**BEFORE THE PUBLIC UTILITIES COMMISSION OF THE**

**STATE OF CALIFORNIA**

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|---|---|
| Application of the California Energy Commission for Approval of Electric Program Investment Charge Proposed 2015 through 2017 Triennial Investment Plan. | Application 14-04-034<br>(Filed April 29, 20014) |
| And Consolidated Matters. | Application 14-05-003<br>Application 14-05-004<br>Application 14-05-005 |

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


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Dated: **February 28, 2018**

**BEFORE THE PUBLIC UTILITIES COMMISSION OF THE**

**STATE OF CALIFORNIA**

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| Application of the California Energy Commission for Approval of Electric Program Investment Charge Proposed 2015 through 2017 Triennial Investment Plan. | Application 14-04-034<br>(Filed April 29, 2014) |
| And Consolidated Matters. | Application 14-05-003<br>Application 14-05-004<br>Application 14-05-005 |

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

In Ordering Paragraph 16 of Decision 12-05-037, the California Public Utilities Commission (CPUC or 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 2017. This is SCE's fourth annual report pertaining to its 2012-2014 EPIC Triennial Investment Plan (Application (A.) 12-11-004), after receiving Commission approval on November 14, 2013. And this is SCE's second annual report pertaining to its 2015-2017 EPIC Triennial Investment Plan (Application (A.) 14-05-005), after receiving Commission approval on April 9, 2015.

Respectfully submitted,

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February 28, 2018

# EPIC ADMINISTRATOR ANNUAL REPORT

# EPIC Annual Report

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## 1. Executive Summary

### a) Overview of Programs/Plan Highlights

2017 represented SCE's fourth 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] Year 2017 also represented almost three 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]

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

#### (1) 2012-2014 Investment Plan

For the period between January 1 and December 31, 2017, SCE expended a total of $3,802,219 toward project costs and $69,816 toward administrative costs for a grand total of $3,872,035. SCE's cumulative expenses over the lifespan of its 2012 – 2014 EPIC program amount to $35,185,276. SCE committed $37,723,624 toward projects and encumbered $17,612,776 through executed purchase orders during this period.

SCE executed 16 projects from its approved portfolio. Four projects were completed during calendar year 2016, eight were completed in 2017, and the remaining four are scheduled for completion in 2018. A list of completed projects is included in the Conclusion of this Report (section 4). In accordance with the Commission's directives,[5] SCE has completed final project reports for all projects and included them with the Annual Report according to the years completed. Reports completed in 2017 are included in the Appendix of this Annual Report.

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

### (2) 2015-2017 Investment Plan

For the period between January 1 and December 31, 2017, SCE expended a total of $11,003,917 toward project costs and $775,372 toward administrative costs for a grand total of $11,779,288. SCE's cumulative expenses over the lifespan of its 2015 – 2017 EPIC program amount to $18,063,399. SCE committed $38,212,859 toward projects and encumbered $24,385,306 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 in section (0. Project execution activities continued in 2017 on the remaining 10 projects. Of those 10 projects, the Advanced Metering Capabilities project was completed in 2017 and the final project report is attached in the Appendix. Nine demonstrations remain in execution.

## b) Status of Programs

### (1) 2012-2014 Investment Plan

As of December 31, 2017, SCE has expended $35,185,276[6] on program costs. Table 1 below summarizes the current funding status of SCE's EPIC projects:

**Table 1: 2012-2014 Triennial Investment Plan: 2017 Projects**

| |
|---|
| 1. Energy Resources Integration |
| • 4 Projects Funded<br>• Total Funding Committed: $2,875,480 |
| 2. Grid Modernization and Optimization |
| • 5 Projects Funded<br>o 1 Project Cancelled in Q2 2014[7]<br>o 1 Project Completed in 2015[8]<br>• Total Funding Committed: $11,156,801 |

---

6 SCE's cumulative project expenses amounted to $33,415,642 based on the project spreadsheet in Appendix A. SCE's cumulative administration expenses amounted to $1,093,108. SCE's accounting system calculates in-house labor overheads separately which amounted to $643,063 for projects and $33,463 for program administration. As a result, SCE expended a total of $35,185,276 on program costs.

7 SCE cancelled the Superconducting Transformer project in 2014. Please refer to the project's status update in Section 4 for additional details.

8 Portable End-to-End Test System.

| 3. Customer Focused Products and Services |
|---|
| • 3 Projects Funded<br>o 1 Project Completed in 2015[9]<br>• Total Funding Committed: $3,628,814 |
| 4. Cross-Cutting/Foundational Strategies and Technologies |
| • 4 Projects Funded<br>o 1 Project Completed in 2015[10]<br>• Total Funding Committed: $20,062,529 |
| Total Projects Funded: 16<br>Total Funding Committed: $37,723,624[11]<br>*Note: Due to intrinsic variability in TD&D /R&D projects, amounts shown are subject to change* |

Table 2 below summarizes SCE's 2017 administrative expenses:

**Table 2: 2012-2014 Triennial Investment Plan: 2017 Administration**

| | |
|---|---|
| • Program Administration | Total Funding Committed: $1,200,105<br>Total 2017 Cost: $69,816<br>Total Cumulative Cost: $1,126,571 |

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

As of December 31, 2017, SCE has expended $18,063,399 [12] on program costs.

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

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

| 1. Energy Resources Integration |
|---|
| • 3 Projects Funded<br>• Total Funding Committed: $568,874 |
| 2. Grid Modernization and Optimization |
| • 6 Projects Funded<br>• Total Funding Committed: $17,763,175 |

---

9 Outage Management & Customer Voltage Data Analytics.

10 Cyber-Intrusion Auto-Response and Policy Management System.

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

12 SCE's cumulative project expenses amounted to $15,940,410 based on the project spreadsheet in Appendix A. SCE's cumulative administration expenses amounted to $1,817,504. SCE's accounting system calculates in-house labor overheads separately, which amounted to $256,942 for projects and $48,543 for program administration. As a result, SCE expended a total of $18,063,399 on program costs.

| |
|---|
| 3. Customer Focused Products and Services |
| • 3 Projects Funded<br>• Total Funding Committed: $3,533,975 |
| 4. Cross-Cutting/Foundational Strategies and Technologies |
| • 1 Projects Funded<br>• Total Funding Committed: $16,346,835 |
| Total Projects Funded: 13<br>Total Funding Committed: $38,212,859[13]<br>*Note: Due to intrinsic variability in TD&D /R&D projects, amounts shown are subject to change* |

Table 4 below summarizes SCE's 2017 administrative expenses:

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

| | |
|---|---|
| • Program Administration | Total Funding Committed: $2,760,371<br>Total 2017 Cost: $775,372<br>Total Cumulative Cost: $1,866,047 |

## 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[14] with an annual budget of $162 million.[15] 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.[16] The IOUs were also limited to only the area of Technology Demonstration and Deployment (TD&D) activities.[17] SCE was allocated 41.1% of the budget and administrative activities.[18]

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[13] For additional details regarding SCE's Committed Funds, please see the attached spreadsheet.
[14] D.12-05-037, OP1.
[15] D.12-05-037, OP7.
[16] *Id*, OP5.
[17] *Id*.
[18] D.12-05-037, OP 7, as modified by D.12-07-001.

