Cumulative Cost: $1,554,822 Total 2020 Cost: $97,864

(2) 2015-2017 Investment Plan

As of December 31, 2020, SCE has expended $33,325,084[29] on program costs. Table 3 below summarizes the current funding status of SCE's EPIC projects:

Table 3: 2015-2017 Triennial Investment Plan: 2020 Projects

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 ○ 1 Project completed in 2017[32] ○ 1 Project completed in 2018[33]

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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.*

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 $31,211,118 based on the project spreadsheet in Appendix A. SCE's cumulative administration expenses amounted to $2,838,400. SCE's accounting system calculates in-house labor and overheads separately, which amounted to $$1,080,316 for projects and $195,250 for program administration. As a result, SCE expended a total of $33,325,084 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.

○ 1 Project completed in 2019[34] ○ 1 Project completed in 2020[35]
3. Customer Focused Products and Services
• 3 Projects Funded ○ 2 Projects completed in 2018[36] ○ 1 Project completed in 2019[37]
4. Cross-Cutting/Foundational Strategies and Technologies
• 1 Projects Funded
Total Projects Funded: 13 Total Authorized Project Budget: $37,504,200[38] Total Project Spend: $31,813,481[39] Total Funding Committed: $3,829,533[40] Total Encumbered: $1,861,186[41] *Note: Due to intrinsic variability in TD&D /R&D projects, amounts shown are subject to change*

Table 4 below summarizes SCE's 2020 administrative expenses:

Table 4: 2015-2017 Triennial Investment Plan: 2019 Administration

• Program Administration	Total Authorized Budget: $4,190,400[42] Total Cumulative Cost: $2,838,400 Total 2020 Cost: $124,982

(3) 2018-2020 Investment Plan

As of December 31, 2020, SCE has expended $8,842,157[43] on program costs. Table 4 below summarizes the current funding status of SCE's EPIC projects:

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[34] Versatile Plug-in Auxiliary Power System.

[35] Dynamic Power Conditioner.

[36] DC Fast Charging and Integration of Big Data for Advanced Automated Customer Load Management.

[37] Regulatory Mandates: Submetering Enablement Demonstration Phase 2.

[38] D.15-04-020, Ordering Paragraph 1 -- Appendix B, Table-5, p. 7.

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

[40] *Ibid.*

[41] *Ibid.*

[42] D.15-04-020, Ordering Paragraph 1 -- Appendix B, Table-5, p. 7

[43] SCE's cumulative project expenses amounted to $6,082,802 based on the project spreadsheet in Appendix A. SCE's cumulative administration expenses amounted to $1,483,789. SCE's accounting system calculates in-house labor and overheads separately, which amounted to $1,080,316 for projects and $195,250 for program administration. As a result, SCE expended a total of $8,842,157 on program costs.

Table 5: 2018-2020 Triennial Investment Plan: 2020 Projects

1. Energy Resources Integration
• 3 Projects Funded
2. Grid Modernization and Optimization
• 2 Projects Funded
3. Customer Focused Products and Services
• 0 Projects Funded
4. Cross-Cutting/Foundational Strategies and Technologies
• 2 Projects Funded
Total Projects Funded: 19 Total Authorized Project Budget: $40,830,795[44] Total Project Spend: $6,082,803[45] Total Funding Committed: $30,533,083[46] Total Encumbered: $4,214,909[47] *Note: Due to intrinsic variability in TD&D /R&D projects, amounts shown are subject to change*

Table 6 below summarizes SCE's 2019 administrative expenses:

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

• Program Administration	Total Authorized Budget: $4,562,100[48] Total Cumulative Cost: $1,483,789 Total 2020 Cost: $999,061

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[49] with an annual budget of $162 million,[50] adjusted for inflation.[51]

[44] D.18-01-008, at p. 38.
[45] For additional details regarding SCE's Committed Funds, please see the attached spreadsheet.
[46] *Ibid.*
[47] *Ibid.*
[48] D.18-01-008, at p. 38.
[49] D.12-05-037, OP1.
[50] D.12-05-037, OP7.
[51] Using the Consumer Price Index.

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.[52] The IOUs were also limited to only the area of Technology Demonstration and Deployment (TD&D) activities.[53] SCE was allocated 41.1% of the IOU portion of the budget and administrative activities.[54]

The Commission approved SCE's 2012-2014 Investment Plan[55] in D.13-11-025 on November 19, 2013. SCE submitted its 2015-2017 Investment Plan Application[56] on May 1, 2014 and the Commission approved the Application in D.15-04-020 on April 9, 2015. SCE submitted its 2018-2020 Application on May 1, 2017 and the Commission approved the Application in D.18-10-052. SCE is currently executing its 2012-2014, 2015-2017 and 2018-2020 EPIC Investment Plans.

The Commission initiated a rulemaking[57] 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 thus far authorized the CEC to continue being an administrator.[58] In Phase 2 of the rulemaking, the Commission will determine whether the Utilities will continue to be administrators, as well as finalizing program design (i.e. program evaluation(s)).

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

The Commission limited SCE's triennial investment applications in this EPIC Program to TD&D projects, per D.12-05-037. The Commission defines TD&D projects as installing and operating pre-commercial technologies or strategies at a scale sufficiently large, and in conditions sufficiently reflective of anticipated actual operating environments, to enable appraisal of the operational and performance characteristics and the associated financial risks.[59]

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52 *Id*, OP5.
53 *Id*.
54 D.12-05-037, OP 7, as modified by D.12-07-001.
55 A.12-11-004.
56 A.14-05-005.
57 R.19-10-005.
58 D.20-08-042.
59 D.12-05-037, OP3.B.

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, 2018-2020 Investment Plans proposed projects for each of these four areas, focusing on the ultimate goals of promoting greater reliability, lowering costs, increasing safety, decreasing greenhouse gas emissions, and supporting low-emission vehicles and economic development for ratepayers.

c) EPIC Program Regulatory Process

The Commission approved SCE's 2012-2014 Application[60] in D.13-11-025 on November 19, 2013. SCE submitted its 2015-2017 Investment Plan Application[61] 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,[62] 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[63] 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[64] on April 23, 2019 and SCE proposed two replacement project

[60] A.12-11-004.
[61] A.14-05-005.
[62] D.15-09-005.
[63] A.17-05-005.
[64] A.19-04-028.

proposals, which was approved by the Commission on February 10, 2020. In compliance with the Commission's requirements for the EPIC Program,[65] SCE submits its 2020 Annual Report to update the Commission and stakeholders on SCE's program implementation.

d) <u>Coordination</u>

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

- Biweekly meetings to discuss stakeholder engagement planning (e.g., Symposium), as well as coordination and collaboration opportunities for the investment plan administrators;
- The October 19-20 virtual EPIC Symposium on transportation electrification, renewables integration, as well as a utility management plenary panel;
- Participation in technical advisory committees, working groups and workshops (e.g., Regional Forum,[66] Long Duration Energy Storage,[67] and Methodologies and Tools to Assessing Benefits of Research and Development Investments[68]);
- Project coordination continued on the Electric Access System Enhancement (EASE) project.[69] EASE was funded ($4M) by the Department of Energy (DOE) under the Enabling Extreme Real-time Grid Integration of Solar Energy (ENERGISE) funding opportunity announcement (DE-FOA-0001495). SCE applied and was awarded CEC match funding ($2M).

As mentioned above in relation to CEC coordination, all the EPIC Administrators met on a near-weekly basis to discuss the items mentioned above, coordinate investment plan activities, and to plan

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[65] 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.
[66] CEC Workshop held February on 25, 2020 in Long Beach.
[67] CEC Workshop held virtually on December 3, 2020.
[68] CEC Workshop held virtually on November 19, 2020.
[69] 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.

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) Transparent and Public Process/CEC Solicitation Activities

On October 19-21, 2020, SCE supported the annual EPIC Symposium held virtually this year due to the corona virus. SCE supported the CEC in a discussion on transportation electrification, renewables integration 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 2020. A total of 36 requests for Letters of Support (LOS) and Commitment (LOC) were received from a diverse array of parties including private vendors, universities and national laboratories, showing interest in partnering on their bids for CEC projects. These requests consisted of 15 LOSs and 21LOCs. Of these requests, 6 LOSs and 9 LOC were approved by the CEC. For SCE, a LOS typically supports the premise of a project. In some instances it will infer technical advisory support if (A) the project is awarded to the recipient and (B) the party and SCE come to a mutual understanding of what advisory support will be required.

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

3. Budget

a) Authorized Budget

(1) 2012 – 2014 Investment Plan

Table 5: 2017 Authorized EPIC Budget

2017 (Jan 1 - Dec 31)	Administrative	Project Funding	Commission Regulatory Oversight Budget

SCE Program	$1.3M	$11.9M	$0.33M[70]
CEC Program	$5.3M	$47.7M	

(2) 2015 – 2017 Investment Plan

Table 6: 2017 Authorized EPIC Budget

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

(3) 2018 – 2020 Investment Plan

Table 7: 2018 Authorized EPIC Budget

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

b) Commitments/ Encumbrances

(1) 2012 – 2014 Investment Plan

As of December 31, 2020, SCE has committed $310,634 and encumbered $498,441 of its authorized 2012-2014 program budget.

(2) 2015 – 2017 Investment Plan

As of December 31, 2020, SCE has committed $ $3,828,911 and encumbered $1,861,186 of its authorized 2015-2017 program budget.

(3) 2018 – 2020 Investment Plan

As of December 31, 2020, SCE has committed $30,533,084 and encumbered $4,214,909 of its authorized 2018-2020 program budget.

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

(4) **CEC & CPUC Remittances**

For CEC remittances, SCE remitted $6,610,995[71] for program administration, and $40,193,933 for encumbered projects during calendar year 2020.

For CPUC remittances, SCE remitted $380,175 in calendar year 2019.

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

(1) **2012 – 2014 Investment Plan**

As of December 31, 92020 has spent $5,853,516[72] on in-house activities.

(2) **2015 – 2017 Investment Plan**

As of December 31, 2020, SCE has spent $2,443,104[73] on in-house activities.

(3) **2018 – 2020 Investment Plan**

As of December 31, 2020, SCE has spent $324,834 on in-house activities.

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

(1) **2012 – 2014 Investment Plan**

As of December 31, 2020, SCE does not have any pending fund shifting requests and/or approvals.

(2) **2015 – 2017 Investment Plan**

As of December 31, 2020, SCE does not have any pending fund shifting requests and/or approvals.

(3) **2018 – 2020 Investment Plan**

As of December 31, 2020, SCE does not have any pending fund shifting requests and/or approvals.

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[71] 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.

[72] SCE expended a total of $5,025,140 on in-house activities through 2020 based on the project spreadsheet in Appendix A. SCE's accounting system calculates in-house labor overheads separately, which amounted to $1,285,607 and are included in the total above.

[73] SCE expended a total of $2,446,023 on in-house activities through 2019 based on the project spreadsheet in Appendix A. SCE's accounting systems calculates in-house labor overheads separately, which amounted to $359,565. As a result, SCE expended a total of $2,805,588 on in-house costs.

e) **Uncommitted/Unencumbered Funds**

(1) **2012 – 2014 Investment Plan**

As of December 31, 2020, SCE has $0 in uncommitted/unencumbered funds.

(2) **2015 – 2017 Investment Plan**

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

(3) **2018 – 2020 Investment Plan**

As of December 31, 2020, SCE has $0 in uncommitted/unencumbered funds.

f) **Joint CEC/SCE Projects**

As of December 31, 2020, the only project with CEC participation is the DOE-funded EASE project described in section 2d of this Report. For this project, the CEC is providing match funding.

g) **Non-Competitive Bidding of Funds**

As of December 31, 2020, 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 2020.

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.

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,[74] 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,[75] some dollar values for completed projects have changed.

[74] 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.

[75] 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.

(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
• 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)</td></tr>
</table>

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

Investment Plan Period: 1st Triennial Plan (2012-2014)	**Assignment to value Chain:** Demand-Side Management
Objective & Scope: On November 14, 2013, the Commission voted to approve the revised Proposed Decision (PD) Modifying the Requirements for the Development of a Plug-In Electric Vehicle Submetering Protocol set forth in D.11-07-029. The investor-owned utilities (IOUs) are to implement a two phased pilot beginning in May 2014, with funding for both phases provided by the EPIC. This project, Phase I of the pilot will (1) evaluate the demand for Single Customer of Record submetering, (2) estimate billing integration costs, (3) estimate communication costs, and (4) evaluate customer experience. IOUs and external stakeholders will finalize the temporary metering requirements, develop a template format used to report submetered, time-variant energy data, register Submeter Meter Data Management Agents and develop a Customer Enrollment Form, and finalize MDMA	

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

EPIC Funds Encumbered:	**EPIC Funds Spent:**
$0	$1,134,368

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 with the 2016 Annual Report, and is available on SCE's public EPIC web site.

3. Distribution Planning Tool

Investment Plan Period:	**Assignment to value Chain:**
1st Triennial Plan (2012-2014)	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 market place (when known)	
Schedule: Q1 2014 – Q4 2015	
EPIC Funds Encumbered: $0	**EPIC Funds Spent:** $39,563

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

6. Voltage and VAR Control of SCE Transmission System

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

8d. Number of information sharing forums held 8f. Technology transfer 9c. EPIC project results referenced in regulatory proceedings and policy reports 9d. Successful project outcomes ready for use in California IOU grid (Path to market)
Schedule: Q1 2014 – Q4 2018

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

8. State Estimation Using Phasor Measurement Technologies

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

<table>
<tr><td>Investment Plan Period:
1st Triennial Plan (2012-2014)</td><td>Assignment to value Chain:
Distribution</td></tr>
<tr><td colspan="2">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.</td></tr>
<tr><td colspan="2">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</td></tr>
<tr><td colspan="2">Metrics:
1c. Avoided procurement and generation costs
1i. Nameplate capacity (MW) of grid-connected energy storage
3b. Maintain / Reduce capital costs</td></tr>
</table>

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: $0	**EPIC Funds Spent:** $72,995	
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 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:	**Assignment to value Chain:**
1st Triennial Plan (2012-2014)	Grid Operation/Market Design
Objective & Scope: Voltage data and customer energy usage data from the Smart Meter network can be collected and leveraged for a range of initiatives focused on achieving operational benefits for Transmission & Distribution. Before a full implementation of this new approach can be considered, a demonstration project will be conducted to understand how voltage and consumption data can be best collected, stored, and integrated with T&D applications to	

provide analytics and visualization capabilities. Further, Smart Meter outage and restoration event (time stamp) data can be leveraged to improve customer outage duration and frequency calculations. Various stakeholders in T&D have identified business needs to pursue more effective and efficient ways of calculating SAIDI (System Average Interruption Duration Index), SAIFI (System Average Interruption Frequency Index), and MAIFI (Momentary Average Interruption Frequency Index) for internal and external reporting. Before a full implementation of this new approach can be considered, a demonstration project will be conducted to understand the feasibility and value of providing smart meter data inputs and enhanced methodology for calculating the Indexes. The demonstration will focus on a limited geography (SCE District or Region) to obtain the Smart Meter inputs to calculate the Indexes and compare that number with the current methodologies to identify any anomalies. A hybrid approach using the Smart Meter-based input data combined with a better comprehensive electric connectivity model obtained from GIS may provide a more efficient and effective way of calculating the Indexes. Additionally, an effort to evaluate the accuracy of the Transformer Load Mapping data will be carried out.		
Deliverables: • Voltage Analytics for Power Quality Model • Simulated Circuit Condition Model • Customer and Transformer Load Analysis Model • Enhanced Inputs and SAIDI/SAIFI Analysis • Final Project Report		
Metrics: 3a. Maintain / reduce operations and maintenance costs 5c. Forecast accuracy improvement 5f. Reduced flicker and other power quality differences 6a. Enhance Outage Reporting Accuracy and SAIDI/SAIFI Calculation 8b. Number of reports and fact sheets published online 8f. Technology transfer 9c. EPIC project results referenced in regulatory proceedings and policy reports		
Schedule: Q1 2014 – Q4 2015		
EPIC Funds Encumbered: $0	**EPIC Funds Spent:** $1,018,549	
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 market place (when known)
Schedule: Q1 2014 – Q3 2021

EPIC Funds Encumbered: $498,441	**EPIC Funds Spent:** $5,796,278

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

<table>
<tr><td colspan="4">

- Intelligent Fuses demonstration and report
- Power Electronic Transformer demonstration and report
- Secondary Network Monitoring demonstration and report
- Final Project Report

</td></tr>
<tr><td colspan="4">Metrics:
3a. Maintain / Reduce operations and maintenance costs
3d. Number of operations of various existing equipment types (such as voltage regulation) before and after adoption of a new smart grid component, as an indicator of possible equipment life extensions from reduced wear and tear
5a. Outage number, frequency and duration reductions
5c. Forecast accuracy improvement
5d. Public safety improvement and hazard exposure reduction
5e. Utility worker safety improvement and hazard exposure reduction
5i. Increase in the number of nodes in the power system at monitoring points
6a. Improve data accuracy for distribution substation planning process
7b. Increased use of cost-effective digital information and control technology to improve reliability, security, and efficiency of the electric grid (PU Code § 8360)
7c. Dynamic optimization of grid operations and resources, including appropriate consideration for asset management and utilization of related grid operations and resources, with cost-effective full cyber security (PU Code § 8360)
7d. Deployment and integration of cost-effective distributed resources and generation, including renewable resources (PU Code § 8360)
7k. Develop standards for communication and interoperability of appliances and equipment connected to the electric grid, including the infrastructure serving the grid (PU Code § 8360)
8b. Number of reports and fact sheets published online
8d. Number of information sharing forums held
8f. Technology transfer
9c. EPIC project results referenced in regulatory proceedings and policy reports
9d. Successful project outcomes ready for use in California IOU grid (Path to market)
9e. Technologies available for sale in the market place (when known)</td></tr>
<tr><td colspan="4">Schedule:
Q1 2014 – Q4 2017</td></tr>
<tr><td colspan="2">EPIC Funds Encumbered:
$0</td><td colspan="2">EPIC Funds Spent:
$4,091,723</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:</td></tr>
</table>

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

<table>
<tr><td>Investment Plan Period:
1st Triennial Plan (2012-2014)</td><td>Assignment to value Chain:
Distribution</td></tr>
<tr><td colspan="2">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.).</td></tr>
<tr><td colspan="2">Deliverables:
Vault Monitoring Technologies Demonstration Report
Vault Ventilation Field Demonstration Report
Hybrid Pole Demonstration Report
Concealed Communication Assets Demonstration Report
Final Project Report</td></tr>
<tr><td colspan="2">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</td></tr>
<tr><td colspan="2">Schedule:</td></tr>
</table>

Q2 2014 – Q4 2016		
EPIC Funds Encumbered: $0	**EPIC Funds Spent:** $79,119	
Partners: N/A		
Match Funding: N/A	**Match Funding split:** N/A	**Funding Mechanism:** N/A
Treatment of Intellectual Property: SCE has no current patents or licensing agreements signed. Future Intellectual Property is to be determined.		
Status Update: The final project report is complete, was submitted with the 2016 Annual Report, and is available on SCE's public EPIC web site.		

15. Dynamic Line Rating Demonstration

Investment Plan Period: 1st Triennial Plan (2012-2014)	**Assignment to value Chain:** Transmission
Objective & Scope: Transmission line owners apply fixed thermal rating limits for power transmission lines. These limits are based on conservative assumptions of wind speed, ambient temperature and solar radiation. They are established to help ensure compliance with safety codes, maintain the integrity of line materials, and help secure network reliability. Monitored transmission lines can be more fully utilized to improve network efficiency. Line tension is directly related to average conductor temperature. The tension of a power line is directly related to the current rating of the line. This project will demonstrate the CAT-1 dynamic line rating solution. The CAT-1 system will monitor the tension of transmission lines in real-time to calculate a dynamic daily rating. If successful, this solution will allow SCE to perform real-time calculations in order to determine dynamic daily rating of transmission lines, thus increasing transmission line capacity.	
Deliverables: • Installed Dynamic Line Rating System Prototypes • Final Project Report	
Metrics: 3b. Maintain / Reduce capital costs 5b. Electric system power flow congestion reduction 6a. Increased power flow throughput 7b. Increased use of cost-effective digital information and control technology to improve reliability, security, and efficiency of the electric grid (PU Code § 8360) 7c. Dynamic optimization of grid operations and resources, including appropriate consideration for asset management and utilization of related grid operations and resources, with cost-effective full cyber security (PU Code § 8360) 8b. Number of reports and fact sheets published online	

8d. Number of information sharing forums held 8f. Technology transfer 9c. EPIC project results referenced in regulatory proceedings and policy reports 9d. Successful project outcomes ready for use in California IOU grid (Path to market) 9e. Technologies available for sale in the market place (when known)
Schedule: Q2 2014 – Q1 2016

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

Partners: N/A

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

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

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

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

Objective & Scope: Viasat in partnership with SCE and Duke Energy has been awarded a DOE contract (DE-0E0000675) to deploy a Cyber-intrusion Auto-response and Policy Management System (CAPMS) to provide real-time analysis of root cause, extent and consequence of an ongoing cyber intrusion using proactive security measures. CAPMS will be demonstrated in the SCE Advanced Technology labs at Westminster, CA. The DOE contract value is $6M with SCE & Duke Energy offering a cost share of $1.6M and $1.2M, respectively.
Deliverables: • System Requirements Artifact • Measurement and Validation Data • System Test Results • Final Project Report
Metrics: 5a. Outage number, frequency and duration reductions 7b. Increased use of cost-effective digital information and control technology to improve reliability, security, and efficiency of the electric grid (PU Code § 8360) 7l. Identification and lowering of unreasonable or unnecessary barriers to adoption of smart grid technologies, practices, and services (PU Code § 8360) 8b. Number of reports and fact sheets published online

8d. Number of information sharing forums held 8f. Technology transfer 10a. Description or documentation of funding or contributions committed by others 10c. Dollar value of funding or contributions committed by others
Schedule: Q3 2014 – Q3 2015

EPIC Funds Encumbered: $0	**EPIC Funds Spent:** $1,809,323

Partners: Viasat; Duke Energy

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

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

(2) 2015 – 2017 Triennial Investment Plan Projects

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

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

Objective & Scope: This proposed project builds upon the "Beyond the Meter Advanced Device Communications" project from the first EPIC triennial investment plan and proposes to demonstrate how the concept of "big data"[76] 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)

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

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:	**EPIC Funds Spent:**
$0	$1,193,834

Partners:
N/A

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

Treatment of Intellectual Property:
SCE has no current patents or licensing agreements signed. Future Intellectual Property is to be determined.
Status Update:
The Final Report for the 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:	**Assignment to value Chain:**
2^{nd} Triennial Plan (2015-2017)	Distribution

Objective & Scope:
This project will examine the possibility of establishing the Phasing information for distribution circuits, by examining the voltage signature at the meter and transformer level, and by leveraging the connectivity model of the circuits. This project will also examine the possibility of establishing transformer to meter connectivity based on the voltage signature at the meter and at the transformer level.

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

EPIC Funds Encumbered: $	**EPIC Funds Spent:** $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

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

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

• Requirements / Use Cases • Measurement and Validation Plan • Supplier's Pilot Report • Technology Transfer Plan • Final project report		
Metrics: 2a. Hours worked in California and money spent in California for each project 3a. Maintain / Reduce operations and maintenance costs 3b. Maintain / Reduce capital costs 5a. Outage number, frequency and duration reductions 5c. Forecast accuracy improvement 5d. Public safety improvement and hazard exposure reduction 8f. Technology transfer 9d. Successful project outcomes ready for use in California IOU grid (Path to market) 9e. Technologies available for sale in the market place (when known)		
Schedule: Q3 2015 – Q4 2018		
EPIC Funds Encumbered: $0	**EPIC Funds Spent:** $1,185,899	
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 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 Intelligence Switch:** Substation Radios, Field Radios, Support Software, Underground Interrupters, Documentation and report • **Intelligent Fuse:** delivery of single phase unit, single phase unit standard approval and publication, training of single phase unit, final report of single phase unit, delivery of three phase unit, three phase unit standard approval and publication, training of three phase unit and final report of three phase unit • **High Impedance:** Prototype 1, Prototype 2, Phase 2B Test Documentation and report
Metrics: 3a. Maintain/reduce operations and maintenance costs 3e. Non-energy economic benefits 5a. Outage number, frequency and duration reductions 5c. Forecast accuracy improvement 5d. Public safety improvement and hazard exposure reduction 5i. Increase in the number of nodes in the power system at monitoring points 7b. Increased use of cost-effective digital information and control technology to improve reliability, security, and efficiency of the electric grid (PU Code § 8360) 7c. Dynamic optimization of grid operations and resources, including appropriate consideration for asset management and utilization of related grid operations and resources, with cost-effective full cyber security (PU Code § 8360) 7f. Deployment of cost-effective smart technologies, including real time, automated, interactive technologies that optimize the physical operation of appliances and consumer devices for metering, communication concerning grid operations and status, and distribution automation (PU Code § 8360) 7k. Develop standards for communication and interoperability of appliances and equipment connected to the electric grid, including the infrastructure serving the grid (PU Code § 8360)
Schedule: Q3 2016 – Q4 2021

<table>
<tr><td colspan="2">EPIC Funds Encumbered:
$725,970</td><td colspan="2">EPIC Funds Spent:
$5,885,407</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:
2020 Accomplishments:
Remote Integrated Switch (RIS):
The RIS team successfully demonstrated DNP3-based decentralized FLISR scheme and identified scalability issues to be resolved in Phase 3 (which will demonstrate a high-speed/GOOSE solution). The team created a circuit-based topology to demonstrate the feature enhancements and a new RTDS model, new circuit-based system design, logic template files based on the new scalability requirements. Preparations for the Phase 3 demonstration has started. The Phase 3 will demonstration advanced features which address system scalability and usability concerns identified by stakeholders in previous demonstrations.

High Impedance Fault Detection:
The validation test scope was developed and revised however there have been delays with getting the purchase order approved with Southwest Research Institute due to enhanced Cyber Security policies which are requiring additional T's and C's. Contract negotiations are continuing and hope to be resolved and testing to commence in the 1st quarter of 2021.

Underground/Overhead Remote Fault Indicator:
The RFI team installed 12 overhead RFI systems on different circuits to demonstrate the various specifications including operation on covered conductors, paralleled circuitry or looped circuits, detection of reverse power flow, operation on circuits with low minimum current less than 5A, operation on 33kV lines with high EMF and extreme temperatures. The systems were monitored through 2020 and was able to capture seven sustained fault events and multiple momentary fault events. The team also demonstrated an overhead transmission fault indicator and identified that the system was not able to fully meet Sub Transmission requirements. Based on the results recommendations were made to the manufacturer to improve system. These recommendations resulted in a revised version by the manufacturer which was tested in the Q3 2020 and met all Sub Transmission requirements.

The RFI team worked with the manufacturer to resolve failures of the both the submersible and non-submersible Underground RFI systems. The resultant upgraded hardware was lab tested and verified. Additionally, previous 54 installation locations updates due to new Standards committee's requirements. Some sites required both a hardware and firmware</td></tr>
</table>

update. The updates were delayed due to Covid-19 impacts and are scheduled to complete by Q2 2021. Submersion testing of the latest revision of a second manufacturers submersible system were successful and were also scheduled to replace previously installed units. These installations were delayed due to Covid-19 and are also scheduled for completion by Q2 2021. Intelligent Fuse: The Intelligent Fuse project will no longer be pursued due to lack of stakeholder interest and has been cancelled. Real-time Equipment Health Diagnostic: As noted in the 2019 EPIC Annual Report, no further work has been done. Long Beach Secondary Network Situation Awareness: As noted in the 2019 EPIC Annual Report, due to Oracle unable to deliver better results this effort has been cancelled.

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 situation awareness capabilities such as high impedance fault detection, intelligent alarming, predictive maintenance, and automated testing. This will be accomplished by integrating intelligent algorithms and advanced applications with the latest substation automation technologies, next generation control systems, latest breakthrough in substation equipment, sensing technology, and communications assisted protection schemes, This system will leverage the International Electrotechnical Commission (IEC) 61850 Automation Standard and will include cost saving technology such as process bus, peer to peer communications, and automated engineering and testing technology. This project will also inform complementary efforts at SCE aimed at meeting security and NERC CIP compliance requirements.	
Deliverables: 1- Intelligent Alarm processing stake-holders lab demonstration 2- Testing tools lab demonstration and hand over to production team 3- Process bus lab demonstration	
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 2020		
EPIC Funds Encumbered: $421,903	**EPIC Funds Spent:** $2,517,734	
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: Substation Test Tools In 2020, the objective was to test and demonstrate a substation test tool capable of automating the test process for IEC 61850 IEDs and HMI and the PLC. The results of this project include the ability to implement a test tool that improves the efficiency of what are today time and labor-intensive test processes. Automating test processes allows for more thorough validation of substation configurations while reducing the amount of resources expended to complete testing. The project had a milestone in 2020 to deliver training on the tool to the Control and Meter Asset Engineering team. Due to COVID 19 travel and in-person meeting restrictions, this training was postponed until late 2020 and moved to an online format so the project milestone was still achieved in 2020. As a lesson learned, The Substation Demonstrations team attempted to demonstrate the tool for a larger substation, the application may require additional processing power. Possible solutions to this include splitting up the substation and running the test tool on two machines or obtaining a computer with additional processing capabilities. Process Bus The Mayberry process bus and optical CT project was successfully commissioned in June 2019 with an evaluation period that ended in March 2020. The objective was to demonstrate new optical sensing technologies with the IEC-61850 process bus standard. Throughout the duration of the pilot project, several operations occurred which provided valuable data in analyzing the behavior of the optical sensing and digital communications. Ultimately, the technology proved successful and worked as intended. The numerous lessons learned will be applied to future process bus projects. Additionally, the findings were presented at various conferences with the collaboration of the manufacturer.		

Fully Digital Substation The fully digital substation project is intended to demonstrate a complete IEC-61850 substation with process bus technology. In late 2019, lab demonstration design was finalized and throughout 2020, the system was installed and configured per the design in a laboratory. Since new devices were installed, a cyber assessment was required in order to identify any potential vulnerabilities. This was successfully completed in Q4 2020. Additionally, a unique network design was developed and completed with the collaboration of SCE's SmartGrid and Enterprise Networking personnel. The goal is to eventually deploy a full station to the field based on a successful lab demonstration. A preliminary list of candidate substations has also been derived through this effort. The lab demonstration will continue throughout and is planned to be completed by late 2021.

6. Regulatory Mandates: Submetering Enablement Demonstration - Phase 2

Investment Plan Period: 2nd Triennial Plan (2015-2017)	**Assignment to value Chain:** Demand-Side Management
Objective & Scope: This project expands on the submetering project from the first EPIC triennial investment plan cycle to demonstrate plug-in electric vehicle (PEV) submetering at multi-dwelling and commercial facilities. Specifically, the project will leverage third party metering to conduct subtractive billing for various sites, including those with multiple customers of record.	
Deliverables: • Manual subtractive billing procedure for multiple customers of record • 3PE final report • PEV submetering protocol • Final project report	
Metrics: 1d. Number and percentage of customers on time variant or dynamic pricing tariffs 1h. Customer bill savings (dollars saved) 3e. Non-energy economic benefits 4a. GHG emissions reductions (MMTCO2e) 6a. The 3rd Party Evaluator, Nexant, in collaboration with the Energy Division and IOUs, will develop a set of metrics for Phase 2 to be included in the final report 7h. Deployment and integration of cost-effective advanced electricity storage and peak-shaving technologies, including plug-in electric and hybrid electric vehicles, and thermal-storage air-conditioning (PU Code § 8360) 7j. Provide consumers with timely information and control options (PU Code § 8360) 7k. Develop standards for communication and interoperability of appliances and equipment connected to the electric grid, including the infrastructure serving the grid (PU Code § 8360) 7l. Identification and lowering of unreasonable or unnecessary barriers to adoption of smart grid technologies, practices, and services (PU Code § 8360)	

8e. Stakeholders attendance at workshops 8f. Technology transfer 9c. EPIC project results referenced in regulatory proceedings and policy reports 9d. Successful project outcomes ready for use in California IOU grid (Path to market) 9e. Technologies available for sale in the market place (when known)
Schedule: Q4 2015 – Q1 2019

EPIC Funds Encumbered: $0	**EPIC Funds Spent:** $1,230,708

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 Regulatory Mandates: Submetering Enablement Demonstration - Phase 2 is complete, is being submitted with the 2019 Annual Report, and will be 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:	**EPIC Funds Spent:**
$0	$42,225

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: In December 2016, this project was cancelled by SCE Senior Leadership as a result of internal organizational change that focused the organization on Distribution System strategic objectives. This was reported in the 2016 EPIC Annual Report.

8. Series Compensation for Load Flow Control

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

$0		$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)

Investment Plan Period: 2nd Triennial Plan (2015-2017)	**Assignment to value Chain:** Distribution
Objective & Scope: This project demonstrates the electrification of transportation and vocational loads that previously used internal combustion engines powered by petroleum fuels in the SCE fleet. The VAPS system uses automotive grade lithium ion battery technology (Chevrolet Volt and Ford Focus EV) which is also used in notable stationary energy storage projects (Tehachapi 32 MWh Storage).	
Deliverables: **Light Duty VAPS Platform – PHEV Pickup Truck:** Purchase Order for PHEV Truck, Test Result Report, Final Report **Class 8 PHEV/BEV:** Purchase Order for Class 8 PHEV/BEV, Test Result Report, Final Report **Medium Duty VAPS Platform – Class 5 PHEV 9ft. Flatbed:** A Plug-in Hybrid Ford F550 Flatbed, Test Result Report, Final Report Small, Medium and Large VAPS Systems: Purchase Order for Small VAPS, Year-end Report, Purchase Order for Medium/Large VAPS, Test Result Report, Final Project Report, New Fleet VAPS System Report	
Metrics: 3a. Maintain/Reduce operations and maintenance costs 3e. Non-energy economic benefits 4a. GHG emissions reductions (MMTCO2e) 4b. Criteria air pollution emission reductions 5d. Public safety improvement and hazard exposure reduction 5e. Utility worker safety improvement and hazard exposure reduction 7h. Deployment and integration of cost-effective advanced electricity storage and peak-shaving technologies, including plug-in electric and hybrid electric vehicles, and thermal-storage air-conditioning (PU Code § 8360) 8f. Technology transfer	
Schedule:	

Q3 2015 – Q1 2019		
EPIC Funds Encumbered: $0	**EPIC Funds Spent:** $1,125,945	
Partners: N/A		
Match Funding: N/A	**Match Funding split:** N/A	**Funding Mechanism:** N/A
Treatment of Intellectual Property: SCE has no current patents or licensing agreements signed. Future Intellectual Property is to be determined.		
Status Update: The Final Report for the VAPS is complete, submitted with the 2019 Annual Report and is posted on SCE's public EPIC web site.		

10. Dynamic Power Conditioner

Investment Plan Period: 2nd Triennial Plan (2015-2017)	**Assignment to value Chain:** Distribution
Objective & Scope: This project will demonstrate the use of the latest advances in power electronics and energy storage devices and controls to provide dynamic phase balancing. The project will also provide voltage control, harmonics cancellation, sag mitigation, and power factor control while fostering steady state operations such as injection and absorption of real and reactive power under scheduled duty cycles or external triggers. This project aims to mitigate the cause of high neutral currents and provide several power quality benefits by using actively controlled real and reactive power injection and absorption.	
Deliverables: • Complete Specification documents for hardware • Use Cases • Lab Test Report of the Dynamic Power Conditioner • Final Project Report Presentation of project detailed findings and results. Final Report on effectiveness of device in the lab including a summary of all data collected and how the data may be accessed.	
Metrics: 1a. Number and total nameplate capacity of distributed generation facilities 1b. Total electricity deliveries from grid-connected distributed generation facilities 1i. Nameplate capacity (MW) of grid-connected energy storage 2. Job creation 3a. Maintain / Reduce operations and maintenance costs 3b. Maintain / Reduce capital costs 3c. Reduction in electrical losses in the transmission and distribution system 5a. Outage number, frequency and duration reductions 5b. Electric system power flow congestion reduction	

5f. Reduced flicker and other power quality differences 7a. Description of the issues, project(s), and the results or outcomes 9. Adoption of EPIC technology, strategy, and research data/results by others
Schedule: Q3 2016 – Q4 2019

EPIC Funds Encumbered: $,1,994	**EPIC Funds Spent:** $900,595

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, submitted as part of the 2020 Annual Report, and is available on SCE's public EPIC web site.

11. Optimized Control of Multiple Storage Systems

Investment Plan Period: 2^{nd} 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 web site.		

13. Integrated Grid Project II

Investment Plan Period: 2nd Triennial Plan (2015-2017)	**Assignment to value Chain:** Cross-Cutting/Foundational Strategies & Technologies
Objective & Scope: The project will deploy, field test and measure innovative technologies that emerge from the design phase of the Integrated Grid Project (IGP) that address the impacts of DER (distributed energy resources) owned by both 3rd parties and the utility. The objectives are to demonstrate the next generation grid infrastructure that manages, operates, and optimizes the distributed energy resources on SCE's system. The results will help determine the controls and protocols needed to manage DER, how to optimally manage an integrated distribution system to provide safe, reliable, affordable service and also how to validate locational value of DERs and understand impacts to future utility investments.	
Deliverables: • Evaluation of system performance and field operations performance • Report on market maturity of technologies demonstrated • Final project report (Phase 2)	
Metrics: 1a. Number and total nameplate capacity of distributed generation facilities 1b. Total electricity deliveries from grid-connected distributed generation facilities 1c. Avoided procurement and generation costs 1d. Number and percentage of customers on time variant or dynamic pricing tariffs 1e. Peak load reduction (MW) from summer and winter programs 1f. Avoided customer energy use (kWh saved) 1g. Percentage of demand response enabled by automated demand response technology (e.g. Auto DR) 1h. Customer bill savings (dollars saved) 1i. Nameplate capacity (MW) of grid-connected energy storage 3a. Maintain / Reduce operations and maintenance costs 3b. Maintain / Reduce capital costs 3c. Reduction in electrical losses in the transmission and distribution system 3d. Number of operations of various existing equipment types (such as voltage regulation) before and after adoption of a new smart grid component, as an indicator of possible equipment life extensions from reduced wear and tear 3e. Non-energy economic benefits 3f. Improvements in system operation efficiencies stemming from increased utility dispatchability of customer demand side management 5a. Outage number, frequency and duration reductions 5b. Electric system power flow congestion reduction 5c. Forecast accuracy improvement 5f. Reduced flicker and other power quality differences 5i. Increase in the number of nodes in the power system at monitoring points	

7b. Increased use of cost-effective digital information and control technology to improve reliability, security, and efficiency of the electric grid (PU Code § 8360) 7c. Dynamic optimization of grid operations and resources, including appropriate consideration for asset management and utilization of related grid operations and resources, with cost-effective full cyber security (PU Code § 8360) 7d. Deployment and integration of cost-effective distributed resources and generation, including renewable resources (PU Code § 8360) 7e. Development and incorporation of cost-effective demand response, demand-side resources, and energy-efficient resources (PU Code § 8360) 7f. Deployment of cost-effective smart technologies, including real time, automated, interactive technologies that optimize the physical operation of appliances and consumer devices for metering, communications concerning grid operations and status, and distribution automation (PU Code § 8360) 7h. Deployment and integration of cost-effective advanced electricity storage and peak-shaving technologies, including plug-in electric and hybrid electric vehicles, and thermal-storage air-conditioning (PU Code § 8360) 7j. Provide consumers with timely information and control options (PU Code § 8360); 7k. Develop standards for communication and interoperability of appliances and equipment connected to the electric grid, including the infrastructure serving the grid (PU Code § 8360) 7l. Identification and lowering of unreasonable or unnecessary barriers to adoption of smart grid technologies, practices, and services (PU Code § 8360) 8b. Number of reports and fact sheets published online 8d. Number of information sharing forums held 8f. Technology transfer 9b. Number of technologies eligible to participate in utility energy efficiency, demand response or distributed energy resource rebate programs 9c. EPIC project results referenced in regulatory proceedings and policy reports 9d. Successful project outcomes ready for use in California IOU grid (Path to market)		
Schedule: Q3 2016 – Q4 2021		
EPIC Funds Encumbered: $711,319	**EPIC Funds Spent:** $17,391,481	
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:
2020 Achievements

1) Controller Communication Design and Testing – Complete
2) Adaptive Protection System - Complete
3) EPRI - Complete
4) NODES NREL - Complete
5) NODES GE - Complete
6) Integrated Grid Analytics - Complete
7) EASE *(Budget Period 3 underway, completion by 12/31/2021)*

Task 6 – DER Market Services in Support of High-Penetration PV Scenarios
6.1 Refine use-cases
Refined EASE's use-cases on voltage and current constraint management on the distribution network, as well as feeder net load management to match findings in the project. Use-cases more clearly specifies the process of the DERMS' role in managing constraints based on specific voltage or current limits, which are configurable.

6.2 DER Market Services
Defined the initial DER Market based services that will be performed by the Distribution System Operator (DSO) platform in EASE. The documents described the interaction of the DSO market with the DERMS' constraint management and net load management functions. The market-based uses-cases will involve DER Services to the Utility (use-case 6), DER services to the Independent System Operator (use-case 7) and DER services to Utility, Independent System Operator, and Customer (Use-case 8).

6.3 Software-in-the-Loop Testing
Demonstrated SCE's DER market-based use-cases in our real-time Software-in-the-Loop (SIL) power system simulation environment. SCE validated the DSO use-cases in real-time to measure the value they provided to produce the optimal DER dispatch for the utility, ISO, or all parties (utility, ISO, and Customer). During simulation testing, SCE validated the Grid impact of the DSO's market-based dispatches on the Camden substation were validated to ensure that feeder voltages and currents remained within the market objective's defined constraints. We also validated that all DER were dispatched within their nameplate ratings. Constraint management was re-tested to validate that the DERMS is still able to perform voltage and current constraint management after our DSO integration into EASE. The DERMS was successful in overriding the DSO's DER dispatches to mitigate circuit constraints by selecting the DER closest and best suited to resolve the constraints. Our DSO's DER market services and DERMS constraint management systems simulated in the lab will be re-evaluated in our field trial in 2021 using real inverters to demonstrate how DER can provide market services while maintaining grid stability with constraint management.

Task 7 – Cyber Security Assessment of 3rd Party DER Aggregator Integration

Cyber Risk Assessment and Network Design was completed to detail the security design solution for integrating a third-party DER aggregator with Southern California Edison's Data Center. As part of this task, SCE has implemented standard industry practices for encrypting and authenticating data traffic through our network and delivering updates to our computing systems within our data center. Task 8 – Expanded Field Trial 8.1 Migration of Lab Setup to Utility's Grid Data Center The EASE project team anticipates migration of the lab set-up to SCE's Grid Data Center to occur in 2021.

(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).	
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: $2,051,384	**EPIC Funds Spent:** $1,205,748	
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 Execution work has launched: • Assembled project execution team in March 2020. Team delivered a project overview which included goals, updated execution schedule, and six use case overviews. A project communication plan was also developed identifying key communication resources and schedules • In response to Covid-19, constructed a remotely accessible lab environment leveraging the facilities and infrastructure in our vendor's Houston Operational Technology Cyber Fusion Center replicating SCE's Operational Technology (OT) production environment • Team identified forty viable solutions for adaptive controls and dynamic zoning across four use cases, • Created a Test Case Results document which aggregates all test case results providing overviews of each use case, allowing easy recreation of tests and replication of results for future programs' use. • Identified sixteen complex test cases centered around various networking scenarios and radio applications programs, as well as a combinations of IT techniques providing defense-in-depth responses to cyber threats to the operational technology environment Key Findings and Lessons Learned • Numerous test cases proved viable in responding to cyber threats, executed simultaneously providing a multifaceted defense-depth approach to threat response • In response to COVID restrictions, an agile approach to project execution proved beneficial in achieving milestones • Building a lab that accurately reflected the functionality and diversity of the OT environment was difficult. It requires specialized equipment and testing that are not commonly found for cybersecurity testing		

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 install 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:	**EPIC Funds Spent:**
$0	$278,851

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:
<u>The project Execution work was launched but placed on hold as of 12/1/2020 due to budget constraints.</u>

- Completed approval of Concept of Operations moving project from Planning to Execution.
- Completed development of detailed use-case and requirements including business objectives and performance metrics for the analytic model results.
- Completed architecture vision document (AVD).
- Competed Data Criticality Assessment
- Completed RFP launch with 5 proposals received. Interviewed and technically scored all bidders and selected highest scoring bidder, Tagup Inc.
- SCE was in the process of negotiating a contracted with Tagup when the project was placed on hold.
- Tagup is currently seeking a funding opportunity through the DOE SBIR grant.
- SCE is investigating methods to reduce internal project costs. If costs can be reduced enough, there is potential to continue the project mid-2021.

<u>Key Findings & Lessons Learned</u>

- There are many analytic vendors interested in this topic, but few have demonstrated the prediction of transformer remaining useful life without dissolved gas analysis samples (DGA). DGA samples are not available for SCE's distribution transformers.
- All analytic vendors interviewed prefer the use of cloud computing, requiring SCE to upload data to their cloud platform. Cloud platforms varied by vendor.
- Requiring the vendors to building the solution within SCE's environment was not preferred by vendors due to the amount of architecture customization required.
- SCE prefers to move the analytics close to the data rather than send large amounts of data to a vendor. The conflict between the vendors' and SCE's preferred method makes the project difficult to accomplish in a low cost manner.
- Developing an efficient/low cost method of secure data sharing is critical for the project's success as a Proof-of-Concept.

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 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.</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:
$61,837</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>
</table>

Status Update: The Project Execution work has launched: • Completed 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 for Augmented Reality. • Completed Project's Detailed Use Case and Requirements document illustrating scope, actors, assumptions, use cases, step by step analysis, and alternative scenarios. • Developed Project's system engineering artifact System Requirement Document (SRD) describing functional and non-functional requirements for the system and sub-system/application."

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. 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).	
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) 8b. Number of reports and fact sheets published online

Schedule: Q4 2019 – Q4 2022	
EPIC Funds Encumbered: $0	**EPIC Funds Spent:** $163,877
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 Execution work has launched: • Completed 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. • Completed Project's Detailed Use Case and Requirements document illustrating scope, actors, assumptions, six microgrid use cases, step by step analysis, and alternative scenarios. • Launched development of Project's architecture artifacts Lab Architecture Briefs (LAB) • An RFP package was completed, and the selected vendor is scheduled to be on-boarded 1Q 2021 The expected benefits of this sub-project include: • Allowing SCE Operators to dynamically transfer load from one circuit to another, supplementing the existing tie switches. It will provide better understanding of a storage system that can support two circuits at the same time, thereby decreasing the cost per system. • Utilizing GHG-free batteries to meet system requirements such as local voltage support, managing line loading, energy shifting, and preventing duct bank temperature violations.		

5. Smart City Demonstration

Investment Plan Period: 3rd Triennial Plan (2018-2020)	**Assignment to value Chain:** Grid Operation/Market Design
Objective & Scope: 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)
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).
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 wide spread 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: $0	**EPIC Funds Spent:** $514,894	
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 Execution work has launched:

- Completed 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.
- Completed Project's Detailed Use Case and Requirements document illustrating scope, actors, assumptions, six microgrid use cases, step by step analysis, and alternative scenarios.
- Completed Project's Architectural Vision Document (AVD) defining the solution overview, business impact, architecture considerations, system context, assumptions, constraints, dependencies, and risks analysis.
- Developed Project's system engineering artifact System Requirement Document (SRD) describing functional and non-functional requirements for the system and sub-system/application.
- Launched development of Project's architecture artifacts Lab Architecture Briefs (LAB) and System Architecture Design (SAD).
- Selected the partnering Local Agency for the Project's demonstration leveraging a selection process using criteria such as Disadvantage Community, strong interest in developing critical/essential facility Microgrids, and existing/planned customer-owned Distributed Energy Resources (DERs).
- Launched regular meetings with Local Agency to engage on the Project's partnership and mutual beneficial agreement. A draft Customer Agreement has been created and submitted to the Local Agency for review.
- Issued request for proposal (RFP) package for the procurement of a Microgrid Control System. Vendor onboarding scheduled 1Q 2021.
- Launched partnership with SCE's Energy Storage Integration Program for front-of-the-meter energy storage with advanced black-start and islanding capabilities.
- Presented the Project's overview, status and challenges/lessons learned at several workshops and meetings including Inter-IOU meeting, EPUC PICG PSPS workshop, EPIC PICG Equity/Disadvantaged Community workshop. Submitted project abstracts to present at several conferences in 2021.

Key Findings and Lessons Learned:

- Leverage combined architecture and vendor synergies with other EPIC III Microgrid Projects for cost efficiency and to accomplish common goals.

- Local agency selection criteria should consist of a minimum set of must have requirements, and additional nice to have requirements for effective site selection.
- EPIC program funding scope is limited and does not fund DERs such as energy storage for the demonstration. Thus, the project explored cities with exiting or planned DERs as a site selection criteria and also other co-investment potential.
- Aesthetics is a key project challenge as Stakeholders demand to visualize a completed installation with lots uncertainty and unknown at the beginning of the project. Clear concept visualization/renderings needed for non-technical audiences and stakeholders.
- Stakeholders engagement and commitment is vital for local DER penetration, flexible control and operation of microgrid resources and the grid.

Development of microgrid project is challenging and complex that requires engagement with several organization units and departments within the company. Commitment and active engagement are essential for successful project deployment and demonstration.

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 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) Duct Bank Monitoring will demonstrate the capability to 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 providing 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 results of the testing in this EPIC project aim to enable uniform, accelerated configuration and enhanced cybersecurity, extending the protocol used by Substation Automation (SA) out to be used by the distribution grid network.

3) Standard for GMS Field Connected Devices will establish 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 lab test system will aim 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 wide spread 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:	EPIC Funds Spent:	
$0	$215,239	

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 Project Execution work has launched:
• Completed 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 for (Duct Bank Monitoring).
• Completed Project's Detailed Use Case and Requirements document illustrating scope, assumptions, step by step analysis, and alternative scenarios.

The expected benefits of this sub-project (Duct Bank Monitoring) include:
• Ability of System Operators to temporarily exceed the historic circuit amperage limit in order to enhance real-time load management, without violating cable temperature ratings
• The ability to get more utilization from the SCE Distribution network, deferring system upgrades
• Reduce complex reconfiguration and switching operations presently used to balance load
• Better leverage SCE's GMS with improved situational awareness of substation conditions
• The ability to better characterize cable duct bank environments and temperature factors.
• Enhance existing cable temperature models and planned ampacities with new real-time data.

o Being changed to a lab only demonstration to obtain the necessary technology and interconnection learnings in anticipation of the anticipated expansion on the grid of medium duty transportation electrification.
o Exploring partnering with an OEM on second-life projects with SCE service territory.
o Exploring partnering with an OEM on second-life projects within SCE service territory.

7. SA-3 Phase III Field Demonstrations

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

Objective & Scope: 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		
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: $409,285	**EPIC Funds Spent:** $720,057	
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 Execution work has launched: • Completed 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 for the evaluation of the IEC 61850 Programmable Automation Controller (PAC), the Virtual Substation Relay Proof-of-Concept, and the Resonant Grounding with an arc suppression coil (ASC) • Completed Project's Detailed Use Case and Requirements document illustrating scope, assumptions, step by step analysis, and alternative scenarios. • Completed Project's architecture artifacts Lab Architecture Briefs (LAB) defining the solution overview, business impact, architecture considerations, system context, assumptions, constraints, dependencies, and risks analysis for the Programmable Logic Controllers (PLC). The outcome of the project will provide SCE's Control & Meter Asset Engineering users the ability to design and test a substation utilizing an IEC 61850 capable PAC.

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, 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: $924,240	**EPIC Funds Spent:** $687,434	
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 Execution work has launched: • Assembled project execution team in March 2020. Team delivered a project overview which included goals, updated execution schedule, and six use case overviews. A project communication plan was also developed identifying key communication resources and schedules • Developed test environment in a digital only virtualized environment allowing portability between cloud vendors and virtualization software, also allowing porting to either self-hosted or cloud infrastructure, enabling scaling based on business needs • Leveraged CTI (Cyber Threat Intelligence) platform to demonstrate program impact. The tool allowed visibility into the code base, allowing customized development for DCTAC specific requirements. As an open-source solution, OpenCTI environment was vetted within SCE to ensure compliance with EPIC and SCE intellectual property and security requirements • Completed the existing process review and began detailing proposed automation. Identified three initial areas where automation can increase the speed and efficiency of this process: data ingestion, data triage, and data sharing. Improvements in these areas will lead to increased process efficiency and decreased dwell time for appropriate actions to occur Key Findings and Lessons Learned • The expected execution date was delayed due to the specificity of skill sets and knowledge base that was difficult to match. Very few vendors possessed the immediate knowledge and product experience necessary to meet the requirements of the project at		

the outset • Multiple versions of the STIX programming language being used introduced compatibility issues. The team addressed this by customizing backend connectors to account for the data irregularities • Identified that alternative threat intelligence sources, such as vendor bulletins and email distribution lists, can provide actionable intelligence that should be incorporated into the DCTAC process. An RSS feed connector is currently under development, and the code can be contributed back to the OpenCTI project under the OASIS organization, if approved.

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, 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 and is looking into alternative funding sources.

10. Distribution Primary & Secondary Line Impedance

Investment Plan Period: 3rd Triennial Plan (2018-2020)	**Assignment to value Chain:** Distribution	
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 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.		
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		
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		
Schedule: TBD		
EPIC Funds Encumbered: $0	**EPIC Funds Spent:** $68,140	
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:
• Completed 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 • Due to budget constraints SCE has put this project on hold.

11. Advanced Comprehensive Hazards Tool

Investment Plan Period: 3rd Triennial Plan (2018-2020)	**Assignment to value Chain:** Grid Operation/Market Design
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.	
Deliverables: The Project will develop and demonstrate a comprehensive natural hazard web application with multi-layer mapping capabilities that provides 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)	

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		
Schedule: Q4 2019 – Q2 2022		
EPIC Funds Encumbered: $0	**EPIC Funds Spent:** $250,725	
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 Execution work has launched:

1. Completed approval of Concept of Operations moving project from Planning to Execution.
2. Completed development of detailed use-case and requirements including business objectives and performance metrics for the analytic model results.
3. Completed architecture vision document (AVD).
4. Competed Data Criticality Assessment
5. RFP bypassed going with direct award.
6. Completed the System Architecture Diagram (SAD).
7. Software vendor ready to onboard, secured resources required to complete modeling work.

Key Findings & Lessons Learned:

1. Constant engagement with vendor to ensure timely completion during the review process. Lesson Learned - took over a month
2. In the past EPIC projects did not follow any standards for data engineering, therefore engagement with EA team on the project has led to procurement of MSP to provide data engineering services, and ensure acceptable standards are being followed
3. Use SCE equipment for smaller vendors to ensure compliance with cybersecurity policies.

4. Agreements are not written in such a way that project can onboard analytics vendors that meet the need

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 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.	
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: $0	**EPIC Funds Spent:** $337,469

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 Execution work has launched:

- Completed 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.
- Completed Project's Detailed Use Case and Requirements document illustrating scope, actors, assumptions, six microgrid use cases, step by step analysis, and alternative scenarios.
- Completed Project's Architectural Vision Document (AVD) defining the solution overview, business impact, architecture considerations, system context, assumptions, constraints, dependencies, and risks analysis.
- Developed Project's system engineering artifact System Requirement Document (SRD) describing functional and non-functional requirements for the system and sub-system/application.
- Launched development of Project's architecture artifacts Lab Architecture Briefs (LAB) and System Architecture Design (SAD).
- Selected the partnering Local Agency for the Project's demonstration leveraging a selection process using criteria such as Disadvantage Community, strong interest in developing critical/essential facility Microgrids, and existing/planned customer-owned Distributed Energy Resources (DERs).
- Launched regular meetings with Local Agency to engage on the Project's partnership and mutual beneficial agreement. A draft Customer Agreement has been created and submitted to the Local Agency for review.
- Issued request for proposal (RFP) package for the procurement of a Microgrid Control System. Vendor onboarding scheduled 1Q 2021.
- Launched partnership with SCE's Energy Storage Integration Program for front-of-the-meter energy storage with advanced black-start and islanding capabilities.
- Presented the Project's overview, status and challenges/lessons learned at several workshops and meetings including Inter-IOU meeting, EPUC PICG PSPS workshop, EPIC PICG Equity/Disadvantaged Community workshop. Submitted project abstracts to present at several conferences in 2021.

Key Findings and Lessons Learned:

- Leverage combined architecture and vendor synergies with other EPIC III Microgrid Projects for cost efficiency and to accomplish common goals.

• Local agency selection criteria should consist of a minimum set of must have requirements, and additional nice to have requirements for effective site selection. • EPIC program funding scope is limited and does not fund DERs such as energy storage for the demonstration. Thus, the project explored cities with exiting or planned DERs as a site selection criteria and also other co-investment potential. • Aesthetics is a key project challenge as Stakeholders demand to visualize a completed installation with lots uncertainty and unknown at the beginning of the project. Clear concept visualization/renderings needed for non-technical audiences and stakeholders. • Stakeholders engagement and commitment is vital for local DER penetration, flexible control and operation of microgrid resources and the grid. • Development of microgrid project is challenging and complex that requires engagement with several organization units and departments within the company. Commitment and active engagement are essential for successful project deployment and demonstration.

13. Distributed Plug-In Electric Vehicle Charging Resources

Investment Plan Period: 3rd Triennial Plan (2018-2020)	**Assignment to value Chain:** Distribution
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, 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.	
Deliverables: • Deliver a Project that includes or addresses: o 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).
  - Use of Charger intelligence to support DR and/or DER capability while minimizing impact to customer and other load management capabilities.
  - 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:**
$0	$310,933

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:

<u>The Project Execution work has launched:</u>

- Completed 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.
- Completed Project's Detailed Use Case and Requirements document illustrating scope, actors, assumptions, use cases, step by step analysis, and alternative scenarios.
- Completed Project's Architectural Vision Document (AVD) defining the solution overview, business impact, architecture considerations, system context, assumptions, constraints, dependencies, and risks analysis.
- Developed Project's system engineering artifact System Requirement Document (SRD) describing functional and non-functional requirements for the system and sub-system/application.
- Launched development of Project's architecture artifacts Lab Architecture Briefs (LAB) and System Architecture Design (SAD).
- An RFI package to identify existing High Energy Charging Systems coupled with Energy storage was performed.

Key Findings and Lessons Learned

- 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.
- As such the Project is:
  - Being changed to a lab only demonstration to obtain the necessary technology and interconnection learnings in anticipation of the anticipated expansion on the grid of medium duty transportation electrification.
  - Exploring partnering with an OEM on second-life projects with SCE service territory.

14. Service and Distribution Centers of the Future

Investment Plan Period: 3rd Triennial Plan (2018-2020)	**Assignment to value Chain:** Distribution
Objective & Scope: 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.	
Deliverables: • A fleet center or depot within a disadvantaged community that will support: o High power, high energy EV charging infrastructure to support light to heavy-duty vehicles o Electrified facilities on site o 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: $0	**EPIC Funds Spent:** $401,870	
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:

<u>The Project Execution work has launched:</u>

- Completed 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.
- Completed Project's Detailed Use Case and Requirements document illustrating scope, actors, assumptions, six microgrid use cases, step by step analysis, and alternative scenarios.
- Completed Project's Architectural Vision Document (AVD) defining the solution overview, business impact, architecture considerations, system context, assumptions, constraints, dependencies, and risks analysis.
- Developed Project's system engineering artifact System Requirement Document (SRD) describing functional and non-functional requirements for the system and sub-system/application.
- Launched development of Project's architecture artifacts Lab Architecture Briefs (LAB) and System Architecture Design (SAD).