The Commission approved SCE's 2012-2014 Investment Plan[19] in D.13-11-025 on November 19, 2013. SCE submitted its 2015-2017 Investment Plan Application[20] on May 1, 2014 and the Commission approved the Application in D.15-04-020 on April 9, 2015. SCE is currently executing its 2012-2014 and 2015-2017 EPIC Investment Plans.

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

The Commission limited SCE's involvement in the first two EPIC triennial cycles (2012-2014 and 2015-2017) 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.[21]

In accordance with the Commission's requirement for TD&D projects, for the 2015-2017 Investment Plan the IOUs continue to successfully utilize the joint IOU framework developed for the 2012-2014 cycle. 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 and 2015-2017 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) <u>EPIC Program Regulatory Process</u>**

The Commission approved SCE's 2012-2014 Application[22] in D.13-11-025 on November 19, 2013. SCE submitted its 2015-2017 Investment Plan Application[23] on May 1, 2014 and the Commission approved the Application in D.15-04-020 on April 9, 2015. The Commission opened a

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19 A.12-11-004.
20 A.14-05-005.
21 D.12-05-037, OP3.B.
22 A.12-11-004.
23 A.14-05-005.

phase II of the proceeding to address projects proposed after Commission approval of an Investment Plan. The Commission issued its Phase II Decision,[24] 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. In compliance with the Commission's requirements for the EPIC Program,[25] SCE submits its 2017 Annual Report to update the Commission and stakeholders on SCE's program implementation.

**d) Coordination**

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

- Several meetings in September 2017 to review proposed 2018-2020 investment plan projects and make sure there is no overlap in scope;
- Several meetings after the EPIC audit to discuss findings and coordinate positions on recommendations and follow-up actions;
- The EPIC Fall Symposium in San Diego on October 18th, 2017;
- Coordination prior to the 2018-2020 Investment Plan filing on May 1st 2017.

SCE also supported the CEC's execution of its 2012-2014 and 2015-2017 Investment Plans. The EPIC Administrators met on a near-weekly basis to discuss the items mentioned above, coordinate investment plan activities, and to plan and coordinate joint stakeholder workshops and the annual joint public symposium. Moreover, SCE had several collaborative meetings with the CEC to help further coordinate the respective investments plans.

In 2017, SCE's Electric Access System Enhancement (EASE) project 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 to the CEC for match

24 D.15-09-005.

25 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.

funding and was granted $2M. This 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.

**e) Transparent and Public Process/CEC Solicitation Activities**

Beginning in the last quarter of 2016, SCE held numerous meetings with stakeholders to formulate proposals for EPIC III projects. Commencing in 2017, suggested projects were vetted internally and reviewed for strategic alignment with company, Commission, and legislative goals. This process culminated in the EPIC III filing on May 1, 2017.

In August 2017, SCE worked together with the CEC and IOUs to review EPIC III initiatives develop synergies and help ensure there is no overlap between Investment Plans. On September 8, 2017, SCE supported and participated in a public workshop at the Commission. There, SCE provided its EPIC III program overview and supported discussions on intellectual property, consumer price index, the advice letter process, any post-EPIC 3 proposals, and clarification of contracting requirements.

On October 18, 2017, SCE supported the public Fall EPIC Symposium in San Diego, CA. SCE gave presentations on the following Next Generation Distribution Automation subprojects: 1) High Impedance Fault Detection (Hi Z) and 2) Underground Remote Fault Indicator (RFI) projects. Final project reports for the Hi Z and above-ground RFI are complete and are attached to this EPIC Annual Report.

SCE supported numerous parties applying for CEC EPIC funding in 2017. A total of 104 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 92 LOSs and 12 LOCs. Of these requests, 71 LOSs and 10 LOCs 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. <u>Budget</u>**

**a) <u>Authorized Budget</u>**

**(1) <u>2012 – 2014 Investment Plan</u>**

**Table 5: 2017 Authorized EPIC Budget**

| 2017<br>(Jan 1 - Dec 31) | Administrative | Project Funding | Commission Regulatory Oversight Budget |
|---|---|---|---|
| SCE Program | $1.3M | $11.9M | $0.33M[26] |
| CEC Program | $5.3M | $47.7M | |

**(2) <u>2015 – 2017 Investment Plan</u>**

**Table 6: 2017 Authorized EPIC Budget**

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

**b) <u>Commitments/ Encumbrances</u>**

**(1) <u>2012 – 2014 Investment Plan</u>**

As of December 31, 2017, SCE has committed $39,749,454 and encumbered $17,955,622 of its authorized 2012-2014 program budget.

26 Advice Letter, 2747-E, p. 6.

(2) **2015 – 2017 Investment Plan**

As of December 31, 2017, SCE has committed $41,694,600 and encumbered $26,667,083 of its authorized 2015-2017 program budget.

For CEC remittances, SCE remitted $1,613,220 for program administration, and $53,868,308 for encumbered projects during calendar year 2017.

For CPUC remittances, SCE remitted $401,023 in calendar year 2017.

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

(1) **2012 – 2014 Investment Plan**

As of December 31, 2017, SCE has spent $6,320,356[27] on in-house activities.

(2) **2015 – 2017 Investment Plan**

As of December 31, 2017, SCE has spent $2,139,974[28] on in-house activities.

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

(1) **2012 – 2014 Investment Plan**

As of December 31, 2017, SCE does not have any pending fund shifting requests and/or approvals.

(2) **2015 – 2017 Investment Plan**

As of December 31, 2017, SCE does not have any pending fund shifting requests and/or approvals.

e) **Uncommitted/Unencumbered Funds**

(1) **2012 – 2014 Investment Plan**

As of December 31, 2017, SCE has $0 in uncommitted/unencumbered funds.

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[27] SCE expended a total of $5,677,293 on in-house activities through 2017 based on the project spreadsheet in Appendix A. SCE's accounting systems calculates in-house labor overheads separately, which amounted to $643,063. As a result, SCE expended a total of $6,320,356 on in-house costs.