- Identified LA Metro El Monte Fleet Service Yard as the Field Pilot location.
  - Companion efforts at LA Metro site:
    - T&D Customer Interconnections/Method of Service completed a Method of Service Study which proposed sub transmission service and a customer owned substation to LA Metro for future expansion beyond initial 100 buses incorporated into project plans.
    - SCE Charge Ready Project at site, first 60 Electric buses scheduled to be delivered one year from now. Submetering architecture design completed. Building electrification components and requirements known.
- An RFP package to engage a Microgrid Control System Vendor (software and hardware) issued. Vendor onboarding scheduled 1Q 2021
- Launched partnership with SCE's Energy Storage Integration Program for front-of-the-meter energy storage to support fleet charging resiliency and islanding capabilities. Completed initial site assessment and reached agreement on siting and infrastructure arrangement.
- Studied EV charging equipment proposed by LA Metro to learn characteristics and control capabilities
- Worked with Build Your Dreams (BYD) and partners to install prospective charger at BYD's Lancaster CA Electric Bus factory ready for SCE inspection.
- Worked with meter services to understand advanced metering future prospects and aligned on submetering strategy.

Key Findings and Lessons Learned

- Leverage combined architecture and vendor synergies with other EPIC III Microgrid Projects for cost efficiency and to accomplish goals.
- With the COVID pandemic, we learned that public transportation, including LA Metro, ridership has fallen by approximately 85%. How this will affect their overall fleet electrification goals and EPIC III Field Pilot, beyond 60 busses already purchased, is yet TBD, but new operations are to be captured.
- The Project Team obtained knowledge of the:
  - LA Metro's pre-COVID bus operational and charging profiles
  - BYD electric bus control constraints
  - LA Metro operations and control direction and their initial prospective partner, Viriciti.

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 new context with 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
    o 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

<table>
<tr><td colspan="4">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</td></tr>
<tr><td colspan="4">Schedule:
Q3 2019 – Q1 2023</td></tr>
<tr><td colspan="2">EPIC Funds Encumbered:
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$431,745</td></tr>
<tr><td colspan="4">Partners:
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<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>
</table>

Status Update: The Project Execution work has launched: • Completed 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. • Completed Project's Detailed Use Case and Requirements document illustrating scope, actors, assumptions, six microgrid use cases, step by step analysis, and alternative scenarios. • Completed Project's Architectural Vision Document (AVD) defining the solution overview, business impact, architecture considerations, system context, assumptions, constraints, dependencies, and risks analysis. • Developed Project's system engineering artifact System Requirement Document (SRD) describing functional and non-functional requirements for the system and sub-system/application. • Launched development of Project's architecture artifacts Lab Architecture Briefs (LAB) and System Architecture Design (SAD). • An RFP package to engage a Microgrid Control System Vendor (software and hardware) was issued. The vendor selection process was completed, and a tentative vendor has been selected pending final negotiations. Vendor onboarding scheduled 1Q 2021. Key Findings and Lessons Learned • Leverage combined architecture and vendor synergies with other EPIC III Microgrid Projects for cost efficiency and to accomplish goals. • With DoD cancelling their Ft. Irwin's Microgrid Project, QA & Field elements will be demonstrated through the Smart City Project. An alternative software Microgrid test model has been selected, which will be used for the testbed testing and validation activities. • ARIBA system: The vendor database was not current, and some vendors had to be contacted directly by phone or email. Discussions initiated on how to improve this system. • Demonstrations & discussions after selecting the top vendor candidates: having a live demonstration was beneficial in the decision-making process.

16. Distributed Energy Resources 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 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.		
Deliverables: TBD		
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: $830,000	**EPIC Funds Spent:** $185,640	
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 execution work has launched: • Completed Project's Detailed Use Case and Requirements document illustrating scope, actors, assumptions, eight smart inverter use cases, step by step analysis, and scenarios. • Completed Project's Lab Architecture Brief (LAB) defining the solution overview, business impact, architecture considerations, system context, assumptions, constraints, dependencies, and risks analysis. • Completed an RFP, and the vendor selection process was completed. An interim PO has been issued to the vendor pending the final negotiations. Vendor onboarding scheduled for Q1 2021.		

- Designed and developed the testing platform in the SCE's DER Laboratory that can support the project demonstration.
- Communicated project objective and deliverables to PG&E, SDG&E, & Rule 21 working group and added them as external stakeholders in the project.
- Submitted an IEEE conference paper based on preliminary modeling, simulation, and experimental results; results validated modeling. Md Arifujjaman, Roger Salas, Anthony P. Johnson, Austen D'Lima, Jorge Araiza, Josh Mauzey, Juan Castaneda, "Modeling and Development of a HIL Testbed for DER Dynamics Integration Demonstration," IEEE Green Energy and Smart Systems Conference (IGESSC), Long Beach, CA, USA 2020

Key Findings and Lessons Learned

1. The developed smart inverter numerical model for this project is very capable of reflecting the inverter characteristics, although dynamics need to be included to reflect the transient phenomena.
2. Very few vendors can model, simulate, and demonstrate the high-fidelity dynamics model on a simulation and demonstration platform.
3. Inverter manufacturers are reluctant to provide the high-fidelity inverter model with advanced functions, as required by the project.
4. The presently used in-house inverter model would need to be upgraded to articulate a physical inverter's dynamics.
5. The vendor database was not current, and some vendors had to be contacted directly by phone or email. Discussions initiated on how to improve this system.
6. Demonstrations & discussions after short listing the top vendor candidates: having an in depth technical call with the vendors was beneficial in the vendor selection process.

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 & 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:
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:** $180,977	
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.		
1. **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 and is looking into alternative funding sources.		

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:** $9,516

Partners: TBD

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

Treatment of Intellectual Property: TBD
Status Update: Project is currently in the planning phase. Currently reviewing potential partner(s) and their energy storage technologies that build on the learnings of prior energy storage projects, while addressing key resilience use cases for the distribution grid.

19. Wildfire Prevention & Resiliency Technology Demonstration

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

Objective & Scope: TBD 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 hardware-based 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.		
Deliverables: TBD		
Metrics: TBD		
Schedule: TBD		
EPIC Funds Encumbered: $0	**EPIC Funds Spent:** $45,108	
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: Project is in the planning phase.		

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, 2020, SCE expended a total of $880,137 toward project costs and $97,864 toward administrative costs for a grand total of $978,001.

SCE's cumulative expenses over the lifespan of its 2012 – 2014 EPIC program amount to $36,847,9369. SCE committed $311,188 toward projects and encumbered $498,441 through executed purchase orders during this period. SCE has no uncommitted EPIC funding for this period.

In 2020, SCE completed the final project that was in execution from its approved EPIC I Portfolio. SCE executed 16 projects. 1 project was cancelled and 15 projects were completed. 3 of these projects were completed during the calendar year 2015, 4 projects were completed in 2016, 4 projects were completed in 2017, two projects were completed in 2018, 1 project was completed in 2019, and 1 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) 2015-2017 Investment Plan

For the period between January 1 and December 31, 2020, SCE expended a total of $3,201,118 toward project costs and $124,982 toward administrative costs for a grand total of $3,326,110. SCE's cumulative expenses over the lifespan of its 2015 – 2017 EPIC program amount to $31,813,481. SCE committed $3,829,533 toward projects and encumbered $1,861,186 through executed purchase orders during this period. SCE has $0 in 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. Project execution activities continued for the remaining 10 projects. Of those ten projects, 1 project was completed in 2017, 3 projects were completed in 2018, 2 projects were completed in 2019, and 1 project was completed in 2020. 3 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

(3) 2018-2020 Investment Plan

For the period between January 1 and December 31, 2020, SCE expended a total of $5,139,969 toward project costs and $999,061 toward administrative costs for a grand total of $6,139,030. SCE's cumulative expenses over the lifespan of its 2018 – 2020 EPIC program amount to $6,082,803. SCE committed $30,533,083 toward projects and encumbered $4,214,909 through executed purchase orders during this period. SCE has $0 in uncommitted EPIC project funding for this period. SCE cancelled 2 projects and has begun executing 17 projects from its approved portfolio, none have yet been completed. SCE's 2018 – 2020 EPIC III program is composed of the following 17 projects for execution:

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

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

During the calendar year 2020, SCE looks forward to continue engaging with the Commission and stakeholders on the EPIC successor program rulemaking. Additionally, SCE will continue to focus on successfully executing the remaining 3 approved project as part of its 2015 – 2017 Investment Plan, as well as executing the 17 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 2020, SCE actively participated in each of the Policy Innovation + Coordination Group (PICG's) Policy + Innovation Partnership Areas and SCE looks forward to participating in the PICG Forum.

SCE will continue its open dialogue with stakeholders through public engagements in 2021 and the Utilities plan to hold a targeted disadvantaged communities EPIC workshop. In this public workshop, as well as the annual symposium, SCE and the other EPIC Administrators will provide stakeholders with an update on EPIC III projects prior to executing, as well as key accomplishments and learnings obtained from their respective EPIC programs.

a) <u>Issues That May Have Major Impact on Progress in Projects</u>

During the upcoming calendar year of 2021, SCE will focus on successfully executing its remaining 7 approved project as part of its EPIC II Investment Plan. Furthermore, SCE will continue executing its 17 approved projects from its EPIC III Investment Plan. While the corona virus did not materially impact SCE's progress toward completing EPIC projects in 2020, SCE will continue monitor for project delays. Lastly, 2020 marks the end of the triennial period for EPIC demonstrations. SCE looks forward working with the Commission in the current rulemaking to continue being an EPIC administrator to continue conducting grid demonstrations for the benefit of customers.

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
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
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
1st triennial (2012-2014)	SCE	Voltage and VAR Control of SCE Transmission System	Energy Resources Integration	This project involves the demonstration of software and hardware products that will enable automated substation volt/var control. Southern California Edison (SCE) will demonstrate a Substation Level Voltage Control (SLVC) unit working with a transmission control center Supervisory Central Voltage Coordinator (SCVC) unit to monitor and control substation voltage. The scope of this project includes systems engineering, testing, and demonstration of the hardware and software that could be operationally employed to manage substation voltage.	8/15/2012	No	Transmission	$ -	$ -	$ 595,576	$ 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
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
1st triennial (2012-2014)	SCE	Distributed Optimized Storage (DOS) Protection & Control Demonstration	Energy Resources Integration	This field demonstration will test end-to-end integration of multiple energy storage devices on a distribution circuit/feeder to provide a turn-key solution that can cost-effectively be considered for SCE's distribution system, where identified feeders can benefit from grid optimization and variable energy resources (VER) integration. To accomplish this, the project team will first identify distribution system feeders where multiple energy storage devices can be operated centrally. Once a feeder is selected, the energy storage devices will be deployed and tested to demonstrate seamless utility integration, control, and operation of these devices using a single centralized controller. At the end of the project, SCE will have established clear methodologies for identifying feeders that can benefit from distributed energy storage devices and will have established necessary standards-based hardware and control function requirements for grid optimization and renewables integration with distributed energy storage devices.	8/15/2012	No	Distribution	$ -	$ -	$ 7,208	$ 65,787	$ 72,995	$ 15,698	TBD	TBD	TBD	TBD	Pay-for-Performance Contracts	SCE has no current patents or licensing agreements signed. Future Intellectual Property is to be determined.	TBD	TBD
1st triennial (2012-2014)	SCE	Dynamic Line Rating	Grid Modernization and Optimization	Transmission line owners apply fixed thermal rating limits for power transmission lines. These limits are based on conservative assumptions of wind speed, ambient temperature and solar radiation. They are established to help ensure compliance with safety codes, maintain the integrity of line materials, and help secure network reliability. Monitored transmission lines can be more fully utilized to improve network efficiency. Line tension is directly related to average conductor temperature. The tension of a power line is directly related to the current rating of the line. This project will demonstrate the CAT-1 dynamic line rating solution. The CAT-1 system will monitor the tension of transmission lines in real-time to calculate a dynamic daily rating. If successful, this solution will allow SCE to perform real-time calculations in order to determine dynamic daily rating of transmission lines, thus increasing transmission line capacity.		No	Distribution	$ -	$ -	$ 399,045	$ 69,556	$ 468,601	$ 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

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
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	$ -	$ -	$ 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
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	$ -		$ 985,987	$ 148,381	$ 1,134,368	$ 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.
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	$ -	$ -	$ 850,922	$ 220,110	$ 1,071,032	$ 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
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
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	TBD	TBD	Pay-for-Performance Contracts	SCE has no current patents or licensing agreements signed. Future Intellectual Property is to be determined.	N/A	N/A

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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	$ -	$ -	$ 599,626	$ 109,470	$ 709,096	$ 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
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
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	$ 498,441	$ 311,188	$ 4,992,993	$ 803,285	$ 5,796,278	$ 386,582	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
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	TBD	Pay-for-Performance Contracts	SCE has no current patents or licensing agreements signed. Future Intellectual Property is to be determined.	Directed Awards Issued to the Following Vendor(s): American Restore, Inc.; Rivcomm, Inc.; California Turbo Inc	N/A

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1st triennial (2012-2014)	SCE	Cyber-Intrusion Auto-Response and Policy Management System (CAPMS)	Cross-Cutting/Foundational Strategies & Technologies	Viasat in partnership with SCE and Duke Energy has been awarded a DOE contract (DE-0E0000675) to deploy a Cyber-intrusion Auto-response and Policy Management System (CAPMS) to provide real-time analysis of root cause, extent and consequence of an ongoing cyber intrusion using proactive security measures. CAPMS will be demonstrated in the SCE Advanced Technology labs at Westminster, CA. The DOE contract value is $6M with SCE & Duke Energy offering a cost share of $1.6M and $1.2M respectively.	7/16/2014	Yes	Grid Operation/Market Design	$ -		$ 1,703,952	$ 105,371	$ 1,809,323	$ 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
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	$ -	$ -	$ 1,175,923	$ 17,911	$ 1,193,834	$ 9,064	TBD	TBD	TBD	TBD	Pay-for-Performance Contracts	SCE has no current patents or licensing agreements signed. Future Intellectual Property is to be determined.	Competitive	1
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	$ 77,718	TBD	TBD	TBD	TBD	Pay-for-Performance Contracts	SCE has no current patents or licensing agreements signed. Future Intellectual Property is to be determined.	TBD	TBD
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	$ -	$ -	$ 1,078,310	$ 107,589	$ 1,185,899	$ 59,315	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

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2nd triennial (2015-2017)	SCE	DC Fast Charging Demonstration	Customer Focused Products and Services	The goal of this project is to demonstrate public DC fast charging stations at SCE facilities near freeways in optimal locations to benefit electric vehicle miles traveled (eVMT) by plug-in electric vehicles (PEVs) while implementing smart grid equipment and techniques to minimize system impact. The Transportation Electrification (TE) Organization is actively pursuing several strategic objectives, including optimizing TE fueling from the grid to improve asset utilization. Deploying a limited number of fast charging stations at selected SCE facilities that are already equipped to deliver power at this level (without additional infrastructure upgrade) will support this objective. The project will leverage SCE's vast service territory and its facilities to help PEV reach destinations that would otherwise be out-of-range	11/16/2015	No	Demand-Side Management	$ -	$ -	$ 11,637	$ 4,324	$ 15,961	$ 7,925	TBD	TBD	TBD	TBD	Pay-for-Performance Contracts	SCE has no current patents or licensing agreements signed. Future Intellectual Property is to be determined.	TBD	TBD
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	$ 725,970	$ 2,323,952	$ 4,985,969	$ 899,438	$ 5,885,407	$ 149,845	TBD	TBD	TBD	TBD	Pay-for-Performance Contracts	SCE has no current patents or licensing agreements signed. Future Intellectual Property is to be determined.	Competitive Bid Directed Awards Issued to the Following Vendor(s): Athena Power, Inc.; G&W Electric Company; Southwest Research Institute	4
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	$ 421,903	$ 262,579	$ 2,332,534	$ 185,200	$ 2,517,734	$ 113,766	TBD	TBD	TBD	TBD	Pay-for-Performance Contracts	SCE has no current patents or licensing agreements signed. Future Intellectual Property is to be determined.	Competitive Bid Directed Awards Issued to the Following Vendor(s): GENERAL NETWORKS, TESCO AUTOMATION LTD, MORRIS & WILLNER PARTNERS,	N/A
2nd triennial (2015-2017)	SCE	Regulatory Mandates: Submetering Enablement Demonstration - Phase 2	Customer Focused Products and Services	This project expands on the submetering project from the first EPIC triennial investment plan cycle to demonstrate plug-in electric vehicle (PEV) submetering at multi-dwelling and commercial facilities. Specifically, the project will leverage 3rd party metering to conduct subtractive billing for various sites including those with multiple customers of record	11/17/2014	Yes	Demand-Side Management	$ -	$ -	$ 1,097,308	$ 133,400	$ 1,230,708	$ 31,694	TBD	TBD	TBD	TBD	Pay-for-Performance Contracts	SCE has no current patents or licensing agreements signed. Future Intellectual Property is to be determined.	TBD	TBD

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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	$ 6,523	TBD	TBD	TBD	TBD	Pay-for-Performance Contracts	SCE has no current patents or licensing agreements signed. Future Intellectual Property is to be determined.	Non-Competitive Nayak Corporation Inc	NA
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	$ -		$ -	$ 5,683	$ 5,683	$ 1,903	TBD	TBD	TBD	TBD	Pay-for-Performance Contracts	SCE has no current patents or licensing agreements signed. Future Intellectual Property is to be determined.	TBD	TBD
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	$ -	$ -	$ 1,056,503	$ 69,442	$ 1,125,945	$ 55,288	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
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	$ 1,994	$ 48,006	$ 883,776	$ 16,819	$ 900,595	$ 9,250	TBD	TBD	TBD	TBD	Pay-for-Performance Contracts	SCE has no current patents or licensing agreements signed. Future Intellectual Property is to be determined.	TBD	TBD

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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	$ -		$ 138,288	$ 1,295	$ 139,583	$ 1,222	TBD	TBD	TBD	TBD	Pay-for-Performance Contracts	SCE has no current patents or licensing agreements signed. Future Intellectual Property is to be determined.	TBD	TBD
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	$ 711,319	$ 1,194,996	$ 16,591,028	$ 800,453	$ 17,391,481	$ 409,730	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
3rd triennial (2018-2020)	SCE	Advanced Comprehensive Hazards Tool	Grid Modernization and Optimization	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	$ -	$ 883,270	$ 244,706	$ 5,569	$ 250,275	$ 976	None	None	N/A	N/A	N/A	Unknown	Competitive bid for technical services	N/A - In progress. Bidders list is not yet created
3rd triennial (2018-2020)	SCE	Advanced Data Analytics Technologies (ADAT)	Grid Modernization and Optimization	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	$ -	$ 8,491	$ 271,642	$ 7,209	$ 278,851	$ 1,271	None	None	N/A	N/A	N/A	UnKnown	Competitive bid for technical services	5

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3rd triennial (2018-2020)	SCE	Advanced Technology for Field Safety (ATFS)	Grid Modernization and Optimization	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	$ -	$ 837,782	$ 59,475	$ 2,362	$ 61,837	$ 407	None	TBD	N/A	N/A	TBD	Unknown	TBD	TBD
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	$ -	$ 490,484	$ 4,472	$ 5,047	$ 9,519	$ 920	None	TBD	N/A	N/A	TBD	TBD	TBD	TBD
3rd triennial (2018-2020)	SCE	Control and Protection for Microgrids and Virtual Power Plants	Grid Modernization and Optimization	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	$ -	$ 2,136,745	$ 404,205	$ 27,540	$ 431,745	$ 5,287	None	TBD	N/A	N/A	TBD	TBD	TBD	TBD
3rd triennial (2018-2020)	SCE	Cybersecurity for Industrial Control Systems	Cybersecurity	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	$ 2,051,384	$ 692,868	$ 1,198,986	$ 6,762	$ 1,205,748	$ 1,342	None	None	N/A	N/A	N/A	Unknown	Competitive bid for technical services	3

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3rd triennial (2018-2020)	SCE	Distributed Cyber Threat Analysis Collaboration	Cybersecurity	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	$ 924,240	$ 288,326	$ 673,059	$ 14,375	$ 687,434	$ 2,760	None	None	N/A	N/A	N/A	Unknown	Competitive bid for technical services	3
3rd triennial (2018-2020)	SCE	Distributed Energy Resources Dynamics Integration Demonstration	Renewables/DER Resource 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	$ 830,000	$ 202,069	$ 171,742	$ 13,898	$ 185,640	$ 2,601	None	None	N/A	N/A		Unknown	Competitive bid for technical services	5
3rd triennial (2018-2020)	SCE	Distributed PEV Charging Resource	Grid Modernization and Optimization	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	$ -	$ 1,062,067	$ 294,799	$ 16,134	$ 310,933	$ 3,025	None	TBD	N/A	N/A	TBD	TBD	TBD	TBD
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	$ -	$ -	$ 66,233	$ 1,907	$ 68,140	$ 330	None	None	N/A	N/A	TBD	TBD	TBD	TBD

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3rd triennial (2018-2020)	SCE	Power System Voltage and VAR Control Under High Renewables Penetration	Renewables/DER Resource Integration	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	$ -	$ 12,940	$ 175,070	$ 5,907	$ 180,977	$ 1,054	None	None	N/A	N/A	TBD	TBD	TBD	TBD
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	$ 409,285	$ 4,240,982	$ 631,913	$ 88,144	$ 720,057	$ 46,187	None	TBD	N/A	N/A	TBD	Unknown	TBD	TBD
3rd triennial (2018-2020)	SCE	Service Center of the Future	Grid Modernization and Optimization	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	$ -	$ 3,700,130	$ 383,015	$ 18,855	$ 401,870	$ 3,587	None	TBD	N/A	N/A	TBD	TBD	TBD	TBD
3rd triennial (2018-2020)	SCE	Smart City Demonstration	Grid Modernization and Optimization	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		$ 3,921,731	$ 482,033	$ 32,861	$ 514,894	$ 6,232	None	TBD	N/A	N/A	TBD	TBD	TBD	TBD

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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	$ -	$ 1,381,999	$ 154,429	$ 9,448	$ 163,877	$ 1,884	None	TBD	N/A	N/A	TBD	Unknown	TBD	TBD
3rd triennial (2018-2020)	SCE	Vehicle-to-Grid Integration Using On-Board Inverter	Grid Modernization and Optimization	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	$ -	$ 2,516,531	$ 321,924	$ 15,545	$ 337,469	$ 2,886	None	TBD	N/A	N/A	TBD	TBD	TBD	TBD
3rd triennial (2018-2020)	SCE	Energy System Cybersecurity Posturing	Cybersecurity	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	$ -	$ -	$ -	$ 13,034	$ 13,034	$ 2,274	None	None	N/A	N/A	N/A	Unknown	Project not advanced (Cancelled)	N/A
3rd triennial (2018-2020)	SCE	Wildfire Prevention & Resiliency Technology Demonstration	Addressing Wildfire Risk	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.				$ -	$ 5,649,367	$ 39,589	$ 5,519	$ 45,108	$ 1,258								

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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. 3) High Impedance Fault Detector – a reflectometry-based technology solution to detect high impedance faults on distribution circuits. Demonstrating the technology at Shawnee Substation Test Facility on an energized distribution circuit, finalizing algorithm and a hardware deployable detector, and finalize system design ready for system-wide deployment on distribution circuits. Improve public safety 4) Predictive Equipment Failure – This Failure Project will implement a pilot on distribution circuits to demonstrate technologies that can monitor and assess SCE equipment (cable, splices, transformers, switches etc.) and indicate			Distribution	$ -	$ 2,507,301	$ 180,677	$ 34,718	$ 215,395	$ 6,634								

Investment Program Period	Program Administrator	Project Name	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
1st triennial (2012-2014)	SCE	Integrated Grid Project Note: Previously referred to as Regional Grid Optimization	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 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)
1st triennial (2012-2014)	SCE	Beyond the Meter: Customer Device Communications, Unification and Demonstration (Phase II)	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); 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 wide spread deployment or technologies included in
1st triennial (2012-2014)	SCE	Voltage and VAR Control of SCE Transmission System	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).
1st triennial (2012-2014)	SCE	State Estimation Using Phasor Measurement Technologies	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).
1st triennial (2012-2014)	SCE	Distributed Optimized Storage (DOS) Protection & Control Demonstration	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.
1st triennial (2012-2014)	SCE	Dynamic Line Rating	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)

Investment Program Period	Program Administrator	Project Name	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
1st triennial (2012-2014)	SCE	Next-Generation Distribution Automation	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).
1st triennial (2012-2014)	SCE	Regulatory Mandates: Submetering Enablement Demonstration	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
1st triennial (2012-2014)	SCE	Distribution Planning Tool	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).
1st triennial (2012-2014)	SCE	Portable End-to-End Test System	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).
1st triennial (2012-2014)	SCE	Superconducting Transformer (SCX) Demo	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

Investment Program Period	Program Administrator	Project Name	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
1st triennial (2012-2014)	SCE	Wide-Area Reliability Management & Control	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
1st triennial (2012-2014)	SCE	Outage Management and Customer Voltage Data Analytics Demonstration	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.
1st triennial (2012-2014)	SCE	SA-3 Phase III Demonstration	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).
1st triennial (2012-2014)	SCE	Enhanced Infrastructure Technology Evaluation	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.

Investment Program Period	Program Administrator	Project Name	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
1st triennial (2012-2014)	SCE	Cyber-Intrusion Auto-Response and Policy Management System (CAPMS)	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.
2nd triennial (2015-2017)	SCE	Integration of Big Data for Advanced Automated Customer Load Management	Kitu, Inc	TBD	TBD	N/A; Applicable to CEC only.	Small Business	N/A; Applicable to CEC only.	Metrics plan TBD
2nd triennial (2015-2017)	SCE	Advanced Grid Capabilities Using Smart Meter Data	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
2nd triennial (2015-2017)	SCE	Proactive Storm Impact Analysis Demonstration	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)

Investment Program Period	Program Administrator	Project Name	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
2nd triennial (2015-2017)	SCE	DC Fast Charging Demonstration	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
2nd triennial (2015-2017)	SCE	Next-Generation Distribution Equipment & Automation - Phase 2	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)
2nd triennial (2015-2017)	SCE	System Intelligence and Situational Awareness Capabilities	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
2nd triennial (2015-2017)	SCE	Regulatory Mandates: Submetering Enablement Demonstration - Phase 2	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)

Investment Program Period	Program Administrator	Project Name	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
2nd triennial (2015-2017)	SCE	Bulk System Restoration Under High Renewables Penetration	NA	NA	NA	N/A; Applicable to CEC only.	Nayak Corporation - NA	N/A; Applicable to CEC only.	Metrics plan TBD
2nd triennial (2015-2017)	SCE	Series Compensation for Load Flow Control (Power Flow Control with TCSC)	TBD	TBD	TBD	N/A; Applicable to CEC only.	TBD	N/A; Applicable to CEC only.	Metrics plan TBD
2nd triennial (2015-2017)	SCE	Versatile Plug-in Auxiliary Power System (VAPS)	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
2nd triennial (2015-2017)	SCE	Dynamic Power Conditioner	TBD	TBD	TBD	N/A; Applicable to CEC only.	TBD	N/A; Applicable to CEC only.	Metrics plan TBD

Investment Program Period	Program Administrator	Project Name	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
2nd triennial (2015-2017)	SCE	Optimized Control of Multiple Storage Systems	TBD	TBD	TBD	N/A; Applicable to CEC only.	TBD	N/A; Applicable to CEC only.	Metrics plan TBD
2nd triennial (2015-2017)	SCE	Integrated Grid Project II (filed as Regional Grid Optimization Demo)	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 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);
3rd triennial (2018-2020)	SCE	Advanced Comprehensive Hazards Tool	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
3rd triennial (2018-2020)	SCE	Advanced Data Analytics Technologies (ADAT)	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

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3rd triennial (2018-2020)	SCE	Advanced Technology for Field Safety (ATFS)	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
3rd triennial (2018-2020)	SCE	Beyond Lithium-ion Energy Storage Demo	TBD	TBD	TBD	TBD	TBD	N/A; Applicable to CEC only.	TBD
3rd triennial (2018-2020)	SCE	Control and Protection for Microgrids and Virtual Power Plants	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) 8b. Number of reports and fact sheets published online 8e. Stakeholders attendance at workshops 8f. Technology transfer
3rd triennial (2018-2020)	SCE	Cybersecurity for Industrial Control Systems	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

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3rd triennial (2018-2020)	SCE	Distributed Cyber Threat Analysis Collaboration	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
3rd triennial (2018-2020)	SCE	Distributed Energy Resources Dynamics Integration Demonstration	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
3rd triennial (2018-2020)	SCE	Distributed PEV Charging Resource	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
3rd triennial (2018-2020)	SCE	Distribution Primary & Secondary Line Impedance	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

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3rd triennial (2018-2020)	SCE	Power System Voltage and VAR Control Under High Renewables Penetration	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)
3rd triennial (2018-2020)	SCE	SA-3 Phase III Field Demonstrations	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
3rd triennial (2018-2020)	SCE	Service Center of the Future	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) 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
3rd triennial (2018-2020)	SCE	Smart City Demonstration	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 Commission approval of utility proposals for wide spread 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

Investment Program Period	Program Administrator	Project Name	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
3rd triennial (2018-2020)	SCE	Storage-Based Distribution DC Link	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
3rd triennial (2018-2020)	SCE	Vehicle-to-Grid Integration Using On-Board Inverter	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 9a. Description/documentation of projects that progress deployment, such as Commission approval of utility proposals for wide spread 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
3rd triennial (2018-2020)	SCE	Energy System Cybersecurity Posturing	N/A	N/A	N/A	N/A	N/A	N/A; Applicable to CEC only.	N/A - Project was cancelled
3rd triennial (2018-2020)	SCE	Wildfire Prevention & Resiliency Technology Demonstration							TBD

Investment Program Period	Program Administrator	Project Name	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
3rd triennial (2018-2020)	SCE	Next Generation Distribution Automation III							TBD

Investment Program Period	Program Administrator	Project Name	2020 Update	Coordination with CPUC Proceedings or Legislation
1st triennial (2012-2014)	SCE	Integrated Grid Project Note: Previously referred to as Regional Grid Optimization		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)	N/A	
1st triennial (2012-2014)	SCE	Voltage and VAR Control of SCE Transmission System	N/A	
1st triennial (2012-2014)	SCE	State Estimation Using Phasor Measurement Technologies	N/A	
1st triennial (2012-2014)	SCE	Distributed Optimized Storage (DOS) Protection & Control Demonstration	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	N/A	

Investment Program Period	Program Administrator	Project Name	2020 Update	Coordination with CPUC Proceedings or Legislation
1st triennial (2012-2014)	SCE	Next-Generation Distribution Automation	N/A	
1st triennial (2012-2014)	SCE	Regulatory Mandates: Submetering Enablement Demonstration		
1st triennial (2012-2014)	SCE	Distribution Planning Tool	N/A	Distribution Resources Plan, R.14-08-013; A.15-07-003
1st triennial (2012-2014)	SCE	Portable End-to-End Test System	N/A	
1st triennial (2012-2014)	SCE	Superconducting Transformer (SCX) Demo	N/A	N/A - Cancelled.

Investment Program Period	Program Administrator	Project Name	2020 Update	Coordination with CPUC Proceedings or Legislation
1st triennial (2012-2014)	SCE	Wide-Area Reliability Management & Control	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	N/A	
1st triennial (2012-2014)	SCE	SA-3 Phase III Demonstration	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.	NA
1st triennial (2012-2014)	SCE	Enhanced Infrastructure Technology Evaluation	N/A	

Investment Program Period	Program Administrator	Project Name	2020 Update	Coordination with CPUC Proceedings or Legislation
1st triennial (2012-2014)	SCE	Cyber-Intrusion Auto-Response and Policy Management System (CAPMS)	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	N/A	
2nd triennial (2015-2017)	SCE	Advanced Grid Capabilities Using Smart Meter Data	N/A	
2nd triennial (2015-2017)	SCE	Proactive Storm Impact Analysis Demonstration	N/A	Distribution Resources Plan, R.14-08-013; A.15-07-003 Integrated Demand-side Resource Program, R.14-10-003

Investment Program Period	Program Administrator	Project Name	2020 Update	Coordination with CPUC Proceedings or Legislation
2nd triennial (2015-2017)	SCE	DC Fast Charging Demonstration	N/A	
2nd triennial (2015-2017)	SCE	Next-Generation Distribution Equipment & Automation - Phase 2	2020 Accomplishments: Remote Integrated Switch (RIS): The RIS team successfully demonstrated DNP3-based decentralized FLISR scheme and identified scalability issues to be resolved in Phase 3 (which will demonstrate a high-speed/GOOSE solution). The team created a circuit-based topology to demonstrate the feature enhancements and a new RTDS model, new circuit-based system design, logic template files based on the new scalability requirements. Preparations for the Phase 3 demonstration has started. The Phase 3 will demonstration advanced features which address system scalability and usability concerns identified by stakeholders in previous demonstrations. High Impedance Fault Detection: The validation test scope was developed and revised however there have been delays with getting the purchase order approved with Southwest Research Institute due to enhanced Cyber Security policies which are requiring additional T's and C's. Contract negotiations are continuing and hope to be resolved and testing to commence in the 1st quarter of 2021. Underground/Overhead Remote Fault Indicator: The RFI team installed 12 overhead RFI systems on different circuits to demonstrate the various specifications including operation on covered conductors, paralleled circuitry or looped circuits, detection of reverse power flow, operation on circuits with low minimum current less than 5A, operation on 33kV lines with high EMF and extreme temperatures. The systems were monitored through 2020 and was able to capture seven sustained fault events and multiple momentary fault events. The team also demonstrated an overhead transmission fault indicator and identified that the system was not able to fully meet Sub Transmission requirements. Based on the results recommendations were made to the manufacturer to improve system. These recommendations resulted in a revised version by the manufacturer which was tested in the Q3 2020 and met all Sub Transmission requirements. The RFI team worked with the manufacturer to resolve failures of the both the submersible and non-submersible Underground RFI systems. The resultant upgraded hardware was lab tested and verified. Additionally, previous 54 installation locations updates due to new Standards committee's requirements. Some sites required both a hardware and firmware update. The updates were delayed due to Covid-19 impacts and are scheduled to complete by Q2 2021. Submersion testing of the latest revision of a second manufacturers submersible system were successful and were also scheduled to replace previously installed units. These installations were delayed due to Covid-19 and are also scheduled for completion by Q2 2021.	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	Substation Test Tools In 2020, the objective was to test and demonstrate a substation test tool capable of automating the test process for IEC 61850 IEDs and HMI and the PLC. The results of this project include the ability to implement a test tool that improves the efficiency of what are today time and labor-intensive test processes. Automating test processes allows for more thorough validation of substation configurations while reducing the amount of resources expended to complete testing. The project had a milestone in 2020 to deliver training on the tool to the Control and Meter Asset Engineering team. Due to COVID 19 travel and in-person meeting restrictions, this training was postponed until late 2020 and moved to an online format so the project milestone was still achieved in 2020. As a lesson learned, The Substation Demonstrations team attempted to demonstrate the tool for a larger substation, the application may require additional processing power. Possible solutions to this include splitting up the substation and running the test tool on two machines or obtaining a computer with additional processing capabilities. Process Bus The Mayberry process bus and optical CT project was successfully commissioned in June 2019 with a evaluation period that ended in March 2020. The objective was to demonstrate new optical sensing technologies with the IEC-61850 process bus standard. Throughout the duration of the pilot project, several operations occurred which provided valuable data in analyzing the behavior of the optical sensing and digital communications. Ultimately, the technology proved successful and worked as intended. The numerous lessons learned will be applied to future process bus projects. Additionally, the findings were presented at various conferences with the collaboration of the manufacturer. Fully Digital Substation The fully digital substation project is intended to demonstrate a complete IEC-61850 substation with process bus technology. In late 2019, lab demonstration design was finalized and throughout 2020, the system was installed and configured per the design in a laboratory. Since new devices were installed, a cyber assessment was required in order to identify any potential vulnerabilities. This was successfully completed in Q4 2020. Additionally, a unique network design was developed and completed with the collaboration of SCE's SmartGrid and Enterprise Networking personnel. The goal is to eventually deploy a full station to the field based on a successful lab demonstration. A preminary list of candidate substations has also been derived through this effort. The lab demonstration will continue throughout and is planned to be completed by late 2021	NA
2nd triennial (2015-2017)	SCE	Regulatory Mandates: Submetering Enablement Demonstration - Phase 2	N/A	

Investment Program Period	Program Administrator	Project Name	2020 Update	Coordination with CPUC Proceedings or Legislation
2nd triennial (2015-2017)	SCE	Bulk System Restoration Under High Renewables Penetration	N/A	
2nd triennial (2015-2017)	SCE	Series Compensation for Load Flow Control (Power Flow Control with TCSC)	N/A	
2nd triennial (2015-2017)	SCE	Versatile Plug-in Auxiliary Power System (VAPS)	N/A	
2nd triennial (2015-2017)	SCE	Dynamic Power Conditioner	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.	NA

Investment Program Period	Program Administrator	Project Name	2020 Update	Coordination with CPUC Proceedings or Legislation
2nd triennial (2015-2017)	SCE	Optimized Control of Multiple Storage Systems	N/A	
2nd triennial (2015-2017)	SCE	Integrated Grid Project II (filed as Regional Grid Optimization Demo)	2020 Accomplishments are: 1) Controller Communication Design and Testing – Complete 2) Adaptive Protection System - Complete 3) EPRI - Complete 4) NODES NREL - Complete 5) NODES GE - Complete 6) Integrated Grid Analytics - Complete 7) EASE (underway - covered in the below section) - demonstrated DER Market Services in support of high penetration PV scenarios to refine use cases on voltage and current constraint management as well as feeder net load management. - defined the initial DER market-based services platform that will support the overall project architecture for the field deployment. - demonstrated DER market-based use cases using real-time software in the loop (SIL) testing scenarios and validated DSO-focused use cases in a real-time scenario. - Completed Cyber Risk Assessment and Network Design was completed to detail the security design solution for integrating a third-party DER aggregator with Southern California Edison's Data Center.	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	The Project Execution work has launched: •Completed 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 for •Completed Project's Detailed Use Case and Requirements document illustrating scope, actors, assumptions, use cases, step by step analysis, and alternative scenarios.	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)	The Project Execution work was launched on 02/27/2020 but placed on hold as of 12/1/2020 due to budget constraints. • Completed approval of Concept of Operations moving project from Planning to Execution. • Completed development of detailed use-case and requirements including business objectives and performance metrics for the analytic model results. • Completed architecture vision document (AVD). • Competed Data Criticality Assessment • Completed RFP launch with 5 proposals received. Interviewed and technically scored all bidders and selected highest scoring bidder, Tagup Inc. • SCE was in the process of negotiating a contracted with Tagup when the project was placed on hold. • Tagup is currently seeking a funding opportunity through the DOE SBIR grant. • SCE is investigating methods to reduce internal project costs. If costs can be reduced enough, there is potential to continue the project mid 2021. Key Findings & Lessons Learned • There are many analytic vendors interested in this topic but few have demonstrated the prediction of transformer remaining useful life without dissolved gas analysis samples (DGA). DGA samples are not available for SCE's distribution transformers. • All analytic vendors interviewed prefer the use of cloud computing which required SCE to upload data to their cloud platform. Cloud platforms varied by vendor. • Requiring the vendors to build the solution within SCE's environment was not preferred by vendors due to the amount of architecture customization required. • SCE prefers to move the analytics close to the data rather than send large amounts of data to a vendor. The conflict between the vendors' and SCE's preferred method makes the project difficult to accomplish in a low cost manner. • Developing an efficient/low cost method of secure data sharing is critical for the project's success as a Proof-of-Concept.	Commission proceedings to support will be determined through the course of the project.

Investment Program Period	Program Administrator	Project Name	2020 Update	Coordination with CPUC Proceedings or Legislation
3rd triennial (2018-2020)	SCE	Advanced Technology for Field Safety (ATFS)	The Project Execution work has launched: •Completed 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 for Augmented Reality. •Completed Project's Detailed Use Case and Requirements document illustrating scope, actors, assumptions, use cases, step by step analysis, and alternative scenarios. •Developed Project's system engineering artifact System Requirement Document (SRD) describing functional and non-functional requirements for the system and sub-system/application.	
3rd triennial (2018-2020)	SCE	Beyond Lithium-ion Energy Storage Demo	• This project is in the Planning phase • Currently looking into potential partners and their respective (beyond lithium ion) battery technology	
3rd triennial (2018-2020)	SCE	Control and Protection for Microgrids and Virtual Power Plants	The Project Execution work has launched: •Completed 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. •Completed Project's Detailed Use Case and Requirements document illustrating scope, actors, assumptions, six microgrid use cases, step by step analysis, and alternative scenarios. •Completed Project's Architectural Vision Document (AVD) defining the solution overview, business impact, architecture considerations, system context, assumptions, constraints, dependencies, and risks analysis. •Developed Project's system engineering artifact System Requirement Document (SRD) describing functional and non-functional requirements for the system and sub-system/application. •Launched development of Project's architecture artifacts Lab Architecture Briefs (LAB) and System Architecture Design (SAD). •An RFP package to engage a Microgrid Control System Vendor (software and hardware) was issued. The vendor selection process was completed, and a tentative vendor has been selected pending final negotiations. Vendor onboarding scheduled 1Q 2021. Key Findings and Lessons Learned •Leverage combined architecture and vendor synergies with other EPIC III Microgrid Projects for cost efficiency and to accomplish goals. •With DoD cancelling their Ft. Irwin's Microgrid Project, QA & Field elements will be demonstrated through the Smart City Project. An alternative software Microgrid test model has been selected, which will be used for the testbed testing and validation activities. •ARIBA system: The vendor database was not current, and some vendors had to be contacted directly by phone or email. Discussions initiated on how to improve this system. •Demonstrations & discussions after selecting the top vendor candidates: having a live demonstration was beneficial in the decision-making process.	This demonstration will identify challenges and protection requirements to enable safe microgrid operation, supporting the Commission's Microgrid rulemaking. The lea rnings 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	The Project Execution work has launched: • Assembled project execution team in March 2020. Team delivered a project overview which included goals, updated execution schedule, and six use case overviews. A project communication plan was also developed identifying key communication resources and schedules • In response to Covid-19, constructed a remotely accessible lab environment leveraging the facilities and infrastructure in our vendor's Houston Operational Technology Cyber Fusion Center replicating SCE's Operational Technology (OT) production environment • Team identified forty viable solutions for adaptive controls and dynamic zoning across four use cases, • Created a Test Case Results document which aggregates all test case results providing overviews of each use case, allowing easy recreation of tests and replication of results for future programs' use. • Identified sixteen complex test cases centered around various networking scenarios and radio applications programs, as well as a combinations of IT techniques providing defense-in-depth responses to cyber threats to the operational technology environment Key Findings and Lessons Learned •Numerous test cases proved viable in responding to cyber threats, executed simultaneously providing a multifaceted defense-depth approach to threat response •In response to COVID restrictions, an agile approach to project execution proved beneficial in achieving milestones •Building a lab that accurately reflected the functionality and diversity of the OT environment was difficult. It requires specialized equipment and testing that are not commonly found for cybersecurity testing	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.

Investment Program Period	Program Administrator	Project Name	2020 Update	Coordination with CPUC Proceedings or Legislation
3rd triennial (2018-2020)	SCE	Distributed Cyber Threat Analysis Collaboration	The Project Execution work has launched: •Assembled project execution team in March 2020. Team delivered a project overview which included goals, updated execution schedule, and six use case overviews. A project communication plan was also developed identifying key communication resources and schedules •Developed test environment in a digital only virtualized environment allowing portability between cloud vendors and virtualization software, also allowing porting to either self-hosted or cloud infrastructure, enabling scaling based on business needs •Leveraged CTI (Cyber Threat Intelligence) platform to demonstrate program impact. The tool allowed visibility into the code base, allowing customized development for DCTAC specific requirements. As an open-source solution, OpenCTI environment was vetted within SCE to ensure compliance with EPIC and SCE intellectual property and security requirements •Completed the existing process review and began detailing proposed automation. Identified three initial areas where automation can increase the speed and efficiency of this process: data ingestion, data triage, and data sharing. Improvements in these areas will lead to increased process efficiency and decreased dwell time for appropriate actions to occur Key Findings and Lessons Learned •The expected execution date was delayed due to the specificity of skill sets and knowledge base that was difficult to match. Very few vendors possessed the immediate knowledge and product experience necessary to meet the requirements of the project at the outset •Multiple versions of the STIX programming language being used introduced compatibility issues. The team addressed this by customizing backend connectors to account for the data irregularities •Identified that alternative threat intelligence sources, such as vendor bulletins and email distribution lists, can provide actionable intelligence that should be incorporated into the DCTAC process. An RSS feed connector is currently under development, and the code can be contributed back to the OpenCTI project under the OASIS organization, if approved.	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	The project execution work has launched: 1.Completed Project's Detailed Use Case and Requirements document illustrating scope, actors, assumptions, eight smart inverter use cases, step by step analysis, and scenarios. 2.Completed Project's Lab Architecture Brief (LAB) defining the solution overview, business impact, architecture considerations, system context, assumptions, constraints, dependencies, and risks analysis. 3.Completed an RFP, and the vendor selection process was completed. An interim PO has been issued to the vendor pending the final negotiations. Vendor onboarding scheduled for Q1 2021. 4.Designed and developed the testing platform in the SCE's DER Laboratory that can support the project demonstration. 5.Communicated project objective and deliverables to PG&E, SDG&E, & Rule 21 working group and added them as external stakeholders in the project. 6.Submitted an IEEE conference paper based on preliminary modeling, simulation, and experimental results; results validated modeling. Md Arifujjaman, Roger Salas, Anthony P. Johnson, Austen D'Lima, Jorge Araiza, Josh Mauzey, Juan Castaneda, "Modeling and Development of a HIL Testbed for DER Dynamics Integration Demonstration," IEEE Green Energy and Smart Systems Conference (IGESSC), Long Beach, CA, USA 2020 Key Findings and Lessons Learned 1.The developed smart inverter numerical model for this project is very capable of reflecting the inverter characteristics, although dynamics need to be included to reflect the transient phenomena. 2.Very few vendors can model, simulate, and demonstrate the high-fidelity dynamics model on a simulation and demonstration platform. 3.Inverter manufacturers are reluctant to provide the high-fidelity inverter model with advanced functions, as required by the project. 4.The presently used in-house inverter model would need to be upgraded to articulate a physical inverter's dynamics. 5.The vendor database was not current, and some vendors had to be contacted directly by phone or email. Discussions initiated on how to improve this system. 6.Demonstrations & discussions after short listing the top vendor candidates: having an in depth technical call with the vendors was beneficial in the vendor selection process.	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.
3rd triennial (2018-2020)	SCE	Distributed PEV Charging Resource	The Project Execution work has launched: • Completed 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. • Completed Project's Detailed Use Case and Requirements document illustrating scope, actors, assumptions, use cases, step by step analysis, and alternative scenarios. • Completed Project's Architectural Vision Document (AVD) defining the solution overview, business impact, architecture considerations, system context, assumptions, constraints, dependencies, and risks analysis. • Developed Project's system engineering artifact System Requirement Document (SRD) describing functional and non-functional requirements for the system and sub-system/application. • Launched development of Project's architecture artifacts Lab Architecture Briefs (LAB) and System Architecture Design (SAD). • An RFI package to identify existing High Energy Charging Systems coupled with Energy storage was performed. Key Findings and Lessons Learned • 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. •As such the Project is: o Being changed to a lab only demonstration to obtain the necessary technology and interconnection learnings in anticipation of the anticipated expansion on the grid of medium duty transportation electrification. o Exploring partnering with an OEM on second-life projects with SCE service territory.	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	• Completed 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.	

Investment Program Period	Program Administrator	Project Name	2020 Update	Coordination with CPUC Proceedings or Legislation
3rd triennial (2018-2020)	SCE	Power System Voltage and VAR Control Under High Renewables Penetration	The Project Execution work was launched on 12/18/2019:•Completed 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. •Completed Project's Detailed Use Case and Requirements document illustrating scope, actors, assumptions, use cases, step by step analysis, and alternative scenarios. •Completed the RFI and RFP processes with 5 vendors and short listed 2 vendors; one of which is a National Lab •Since this is a lab demonstration only, completed Project's Lab Architecture Brief (LAB) defining the lab impacts, architecture considerations, lab infrastructure, technology, & configuration detail, system context, assumptions, constraints, dependencies, and risks analysis. •Developed Project's system engineering artifact System Requirement Document (SRD) describing functional and non-functional requirements for the system and sub-system/application. Key Findings and Lessons Learned •Technical work expected to start in 2021 •Contracting with a national lab like NREL is very challenging; labs are subject to DOE requirements which conflict with EPIC flow downs regarding IP ownership and licensing •Additional scope is being evaluated to update the model of SCE's Bulk Power System in the RTDS environment.	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	The Project Execution work has launched: •Completed 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 for the evaluation of the IEC 61850 Programmable Automation Controller (PAC), the Virtual Substation Relay Proof-of-Concept, and the Resonant Grounding with an arc suppression coil (ASC) •Completed Project's Detailed Use Case and Requirements document illustrating scope, assumptions, step by step analysis, and alternative scenarios. •Designed and started implementation of target system in the lab, includes wiring equipment following SA3 standards, energizing devices, and creating a test network to support remote testing while work from home orders are in place. •Maintained a direct line of communication with main stakeholders and project team by way of weekly update meetings and regularly scheduled working sessions throughout the year. •Completed Project's architecture artifacts Lab Architecture Briefs (LAB) defining the solution overview, business impact, architecture considerations, system context, assumptions, constraints, dependencies, and risks analysis for the Programmable Logic Controllers (PLC). The outcome of the project will provide SCE's Control & Meter Asset Engineering users the ability to design and test a substation utilizing an IEC 61850 capable PAC. Key Findings and Lessons Learned: (IEC 61850 PAC) •As we progress through the project work, we must remain aligned with some CMAE efforts where we have had the opportunity to give and receive feedback on our device configurations as it concerns "Ultimate Datasets" work. •During testing, some of our assumptions were found to be untrue and we have had to work with the vendor to resolve issues or get a better understanding of some of the network properties of the equipment. Various firmware versions were tested by the vendor to provide an adequate solution. •The idea of a "version lock" for software or firmware has not concerned previous efforts in this space regarding new device types, but testing has forced us to raise this concern and promote quality checks for software and firmware versions. •There are other organizations and efforts that will rely on the outcome of this lab demonstration and we have had to pivot or change priority while working on specific configurations for various device types. •With new devices being introduced, it has almost become expected that one vendor will not implement the IEC61850 standard the same way as a second vendor. We're continuing to broaden our knowledge of the 61850 standard and how it can be used across various device types	CPUC proceedings to support will be determined through the course of the project.
3rd triennial (2018-2020)	SCE	Service Center of the Future	The Project Execution work has launched: •Completed 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. •Completed Project's Detailed Use Case and Requirements document illustrating scope, actors, assumptions, six microgrid use cases, step by step analysis, and alternative scenarios. •Completed Project's Architectural Vision Document (AVD) defining the solution overview, business impact, architecture considerations, system context, assumptions, constraints, dependencies, and risks analysis. •Developed Project's system engineering artifact System Requirement Document (SRD) describing functional and non-functional requirements for the system and sub-system/application. •Launched development of Project's architecture artifacts Lab Architecture Briefs (LAB) and System Architecture Design (SAD). •Identified LA Metro El Monte Fleet Service Yard as the Field Pilot location. oCompanion efforts at LA Metro site: T&D Customer Interconnections/Method of Service completed a Method of Service Study which proposed sub transmission service and a customer owned substation to LA Metro for future expansion beyond initial 100 buses incorporated into project plans. SCE Charge Ready Project at site, first 60 Electric buses scheduled to be delivered one year from now. Submetering architecture design completed. Building electrification components and requirements known. •An RFP package to engage a Microgrid Control System Vendor (software and hardware) issued. Vendor onboarding scheduled 1Q 2021 •Launched partnership with SCE's Energy Storage Integration Program for front-of-the-meter energy storage to support fleet charging resiliency and islanding capabilities. Completed initial site assessment and reached agreement on siting and infrastructure arrangement. •Studied EV charging equipment proposed by LA Metro to learn characteristics and control capabilities •Worked with Build Your Dreams (BYD) and partners to install prospective charger at BYD's Lancaster CA Electric Bus factory ready for SCE inspection. •Worked with meter services to understand advanced metering future prospects and aligned on submetering strategy. Key Findings and Lessons Learned •Leverage combined architecture and vendor synergies with other EPIC III Microgrid Projects for cost efficiency and to accomplish goals. •With the COVID pandemic, we learned that public transportation, including LA Metro, ridership has fallen by approximately 85%. How this will affect their overall fleet electrification goals and EPIC III Field Pilot, beyond 60 busses already purchased, is yet TBD, but new operations are to be captured	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	The Project Execution work has launched: • Completed 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. • Completed Project's Detailed Use Case and Requirements document illustrating scope, actors, assumptions, six microgrid use cases, step by step analysis, and alternative scenarios. • Completed Project's Architectural Vision Document (AVD) defining the solution overview, business impact, architecture considerations, system context, assumptions, constraints, dependencies, and risks analysis. • Developed Project's system engineering artifact System Requirement Document (SRD) describing functional and non-functional requirements for the system and sub-system/application. • Launched development of Project's architecture artifacts Lab Architecture Briefs (LAB) and System Architecture Design (SAD). • Selected the partnering Local Agency for the Project's demonstration leveraging a selection process using criteria such as Disadvantage Community, strong interest in developing critical/essential facility Microgrids, and existing/planned customer-owned Distributed Energy Resources (DERs). • Launched regular meetings with Local Agency to engage on the Project's partnership and mutual beneficial agreement. A draft Customer Agreement has been created and submitted to the Local Agency for review. • Issued request for proposal (RFP) package for the procurement of a Microgrid Control System. Vendor onboarding scheduled 1Q 2021. • Launched partnership with SCE's Energy Storage Integration Program for front-of-the-meter energy storage with advanced black-start and islanding capabilities. • Presented the Project's overview, status and challenges/lessons learned at several workshops and meetings including Inter-IOU meeting, EPUC PICG PSPS workshop, EPIC PICG Equity/Disadvantaged Community workshop. Submitted project abstracts to present at several conferences in 2021. Key Findings and Lessons Learned: • Leverage combined architecture and vendor synergies with other EPIC III Microgrid Projects for cost efficiency and to accomplish common goals. • Local agency selection criteria should consist of a minimum set of must have requirements, and additional nice to have requirements for effective site selection. • EPIC program funding scope is limited and does not fund DERs such as energy storage for the demonstration. Thus, the project explored City's with exiting or planned DERs as a site selection criteria and also other co-investment potential	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.

Investment Program Period	Program Administrator	Project Name	2020 Update	Coordination with CPUC Proceedings or Legislation
3rd triennial (2018-2020)	SCE	Storage-Based Distribution DC Link	The Project Execution work has launched: •Completed 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. •Completed Project's Detailed Use Case and Requirements document illustrating scope, actors, assumptions, six microgrid use cases, step by step analysis, and alternative scenarios. •Launched development of Project's architecture artifacts Lab Architecture Briefs (LAB) •An RFP package was completed, and the selected vendor is scheduled to be onboarded 1Q 2021 The expected benefits of this sub-project include: •Allowing SCE Operators to dynamically transfer load from one circuit to another, supplementing the existing tie switches. It will provide better understanding of a storage system that can support two circuits at the same time, thereby decreasing the cost per system. •Utilizing GHG-free batteries to meet system requirements such as local voltage support, managing line loading, energy shifting, and preventing duct bank temperature violations.	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	The Project Execution work has launched: •Completed 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. •Completed Project's Detailed Use Case and Requirements document illustrating scope, actors, assumptions, use cases, step by step analysis, and alternative scenarios. •Completed Project's Architectural Vision Document (AVD) defining the solution overview, business impact, architecture considerations, system context, assumptions, constraints, dependencies, and risks analysis. •Developed Project's system engineering artifact System Requirement Document (SRD) describing functional and non-functional requirements for the system and sub-system/application. •Launched development of: oThe Project's architecture artifacts Lab Architecture Briefs (LAB) and System Architecture Design (SAD). oAgreements and statements of work, with EV & EVSE (Chargers) OEMs to partner in Lab demonstration work to test AC & DC V2G use cases. oA V2G Technical Advisory Board (TAB), to be comprised of National Labs, Cal-ISO, Utilities & OEM reps amongst others, to support, inform, and provide a vision of joint Utility & OEM V2G policies and procedures for standardization, certification, and interconnection, as well as potential value proposition to support key V2G use cases •The Project Team: oConsulted in the Rule 21 OIR process to evolve and understand V2G interconnection requirements oParticipated in SAE J3072 to advance to ballot the updated standard based on Rule 21 developments. oConsulted with internal regulatory and interconnection process personnel on V2G applications. oConsulted with Cal ISO on V2G pilot procedures. oConsulted with Charge Ready program on prospective V2G applications and coordinated technology advancement through EPIC project. oNow has two light duty OEMS with prospective charger and controls participants in contract negotiation, and one electric school bus provider. oCombined a new DC V2G charger supplier with an existing EV OEM for project participation. Key Findings and Lessons Learned •During this period the project 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	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	N/A - Project was cancelled	
3rd triennial (2018-2020)	SCE	Wildfire Prevention & Resiliency Technology Demonstration	Project is in the planning phase	

Investment Program Period	Program Administrator	Project Name	2020 Update	Coordination with CPUC Proceedings or Legislation
3rd triennial (2018-2020)	SCE	Next Generation Distribution Automation III	•Completed 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 for Duct Bank Monitoring. •Completed Project's Detailed Use Case and Requirements document illustrating scope, assumptions, step by step analysis, and alternative scenarios. The expected benefits of this sub-project (Duct Bank Monitoring) include: •Ability of System Operators to temporarily exceed the historic circuit amperage limit in order to enhance real-time load management, without violating cable temperature ratings •The ability to get more utilization from the SCE Distribution network, deferring system upgrades •Reduce complex reconfiguration and switching operations presently used to balance load •Better leverage SCE's GMS with improved situational awareness of substation conditions •The ability to better characterize cable duct bank environments and temperature factors. •Enhance existing cable temperature models and planned ampacities with new real-time data.	

Appendix B

Substation Automation III, Phase 1

Final Project Report

Substation Automation 3 (SA-3) Phase III EPIC I Final Project Report

Developed by

SCE Transmission & Distribution - Asset Management, Strategy, and Engineering

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1. Executive Summary

Southern California Edison (SCE) is at the forefront in the industry with its work to improve reliability and support California's transition to a cleaner and more sustainable energy future. To this end, SCE is continually reviewing its operations, identifying opportunities to improve existing practices, and leveraging new and emerging energy technologies to strengthen and modernize the grid.

As part of these initiatives, under the California Public Utilities Commission's (CPUC) Electric Program Investment Charge (EPIC) 1 investment period, SCE undertook the Substation Automation 3 (SA-3) Phase III project – one in a series of projects to ultimately deploy a digital substation protection and control solution that utilizes the latest industry standards, meets physical and cybersecurity requirements, and complies with the North American Electric Reliability Corporation (NERC) Critical Infrastructure Protection (CIP) reliability standards. Such a substation is expected to provide measurable engineering, operations, and maintenance benefits through improved reliability and cybersecurity.

The previously completed Phase II evaluation (funded through the American Recovery and Reinvestment Act, ARRA, as part of SCE's Irvine Smart Grid Demonstration, ISGD) successfully led to the third-generation microprocessor-based automation system – SA-3 – for distribution-level substations. The project team selected the International Electrotechnical Commission (IEC) 61850 modern utility communication standard for intelligent electronic devices (IEDs) for the project design foundation, thus enabling standards-based communication, automated configuration of substation devices, and an enhanced system design.

The SA-3 Phase III project (covered in this report) demonstrated a transmission substation modern automation design that builds on the distribution substation design while validating specific requirements and functionality for bulk power substations, additional technologies described in the IEC 61850 standard, and compliance with NERC CIP and SCE cybersecurity requirements.

The project concluded by the end of 2020 with laboratory testing of the substation automation system, and successfully demonstrated technologies that can provide cost reduction, capability improvements, compliance, and adaptability to emerging requirements. Key elements the demonstration validated included adoption of peer-to-peer communications for critical power system protection functions, introduction of cybersecurity and external Internet Protocol (IP) connectivity to the substation, and password management for chosen devices. (See **Project Summary, Section 3**, for more details.)

Beyond this, the Phase II and Phase III projects combined served as a test bed to advance SCE's cybersecurity processes and standards, and the project results can inform the use of future cybersecurity infrastructure.