[28] SCE expended a total of $1,883,032 on in-house activities through 2016 based on the project spreadsheet in Appendix A. SCE's accounting systems calculates in-house labor overheads separately, which amounted to $256,942. As a result, SCE expended a total of $2,139,974 on in-house costs.

**(2) 2015 – 2017 Investment Plan**

As of December 31, 2017, SCE has $0 in uncommitted/unencumbered funds.

**f) Joint CEC/SCE Projects**

As of December 31, 2017, the only project with CEC participation is the DOE-funded EASE project described in section 2d of this Report. For this project, the CEC is providing match funding.

**g) High-Level Summary**

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

**h) Project Status Report**

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

i) **Description of Projects:**

(i) **Investment Plan Period**

(ii) **Assignment to Value Chain**

(iii) **Objective**

(iv) **Scope**

(v) **Deliverables**

(vi) **Metrics**

(vii) **Schedule**

(viii) **EPIC Funds Encumbered**

(ix) **EPIC Funds Spent**

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

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

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

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

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

j) **Status Update**

The following project descriptions for the objective and scope reflect the proposals filed in the EPIC Investment Plans[29], while the projects' status information show progress as of December 31, 2017.

[29] 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.

## (1) 2012 – 2014 Triennial Investment Plan Projects

1. Integrated Grid Project – Phase 1

<table>
<tr><td>Investment Plan Period:<br>1st Triennial Plan (2012-2014)</td><td>Assignment to value Chain:<br>Grid Operation/Market Design</td></tr>
<tr><td colspan="2">Objective & Scope:<br>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.<br><br>This value-oriented demonstration informs many key questions that have been asked:<br><br>• What is the value of distributed generation and where is it most valuable?<br>• What is the cost of intermittent resources?<br>• What is the value of storage and where is it most valuable?<br>• How are DER resources/devices co-optimized?<br>• What infrastructure is required to enable an optimized solution?<br>• What incentives/rate structure will enable an optimized solution?</td></tr>
<tr><td colspan="2">Deliverables:<br>• An IGP cost/benefit analysis and business case<br>• A systems requirement specification<br>• An IGP demonstration architecture<br>• 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<br>• A data management and integration architecture supporting the overarching IGP architecture<br>• A supporting network and cybersecurity architecture for the IGP architecture<br>• Incentive structures that encourage technology adoption that provide benefits to overall system operations<br>• A volt/Var optimization strategy<br>• RFPs to secure control vendor solutions for the field demonstration phase of the IGP project<br>• IGP lab demonstration using a simulated environment<br>• 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)<br>7l. Identification and lowering of unreasonable or unnecessary barriers to adoption of smart grid technologies, practices, and services (PU Code § 8360)<br>8b. Number of reports and fact sheets published online<br>8d. Number of information sharing forums held<br>8f. Technology transfer<br>9b. Number of technologies eligible to participate in utility energy efficiency, demand response or distributed energy resource rebate programs<br>9c. EPIC project results referenced in regulatory proceedings and policy reports<br>9d. Successful project outcomes ready for use in California IOU grid (Path to market) |
| **Schedule:**<br>IGP Phase 1: Q2 2014 – Q4 2017 |

| **EPIC Funds Encumbered:** | **EPIC Funds Spent:** |
|---|---|
| $11,234,429 | $17,397,139 |

| |
|---|
| **Partners:**<br>None |

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

| |
|---|
| **Treatment of Intellectual Property**<br>SCE has no current patents or licensing agreements signed. Future Intellectual Property is to be determined. |
| **Status Update**<br>The EPIC I Final Report for the Integrated Grid Project is complete, is being submitted with the 2017 Annual Report, and will be posted on SCE's public EPIC web site. |

2. Regulatory Mandates: Submetering Enablement Demonstration

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

| |
|---|
| **Objective & Scope:**<br>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:**<br>1. Submetering Protocol Report<br>2. Manual Subtractive Billing Procedure<br>3. 3PE Final Report and Recommendation |
| **Metrics:**<br>6a. TOTAL number of SCE customer participants (Phase 1 & 2 each have 500 submeter limit)<br>6b. Number of SCE NEM customer participants (Phase 1 & 2 each have 100 submeter limit of 500 total)<br>6c. Submeter MDMA on-time delivery of customer submeter interval usage data<br>6d. Submeter MDMA accuracy of customer submeter interval usage data |
| **Schedule:**<br>Q1 2014 – Q1 2017 |

| | |
|---|---|
| **EPIC Funds Encumbered:**<br>$0 | **EPIC Funds Spent:**<br>$1,138,359 |

| |
|---|
| **Partners:**<br>N/A |

| | | |
|---|---|---|
| **Match Funding:**<br>N/A | **Match Funding split:**<br>N/A | **Funding Mechanism:**<br>N/A |

| |
|---|
| **Treatment of Intellectual Property**<br>SCE has no current patents or licensing agreements signed. Future Intellectual Property is to be determined. |
| **Status Update**<br>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:**<br>1st Triennial Plan (2012-2014) | **Assignment to value Chain:**<br>Distribution |

| |
|---|
| **Objective & Scope:**<br>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. |

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| **Deliverables:**<br>• Grid LAB-D user interface<br>• SCE circuit model<br>• Updated GridLAB-D to handle Cyme 7 database<br>• Base cases & benchmark<br>• Specifications for test cases from stakeholders<br>• Created test cases<br>• Periodic updates/meetings with stakeholders<br>• Executed test cases<br>• Final project report |
| **Metrics:**<br>1d. Number and percentage of customers on time variant or dynamic pricing tariffs<br>1g. Percentage of demand response enabled by automated demand response technology (e.g. Auto DR)<br>5c. Forecast accuracy improvement<br>7b. Increased use of cost-effective digital information and control technology to improve reliability, security, and efficiency of the electric grid (PU Code § 8360)<br>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)<br>7e. Development and incorporation of cost-effective demand response, demand-side resources, and energy-efficient resources (PU Code § 8360)<br>8c. Number of times reports are cited in scientific journals and trade publications for selected projects<br>8d. Number of information sharing forums held<br>8f. Technology transfer<br>9b. Number of technologies eligible to participate in utility energy efficiency, demand response or distributed energy resource rebate programs<br>9c. EPIC project results referenced in regulatory proceedings and policy reports<br>9d. Successful project outcomes ready for use in California IOU grid (Path to market) |
| **Schedule:**<br>Q1 2014 – Q1 2017 |

| **EPIC Funds Encumbered:** | **EPIC Funds Spent:** |
|---|---|
| $0 | $1,071,128 |

| **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 |
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| 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:**<br>1st Triennial Plan (2012-2014) | **Assignment to value Chain:**<br>Demand-Side Management |
| --- | --- |
| **Objective & Scope:**<br>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.<br><br>Three project objectives include:<br>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:**<br>• "Enabling Communication Unification" status report<br>• Written specifications for all three class of devices (EVSEs, solar inverters, and RESUs)<br>• "Industry Harmonization and Closing Gaps" report<br>• Receive devices for testing<br>• Complete final report and recommendations | |
| **Metrics:**<br>1a. Number and total nameplate capacity of distributed generation facilities<br>1b. Total electricity deliveries from grid-connected distributed generation facilities<br>1c. Avoided procurement and generation costs<br>1e. Peak load reduction (MW) from summer and winter programs<br>1f. Avoided customer energy use (kWh saved)<br>1g. Percentage of demand response enabled by automated demand response technology (e.g. Auto DR)<br>3f. Improvements in system operation efficiencies stemming from increased utility dispatchability of customer demand side management<br>5b. Electric system power flow congestion reduction<br>5f. Reduced flicker and other power quality differences<br>5i. Increase in the number of nodes in the power system at monitoring points | |