In addition, the Phase III project results can help lay the foundation for an EPIC III project to investigate how to use the IEC 61850 process bus standard, which is expected to further reduce new substation costs by 10%-20% and could result in cost savings of approximately $9.4 million annually.

While the SA-3 project focused on transmission-level substations, learnings also can be applied to improve distribution substations as part of SCE's "Pathway 2045"[1] roadmap to help California further integrate Distributed Energy Resources (DERs, smaller-scale local resources) and support the achievement of a carbon-neutral future.

2. Background

Bulk power system substations play a critical role in delivering electricity to customers, stepping down high-voltage power from the transmission system to lower-voltage power, so it can be supplied to customers through distribution lines.

As part of its ongoing grid modernization initiatives, SCE is working toward deploying fully digital substations in its system. A digital substation is intended to utilize the IEC 61850 standard to move from today's hard-wired, traditional substation architecture to one that utilizes largely fiber optic cables, with standardized configurations and interoperability among multiple device manufacturers. Use of the technologies outlined by IEC 61850 and related standards is expected to result in measurable engineering, operations, and maintenance benefits, while improving cybersecurity and reliability.

In the long term, the deployment of digital substations is also anticipated to provide the communication features and flexibility needed for more efficient adoption of DERs, smaller-scale local resources that enable greater customer choice while helping to achieve clean energy policies and facilitate the growth of new markets for energy products and services.

The goal of deploying fully digital substations represents a major paradigm shift in how utilities design, test, build, and maintain substations. Ultimately, SCE intends to leverage the IEC 61850 standard to enable "centralized protection," which consists of the consolidation of multiple protection relays into fewer devices. SCE envisions eventually utilizing machine virtualization – creation of a virtual version of a device or resource – instead of dedicated hardware.

Virtualization has been used in IT environments for some time, resulting in greater efficiencies, lower operating costs, faster workload deployment, increased application performance, and higher server availability.

[1] https://www.edison.com/home/our-perspective/pathway-2045.html.

3. Project Summary

Based on the technologies outlined by the IEC 61850 modern utility communication standard and related standards, the SA-3 Phase III project was designed to improve upon the distribution substation automation capabilities established by the SA-3 Phase II (Irvine Smart Grid Demonstration) project. SA-3 Phase III also was intended to provide a pathway to an SCE SA-3 transmission substation standard by adopting scalable technology that enables advanced functionality to meet cybersecurity and utility industry reliability standards.

The Phase III project sought to demonstrate technologies that are expected to provide cost reduction; capability and reliability improvements; compliance with the NERC CIP standards; adaptability to emerging requirements; enhanced cybersecurity; and the flexibility to implement the best solution(s) available. Specific key benefits a transmission-level SA-3 is expected to result in include:

- Remote monitoring of substation device health and the related data analytics;
- Secure access to real-time transmission substation data necessary to reliably and efficiently operate the bulk power system;
- Greater flexibility in procuring the best substation equipment by moving to an open, non-proprietary communication standard;
- Adoption of technology that enables advanced functionality such as password management and automatic device configuration; and
- A streamlined engineering, design, and construction process for the installation of a substation protection and control system, shortening the amount of time needed for this work.

Features demonstrated in the Phase III project focused on two major areas:

1. **Further transitioning to a fully digital substation** by evaluating the use of peer-to-peer relay communication for breaker failure protection; high-accuracy time synchronization over the substation Ethernet network that connects all of the substation devices; and utilization of high-availability network protocols. These technologies can lay the groundwork for establishing the necessary processes to move to the use of fully digital substations that can provide the flexibility and adaptability necessary to meet the needs of a modern power systems grid.

2. **Conducting centralized data collection and compliance** via the demonstration of a Substation Management System (SMS). This system supplies centralized functions such as event/fault file collection, firmware version monitoring, configuration monitoring, user access control, and reporting mechanisms. These features provide automated mechanisms for SCE cybersecurity standards and NERC CIP reliability standards, as well as the necessary data to engineers and substation personnel in a centralized environment. Connectivity from the substation to a centralized historian also was demonstrated for collection of non-operational data for planning and analysis.

The SA-3 Phase III project concluded by the end of 2020 with laboratory testing of the substation automation system, and the demonstration successfully validated the following key elements:

- Adoption of peer-to-peer communications (Generic Object-Oriented Substation Event, or, GOOSE messaging) for critical power system protection functions;
- Use of some of the other technologies called for by the IEC 61850 standard;
- Introduction of cybersecurity and external IP connectivity to the substation;
- Compliance with NERC CIP and SCE cybersecurity requirements/standards;
- Password management of the chosen relays, network switches, Human Machine Interface (HMI, the existing operator control interface); and
- Configuration and firmware monitoring.

Equipment is scheduled to be sent to the field for substation commissioning by the end of Q2 in 2021, continuing SCE's progress toward the deployment of a new automated standard for transmission system substations.

The SA-3 Phase III project was implemented through the CPUC EPIC 1 Program.[2] EPIC aims to fund applied research and development, technology demonstrations and deployments, and market facilitation programs for the benefit of the electricity ratepayers of SCE and the state's other investor-owned utilities (IOUs). The utilities are limited to demonstrations, which focus on advancing the grid. (SCE benchmarked other California IOUs, and did not find any work being performed similar to that in its SA-3 Phase III project.)

Based on **Figure 1. Joint Utilities EPIC Framework,** which was included in each of the Utility's respective EPIC I Investment Plans, this project supported EPIC's Reliability and Affordability principles, as well Grid Modernization and Optimization, based on its successful demonstration of cost reduction, capability improvements, compliance, and adaptability to emerging technologies and requirements.

[2] 2012-2014 Investment Plan Application (A.)12-11-004.

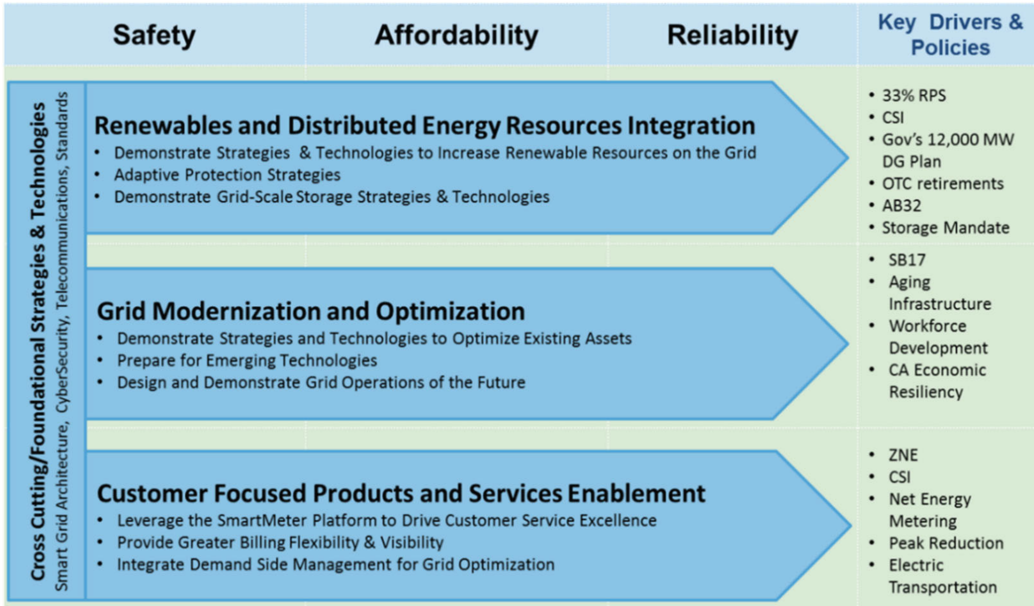

Figure 1. Joint Utilities EPIC Framework[3]

3.1. Problem Statement

In the bulk power system – a large interconnected electrical system comprised of generation and transmission facilities and their control systems – substations perform a crucial function by stepping down high-voltage electricity from the transmission system to lower-voltage electricity so it can be supplied to customers through distribution lines.

Despite the need for advanced technologies to increase grid reliability and system resilience, including those vital to meeting California's 2045 carbon neutrality goal, SCE's substations continue to rely on outdated (legacy) technology, complex architecture and design, and a largely manual process for testing and modifications.

The SA-3 Phase III project took important steps toward addressing these issues by demonstrating the integration of modern substation technologies and their application to transmission substations (bulk electric solution). Although Bulk Electric stations share many similar requirements with distribution substations such as cybersecurity, Bulk Electric substations have additional requirements not typically applicable to distribution substations such as NERC CIP compliance, redundancy, and a larger amount of data. The project learnings also can be applied to distribution substations as SCE advances

[3] See Application 12-11-004 for more details on the EPIC program and SCE's 2012-2014 Investment Plan Application.

work on modernization of its entire electricity network to further support the integration of DERs on the path toward decarbonization.

4. Project Scope

SCE's SA-3 Phase III project demonstrated a transmission substation modern automation design that builds on the distribution substation design from a previous project, while validating specific requirements and functionality for bulk power substations; additional technologies described in the IEC 61850 modern utility communication standard; and compliance with industry reliability and SCE cybersecurity requirements.

The design of the transmission-level SA-3 (third-generation microprocessor-based automation system) was evaluated in a laboratory environment and tested through new methods utilizing a Real-Time Digital Simulator (RTDS). The project demonstrated the following technologies:

- **Peer-to-peer communication for protection schemes** using GOOSE. This technology is used to help reduce the amount of wiring necessary in the substation and gain efficiencies in the substation design.
- **Parallel Redundancy Protocol (PRP), a high-availability network protocol** for devices providing critical communication functions. The PRP technology has been adopted as part of the IEC 61850 standard and guarantees that no data is lost upon equipment network failure.

  The project evaluated two scenarios. In the first one, network diversity provided a primary network utilizing standard networking technology and a secondary network utilizing a Software-Defined Network (SDN). The second approach used two redundant networks employing standard technology. SDN networks provide greater flexibility in the network design with a streamlined centralized configuration and management tools, while adding additional security measures.
- **A new substation annunciator system.** (These indicate alarm conditions in the facility.) The goal is to lower the cost of the annunciator system and to eliminate mechanical relays that require significant engineering and wiring, while utilizing IEC 61850 communication and data-driven configuration.
- **Institute of Electrical and Electronics Engineers (IEEE) 1588 Precision Time Protocol (PTP).** This standard delivers significant improvements over the legacy time synchronization methods being utilized in the substations. It provides time synchronization over the network, eliminating the need for the coaxial networks required with current time synchronization methods, and also provides sub-microsecond accuracy versus the millisecond accuracy currently available. The PTP can take advantage of the network redundancy to maintain proper time synchronization.

The SA-3 Phase III demonstration also included a server-grade computing system using machine virtualization to host substation applications such as the HMI, and to provide the necessary cybersecurity controls utilizing a virtualized version of network security appliances such as firewalls. Specifically, the system demonstrated the following applications and features:

- **IP-based communication to the transmission substation** while demonstrating compliance with the NERC CIP reliability standards.
- **SMS**:
  1. **Configuration Management Application:** Provides a mechanism for maintaining substation and IED configuration files and provides a controlled process to ensure the consistency of these files.
  2. **Firmware Version Management Application:** Provides a mechanism for tracking the evolution of device firmware over time, and a central database to track current and past releases.
  3. **Password Management Application:** Enables SA-3 to manage, store, and organize device passwords; and also provides the mechanisms to automatically change device passwords after pre-defined events.
  4. **Fault/Event File Management Application:** Automatically collects disturbance data from all of the substation devices capable of producing them, and can make the data available to authorized users as soon as possible.

The following sections describe the project's system architecture, major system components, and appropriate testing methodologies and findings.

4.1. System Architecture

The SCE SA-3 Phase III project team sought to design, fabricate, test, and demonstrate a complete substation's protection and control system with all of its technologies and benefits. This approach provided the ability to both test the technology and evaluate how the technology could integrate into SCE's processes. To achieve this, the project was designed based on one of SCE's transmission substations, and included all of the relays and devices necessary to have a fully operational substation. The system architecture that was demonstrated, features numerous multi-vendor devices, with most devices connected to two redundant networks referred to as LAN A and LAN B. These two networks are completely independent and autonomous from each other, which is achieved using the PRP described below.

LAN A and LAN B are primarily used for relay-to-relay protection signals being communicated over the communication network, which utilizes the IEC 61850's GOOSE messages.

Full redundancy is required because of the use of GOOSE messages for breaker failure protection applications. Redundant networks also provide the substation annunciator with redundant alarm/annunciator reports, which is required due to the criticality of the annunciator functionality at SCE's transmission stations. In addition, PTP messages are sent on both networks, which is not a critical requirement for the system, but does offer additional reliability for time synchronization.

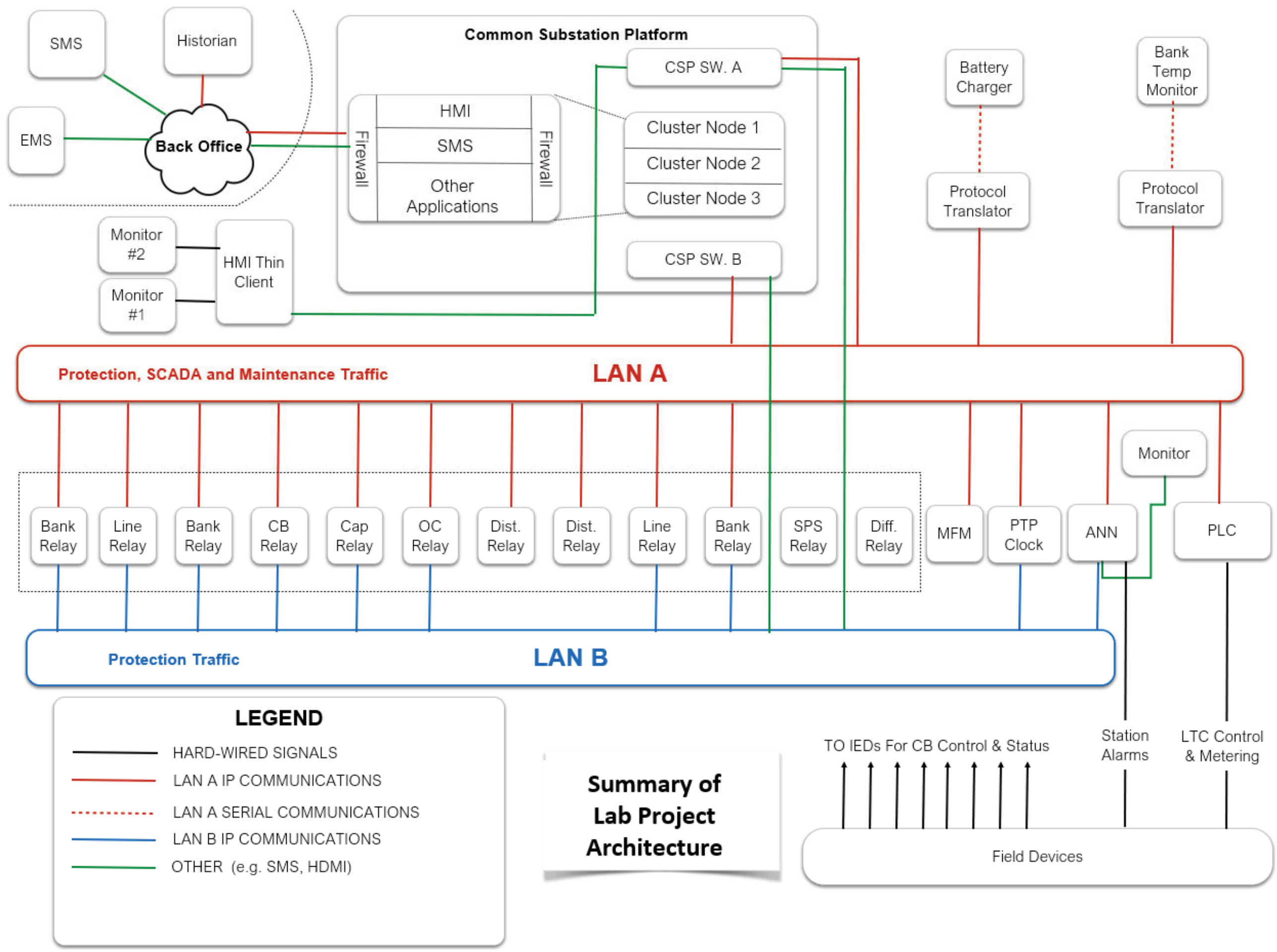

Figure 2. System Architecture

The network switches for LAN A are connected in a dual star topology, while LAN B is a full mesh topology, with each network completely separated from the other. The exception to this rule is the managed switches for the Common Substation Platform (CSP). These are connected to both LAN A and LAN B, and have special configurations to manage the bridging of the two networks.

For devices participating in communication-based protection schemes, all signals were made redundant on LAN A and LAN B through the use of the PRP. The distribution protection relays and the bus zone relays are not communication-based protection schemes, so therefore they are only connected to LAN A.

4.2. Common Substation Platform

The CSP is a general purpose computing platform that is designed to run in a substation environment, using virtualization software capable of running a variety of operating systems and applications simultaneously while providing a high level of redundancy only available in a server environment. The system is intended to provide the following features:

- Computing capabilities beyond substation-grade PCs
    - Necessary computing power for machine virtualization
    - High availability/redundancy
    - Data center grade stability
- Commercial-grade firewall
- Centralized management
- Designed with NERC CIP compliance in mind

The CSP establishes a secured computing platform that provides data center capabilities to the substation environment.

4.3. Human Machine Interface

The HMI application makes available local and remote Supervisory Control and Data Acquisition (SCADA) for the purpose of monitoring and controlling the transmission substation. It provides a local means for a user-interactive single line diagram that in turn can provide a centralized means for monitoring and control of the Substation.

The HMI works in conjunction with an Energy Management System (EMS) to perform the remote monitoring and control of this substation. The HMI manages and renders the SCADA information and implements the user-interface through which the administrator, acting operator, and/or technician monitors and controls the substation equipment. The HMI chosen for the SA-3 Phase III project includes the following features:

- Supports data-driven configurations, including the auto-build of the HMI application and support for sophisticated test tools
- Provides a centralized view of all local substation data in a user-specified format and layout
- Provides centralized control for the local operation of substation equipment
- Provides substation alarm and event handling with a built-in digital alarm annunciator
- Utilizes secure authentication and authorization technologies to ensure proper substation operation with a complete audit trail
- Provides all SCADA locally and remotely to the EMS; provides direct connectivity and communication to the data historian server for additional point data; and has the ability to accommodate additional IEC 61850 clients for future applications
- Supports role-based access for the HMI logon and all of its applications

For the project, the HMI was hosted on a virtual machine on the common substation platform. To furnish a user interface to a substation operator, a single-purpose dedicated device called a thin client was utilized to provide a connection over the substation network to the HMI user interface. A thin client provides all of the benefits of dedicated hardware, including the user access control, dual displays, and the necessary input/output peripherals.

4.4. Programmable Logic Controller (PLC)

The SA-3 Phase III PLC is the heart of the system's automated restoration functions. It monitors the transmission and sub-transmission relays for abnormal conditions and initiates restoration sequences based on pre-defined logic for the specific type of substation and voltage. At the time of the initial project design, a PLC that met all of SCE's requirements and had IEC 61850 support was not available; however, other recent projects have made progress in adopting IEC 61850 communication for the PLC. The equipment utilized for the SA-3 Phase III project supports Ethernet communications with common communication protocols utilized in substations and industrial systems.

Utilizing Ethernet communications, the PLC monitors analog status, digital controls, and alarms on each device at the substation, while still providing hard-wired analog and digital I/O serial devices. The PLC performs the bank, source line, and other miscellaneous automated functions. It also continuously monitors substation conditions; performs substation restoration after bus, transformer, and source line faults; and handles Load Tap Changer (LTC)/regulator/capacitor control functions.

4.5. Multi-Function Meter (MFM) with IEC 61850 Communication

The MFM takes voltage and current inputs as shown in Figure 3. It makes this data and calculated data, such as watts and vars, available to devices over the network, and also displays the metered information locally. The MFM is enabled with IEC 61850 communication capabilities, which it uses to report metering quantities to the HMI via LAN A (not LAN B). The HMI then sends these metering values remotely to the EMS for the EMS' primary analog points. The MFM features a user-configurable front faceplate that can display different types of signals on a per-phase basis. For transformer banks, the MFM also communicates via Modbus to the PLC for transformer bank LTC control. The selected meters support IEC 61850 interface and a Modbus TCP/IP interface.

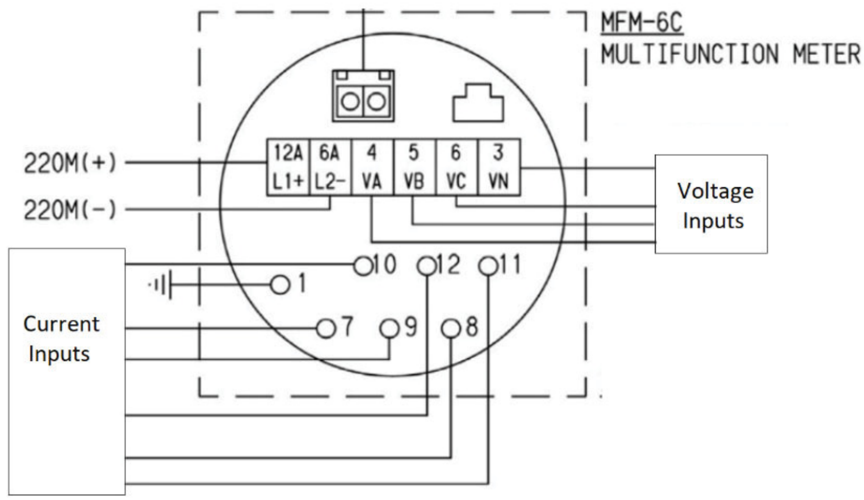

Figure 3. Multi-Function Meter

4.6. Transformer Monitoring System

The Intelligent Transformer Monitor (ITM) system monitors transformer bank temperature, controls cooling fans, and activates alarms. Within the SA-3 Phase III project system, the ITMs communicate alarms and temperature data to a protocol translator, which subsequently sends data to the HMI.

The ITM uses several measurement sensors to monitor the transformer bank temperature. Temperature measurements are taken directly through Resistance Temperature Detector (RTD) Sensors and through Fiber Optic Temperature Sensors connected to the Optical Hot Spot Module. Current Transformer (CT) sensors also measure winding current, which is used to calculate the winding temperature.

The ITM is configured to activate alarms when temperature measurements exceed a set value. When an alarm is activated, the output is visible on the front panel LEDs, and alarms also are communicated to the ITM PLC. Additionally, the ITM is capable of recording data, logging events, and evaluating the remaining life of a transformer.

4.7. Substation Annunciator

The diagram below depicts the system annunciator (which indicates alarm conditions in the facility) and HMI alarm philosophy for traditional/legacy annunciator systems, which are based on hard-wired signals and electromechanical relays. These interposing relays increase engineering efforts, cabling, and construction costs, and introduce electromechanical delays. The project addressed these challenges with the use of an IEC 61850-based annunciation scheme, which replaced hard-wired connections with IEC 61850 communications messages. These challenges have been addressed with the use of an IEC 61850-based annunciation scheme.

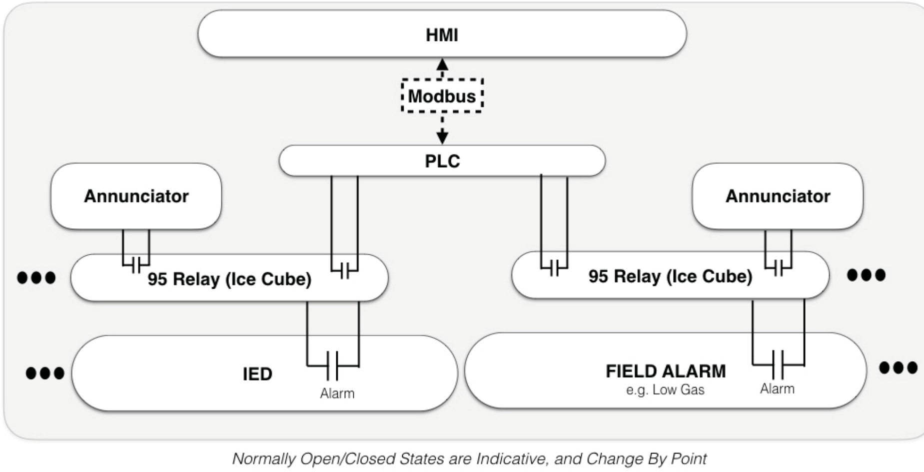

Figure 4. Typical Legacy Annunciator Wiring

The project's annunciator design philosophy introduced the use of IEC 61850 Manufacturing Message Specification (MMS) reports to exchange information between the relays and the annunciator. This alleviates the need to wire each annunciator alarm point from the relays. Instead, the design only wires out the annunciation signals that are not available with IEC 61850, such as the failure alarms and other field devices (e.g., field alarms) that do not support IEC 61850. The design consists of utilizing a Programmable Automation Controller (PAC) that supports IEC 61850 and a modular design. The PAC's fully redundant components – including a redundant power supply and network interface with PRP – allow maximum availability and reliability.

This new design eliminates the need for the interposing relays that were required to split/multiply the hard-wired signals to the PLC and legacy annunciator. To maintain complete visibility, additional alarms were added to the systems:

- **GOOSE Fail Alarms:** This alarm is available in every relay that subscribes to GOOSE messages. If the relay does not receive a GOOSE heartbeat message within the expected time from any relay it is subscribed to, the relay virtually sends the GOOSE Fail Alarm to the PAC and HMI.
- **LAN A/B Network Fail Alarms:** These alarms are available in every relay that publishes or subscribes to GOOSE messages. If the connection from either port on the relay to either network switch has problems (bad fiber, bad port, one of the switches being offline, etc.), the relay virtually sends the LAN A/B Fail Alarm to the PAC and HMI.
- **Network Switch Fail Alarms:** This alarm is a combination of all of the hard-wired alarms from the network switches. There is a combined "LAN A Switch Fail" alarm and a separate "LAN B Switch Fail" alarm. These two alarms are hard-wired into the PAC as two inputs.

4.8. Peer-to-Peer Communications

4.8.1. History

Legacy communication protocols (Modbus, Distributed Network Protocol (DNP), CDC Type1, etc.) were designed with dual objectives: 1) providing the necessary functions required by the traditional substation automation system; and 2) minimizing the number of bytes used by the protocol because of bandwidth limitations that are inherent with serial communications.

Substation automation systems have evolved to now incorporate high-speed Ethernet communications utilizing networking protocols like TCP/IP, and legacy protocols have been adapted to run over TCP/IP (e.g., DNP/TCP, Modbus TCP). Over the past decade, Ethernet has been utilized for IEC 61850 MMS communications that support SCADA client/server applications, as well as IEC 61850 GOOSE messages.

These peer-to-peer messages only use the lower “layers” of the Ethernet protocol, which is referred to as Layer 2 (L2) communications. As a result, these L2 GOOSE messages are extremely fast, but they are not confirmed communications like MMS. Confirmed communications utilize all “layers” of the Ethernet protocol, including its flow control and error checking mechanisms, which is not the case with GOOSE messages.

In order to address the unconfirmed nature of GOOSE messages, they are designed to be re-transmitted with increasing time periods between re-transmissions to make them more deterministic. This feature ensures the GOOSE message is received by the subscribing IED(s). The subscriber(s) only processes the first GOOSE message it receives and ignores the repeated ones. This provides the speed and the dependability that is required for these important GOOSE messages.

4.8.2. Purpose

GOOSE messaging, which was incorporated into the SA-3 Phase III system, is a mechanism by which any data format (alarms, breaker trips, status indications, measurements, etc.) can be grouped into a data set and transmitted with a minimum latency of 3-4 milliseconds.

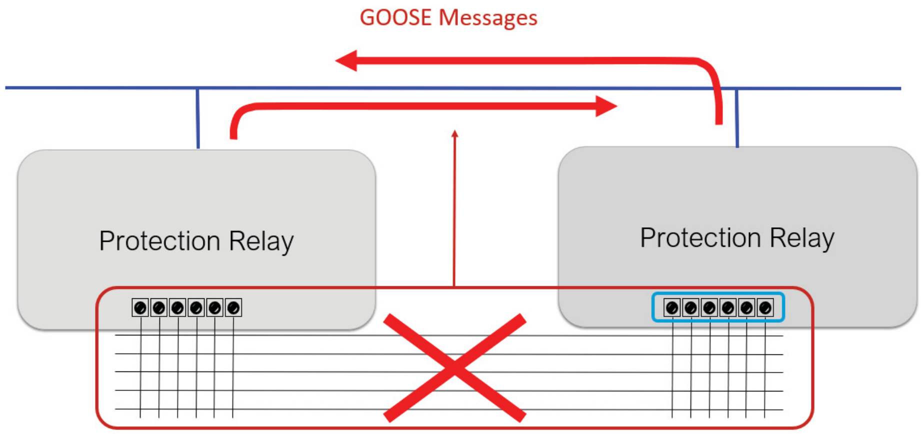

Figure 5. GOOSE Digital Wires

GOOSE messages are vendor agnostic and support standardized information exchange between multi-vendor relays. The GOOSE messages enable high-speed communication between devices within the same network, enabling transfer of digital signals over the network, and provide a replacement for hard-wired communication between substation devices.

4.8.3. Benefits

GOOSE communication offers unique features that provide a direct and positive impact on the design, build, installation, commissioning, and operation of the SA-3 system. The following table summarizes the benefits of GOOSE, along with those of other IEC 61850 features.

Minimize Wiring & Construction Costs	Minimize Engineering	Increased Performance	Increased Availability	Decreased O&M Costs
Decrease CAPEX via reduced wiring costs, and increase asset utilization by fully exploiting IED capabilities	Decrease CAPEX via minimizing re-engineering; ease of design replication via SCL files	Increased performance and functionality via IEC 61850's GOOSE/SV messaging and self-monitoring services	Increased availability from high-availability networks (PRP/HSR) and IEC 61850 mechanisms that are actively monitoring the network/IEDs	Decreased OPEX due to condition-based monitoring, as well as the interchangeability of IEDs

Table 1. GOOSE Benefits

The benefit of implementing GOOSE messages over a hard-wired solution is largely attributed to decreased cabling and the associated engineering, material, and testing needs. This is in addition to the GOOSE mechanisms that actively supervise and monitor the health of the communication connections.