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| 7b. Increased use of cost-effective digital information and control technology to improve reliability, security, and efficiency of the electric grid (PU Code § 8360)<br>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)<br>7d. Deployment and integration of cost-effective distributed resources and generation, including renewable resources (PU Code § 8360)<br>7e. Development and incorporation of cost-effective demand response, demand-side resources, and energy-efficient resources (PU Code § 8360)<br>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)<br>7g. Integration of cost-effective smart appliances and consumer devices (PU Code § 8360)<br>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)<br>7j. Provide consumers with timely information and control options (PU Code § 8360)<br>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)<br>7l. Identification and lowering of unreasonable or unnecessary barriers to adoption of smart grid technologies, practices, and services (PU Code § 8360)<br>8b. Number of reports and fact sheets published online<br>8d. Number of information sharing forums held.<br>8f. Technology transfer<br>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<br>9b. Number of technologies eligible to participate in utility energy efficiency, demand response or distributed energy resource rebate programs<br>9c. EPIC project results referenced in regulatory proceedings and policy reports<br>9d. Successful project outcomes ready for use in California IOU grid (Path to market) |
| **Schedule:**<br>Q3 2014 – Q4 2017 |
| **Partners:**<br>N/A |

| **Match Funding:**<br>N/A | **Match Funding split:**<br>N/A | **Funding Mechanism:**<br>N/A |
|---|---|---|

| **Treatment of Intellectual Property**<br>SCE has no current patents or licensing agreements signed. Future Intellectual Property is to be determined. |
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| 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:**<br>1st Triennial Plan (2012-2014) | **Assignment to value Chain:**<br>Transmission |
| --- | --- |
| **Objective & Scope:**<br>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:**<br>• PETS portable RTDS test equipment<br>• PETS operating instructions<br>• PETS standard test report<br>• Final project report | |
| **Metrics:**<br>3a. Maintain / reduce operations and maintenance costs<br>5a. Outage number, frequency and duration reductions<br>6a. Reduce testing cost<br>6b. Number of terminals tested on a line (more than 2 terminals/substations)<br>7b. Increased use of cost-effective digital information and control technology to improve reliability, security, and efficiency of the electric grid (PU Code § 8360)<br>8b. Number of reports and fact sheets published online<br>8d. Number of information sharing forums held<br>8f. Technology transfer<br>9c. EPIC project results referenced in regulatory proceedings and policy reports<br>9e. Technologies available for sale in the market place (when known) | |
| **Schedule:**<br>Q1 2014 – Q4 2015 | |
| **EPIC Funds Encumbered:**<br>$0 | **EPIC Funds Spent:**<br>$39,564 |
| **Partners:**<br>N/A | |

| Match Funding: | Match Funding split: | Funding Mechanism: |
| --- | --- | --- |
| N/A | N/A | N/A |
| **Treatment of Intellectual Property**<br>SCE has no current patents or licensing agreements signed. Future Intellectual Property is to be determined. | | |
| **Status Update**<br>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: | Assignment to value Chain: |
| --- | --- |
| 1st Triennial Plan (2012-2014) | Transmission |
| **Objective & Scope:**<br>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:**<br>• Demonstration design specification<br>• Construction documents: drawings, cable schedule, and bill of material<br>• Monitoring console software and hardware<br>• Advanced Volt/VAR Control (AVVC) testing<br>• Field deployment<br>• Controller operation monitoring and adjustment<br>• AVVC final report and closeout | |
| **Metrics:**<br>3a. Maintain / reduce operations and maintenance costs<br>3c. Reduction in electrical losses in the transmission and distribution system<br>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<br>7b. Increased use of cost-effective digital information and control technology to improve reliability, security, and efficiency of the electric grid (PU Code § 8360)<br>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)<br>8b. Number of reports and fact sheets published online<br>8d. Number of information sharing forums held<br>8f. Technology transfer | |

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|---|
| 9c. EPIC project results referenced in regulatory proceedings and policy reports<br>9d. Successful project outcomes ready for use in California IOU grid (Path to market) |

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| **Schedule:**<br>Q1 2014 – Q4 2018 |

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|---|---|
| **EPIC Funds Encumbered:**<br>$563,428 | **EPIC Funds Spent:**<br>$523,719 |

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| **Partners:**<br>N/A |

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|---|---|---|
| **Match Funding:**<br>N/A | **Match Funding split:**<br>N/A | **Funding Mechanism:**<br>N/A |

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| **Treatment of Intellectual Property**<br>SCE has no current patents or licensing agreements signed. Future Intellectual Property is to be determined. |
| **Status Update**<br>In 2017, the project accomplished the following:<br>1) Developed a Business Requirement Document and an Implementation Plan detailing how the Volt and Var Optimization demonstration will be formulated, implemented, and integrated with existing SCE systems.<br>2) Implemented User Interfaces for the Voltage and Var Optimization tool.<br>3) Implemented the Security Constrained Optimal Power Flow Formulation and Solution.<br>4) Implemented a data conversion module to allow reading data from the Energy Management System into the Voltage and Var Optimization tool.<br><br>This project is scheduled for completion in 2018. |

7. Superconducting Transformer (SCX) Demonstration

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| **Investment Plan Period:**<br>1st Triennial Plan (2012-2014) | **Assignment to value Chain:**<br>Distribution |

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| **Objective & Scope:**<br><br>This project was cancelled in 2014. No further work is planned.<br><br>*Original Project Objective and Scope:*<br>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. |

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

8. State Estimation Using Phasor Measurement Technologies

| **Investment Plan Period:**<br>1st Triennial Plan (2012-2014) | **Assignment to value Chain:**<br>Grid Operation/Market Design |
|---|---|
| **Objective & Scope:**<br>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:**<br>• Demonstrated algorithm performance based on observations.<br>• Report that addresses tests conducted and test results.<br>• Final project report. | |
| **Metrics:**<br>6a. Enhanced grid monitoring and on-line analysis for resiliency<br>7b. Increased use of cost-effective digital information and control technology to improve reliability, security, and efficiency of the electric grid (PU Code § 8360)<br>8b. Number of reports and fact sheets published online<br>8d. Number of information sharing forums held<br>8f. Technology transfer<br>9d. Successful project outcomes ready for use in California IOU grid (Path to market)<br>9e. Technologies available for sale in the market place (when known) | |

| Schedule: | | |
|---|---|---|
| Q2 2014 – Q4 2017 | | |
| **EPIC Funds Encumbered:**<br>$0 | **EPIC Funds Spent:**<br>$822,182 | |
| **Partners:**<br>N/A | | |
| **Match Funding:**<br>N/A | **Match Funding split:**<br>N/A | **Funding Mechanism:**<br>N/A |
| **Treatment of Intellectual Property**<br>SCE has no current patents or licensing agreements signed. Future Intellectual Property is to be determined. | | |
| **Status Update**<br>The EPIC I Final Report for the State Estimation Using Phasor Measurement Technologies Project is complete, is being submitted with the 2017 Annual Report, and will be posted on SCE's public EPIC web site. | | |

9. Wide-Area Reliability Management & Control

| Investment Plan Period: | Assignment to value Chain: |
|---|---|
| 1st Triennial Plan (2012-2014) | Grid Operation/Market Design |
| **Objective & Scope:**<br>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:**<br>• Lab demonstration of control algorithms using real time simulations with Hardware in the loop<br>• Develop recommendations based on the control system testing<br>• Final project report | |
| **Metrics:**<br>6a. Enhanced contingency planning for minimizing cascading outages<br>8b. Number of reports and fact sheets published online<br>8d. Number of information sharing forums held<br>8f. Technology transfer | |

| Schedule: | | |
|---|---|---|
| Q2 2014 – Q4 2018 | | |
| **EPIC Funds Encumbered:**<br>$949,510 | **EPIC Funds Spent:**<br>$441,057 | |
| **Partners:**<br>N/A | | |
| **Match Funding:**<br>N/A | **Match Funding split:**<br>N/A | **Funding Mechanism:**<br>N/A |
| **Treatment of Intellectual Property**<br>SCE has no current patents or licensing agreements signed. Future Intellectual Property is to be determined. | | |
| **Status Update**<br>In 2017, SCE worked with Siemens on utilizing Devers Static Var Compensators (SVC) for power oscillation damping (POD) to accommodate increased penetration of renewable resources. To demonstrate the effectiveness and benefits of the proposed POD, a series of test cases were created to assess SVC POD functionality under different operating conditions and to help ensure that the functionality will not negatively impact SCE Bulk system operation and control. SCE is also working with Manitoba HVDC to provide technical services support to SCE to 1) assist the ongoing Devers SVC POD tuning and testing demonstrations and 2) expand the POD functionality to damp forced oscillations created by Solar PV generating stations due to improper tuning of the inverter control system.<br>Siemens has completed updating the SVC dynamic models to include the POD Controller and added POD capabilities to the Devers SVC transient model (i.e. PSCAD Model). The models are currently used to tune and select the best gains for the POD controller.<br><br>SCE plans to complete this project in 2018. | | |

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

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

A second part of this project will investigate how energy storage devices located on distribution circuits can be used for reliability while also being bid into the CAISO markets to provide ancillary services. This is also known as dual-use energy storage. Initial use cases will be developed to determine the requirements for the control systems necessary to accomplish these goals.

**Deliverables:**

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

**Metrics:**

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

**Schedule:**

Q2 2014 – Q4 2017

| EPIC Funds Encumbered: | EPIC Funds Spent: | |
|---|---|---|
| $0 | $68,175 | |
| **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 DOS Protection and Control project was approved in the SCE EPIC I Triennial plan. Command and control of distributed energy resources (DER) is a common goal of DOS and the Integrated Grid Project (IGP). To optimally manage DOS and maximize cost efficiency, the design, procurement, and testing of the control systems have been combined. In addition, since field demonstrations are difficult to schedule and costly to conduct, the DOS Protection and Control field demonstration has been combined with the IGP field demo (filed as the Regional Grid Optimization Demo in EPIC II). Following successful testing of the DOS/IGP control systems in the laboratory environment, the controls will be deployed in SCE's production environment as part of the IGP field demonstration.<br><br>Milestones achieved in 2017<br><br>- Completed selection of control system<br>- Completed Pre-Factory Acceptance Testing (FAT)<br>- Completed FAT 1 Sandbox Testing<br>- Completed FAT 1<br>- Refined battery "Dual Use" use cases | | |

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. | |

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

| | |
|---|---|
| **EPIC Funds Encumbered:**<br>$0 | **EPIC Funds Spent:**<br>$1,018,405 |

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|---|
| **Partners:**<br>N/A |

| | | |
|---|---|---|
| **Match Funding:**<br>N/A | **Match Funding split:**<br>N/A | **Funding Mechanism:**<br>N/A |

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| **Treatment of Intellectual Property**<br>SCE has no current patents or licensing agreements signed. Future Intellectual Property is to be determined. |
| **Status Update**<br>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

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

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| **Objective & Scope:**<br>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:**<br>• Bulk & Hybrid System Design Drawings & Diagrams<br>• Hybrid System Deployment and Demonstration<br>• BES System Deployment and Demonstration<br>• Final Project Report |
| **Metrics:**<br>3a. Maintain / Reduce operations and maintenance costs<br>3b. Maintain / Reduce capital costs<br>5a. Outage number, frequency and duration reductions<br>5i. Increase in the number of nodes in the power system at monitoring points<br>6a. Increased cybersecurity<br>7b. Increased use of cost-effective digital information and control technology to improve reliability, security, and efficiency of the electric grid (PU Code § 8360)<br>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)<br>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)<br>8b. Number of reports and fact sheets published online<br>8d. Number of information sharing forums held<br>8f. Technology transfer<br>9c. EPIC project results referenced in regulatory proceedings and policy reports<br>9d. Successful project outcomes ready for use in California IOU grid (Path to market)<br>9e. Technologies available for sale in the market place (when known) |

| Schedule:<br>Q1 2014 – Q4 2018 | | |
|---|---|---|
| **EPIC Funds Encumbered:**<br>$2,785,584 | **EPIC Funds Spent:**<br>$2,936,775 | |
| **Partners:**<br>N/A | | |
| **Match Funding:**<br>N/A | **Match Funding split:**<br>N/A | **Funding Mechanism:**<br>N/A |
| **Treatment of Intellectual Property:**<br>SCE has no current patents or licensing agreements signed. Future Intellectual Property is to be determined. | | |
| **Status Update:**<br><br>2017 accomplishments:<br>The original project scope addressing field demonstration has been restored to the project. With this change, the SA-3 Phase III project will be deployed at Viejo A-station for field demonstration with an in-service date of Jun 28, 2019.<br><br>High level 2017 accomplishments:<br>• Viejo relay rack wiring has been completed in the Grid Technology & Demonstration (GT&M) lab.<br>• The SA-3 component configuration files were developed to enable vendor Factory Acceptance Testing.<br>• Relay racks have been delivered and installed in SCE's GT&M lab.<br>• An SCE Cybersecurity assessment for the Substation Management System (SMS) was performed.<br>• The HMI Service (software) has been received, tested, and minor issue have been reported.<br>• The new A-Station Annunciator has been received and is set up for testing. | | |