GOOSE messaging enables devices to efficiently exchange data over the SA-3 Local Area Network (LAN), minimizing the amount of cabling between devices by reducing the need for additional relay modules, test switches, rack wiring, and rack-to-rack cables, along with the engineering work in these areas.

The reduction in cabling can be seen in the following figure, which shows a traditional relay diagram compared to a diagram for the same type of relay for the SA-3 Phase III project. The green highlighted section is associated with the new wiring (inner-panel wiring only) that was added to support the GOOSE enable/disable features.

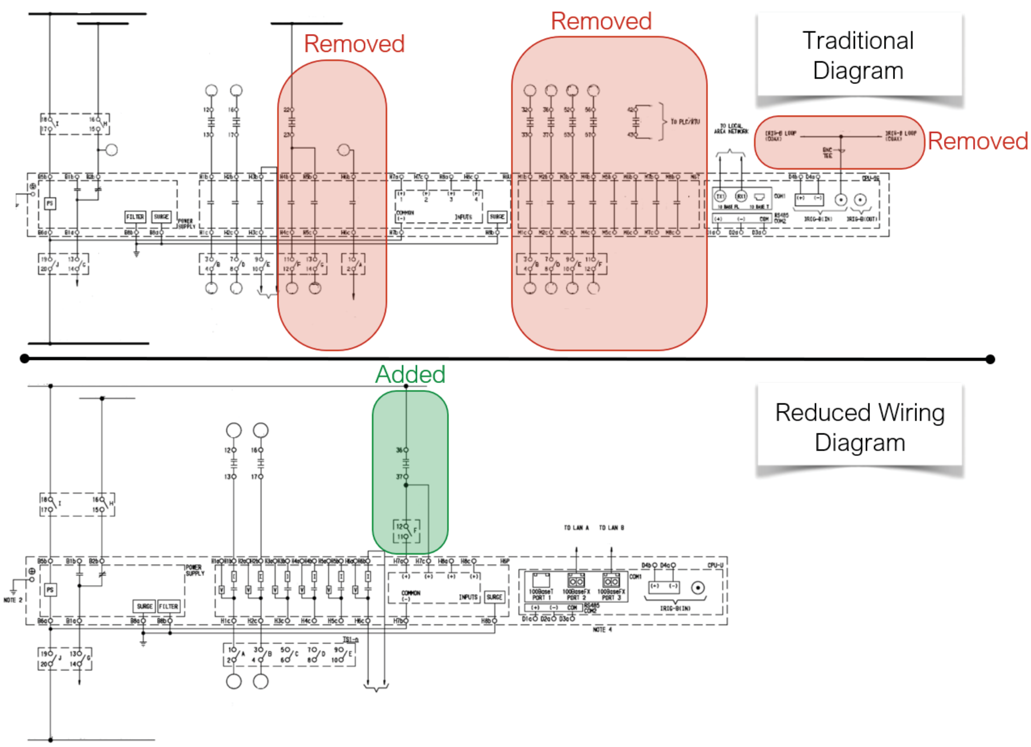

Figure 6. GOOSE Wiring Reduction

This wiring reduction only provided a small cost benefit to the SA-3 Phase III project. However, it enabled SCE to test and evaluate the processes needed to support a future protection and automation system that would replace most of the traditional wiring with fiber optic networks, providing a completely simplified substation design that could be drawn up, engineered, and tested in a fraction of the time needed for the deployment of a traditional system. The future system would be based on the IEC 61850 process bus and eventually could utilize a virtualization environment for protection relays, as shown in the following diagram.

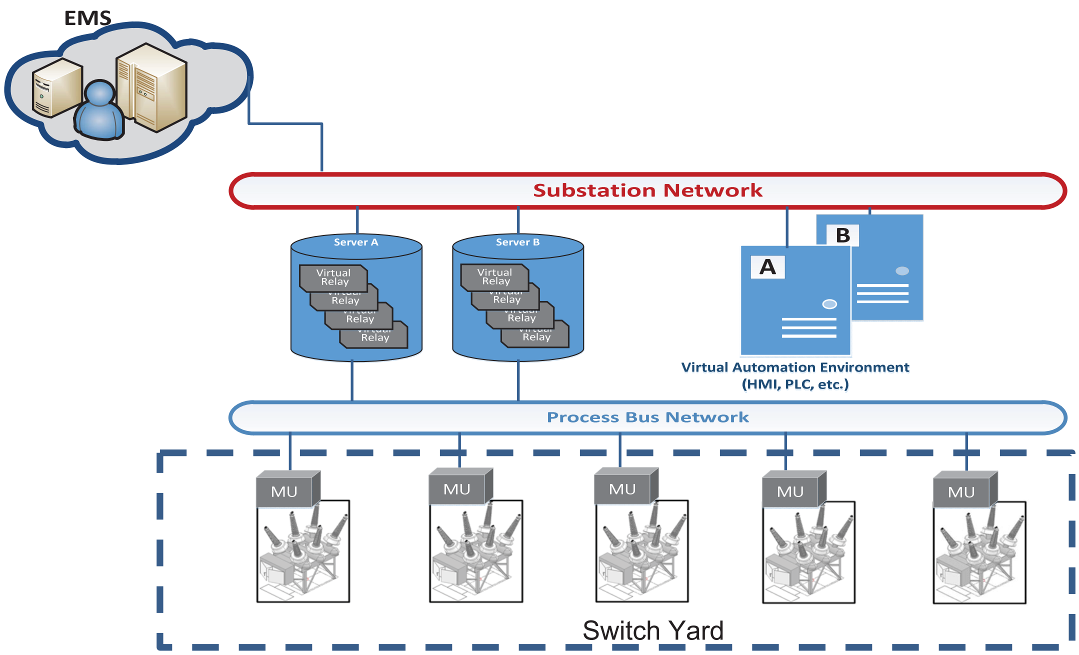

Figure 7. Fully Digital Substation utilizing machine virtualization

Furthermore, GOOSE messaging, combined with a redundant network architecture, supports the high-availability requirements of protection applications. All things considered, GOOSE messaging combined with redundant networks offers the fastest, most reliable, and robust peer-to-peer communication. GOOSE is also superior due its ability to implement supervision and monitoring features, which provides personnel with greater transparency on the status and health of each communication interface.

4.8.4. Testing and Results

4.8.4.1. Testing methodology

To validate the reliability of GOOSE messages and the substation network, the SA-3 Phase III project team utilized a Real-Time Simulator to provide scripted testing for thousands of scenarios. The test setup interface diagram shown in **Figure 8** includes the following devices:

- **Real-Time Simulator** is the hardware used to simulate the power grid (transmission lines and substation equipment) in detail. This device provided analog outputs that were connected to the amplifier inputs. It also received GOOSE messages from the relay through the substation network to analyze their performance.
- **Simulation Control** is the interface between the software and the Real-Time Simulator, and communicates with the Real-Time Simulator over the control network. This was used to model a variety of fault scenarios, including different fault combinations and trigger times. The computer utilized for simulation control was the location where the fault data was stored for further analysis.

- **Amplifier** is used to amplify the analog outputs that come from the Real-Time Simulator and feed them into the relays.
- **Relay** is the device under test (DUT). The DUT steady state and fault currents are generated by the amplifier. These relays were interconnected to the substation network, where they sent and received GOOSE messages.

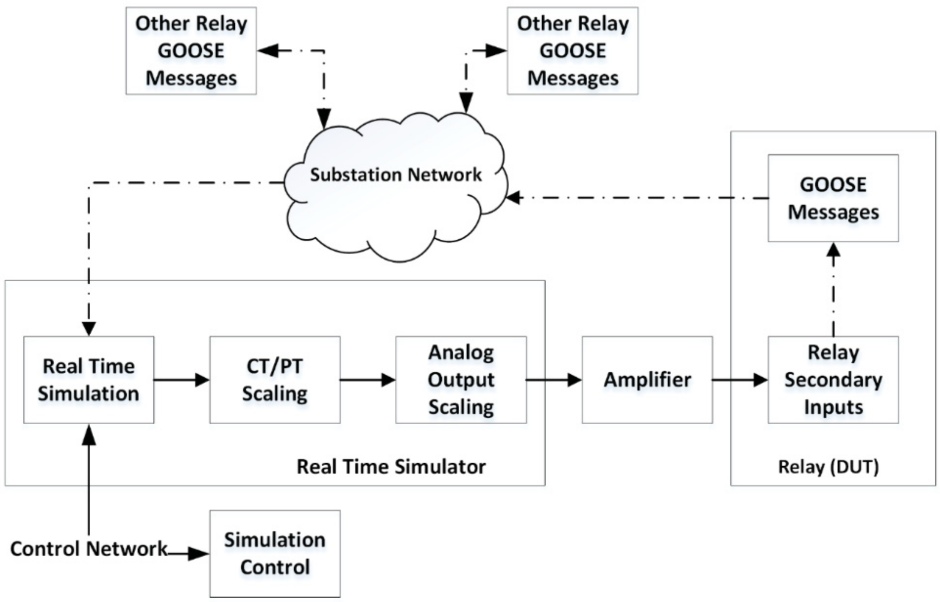

Figure 8. GOOSE message test setup

The Real-Time Simulator was configured with a model of the entire substation bus, including all transmission lines, transformers, and simulated loads. Initially the project team planned to model an entire substation; however, this was not technically feasible at the time. The DUTs were integrated utilizing hardware-in-the-loop into the model, while maintaining connectivity to the rest of the devices in the system. The Real-Time Simulator controlled three different scaling factors for the secondary signals:

1. Steady state and fault voltage and current magnitudes
2. Scales the simulated values up to actual values for the Current Transformer (CT) and Potential Transformer (PT)
3. Scales the simulated CT and PT values down to output analog voltage and current levels appropriate for an external amplifier

During fault events, a DUT generated GOOSE messages that were transmitted over the substation network. The Real-Time Simulator subscribed to these messages to provide status indications of the relays, which then manipulated certain parameters of the simulation model, such as breaker position and fault indications. These indications were used for data analysis of each tested relay's fault responses. On a separate, isolated network, the Real-Time Simulator logged status indications for all of the model parameters in addition to the status of the model's monitored GOOSE messages. The choice of a separate network for collecting logs and driving the simulation was made to eliminate network traffic that normally would not be part of the substation network. Some relays provided enough network ports to achieve this, while other devices without spare network ports were added to the separate network utilizing serial-to-Ethernet devices.

Matching the ratios of CTs and PTs was essential in the simulation process. Each analog output data point is scaled based on the real signal value. In addition, the hardware itself has a scaling parameter to translate the actual values down to an analog equivalent output. An external amplifier is used to amplify the scaled analog outputs to the correct input voltages and currents for each relay's PT and CT input.

Each set of protection tests were performed on three relays of a double bus double breaker scheme for a 230kV substation, "A Station." This isolated network scheme, as shown in **Figure 9**, consisted of:

1. A single line protection relay, which is used to protect substation equipment from transmission line faults; and
2. Two circuit breaker (CB) protection relays, which are used to protect the substation CBs to prevent catastrophic failures.

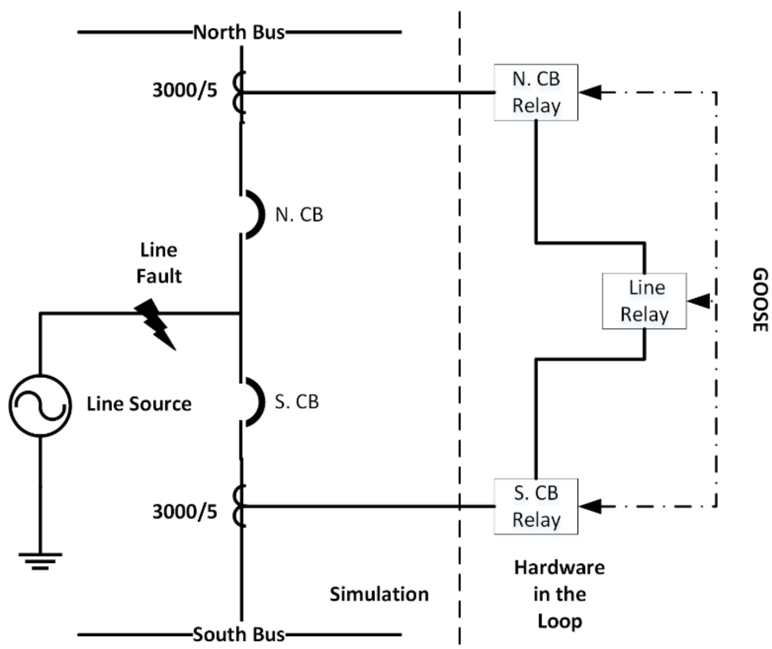

Figure 9. Relay testing layout

The secondary currents of the relays were set using a current loop through the North and South breaker relays to minimize the number of amplifiers needed for the testing. A loop of two currents uses a single 6-channel amplifier, and a looped current scheme only works if the CT ratios are matched for the secondary current loop. The CT ratios for the devices were set to match the substation's actual CT ratios: 3000:5.

Faults were simulated on the line side of the circuit breakers (an "in-zone" fault for a protected line).

1. The line protection relay was programmed with a "Breaker Fail Initiate" (BFI) GOOSE message that would be transmitted if a fault occurred within its zone of protection.
2. The two-line protection relays were programmed with the 52a and 52b breaker status as well as a "Breaker Fail High" (BFH) GOOSE message that would be transmitted if both fault duty occurred for longer than the programmed duration (e.g., 8 cycles or 134 milliseconds) and the BFI GOOSE message remained high. This test would result in a BFH message approximately 134 milliseconds after the BFI message.

To validate the proper setup of the system, the steady state Root Mean Square (RMS) values (e.g., bus voltages and relay currents) were measured as shown in **Table 2.**

Condition	$I_{RMS\text{-}North}$	$I_{RMS\text{-}South}$	$I_{RMS\text{-}Line}$	$V_{RMS\text{-}Line}$
Simulated (Model)	1.128 kA	0.724 kA	1.853 kA	212.9 kV
Actual (Relay)	1.128 kA	0.723 kA	1.850 kA	212.9 kV

Table 2. Steady State Currents and Voltages

With a duration of 9.5 cycles, the fault opened the North side breaker in 7 cycles and the South side breaker after 9 cycles. This established a condition in which one of the CB protective relays would see a fault duration slightly shorter than the BFH GOOSE message timer, and the other CB protective relay would see a fault duration slightly longer than the BFH GOOSE message timer. This determined the criteria for test failure as follows:

- Any relay that would send a BFH GOOSE message when it should not, would be a failure, and
- Any relay that would not send a BFH GOOSE message when it should, would also be a failure.

The test scheme would trigger protective actions that issue GOOSE messages. The system simulated two different scenarios as described below. Each scenario involved an asymmetric tripping sequence in which one breaker operates normally, and the other breaker goes into breaker failure condition.

4.8.4.2. GOOSE Test Results

This section covers two of the tested fault scenarios: “Phase A to Ground” and “Phase A to B.” Simulations for each fault were performed 100 times to ensure reliable GOOSE message testing.

A. “Phase A to Ground” Fault

Prior to the fault testing, a baseline test was performed to verify the simulated instantaneous values (of currents and voltages) to ensure that the relays received the same instantaneous values for the fault condition in their COMTRADE files. Due to the current loop, the simulated fault current magnitudes should add in phase with each other.

The simulated “Phase A to Ground” fault started at 3 cycles into the waveform. At 7 cycle into the fault, the North side breaker opened as shown in **Figure 10.** Full fault magnitude was carried through the South side breaker’s relay after 7 cycles, as shown in **Figure 11.** With the Current Transformer (CT) ratio of 3000:5, the amplifier produced a 26.67 amps peak at the DUT’s secondary (16 kA simulated on the South bus), as shown in **Figure 12.** This was greater than the instantaneous rating of 20.5 amps per channel (12.3 kA simulated) for the amplifier. This caused the clipping observed in the waveform after the North side breaker opened due to amplifier saturation and current limiting.

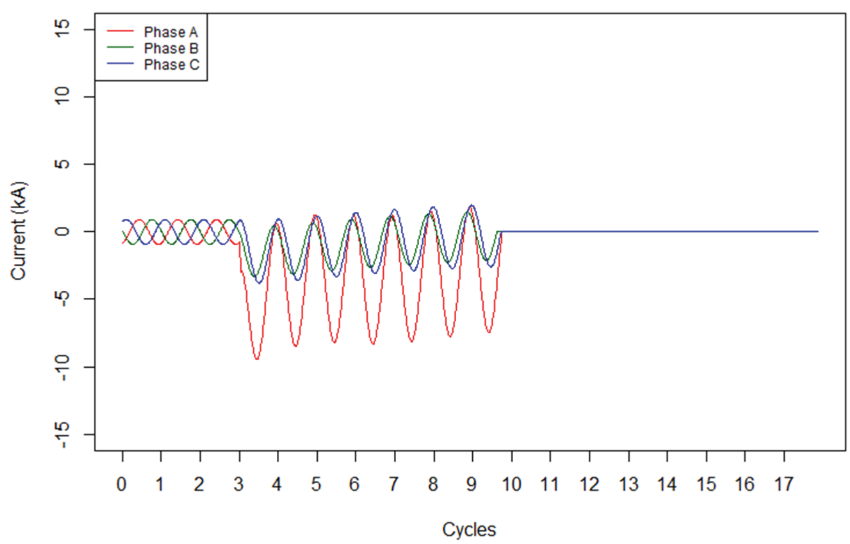

Figure 10. Simulated fault duty through the North circuit breaker protective relay during a “Phase A to Ground” fault

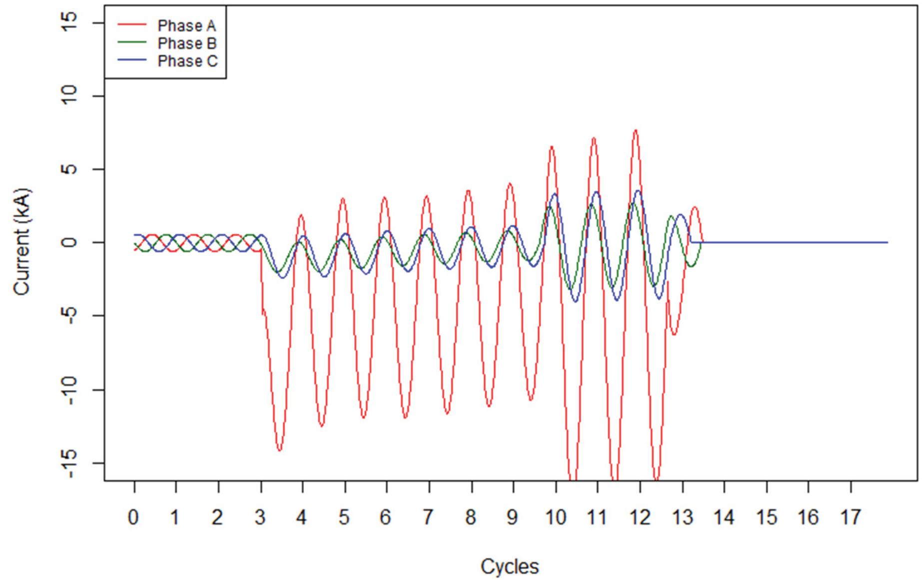

Figure 11. Simulated fault duty through the South circuit breaker protective relay during a "Phase A to Ground" fault

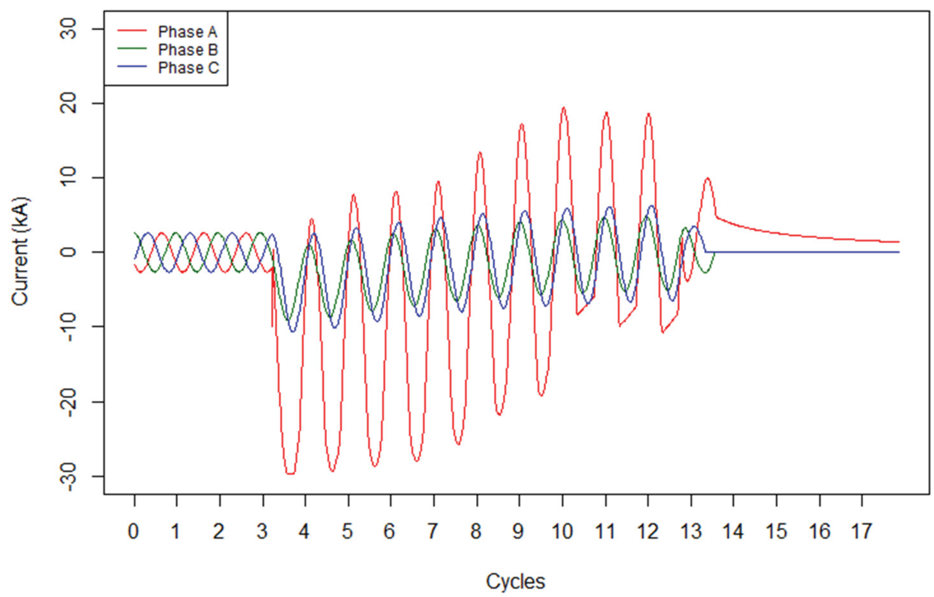

Figure 12. Current observed at the line protection relay during a "Phase A to Ground" fault

B. "Phase A to B" Fault

Figure 13 shows that the North side breaker opened after 7 cycles, which was consistent with the expected time. **Figure 14** displays the fault magnitudes that were simulated through the South circuit breaker, peaking at 14 kA through the South circuit breaker relay after the North circuit breaker opened. As with the "Phase A to Ground" fault, **Figure 15** shows instantaneous current over the amplifier threshold, which caused amplifier saturation and current limiting at 23.3 amps (14 kA simulated on the South bus).

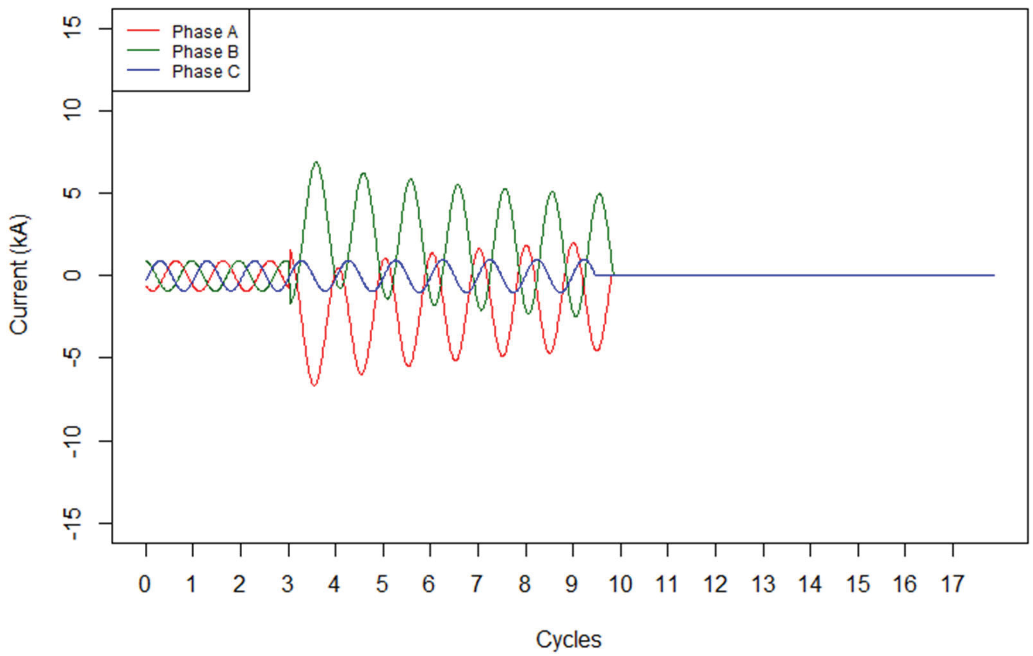

Figure 13. Simulated fault duty through the North circuit breaker protective relay during a "Phase A to B" fault

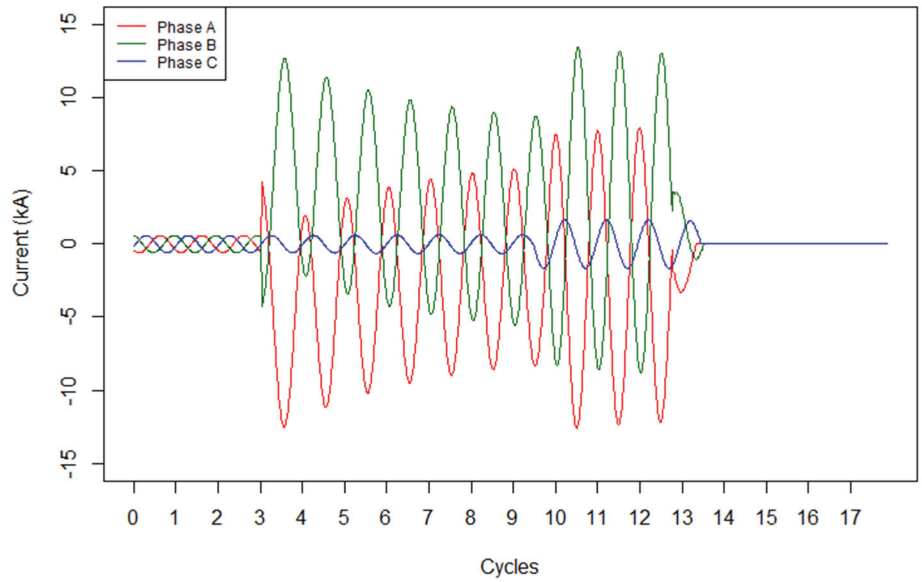

Figure 14. Simulated fault duty through the South circuit breaker protective relay during a "Phase A to B" fault

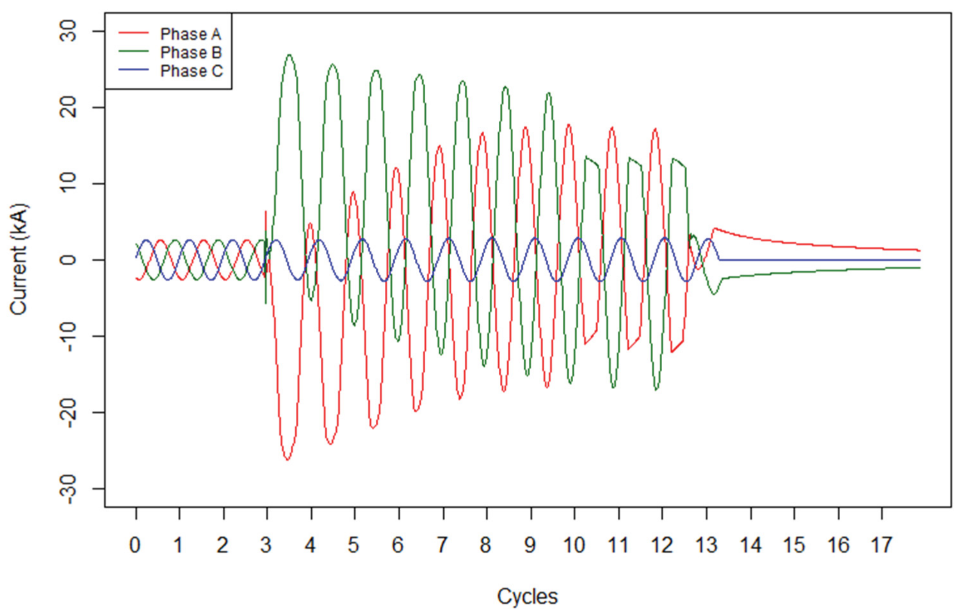

Figure 15. Current observed at the line protection relay during a "Phase A to B" fault

The expected GOOSE message for an instantaneous protective action is a BFI from the line protection relays, and status changes for the protected breakers. Any protective action taking place after the BFI timing sequence will cause an additional BFH GOOSE message to occur from the affected breaker.

Fault	Number of Tests	Avg. BFI Time	Avg. BFH Time	Std. Dev. BFH Time
A-B	100	27.3 ms	160.6 ms	16.7 ms
A-G	100	29.6 ms	165.0 ms	2.6 ms

Table 3. GOOSE Message Time During Fault Scenarios

There were no failed tests during the 200 tests tabulated on this example. Failure of a protective element is usually a catastrophic event that can result in equipment damage, an explosion, and/or fire under actual operating conditions. Table 3 shows the average generation time of the BFI or BFH GOOSE messages for both the “Phase A to Ground” and “Phase A to B” fault scenarios. The BFI message triggered as soon as the relay identified a fault in its zone of protection. The BFH message time was consistent with the expected time, which is after the relay sees fault duty for 8 cycles (or 134 milliseconds) following the sending of the BFI message. The large volume of tests also allowed for the generation of other meaningful statistics, such as the standard deviation of the message time. On average, the “Phase A to Phase B” faults responded more quickly, with a much larger spread of the BFH response time.

Utilizing the method described above, the SCE project team tested various scenarios with similar results. Some of the scenarios included adding additional network traffic on the substation network to simulate various network load scenarios up to a 100% network utilization broadcast storm. The test verified that the devices being tested, and the network Quality of Service (QoS) parameters, provided adequate reliability under abnormal conditions. During the testing it was determined that although the relays transmitting and subscribing to GOOSE messages were sufficiently robust in handling broadcast storms, other devices on the network were not, and other mitigations such as VLAN segmentations needed to be applied.

4.9. Substation Management Service (SMS)

4.9.1. Background

The SMS was envisioned as a key component of the digital substation to provide a central repository for automating commonly manually retrieved device information in near real time, and for providing cybersecurity and compliance features. As originally defined, the SMS is composed of two major components: 1) the centralized SMS, which is the central component of the system running in the data center; and 2) the SMS Local, which is the component that provides local data gathering in the substation. The centralized SMS and the SMS Local work together to provide applications that include Configuration Management, Firmware Version Management, Access Management, Password Management, Fault File Management, Auto-Build, and Reporting and Logging.

Some of the key drivers for demonstrating the SMS system include improvements in operational efficiency, cybersecurity, and compliance. Operational efficiency is enhanced by enabling easy and efficient access to substation data. Rather than having crews drive to substations to obtain data, the data is automatically retrieved and transferred into a central repository. Regulatory compliance data gathering is also simplified due to the automated reporting and logging that the SMS executes.