13. Next-Generation Distribution Automation

| **Investment Plan Period:**<br>1st Triennial Plan (2012-2014) | **Assignment to value Chain:**<br>Distribution |
|---|---|
| **Objective & Scope:**<br>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 | |

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| 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:**<br>• Remote Intelligent Switch demonstration and report<br>• Overhead and Underground Remote Fault Indicators demonstration and report<br>• Intelligent Fuses demonstration and report<br>• Power Electronic Transformer demonstration and report<br>• Secondary Network Monitoring demonstration and report<br>• Final Project Report |
| **Metrics:**<br>3a. Maintain / Reduce operations and maintenance costs<br>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<br>5a. Outage number, frequency and duration reductions<br>5c. Forecast accuracy improvement<br>5d. Public safety improvement and hazard exposure reduction<br>5e. Utility worker safety improvement and hazard exposure reduction<br>5i. Increase in the number of nodes in the power system at monitoring points<br>6a. Improve data accuracy for distribution substation planning process<br>7b. Increased use of cost-effective digital information and control technology to improve reliability, security, and efficiency of the electric grid (PU Code § 8360)<br>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)<br>7d. Deployment and integration of cost-effective distributed resources and generation, including renewable resources (PU Code § 8360)<br>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)<br>8b. Number of reports and fact sheets published online<br>8d. Number of information sharing forums held<br>8f. Technology transfer<br>9c. EPIC project results referenced in regulatory proceedings and policy reports<br>9d. Successful project outcomes ready for use in California IOU grid (Path to market)<br>9e. Technologies available for sale in the market place (when known) |
| **Schedule:**<br>Q1 2014 – Q4 2017 |

| EPIC Funds Encumbered: | | EPIC Funds Spent: |
|---|---|---|
| $0 | | $4,129,805 |
| **Partners:**<br>N/A | | |
| **Match Funding:**<br>N/A | **Match Funding split:**<br>N/A | **Funding Mechanism:**<br>N/A |
| **Treatment of Intellectual Property:**<br>SCE has no current patents or licensing agreements signed. Future Intellectual Property is to be determined. | | |
| **Status Update:**<br>EPIC I final reports have been completed for the sub-projects within Next Generation Distribution Automation listed below. SCE is in the process of writing a holistic Final Report for Distribution Automation, but have included the Final Reports for the sub-projects in this Annual Report, since these projects were presented separately in the EPIC I Application. SCE will post these final reports to SCE's public EPIC site. Please refer to the final reports for details:<br>- Remote Intelligent Switch<br>- Remote Fault Indicator<br>- Intelligent Fuse<br>- High Impedance Fault Detector | | |

14. Enhanced Infrastructure Technology Evaluation

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

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| **Deliverables:**<br>• Vault Monitoring Technologies Demonstration Report<br>• Vault Ventilation Field Demonstration Report<br>• Hybrid Pole Demonstration Report<br>• Concealed Communication Assets Demonstration Report<br>• Final Project Report |
| **Metrics:**<br>3a. Maintain / Reduce operations and maintenance costs<br>3b. Maintain / Reduce capital costs<br>4g. Wildlife fatality reductions (electrocutions, collisions)<br>5a. Outage number, frequency and duration reductions<br>6a. Operating performance of underground vault monitoring equipment<br>8b. Number of reports and fact sheets published online<br>8d. Number of information sharing forums held<br>8f. Technology transfer<br>9c. EPIC project results referenced in regulatory proceedings and policy reports |
| **Schedule:**<br>Q2 2014 – Q4 2016 |

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|---|---|
| **EPIC Funds Encumbered:**<br>$0 | **EPIC Funds Spent:**<br>$79,119 |

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|---|
| **Partners:**<br>N/A |

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|---|---|---|
| **Match Funding:**<br>N/A | **Match Funding split:**<br>N/A | **Funding Mechanism:**<br>N/A |

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| **Treatment of Intellectual Property:**<br>SCE has no current patents or licensing agreements signed. Future Intellectual Property is to be determined. |
| **Status Update:**<br>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

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

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| **Objective & Scope:**<br>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 |

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| 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:**<br>• Installed Dynamic Line Rating System Prototypes<br>• Final Project Report |
| **Metrics:**<br>3b. Maintain / Reduce capital costs<br>5b. Electric system power flow congestion reduction<br>6a. Increased power flow throughput<br>7b. Increased use of cost-effective digital information and control technology to improve reliability, security, and efficiency of the electric grid (PU Code § 8360)<br>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)<br>8b. Number of reports and fact sheets published online<br>8d. Number of information sharing forums held<br>8f. Technology transfer<br>9c. EPIC project results referenced in regulatory proceedings and policy reports<br>9d. Successful project outcomes ready for use in California IOU grid (Path to market)<br>9e. Technologies available for sale in the market place (when known) |
| **Schedule:**<br>Q2 2014 – Q1 2016 |

| | |
|---|---|
| **EPIC Funds Encumbered:**<br>$0 | **EPIC Funds Spent:**<br>$468,601 |

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|---|
| **Partners:**<br>N/A |

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|---|---|---|
| **Match Funding:**<br>N/A | **Match Funding split:**<br>N/A | **Funding Mechanism:**<br>N/A |

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| **Treatment of Intellectual Property:**<br>SCE has no current patents or licensing agreements signed. Future Intellectual Property is to be determined. |
| **Status Update:**<br>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:**<br>1st Triennial Plan (2012-2014) | **Assignment to value Chain:**<br>Grid Operation/Market Design |

<table>
<tr><td colspan="3">Objective & Scope:<br>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.</td></tr>
<tr><td colspan="3">Deliverables:<ul><li>System Requirements Artifact</li><li>Measurement and Validation Data</li><li>System Test Results</li><li>Final Project Report</li></ul></td></tr>
<tr><td colspan="3">Metrics:<br>5a. Outage number, frequency and duration reductions<br>7b. Increased use of cost-effective digital information and control technology to improve reliability, security, and efficiency of the electric grid (PU Code § 8360)<br>7l. Identification and lowering of unreasonable or unnecessary barriers to adoption of smart grid technologies, practices, and services (PU Code § 8360)<br>8b. Number of reports and fact sheets published online<br>8d. Number of information sharing forums held<br>8f. Technology transfer<br>10a. Description or documentation of funding or contributions committed by others<br>10c. Dollar value of funding or contributions committed by others</td></tr>
<tr><td colspan="3">Schedule:<br>Q3 2014 – Q3 2015</td></tr>
<tr><td>EPIC Funds Encumbered:<br>$0</td><td colspan="2">EPIC Funds Spent:<br>$1,809,323</td></tr>
<tr><td colspan="3">Partners:<br>Viasat; Duke Energy</td></tr>
<tr><td>Match Funding:<br>N/A</td><td>Match Funding split:<br>N/A</td><td>Funding Mechanism:<br>N/A</td></tr>
<tr><td colspan="3">Treatment of Intellectual Property:<br>SCE has no current patents or licensing agreements signed. Future Intellectual Property is to be determined.</td></tr>
<tr><td colspan="3">Status Update:<br>The final project report is complete, was submitted with the 2015 Annual Report, and is available on SCE's public EPIC web site.</td></tr>
</table>

## (2) 2015 – 2017 Triennial Investment Plan Projects

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

<table>
<tr><td>Investment Plan Period:<br>2nd Triennial Plan (2015-2017)</td><td>Assignment to value Chain:<br>Demand-Side Management</td></tr>
<tr><td colspan="2">Objective & Scope:<br>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”[30] 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.</td></tr>
<tr><td colspan="2">Deliverables:<ul><li>DERMS Functional Specification</li><li>Acceptance Test Plan and Report</li><li>Final Project Report</li></ul></td></tr>
<tr><td colspan="2">Metrics:<br>7b. Increased use of cost-effective digital information and control technology to improve reliability, security, and efficiency of the electric grid (PU Code § 8360)<br>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)<br>7d. Deployment and integration of cost-effective distributed resources and generation, including renewable resources (PU Code § 8360)<br>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)<br>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)<br>8e. Stakeholders attendance at workshops<br>8f. Technology transfer</td></tr>
<tr><td colspan="2">Schedule:<br>Q1 2016-Q4 2018</td></tr>
<tr><td>EPIC Funds Encumbered:<br>$842,560</td><td>EPIC Funds Spent:<br>$804,821</td></tr>
<tr><td colspan="2">Partners:<br>N/A</td></tr>
</table>

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

| **Match Funding:**<br>N/A | **Match Funding split:**<br>N/A | **Funding Mechanism:**<br>N/A |
|---|---|---|

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| **Treatment of Intellectual Property:**<br>SCE has no current patents or licensing agreements signed. Future Intellectual Property is to be determined. |
| **Status Update:**<br>In 2017 the Big Data project accomplished many of its objectives. These included:<br>• Procurement of the IEEE 2030.5 Application server,<br>• Collaboration with key internal and external stakeholders to develop lab and production network architectures,<br>• Deployment of the servers in the lab, and<br>• Completion of the substantial majority of the lab integration, cybersecurity, acceptance and functional testing.<br><br>There were some important benefits resulting from the testing, which included:<br>• Revisions to the IEEE 2030.5 standard, Rule 21 regulatory documents including the tariff and the California Smart Inverter Implementation Profile (CSIP) of IEEE 2030.5,<br>• Support for the production Distributed Energy Management System (DERMS) procurement specifications, and<br>• Revisions to the production network architectures due to cyber security deficiencies (e.g., cipher suites[31] and support by other cyber security technologies).<br><br>The project is currently planned for completion in 2018. |

2. Advanced Grid Capabilities Using Smart Meter Data

| **Investment Plan Period:**<br>2nd Triennial Plan (2015-2017) | **Assignment to value Chain:**<br>Distribution |
|---|---|
| **Objective & Scope:**<br>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:**<br>• Validated TLM algorithm<br>• Validated Phase ID algorithm<br>• Final project report | |
| **Metrics:**<br>3a. Maintain / Reduce operations and maintenance costs<br>7b. Increased use of cost-effective digital information and control technology to improve reliability, security, and efficiency of the electric grid (PU Code § 8360) | |

[31] Cipher Suites are sets of algorithms that help secure a network connection.

| | | |
|---|---|---|
| 8d. Number of information sharing forums held<br>8f. Technology transfer | | |
| **Schedule:**<br>Q3 2015 – Q1 2017 | | |
| **EPIC Funds Encumbered:**<br>$0 | **EPIC Funds Spent:**<br>$206,117 | |
| **Partners:**<br>N/A | | |
| **Match Funding:**<br>N/A | **Match Funding split:**<br>N/A | **Funding Mechanism:**<br>N/A |
| **Treatment of Intellectual Property:**<br>SCE has no current patents or licensing agreements signed. Future Intellectual Property is to be determined. | | |
| **Status Update:**<br>The EPIC II Final Report for the Advanced Grid Capabilities Project is complete, being submitted with the 2017 Annual Report, and will be posted on SCE's public EPIC web site. | | |

3. Proactive Storm Impact Analysis Demonstration

| **Investment Plan Period:** | **Assignment to value Chain:** |
|---|---|
| 2nd Triennial Plan (2015-2017) | Distribution |
| **Objective & Scope:**<br>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:**<br>• RFP Package<br>• Requirements / Use Cases<br>• Measurement and Validation Plan<br>• Supplier's Pilot Report<br>• Technology Transfer Plan<br>• Final project report | |

| Metrics: |
|---|
| 2a. Hours worked in California and money spent in California for each project<br>3a. Maintain / Reduce operations and maintenance costs<br>3b. Maintain / Reduce capital costs<br>5a. Outage number, frequency and duration reductions<br>5c. Forecast accuracy improvement<br>5d. Public safety improvement and hazard exposure reduction<br>8f. Technology transfer<br>9d. Successful project outcomes ready for use in California IOU grid (Path to market)<br>9e. Technologies available for sale in the market place (when known) |

| | | |
|---|---|---|
| **Schedule:**<br>Q3 2015 – Q4 2018 | | |
| **EPIC Funds Encumbered:**<br>$845,257 | **EPIC Funds Spent:**<br>$886,908 | |
| **Partners:**<br>N/A | | |
| **Match Funding:**<br>N/A | **Match Funding split:**<br>N/A | **Funding Mechanism:**<br>N/A |
| **Treatment of Intellectual Property:**<br>SCE has no current patents or licensing agreements signed. Future Intellectual Property is to be determined. | | |
| **Status Update:**<br>In 2017 the project team completed a proof of concept (PoC) storm damage model and visualization tools. The storm damage model and visualization forecast asset damage and the estimate the number of field staff required for post-storm restoration across SCE's service territory. SCE has started to demonstrate the solution with Grid Operations during storm events, optimizing field deployment decisions. Completion of final PoC storms model is targeted for May 2018. We anticipate that full production implementation of the solution in the SCE IT environment will to occur after the project ends (post-May 2018). | | |