4.9.2. Concept

The SA-3 system has three software services that can run in dedicated hardware or in a virtual environment: Substation Management Service (SMS), SMS Local, and a combined Data Concentrator Service (DCS) and the HMI service (see **Figure 16).** The SMS resides at the enterprise level and is a central service, whereas the SMS Local and the combined DCS and HMI services are distributed and located at the substation level.

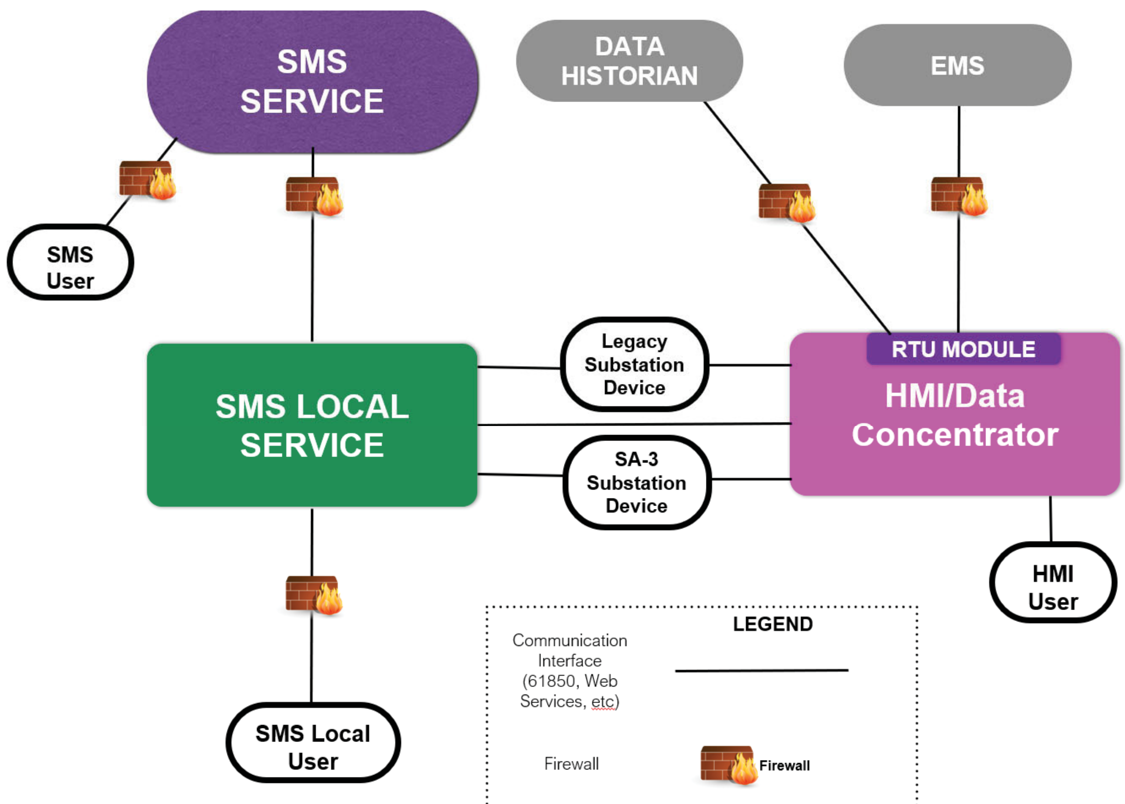

Figure 16. SA-3 System Services and Communication Interfaces

Services-Based

In the SA-3 Phase III project, the SMS services were defined with the following complementary applications targeted to serving the needs of both the local substation environment and a centralized environment:

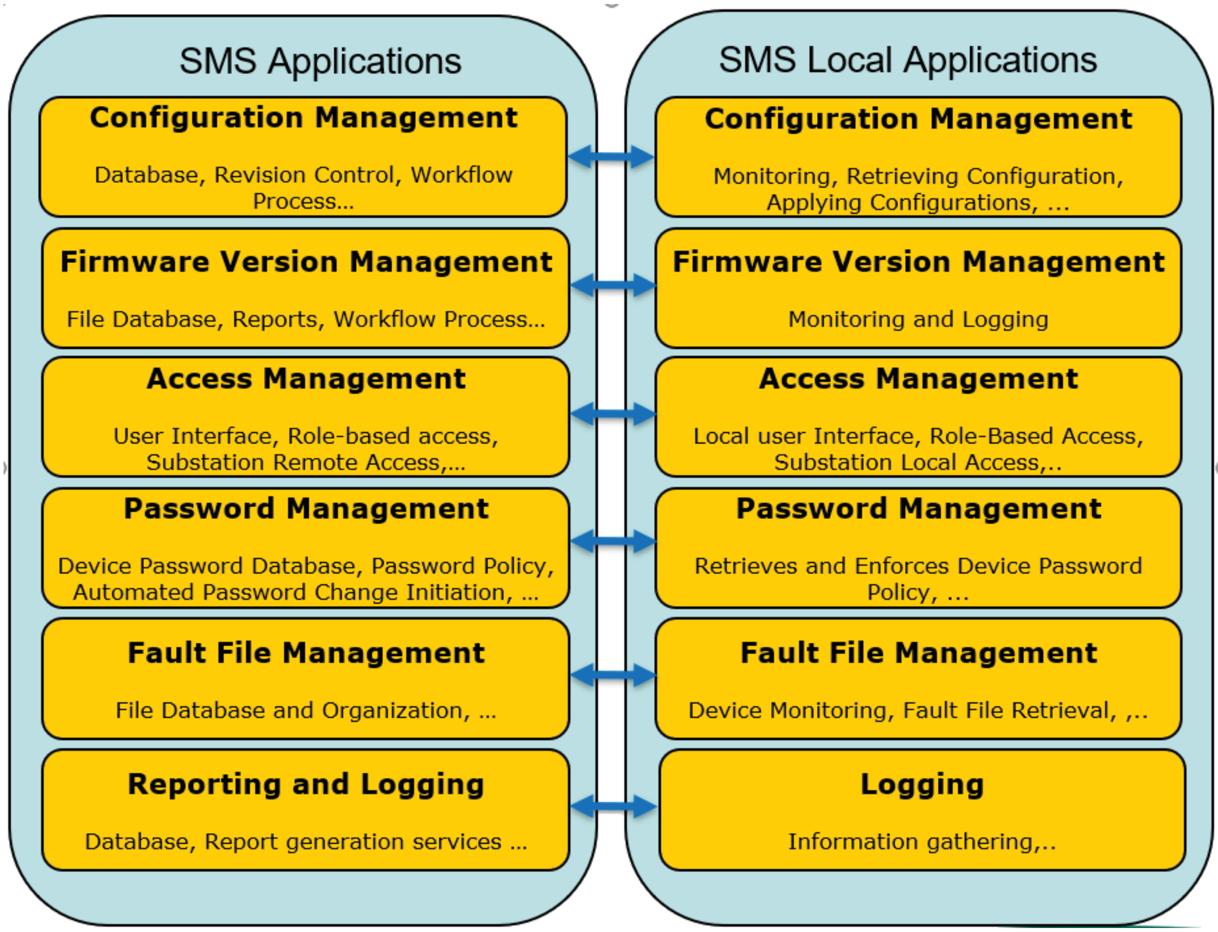

Figure 17. SMS Services-Oriented Architecture

4.9.3. Achievements

After a rigorous RFQ/RFP process, the SCE project team realized that no vendor had an SMS system readily available that could provide all of the specified options. The team opted to select the vendor that was closest to the mark, and through future efforts could expand its capabilities to fully realize the project's vision. A decision was made to test the off-the-shelf vendor implementation as the initial step. The project team worked closely with the selected vendor and SCE's cybersecurity team to mitigate cybersecurity concerns and evaluated how this system would integrate with the rest of SCE's system. The following features were demonstrated:

1. Secure Remote Engineering Access
This feature implements role-based access, which allows a user to be logged in remotely (at their allowed access level) to the end device. Remote access is accomplished by initiating a connection via SMS Remote to the individual device. Data access can be used for several purposes, such as retrieving settings, viewing real-time analog and digital values, or troubleshooting. Authorized remote access to substation devices reduces “windshield time” when device access or troubleshooting of a problem is required. Remote access is generally used as a backup method when data cannot be automatically retrieved by the SMS in an automated manner.

2. Password Management
Managing device passwords from a central location is a critical part of substation cybersecurity and compliance. The SA-3 system accomplishes password management by using the SMS as a central password repository, and the local component as the vehicle to change/update passwords at the substation level. If an authorized user requires a password for a device, the system employs a check-in/check-out feature in which the user is granted the password for a limited amount of time before it expires. Upon expiration or user check-in, the management system automatically changes the device password. All password transactions are securely logged and stored. The system is also capable of automatically changing passwords on a scheduled basis.

3. Automated Fault/Event File Retrieval Features
The SMS implements retrieval of Fault and Event records, which are data files that the relays create when there is a fault or anomaly on the power grid. They are used by skilled personnel to analyze and assist in diagnosing the system event. Upon detection of a new record in the device, the SMS Local retrieves and transfers it to the centralized SMS for processing and archiving. These records can then be used later for analysis if required. The system is also designed to consider possible failure modes such as when the device or SMS link is down, thus ensuring that no records are lost.

4. Firmware Version Monitoring
The SMS implements firmware version monitoring for devices. An initial baseline version is established when the system is initially set up, and upon detection of a new firmware version in the device, the SMS Local retrieves and transfers it to the SMS Remote for processing and archiving. These version changes can then be used later for analysis if required. The system also allows for notifications to controlled user groups to enable quick action.

5. Configuration Monitoring
The Configuration Monitoring service provides a mechanism for maintaining substation and IED configuration files, as well as a controlled process to ensure the consistency of these files. The monitoring system also allows for notifications to controlled user groups when there are inconsistencies between file versions.

6. Connectivity Monitoring
The Connectivity Monitoring service periodically checks for healthy device communications and sends alarms/notifications to controlled user groups when there are communication issues with the SMS.

4.9.4. SMS Architecture

The SMS architecture consists of back office and substation components. The vendor initially proposed a back office-centric solution, but SCE provided further requirements to segment the solution into more comprehensive remote and local components due mainly to cybersecurity concerns.

The back office components consist of many other systems that work together with the SMS to provide a comprehensive solution. Several of these systems, such as the cybersecurity and access control software, are controlled by IT/cybersecurity teams at SCE. Collaboration between both operational and IT groups was essential to successfully completing the SA-3 Phase III project.

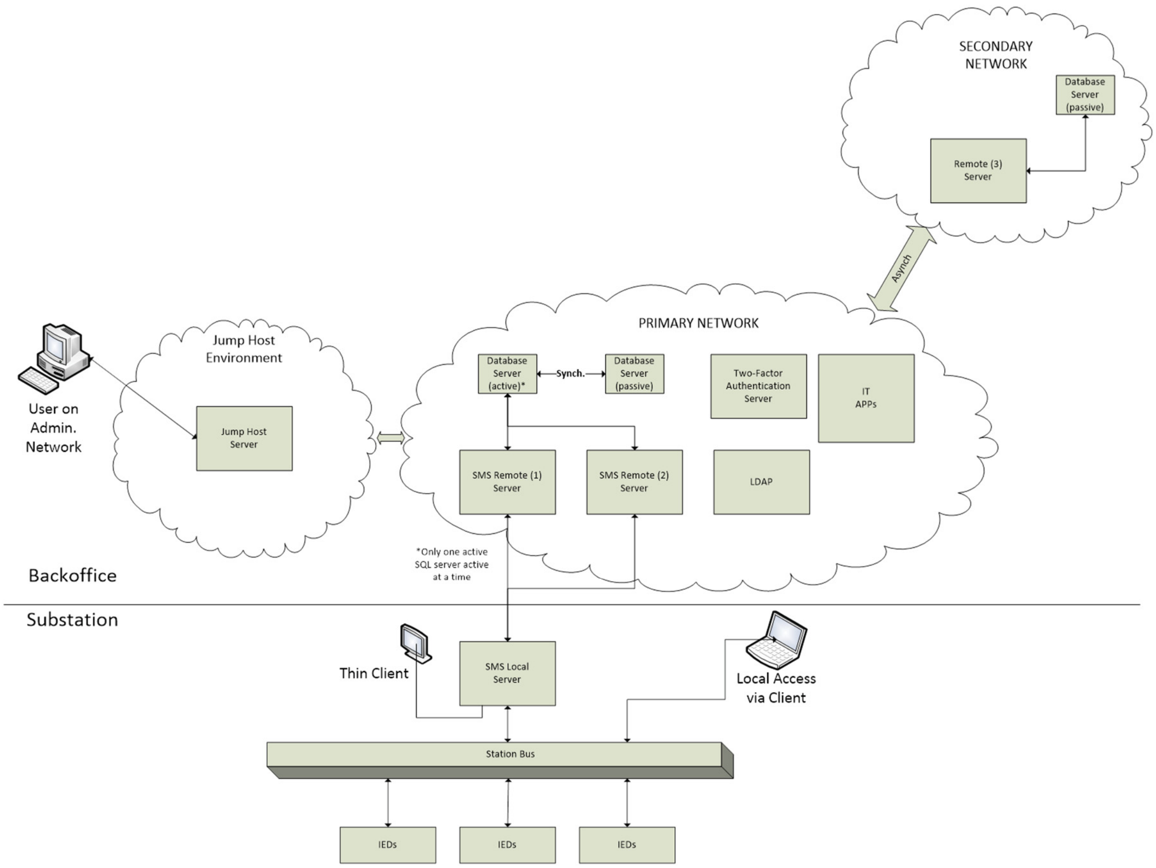

Figure 18. SMS Implementation Tested

4.9.4.1. Back Office Component

In the project, a jump host environment was used as the primary method for SMS users to access the system via a remote site, such as the office administration network environment. The system also provided reliable data communication by utilizing redundant databases for the stored data, plus a physically alternate back office location for additional redundancy. Lightweight Direct Access Protocol (LDAP) and two-factor authentication were used for access control to the system. The systems allows for integration to third-party applications that SCE's cybersecurity and IT teams can use for additional data aggregation and analysis.

4.9.4.2. Substation Component

A local component was used to satisfy several requirements such as system uptime, access control, and cybersecurity. Due to the critical nature of the data being stored, it was essential to ensure that processes would continue in the unlikely scenario that back office communications were severed. Therefore, the system was designed to continue functioning as normal even when there is a temporary disconnection to the back office. Traditional device access is performed by basic authentication mechanisms, such as the use of shared passwords, and requires the user to know the password. The method tested with the SMS included using it as a proxy to access the devices based on the user group's role and also make use of standard IT two-factor authentication methods. By proxy, the user is never required to know the device passwords, as the SMS automatically logs in the user to their designated level of access. By making use of SMS Local, the system provides an additional level of security due to the ability to segment the compromised substation.

4.9.4.3. Lessons Learned and Recommendations

System testing provided the opportunity to identify areas where improvement can be made on the devices and the system. The first major improvement covers all vendors, including device manufacturers. The need to develop standard interfaces for retrieving data is essential to minimize system integration issues and speed up the integration process from the SMS vendor. Some vendors' devices contained proprietary data and file types that were transferred over unsecured transfer protocols. This made certain functions such as configuration file monitoring limited, as the file could not be decoded by the SMS. IEC 61850 file types and standard IT secured interfaces and transfer protocols are preferred. Communication issues between the SMS Local and Remote were experienced; therefore, robust communications are required and highly valued. It is also critical to involve cybersecurity and IT personnel as stakeholders during the initial project planning stages.

4.10. Network

The substation LAN is the core communication avenue for a modern protection and control system and provides the necessary connectivity between substation relays and other substation devices to communicate and provide automated functions, metering, status, and alarms.

The SA-3 Phase III project included a redundant network using the PRP. The PRP enables critical devices on the network to continue normal operation in the event of a single network switch failure, providing the needed network reliability for the peer-to-peer communication schemes used in the SA-3 transmission stations.

Each redundant network consists of various network switches connected in a topology optimized for a combination of reduced latency with reliability and expandability. The diagram below presents an architectural overview of the substation network and its major components in the Protection & Control (P&C) system.

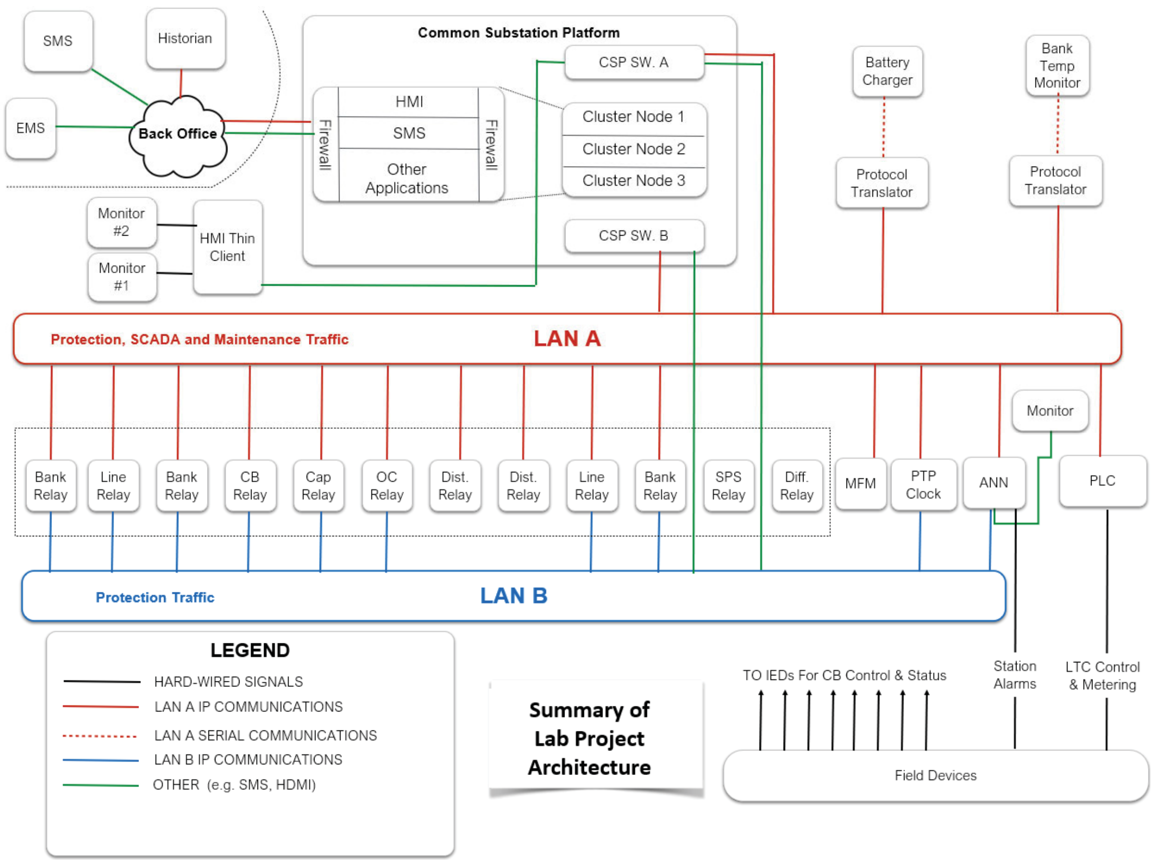

Figure 19. Project Architecture

As shown on the diagram above, there are two separate networks, each with a primary purpose. LAN A is the primary network for both SCADA communications and peer-to peer communications (GOOSE) to all devices. LAN B is primarily intended to provide a redundant communication channel for devices utilizing GOOSE messaging, and for alarms to the annunciator.

The following sections describe the various elements and components of the substation network and design choices for the SA-3 Phase III demonstration project.

4.10.1. Parallel Redundancy Protocol

The PRP is one of two network architectures that have been adopted as part of the IEC 61850 standard, and provides guaranteed zero-packet loss in case of a single failure by duplicating the network architecture. This is achieved by utilizing two separate, redundant networks with devices connecting to both networks simultaneously. Each Doubly Attached Node (Network Device) supporting the PRP will send the same packets on both networks; however, each receiving node or device will only take the first packet it receives and will ignore the packet on the second network.

This network architecture provides the greatest reliability, although with the added cost of duplicating the number of needed switches. It was the chosen redundancy technology for the LAN for the SA-3 Phase III project.

4.10.2. Network Switches

LAN A and LAN B are composed of independent networks, with the option to use two different switch manufacturers to provide diversity. Each substation LAN consists of Ethernet Switches with a combination of fiber optic and copper Ethernet ports. The network switches chosen for the substation network support the following connectivity.

- 100 Megabit 100FX Multimode Fiber Optic Ports: These are the majority of the switch ports and are used for connecting most substation relays and devices.
- 1000 Megabit 1000SX Multimode Fiber Optic Ports: These ports are used for switch-to-switch communication.
- 10/100/100 Megabit TX Ethernet Copper Ports: These ports are used for connecting devices not supporting fiber optic standards.

4.10.3. Substation Relays

The substation relays fall under two categories when it comes to network connectivity:

- Relays utilizing GOOSE: These have been specified to support the PRP and are connected to both networks.
- Relays that are not participating on a GOOSE messaging scheme: These do not require PRP and are only connected to LAN A.

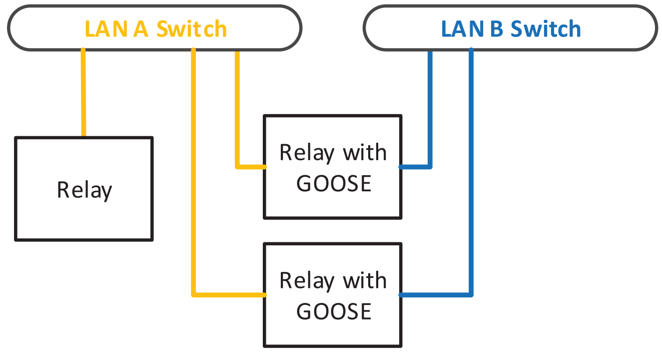

Figure 20. Simplified relays network connection

To provide an additional level of redundancy, the network design ensured that redundant relays, e.g., primary and backup protection, are not connected to the same switch on each of the redundant networks.

4.10.4. Network Technologies

As part of selecting a substation network, the project included standard networking technology utilizing Rapid Spanning Tree Protocol (RSTP), and a newer networking technology to the substation environment called Software-Defined Network.

The project demonstrated both technologies in parallel by utilizing an RSTP network for LAN A, and an SDN network for LAN B. The benefits of common RSTP networks are well known, while SDN was one of the technologies focused on in the demonstration.

SDNs have already proven valuable to data centers, but at the onset of this project they had yet to be deployed in a substation environment. The benefits the project team sought to demonstrate are as follows.

1. **Increased cybersecurity.** The switches themselves work similarly to a network firewall, denying all traffic by default. Also, all traffic moved through the network must be clearly defined.
2. **Settling time on network failures.** Traditional networking equipment has a settling time whenever a network failure is encountered. This means that the entire LAN is down for a small amount of time, typically from a few milliseconds to a couple of seconds. This is acceptable for networks used by most businesses, but not adequate for critical applications without the necessary redundancy. Because SDNs have pre-programmed traffic flows, the settling time in case of failure is negligible.
3. **Possible automated configuration**. SDNs are centrally configured and monitored by an SDN flow controller. Some of these controllers support open protocols that can be leveraged to create automated network configurations utilizing the same configuration files used for IEC 61850 devices.

The system demonstrated an SDN network consisting of five SND switches and a flow controller with the topology shown in the diagram below. The switches were configured with flows for normal traffic and alternate flows for abnormal conditions in the event of equipment failure.

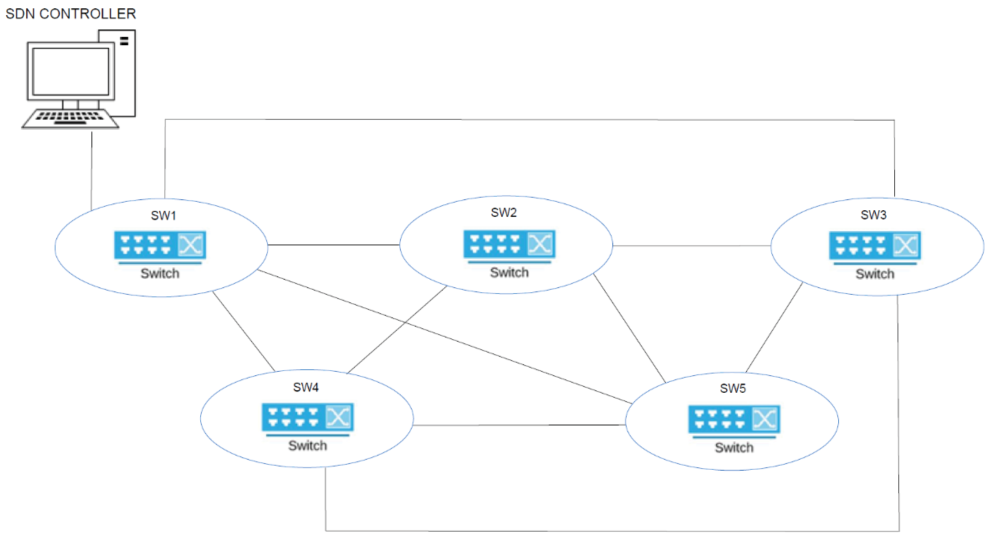

Figure 21. SDN Network

4.10.5. Results

The SA-3 Phase III project successfully demonstrated both RSTP and SDN technology applied to a substation in the laboratory environment. For SDNs, the demonstration proved that there are settling time efficiencies; however, these come at cost. Key findings included:

1. Engineering of the traffic flows is a significant effort requiring advanced networking knowledge not typically possessed by substation maintenance personnel.
2. Although IT network engineers have adequate knowledge of networking technology and cybersecurity considerations, there is a gap in understanding the power system protection functions and requirements to properly configure the data flows.
3. At the time of this work there were no commercially available flow controllers that could utilize standard IEC 61850 System Configuration Description (SCD) files to program flows. However, there were some early prototypes that showed promise and would alleviate items 1 and 2 above.
4. Cybersecurity requires adequate infrastructure for logging and monitoring network events. This means a significant investment by a utility with an infrastructure that may not be readily compatible with all SDN vendors' solutions, which could lower this technology's value proposition.

5. Milestones and Deliverables

Milestone Description	Milestone Date
SA-3 Phase III Project Use Case Requirements Development	Q4 2014
Engineering Job Walk	Q4 2015
SA-3 Racks Engineering Begins	Q2 2016
RFP to Procurement for Relay Racks Manufacturer for All SA-3 Equipment	Q3 2016
Design Specification for Fabrication Issued	Q4 2016
SA-3 Racks Fabrication Begins	Q1 2017
SMS Lab Installation	Q2 2017
SA-3 Racks Engineering Completed	Q3 2017
SDN in Configuration and Lab Testing	Q3 2017
SA-3 Racks Fabrication Completed	Q4 2017
SA-3 Racks Factory Acceptance Testing (FAT) Completed	Q1 2018
IT Network Design Update	Q2 2018
SMS Cybersecurity Update 1	Q3 2018
Network System Handover to OT for Lab Testing	Q1 2019
SMS Cybersecurity Update 2	Q2 2019
Cybersecurity Assessment Completed	Q2 2020
Final Evaluation and Testing Begin	Q3 2020
Lab Demonstrations Completed	Q4 2020

6. Overall Project Results/Achievements

The SA-3 Phase III demonstration was able to demonstrate a fully functional protection and control system in the laboratory environment with the targeted technologies. Most of the technologies were deemed ready to be deployed to the field; however, there are still several challenges in some areas of cybersecurity. The project concluded with laboratory testing of the transmission substation automation system and produced the following results. For additional information on lessons learned, see **Section 9, Lessons Learned and Recommendations.**

1. **Peer-to-peer communication for protection schemes.** GOOSE was shown to be reliable enough to use for protection applications when utilized with a PRP network. Some reduction in wiring and modules on substation relays was achieved, and processes for testing and deploying this type of technology were successfully demonstrated. This effort sets the foundation for future design of a fully digital substation where further wiring reduction and processes can be explored.
2. **High-availability network for devices providing critical communication functions.** The PRP was successfully implemented and tested on this system, with a few lessons learned for SCE's network team. The project team demonstrated the PRP with RSTP on one network and an SDN on the secondary network, as well as RSTP on both networks. The result was that a redundant network with the same technology is preferable, primarily because long-term operations, training, and maintenance were deemed to be less complex with this approach. The project team determined that the SDN evaluated in the other scenario required further refinements to be more easily maintained and supported in the substation environment.
3. **A new substation annunciator system.** To achieve cost reduction, the project team opted to utilize the IEC 61850 modern utility communications standard for replacing traditional hard wires used for the annunciator system (which indicates alarm conditions in the facility). The resulting system took advantage of the PRP network to provide the required reliability necessary for a transmission substation. It also demonstrated significant reduction in wiring necessary for this application and lessons learned in cybersecurity.
4. **IEEE 1588 PTP.** IEEE 1588 was demonstrated to provide adequate time synchronization accuracy for the current applications and upcoming process bus applications. The demonstration eliminated most of the legacy time synchronization methods, with only a few incompatible devices remaining. The incompatibilities that were found among different vendor implementations were resolved by the respective manufacturers. The encountered issues stemmed from how devices address leap years in an earlier version of the standard versus the most current version.

5. **External Routable Connectivity.** The demonstrated system included a use of SCE's previously developed CSP. This platform was leveraged to evaluate adding external routable connectivity to the substation, while addressing requirements for cybersecurity and NERC CIP compliance. The project team evaluated cybersecurity requirements and found various lessons learned on equipment capabilities and infrastructure needs. The findings triggered separate efforts within SCE to properly prepare for a network-connected substation and highlighted some of the changes vendors can implement in their products to further support system cybersecurity.
6. **Substation Management System.** A complete SMS system envisioned for the project is not currently available on the market; thus the project demonstrated a readily available system that met many of the identified requirements. The SMS chosen was evaluated to determine how such a system can help achieve NERC CIP compliance and how it can be integrated into current and future cybersecurity infrastructure. Results indicated that additional effort is required for any SMS system to be ready for field deployment. These efforts include organizational change management, and cybersecurity and compliance infrastructure and processes.

7. Value Proposition

The SA-3 Phase III project expanded on the results of SCE's ARRA-funded SA-3 distribution-level substation demonstration (part of the ISGD) by demonstrating a transmission substation architecture and new technologies that can provide cost reduction, capability and reliability improvements, compliance, and adaptability to emerging requirements. It evaluated a transition to a fully digital substation and centralized data collection and compliance. This design was demonstrated in a lab environment and tested through methods utilizing an RTDS. Since the project focused on a transmission substation, centrally managed cybersecurity measures needed to be put in place to meet NERC CIP standards. The majority of the demonstrated technologies can be applied to both transmission and distribution standards.

8. Metrics

The following metrics were identified for the SA-3 Phase III project and evaluated during project execution:

Identification of barriers or issues resolved that prevented widespread deployment of technology or strategy: The project successfully demonstrated both standard networking technology utilizing RSTP, and the newer SDN technology, as applied to a transmission-level substation in a laboratory environment. Because SDNs include pre-programmed data traffic flows, the demonstration showed that there are settling time efficiencies in the event of a network failure. However, the SDN benefits also create challenges:

- Engineering the traffic flows is a significant effort requiring advanced networking knowledge not typically possessed by substation maintenance personnel.

- At the time of this work, there were no commercially available flow controllers that could utilize standard IEC 61850 SCD files to program flows, although some early prototypes showed promise.
- Cybersecurity requires adequate infrastructure for logging and monitoring network events. This means a significant investment by a utility with an infrastructure that may not be readily compatible with all SDN vendors' solutions, which could lower this technology's value proposition.

A related barrier identified as a result of the SA-3 Phase III project is that most substation device manufacturers do not provide a means for centrally managing and updating device firmware; and existing utility processes do not allow for this, as it could result in critical components of the electric system being out of service. New tools and methods are needed for utilities to be able to deploy cybersecurity updates for relays in a substation with external routable connectivity.

SCE can analyze and quantify, where possible, the following sub-metrics when the project solution enters the production environment:

- Increased use of cost-effective digital information and control technology to improve reliability, security, and efficiency of the electric grid (PU Code § 8360)
- 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 cybersecurity (PU Code § 8360)
- Develop standards for communication and interoperability of appliances and equipment connected to the electric grid, including the infrastructure serving the grid (PU Code § 8360)
- Increased cybersecurity

For additional information related to project metrics, see **Sections 4 (Project Scope), 6 (Overall Project Results/Achievements), and 9 (Lessons Learned and Recommendations).**

9. Lessons Learned and Recommendations

The SA-3 Phase III project provided SCE with many lessons learned that could benefit the utility industry. The following list includes the more significant ones observed by the project team.

- Transitioning from a traditional hard-wired substation to a digital substation requires a well-thought-out change management plan. This transition involves significantly more than an engineering effort, as it affects the operational processes associated with these systems.

- Hands-on training proved to be critically important when implementing the IEC 61850 standard. While various vendors can provide basic overviews of the standard, this training does not readily translate into practical knowledge. Significant hands-on training with the utility-specific relays and testing tools is needed to speed up the transition to a digital substation. To address this during the project, at various times SCE involved field resources not normally part of the engineering process.
- GOOSE messaging can have many potential benefits if implemented properly. However, configuring the network and relays requires a combination of IT and Operational Technology (OT) knowledge, and this knowledge transfer takes a significant amount of time to achieve. Further efforts must ensure that the correct resources and training are available.
- Standardization of a single GOOSE message configuration tool is required. Ideally a single tool would be able to configure GOOSE messages on multiple devices. However, multi-vendor implementation of GOOSE messaging can be cumbersome to implement since each vendor's configuration tool works differently, and it might require going back and forth, importing and exporting Configured IED Description (CID) files between the multiple vendor tools.
- GOOSE messages as tested were designed for high-speed peer-to-peer communications and do not support desired cybersecurity features. Some of these issues have been addressed in the Routable GOOSE standard; however, that is more applicable to wide-area applications.
- Having a centralized SMS proved to be a challenge when attempting to integrate multiple vendors and device types. The project results were mixed since the centrally managed system needs to interrogate devices utilizing a variety of communication technologies that also include proprietary communication protocols. Such a system requires utilities to work with vendors in implementing standardized mechanisms for transferring configurations to devices, and interrogating information such as version firmware.
- SDN technology is promising. However, resources with the right mixture of IT and OT skills must be available, and consideration of how SDN fits into existing infrastructure must be made. An SDN controller capable of automatically configuring logic flows based on IEC 61850 configuration files could help lessen the knowledge gap.
- Cybersecurity practices require updating devices' software and firmware to mitigate vulnerabilities. This can be challenging for network-connected substation equipment such as relays, where upgrading firmware typically requires someone to be present in the substation to perform the upgrade. Most substation device manufacturers do not provide a means for centrally managing and updating device firmware; and existing utility practices do not allow for this, as it could result in critical components of the electric system being out of service. New tools and processes are needed for utilities to be able to deploy cybersecurity updates for relays in a substation with external routable connectivity.

- PRP is designed for high-availability/critical applications, and it worked very well in the project when completely isolated from other networks. However, there were some challenges with integrating PRP network redundancy with traditional network redundancy. This issue stemmed from the lack PRP-capable server-grade network cards, as well as the requirement for the redundant networks to be completely isolated from each other. Support of PRP network cards on hardened server-grade hardware is required for streamlined integration.
- Great care must be taken to ensure that PRP networks are not accidentally bridged together. In the project there was an instance of this, and it resulted in a broadcast storm that halted all network traffic, with some devices becoming unresponsive until they were restarted. In contrast, all substation relays participating in the GOOSE protection scheme were robust enough to continue operating properly during this scenario. To mitigate the likelihood of bridging the two PRP networks, measures put in place included separate racks for each set of network switches, and color-coded cables for each network. Additional measures for field deployment would include separate cable trays for each network.

10. Technology/Knowledge Transfer Plan

The key technology and knowledge transfer elements of the SA-3 Phase III project are as follows:

- **Market Products Influenced:** Through the project, the team found various incompatibilities among device manufacturers utilizing standards-based communications. This has resulted in product updates from various product vendors.
- **Industry Standards Informed:** The IEC 61850 standard was used extensively in the design, test, and implementation of the SA-3 system. Relevant findings will be shared with the IEC Standards Committee. The fully integrated system is expected to become SCE's new transmission substation control and protection systems design, and to provide updates to the distribution substation design with the demonstrated technologies. SCE also submitted a paper for consideration to the Institute of Electrical and Electronics Engineers (IEEE) on the methods utilized for GOOSE message testing; however, this paper was not published.
- **General Rate Case (GRC) Capital Request:** The validated control and protection design, once approved by SCE's standards group, will be used as the basis for all new and remodeled transmission substations. Funding for these substations will be requested as part of the normal GRC process.
- **Interaction with Other Utilities:** As a result of this project, other utilities have expressed in various aspects of the work and SCE's overall fully digital substation Strategy. This has led to discussions and possible partnerships in future digital substation efforts.

11. Procurement

Procurement for the SA-3 Phase III project proved to be challenging in two key areas:

Technology Availability

- The design of a complete substation requires devices from various manufacturers. Finding a complete set of devices that had implemented all of the essential technologies was not possible for this project, and thus some compromises had to be made. SCE expects this to be resolved over time as the implementation of the IEC 61850 standard becomes more consistent across devices manufacturers.
- In addition, the project envisioned an SMS with a set of well-defined features. However, a system that met all of the requirements also was not available, so one that met a set of high-priority features was selected.

Cybersecurity

- Substation devices provide a broad range of support for cybersecurity features, but it was not possible to integrate all devices with consistent cybersecurity mechanisms for the project. This was addressed by performing cybersecurity risk assessments; however, the assessments and required mitigation measures resulted in significant impacts to cost and schedule.

12. Stakeholder Engagement

Following are the SCE stakeholders that were involved in the SA-3 Phase III project:

Stakeholder Organization	Interest in the Project
Protection Automation	Applicable standards changes might affect team's workflow
Protection	Applicable standards changes might affect team's workflow
Substation Operations	Applicable standards changes might affect team's workflow
Asset Strategy Integration	Project management coordination
Substation Engineering: Primary Stakeholder	Will perform substation testing
Substation Test	IT Project Management will oversee the testing and deployment of the project's IT components
IT	Applicable standards changes might affect team's workflow
Cybersecurity	Will review and approve the cybersecurity requirements for this project

List of Acronyms

ARRA	American Recovery and Reinvestment Act
BFH	Breaker Fail High
BFI	Breaker Fail Initiate
CAPEX	Capital Expenditure
CB	Circuit Breaker
CID	Configured IED Description
CIP	Critical Infrastructure Protection
CPUC	California Public Utilities Commission
CSP	Common Substation Platform
CT/VT	Current Transformer/Voltage Transformer
DER	Distributed Energy Resources
DCS	Data Concentrator Service
DNP	Distributed Network Protocol
DUT	Device Under Test
EMS	Energy Management System
EPIC	Electric Program Investment Charge
EPRI	Electric Power Research Institute
FAT	Factory Acceptance Testing
GOOSE	Generic Object-Oriented Substation Event
GRC	General Rate Case
HMI	Human Machine Interface
HSR	High-Availability Seamless Redundancy
I/O	Hardware Input/Output
IEC	International Electrotechnical Commission
IED	Intelligent Electronic Device
IEEE	Institute of Electrical and Electronics Engineers
IOU	Investor-Owned Utility
IP	Internet Protocol
ISGD	Irvine Smart Grid Demonstration
IT	Information Technology
ITM	Intelligent Transformer Monitor
KA	Kiloampere
KV	Kilovolt
LAN	Local Area Network
LDAP	Lightweight Direct Access Protocol
LTC	Load Tap Changer
MFM	Multi-Function Meter
MMS	Manufacturing Message Specification
NERC	North American Electric Reliability Corporation
OPEX	Operating Expenditure
OT	Operational Technology
PAC	Programmable Automation Controller
P&C	Protection & Control (System)

PLC	Programmable Logic Controller
PRP	Parallel Redundancy Protocol
PT	Potential Transformer
PTP	Precision Time Protocol
QoS	Quality of Service
RFP	Request for Proposal
RFQ	Request for Qualifications
RMS	Root Mean Square
RSTP	Rapid Spanning Tree Protocol
RTD	Resistance Temperature Detector
RTDS	Real-Time Digital Simulator
SA-3	Substation Automation 3
SCADA	Supervisory Control and Data Acquisition
SCD	System Configuration Description
SCE	Southern California Edison
SCL	System Configuration Language
SDN	Software-Defined Network
SMS	Substation Management System
SV	Sampled Value
TCP	Transmission Control Protocol

Appendix C

Dynamic Power Conditioner

Final Project Report

Dynamic Power Conditioner
EPIC II Final Project Report

Developed by

SCE Transmission & Distribution, Asset Management, Strategy and Engineering

December 2020

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Acknowledgments

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1 Executive Summary

Batteries provide the ability to capture and store energy during times of low demand – when it is plentiful and inexpensive – and use it during times of high demand – when it is in short supply and more costly.

As more and more renewable resources such as solar and wind come online, batteries can help smooth out the fluctuations in these resources by storing the energy they generate and supplying it to the grid later when the sun isn't shining or the wind isn't blowing. Energy storage also can support local distribution circuits impacted by the high penetration of renewable resources, plus improve power quality.

To help evaluate the use of energy storage as a grid reliability and power quality asset, Southern California Edison (SCE) undertook the Dynamic Power Conditioner (DPC) project. This project demonstrated phase balancing (balancing load current on all three phases of a circuit) achieved by a DPC installed downstream of where this function was desired.

A DPC is a Battery Energy Storage System (BESS) that utilizes an enhanced inverter capable of phase balancing. It provides an advantage over traditional methods of phase balancing because it can perform this function dynamically and can balance loads in any increment. In contrast, traditional methods of performing phase balancing involve transferring load from one phase to another in very discrete quantities, as with manual switching operations. A DPC's capabilities potentially can reduce maintenance costs and achieve more accurate phase balancing on a circuit.

DPCs are not envisioned as replacements for traditional methods of phase balancing, but rather as an additional option for grid operators to utilize. Thus the intent of the project was to validate the ability of currently available inverter technology to perform the phase balancing function.

Overall, the project results indicated that a DPC installed for the sole purpose of phase balancing is technically capable of performing this function, but that this approach is currently neither practical nor cost-effective. However, if a BESS was installed to address a traditional energy storage use case, utilizing an inverter capable of phase balancing could add to the BESS' grid reliability support capabilities, thus providing system benefits.

2 Project Summary

One of the main objectives of electric utility distribution engineers is keeping the loading on all three phases on each circuit as closely balanced as possible. This minimizes neutral current flow and, as a result, improves power quality on the circuit. However, traditional methods of phase balancing are neither perfect nor always feasible in a distribution system. In addition, the issue of phase balancing is becoming more critical due to the increasing penetration of Distributed Energy Resource (DER) devices such as solar photovoltaic (PV) inverters deployed on residential rooftops, causing unpredictable loading and variable generation profiles. Load characteristics associated with electronically controlled customer-side loads also inject harmonics into the system, causing undesirable current flows on the neutral conductor.

Given these issues, SCE undertook the DPC project to evaluate this technology, which is a BESS that uses an enhanced inverter capable of phase balancing.

The benefits identified for this project included:

- **Increased Safety:** The enhanced inverter can balance the load on all three phases of a circuit and prevent the overloading of its neutral cable, thus preventing failure of the neutral cable and improving safety for utility workers and the public.
- **Improved Reliability:** Keeping the three phases of an electrical system balanced can 1) reduce the possibility of equipment failure and the tripping of protection equipment (thus helping to prevent outages due to high neutral current); 2) improve power quality; and 3) help prevent voltage sags.
- **Reduced Costs:** Installing the DPC can lower O&M costs by reducing or even eliminating the need for field crews to perform manual phase balancing operations. In addition, improving current phase imbalances can lead to lower energy and footprint requirements, and thus cost, for Energy Storage Systems.
- **Complementary Benefits:** Having a balanced three-phase power system can enable increased penetration of clean, inverter-based generation (e.g., solar PV, battery storage) on a circuit, which can decrease dependence on non-renewable resources.

In October 2017, SCE initiated a purchase order with Siemens Industry (now called Fluence) to procure and install a 250 kW / 250 kWh DPC at the Pomona Grid Technology Learning Center. System delivery was initially scheduled for January 2018, and final acceptance was to be completed in July 2018.

Several issues caused delays in the DPC installation, commissioning, and testing. These included the inability of the contractor and subcontractors to deliver system components during the initially planned timelines, the need to perform troubleshooting on several system integration issues, and work/travel restrictions that were imposed on SCE personnel and contractors due to the COVID-19 pandemic.

The DPC was installed at the Pomona Grid Technology Learning Center in June 2019. After installation, the project team began preliminary testing and troubleshooting. Several issues were discovered and addressed, and final acceptance of the fully functioning system occurred in November 2020. Measurement and verification took place in December 2020.

Although the project verified that the inverter evaluated was technically capable of performing phase balancing, there were still some limitations to the capability. The inverter did not have a neutral connection, so the phase balancing was only possible for phase-to-phase imbalances, and would not work for phase-to-neutral imbalances.

Overall, the project results indicated that installing a DPC for the sole purpose of performing phase balancing is currently neither practical nor cost-effective. However, if a BESS was installed to address a traditional energy storage use case, utilizing an inverter capable of phase balancing could add to the grid reliability support capabilities of the BESS.

In certain circumstances, using an inverter capable of phase balancing also potentially could decrease the energy footprint requirement of the BESS and, as a result, the cost. Phase balancing could be added to an EPC Power Corporation (EPC) Power-manufactured inverter through a firmware update, so if a BESS was installed on a circuit that did not initially have a large phase imbalance, and an imbalance was observed on the circuit at a future date, the feature could be utilized rather than traditional phase balancing methods.

The DPC project was implemented through the California Public Utilities Commission's (CPUC) Electric Program Investment Charge (EPIC) II Program.[1] EPIC aims to fund applied research and development, technology demonstrations and deployments, and market facilitation programs for the benefit of the electricity ratepayers of SCE and the state's other investor-owned utilities (IOUs). The utilities are limited to demonstrations, which focus on advancing the grid.

In reference to Figure 1, EPIC Investment Framework for Utilities, the DPC project addressed items in the categories of Renewables and Distributed Energy Resources Integration, and Grid Modernization and Optimization.

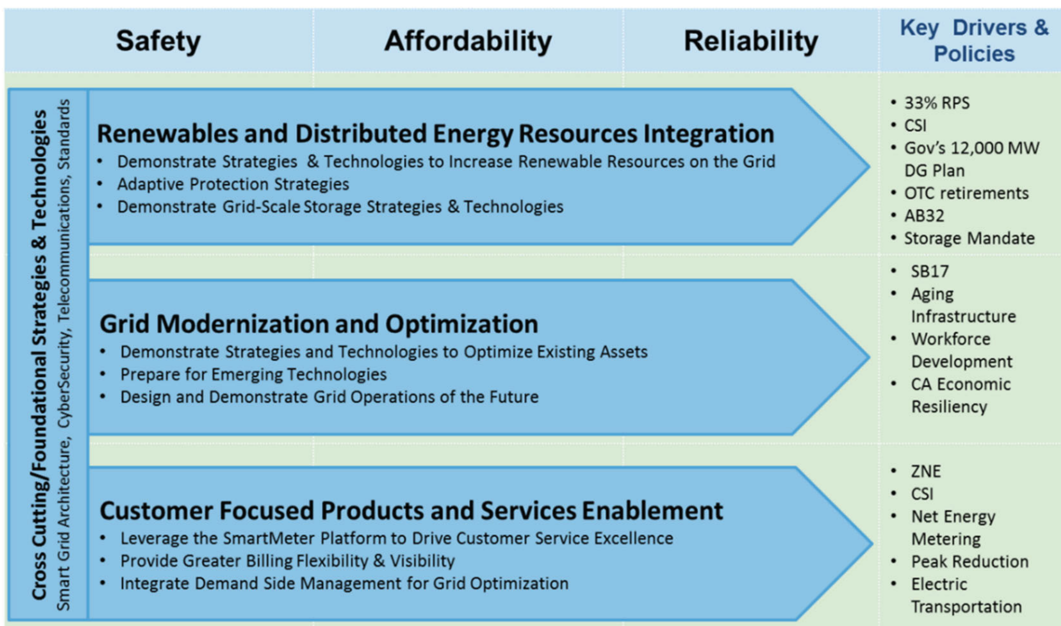

Figure 1. EPIC Investment Framework for Utilities[2]

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[1] 2015-2017 Investment Plan Application (A.)14-05-005.

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

2.1 Problem Statement

It is the responsibility of distribution engineers to balance loads on all three phases of the grid. To minimize neutral current flow and to optimize distribution system voltage, distribution engineers typically target having phase imbalances of less than 3% on the circuits for which they are responsible.

The issue of phase balancing is becoming more prevalent as more single-phase DER devices are deployed, such as solar PV inverters on residential rooftops. These DERs cause imbalanced loads due to the uneven distribution of single-phase transformers on distribution circuits (which requires manual reconfiguration), and because of areas with clustered DER installations that can impact the load profile and cause phase imbalances during part of the day.

Traditional methods of performing phase balancing consist of moving loads from one phase to another, which is achieved by sending out field crews to manually perform switching operations. As more DERs come online and add to phase imbalances, more field crews are needed for these switching operations, resulting in human resources and maintenance expenses. In addition, performing switching operations only allows for moving very discrete amounts of load, and this limitation sometimes make it difficult to achieve a less than 3% phase imbalance.

A DPC installed on a circuit can potentially perform phase balancing without the need to send out field crews to perform manual switching operations. DPCs also are not limited to transferring discrete amounts of load like manual switching operations are. This can result in reduced maintenance costs and more accurate phase balancing on the circuit.

In addition to performing phase balancing, under certain circumstances a DPC can decrease the energy footprint requirement of an Energy Storage System (ESS) and, as a result, the overall cost. For load shifting applications, Energy Storage Systems are typically sized to support the highest loaded phase on the circuit. If one phase is loaded significantly more than the other phases, that phase would typically result in the need for a larger capacity for the ESS. If a DPC initiates phase balancing on the circuit and reduces the current on the highest loaded phase, this would decrease the necessary size of the ESS.

2.2 Project Scope

The DPC project proposed to demonstrate the use of an actively controlled power flow device to mitigate phase balancing difficulties and to dynamically respond to circuit conditions.

During its execution, the project: 1) defined power flow control criteria; 2) established system requirements based on analysis of power flow control criteria; 3) procured equipment and services capable of actively performing phase balancing; and 4) demonstrated the use of the DPC at an SCE distribution circuit.

The DPC was installed at the Pomona Grid Technology Learning Center Advanced Energy Storage Test Pad by Fluence (contractor) and its subcontractors. SCE’s project team worked with Fluence to determine the best layout for the selected site. The final installed DPC is shown in Figure 2 below.

Figure 2. Fully Installed DPC

In addition to the Current Transformers required for the DPC's inverter to operate, SCE contractors installed power quality monitoring and data acquisition devices to take all of the measurements used for the test plan.

2.2.1 Phase Balancing Test

The purpose of the Phase Balancing Test was to validate the DPC's ability to perform load balancing on the switchgear to which the DPC was connected.

A custom test procedure for testing the phase balancing function was developed. The Pomona Grid Technology Learning Center consists of electrical infrastructure that allowed the project team to connect the DPC and a load bank to the same switchgear. The load bank was configured to only load two out of the three phases. This enabled the team to create imbalanced loads that the DPC had to balance. Results of the Phase Balancing Test are shown in the following figure.

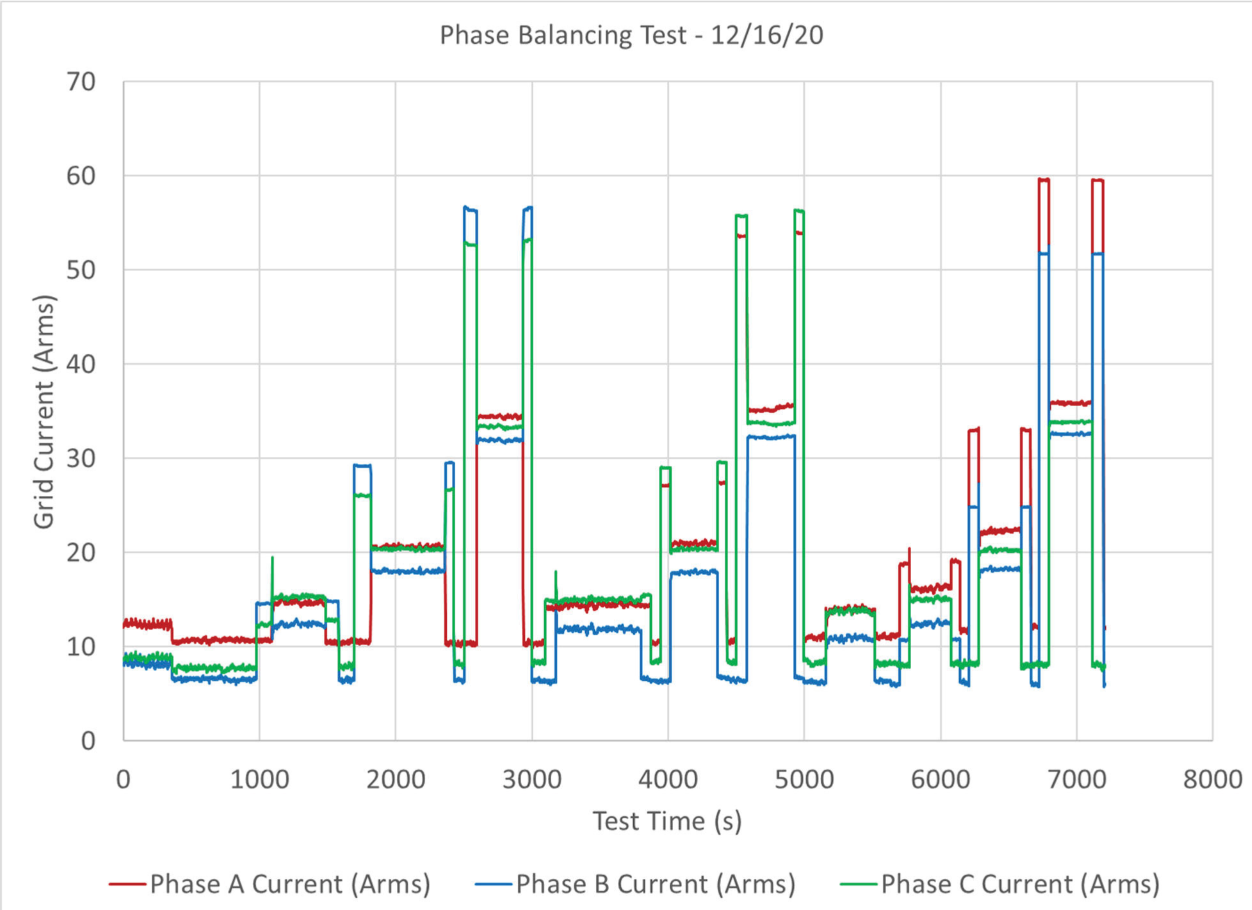

Figure 3. DPC Phase Balancing Test

2.3 Milestones/Deliverables

Following are the key milestones and deliverables for the DPC project:

Milestone/Deliverable Description	Milestone/Deliverable Date
Complete specification documents for hardware	Q2 2017
Source and initiate procurement of hardware	Q2 2017
Complete site preparation	Q2 2017
Energy Management System (EMS) cabinet and inverter completed	Q1 2019
Receive and install the system (required lab resources)	Q4 2019
Final acceptance (delayed due to COVID-19)	Q4 2019 – Q4 2020
Testing and evaluation	Q4 2020
Final report	Q4 2020

Table 1. Project Milestones and Deliverables

3 Project Results

The DPC testing verified its ability to perform traditional BESS functions such as dispatching manual real and reactive power commands, dispatching according to a schedule, and performing current and load limiting. There were some limitations to the phase balancing capability. For example, the inverter did not have a neutral connection, so the phase balancing was only possible for phase-to-phase imbalances, and would not work for phase-to-neutral imbalances. Overall, based on the project results, installing a DPC only for phase balancing is currently neither practical nor cost-effective. See Section 2, Project Summary, for more information on the project results.

3.1 Value Proposition

Via the DPC project, SCE demonstrated phase balancing through use of a DPC, a BESS that utilizes an enhanced inverter capable of performing this function. With the ability to achieve more accurate phase balancing on a circuit, a DPC potentially can provide grid reliability and power quality benefits, and its full capabilities potentially can result in reduced maintenance costs. In addition, improving current phase imbalances can lead to lower energy and footprint requirements (and thus costs) for BESS units.

4 Metrics

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

Safety, Power Quality, and Reliability: Although the project verified that the inverter evaluated was technically capable of performing phase balancing, there were still some limitations to the capability. As long as grid planners understand the capabilities and limitations, the DPC provides another tool that they can utilize under applicable conditions to enhance grid reliability and power quality.

Economic Benefits: The project indicated that using a DPC solely for phase balancing is currently neither practical nor cost-effective. However, if a BESS was installed to address a traditional energy storage use case, utilizing an inverter capable of phase balancing could lower O&M costs by reducing or even eliminating the need for field crews to perform manual phase balancing operations. In addition, improving current phase imbalances can lead to lower energy and footprint requirements, and thus costs, for Energy Storage Systems.

SCE can analyze and quantify, where possible, the following sub-metrics if the project solution enters the production environment:

- Outage number, frequency, and duration reductions
- Electric system power flow congestion reduction
- Reduced flicker and other power quality differences
- Maintain/reduce operations and maintenance costs
- Maintain/reduce capital costs
- Reduction in electrical losses in the transmission and distribution system

5 Lessons Learned/Recommendations

Key lessons learned from the DPC project include:

- The DPC inverter's load balancing capability was not completely ready when the project was first initiated, and required some additional development to make the demonstration possible. Project results indicated that a DPC installed for the sole purpose of phase balancing is technically able to perform this function, but with some capability limitations.
- A DPC installed only for phase balancing is currently neither practical nor cost-effective. This technology most likely will not replace traditional methods of balancing load on the distribution grid, but instead will supplement existing methods and serve as an additional tool for grid operators to perform their job.
- Using an inverter capable of phase balancing potentially can decrease the energy footprint requirement of a BESS and, as a result, the overall BESS cost. In certain situations, the inverter potentially can be added to an existing BESS in the form of a firmware update.

5.1 Technology/Knowledge Transfer Plan

In early 2020, SCE's DPC project consulting engineer gave a presentation on the project at the DISTRIBUTECH International Conference, an event that addresses technologies related to electricity delivery automation and control systems, renewable energy integration, transmission and distribution system operation and reliability, and other key industry topics. This enabled SCE to share information on the project and technology with interested stakeholders and broadly across the electric industry from utilities, Energy Service Providers, federal power agencies, commercial and industrial electricity end-users, and additional industry organizations.

6 Procurement

Procurement for the DPC project proved to be challenging, due to several vendor manufacturing issues.

The battery plant experienced capacity issues, which impacted the ability to deliver the selected project inverters according to the project schedule. Because SCE did not receive the inverters on schedule, and production of the inverters was subsequently discontinued, the project team did not have the technology to demonstrate phase balancing and the project was delayed. In Q4 of 2018, SCE worked with another manufacturer, EPC, to propose a DPC option that incorporated an EPC inverter and would be able to perform load balancing with some minor adjustments.

7 Stakeholder Engagement

The following were the key SCE project stakeholders for the DPC project:

Stakeholder Organization	Interest in the Project
Distribution Engineering	Additional benefits for Energy Storage Systems and the distribution system
Technology Strategy	New technology development

List of Acronyms

AES	Asset & Engineering Strategy
BESS	Battery Energy Storage System
CPUC	California Public Utilities Commission
CT	Current Transformer
DER	Distributed Energy Resources
DPC	Dynamic Power Conditioner
EMS	Energy Management System
EPC	EPC Power Corporation
EPIC	Electric Program Investment Charge
ESIP	Energy Storage Integration Program
ESS	Energy Storage System
IOU	Investor-Owned Utility
kW	Kilowatt
kWh	Kilowatt-Hour
O&M	Operations & Maintenance
PV	Photovoltaic
SCE	Southern California Edison