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

| **Investment Plan Period:**<br>2nd Triennial Plan (2015-2017) | **Assignment to value Chain:**<br>Distribution |
|---|---|
| **Objective & Scope:**<br>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:**<br>• **Hybrid Pole:** specification and report<br>• **Underground Antenna:** functional specification, lab test report, demonstration summary and report<br>• **Underground Remote Fault Indicator:** identification of viable products, publication of standard SCE-configured prototype Mobile Application and report<br>• **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<br>• **Remote Intelligence Switch:** Substation Radios, Field Radios, Support Software, Underground Interrupters, Documentation and report<br>• **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<br>• **High Impedance:** Prototype 1, Prototype 2, Phase 2B Test Documentation and report |
|---|
| **Metrics:**<br>3a. Maintain/reduce operations and maintenance costs<br>3e. Non-energy economic benefits<br>5a. Outage number, frequency and duration reductions<br>5c. Forecast accuracy improvement<br>5d. Public safety improvement and hazard exposure reduction<br>5i. Increase in the number of nodes in the power system at monitoring points<br>7b. Increased use of cost-effective digital information and control technology to improve reliability, security, and efficiency of the electric grid (PU Code § 8360)<br>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)<br>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)<br>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:**<br>Q3 2016 – Q4 2019 |

<table>
<tr><td colspan="2">EPIC Funds Encumbered:<br>$3,255,942</td><td colspan="2">EPIC Funds Spent:<br>$2,465,317</td></tr>
<tr><td colspan="4">Partners:<br>N/A</td></tr>
<tr><td>Match Funding:<br>N/A</td><td colspan="2">Match Funding split:<br>N/A</td><td>Funding Mechanism:<br>N/A</td></tr>
<tr><td colspan="4">Treatment of Intellectual Property:<br>SCE has no current patents or licensing agreements signed. Future Intellectual Property is to be determined.</td></tr>
<tr><td colspan="4">Status Update:<br>In 2017, the project team accomplished the following:<br>Underground Remote Fault Indicator- successfully demonstrated the first UG RFI model. SCE is the first utility able to develop this product for underground application. SCE installed UG RFIs at 50 locations in December 2017 for field demonstration in 2018. This is a significant breakthrough for the electric utility industry.<br>Long Beach Secondary Network Situation Awareness- successfully developed the first Current & Voltage Sensors model for the secondary network. We installed four units at four locations and demonstrated good data telemetry. This enables demonstration in 2018 of the use of real-time data together with load flow simulation to provide system operators with real-time situational awareness and contingency planning capability.<br>High Impedance Fault Detection- completed proof of concept testing for High Impedance Fault Detection using Spread Spectrum Time Domain Reflectometry Technology in SCE's energized lab. Energized demonstration is scheduled at SCE's Equipment Demonstration & Evaluation (12kV) Facility (EDEF) for Q2 2018 prior to seeking approval for field demonstration on several distribution circuits.<br>Remote Integrated Switch- completed the planning for field demonstration of 26 RIS at Johanna Substation. On track to implement new RIS automation schemes at Johanna Substation in Q1 2018.<br>Real-time Equipment Health Diagnostic- successfully completed technology evaluations for the Predictive Equipment Failure Project to evaluate and demonstrate technologies that can monitor and assess energized equipment (cable, splices, transformers, switches etc.) and indicate remaining life or existing condition. The goal is to enable testing on energized distribution systems to avoid scheduling planned outages. Evaluated five technologies and vendors and identified two for additional testing in 2018-2019. This project has significant potential impacts on reliability, safety, and affordability.<br>Hybrid Pole – Received prototype poles for demonstration and completed strength testing. Hybrid poles weigh 1/3 of wood poles with similar pole ratings. The goal is to evaluate poles designed to withstand wildfires, thereby improving our system. If successfully demonstrated, hybrid poles could be standard equipment in high-fire hazard areas.</td></tr>
</table>

5. System Intelligence and Situational Awareness Capabilities

<table>
<tr><td colspan="2">Investment Plan Period:<br>2nd Triennial Plan (2015-2017)</td><td colspan="2">Assignment to value Chain:<br>Distribution</td></tr>
<tr><td colspan="4">Objective & Scope:<br>This project will demonstrate system intelligence and situation awareness capabilities such as high impedance fault detection, intelligent alarming, predictive maintenance, and automated testing. This will be accomplished by integrating intelligent algorithms and advanced applications with the latest substation automation technologies, next generation control systems, latest breakthrough in substation equipment, sensing technology, and communications assisted protection schemes, This system will leverage the International Electrotechnical Commission (IEC) 61850 Automation Standard and will include cost saving technology such as process bus, peer to peer communications, and automated engineering and testing technology. This project will also inform complementary efforts at SCE aimed at meeting security and NERC CIP compliance requirements.</td></tr>
<tr><td colspan="4">Deliverables:<br>1- Intelligent Alarm processing stake-holders lab demonstration<br>2- Testing tools lab demonstration and hand over to production team<br>3- Process bus lab demonstration</td></tr>
<tr><td colspan="4">Metrics:<br>2a. Hours worked in California and money spent in California for each project<br>3a. Maintain / reduce operations and maintenance costs<br>3b. Maintain / reduce capital costs<br>3c. Reduction in electrical losses in the transmission and distribution system<br>3f. Improvements in system operation efficiencies stemming from increased utility dispatchability of customer demand side management<br>5a. Outage number, frequency and duration reductions<br>5e. Utility worker safety improvement and hazard exposure reduction<br>7b. Increased use of cost-effective digital information and control technology to improve reliability, security, and efficiency of the electric grid (PU Code § 8360)<br>8e. Stakeholders attendance at workshops<br>8f. Technology transfer</td></tr>
<tr><td colspan="4">Schedule:<br>Q1 2016- Q4 2018</td></tr>
<tr><td colspan="2">EPIC Funds Encumbered:<br>$2,047,294</td><td colspan="2">EPIC Funds Spent:<br>$1,247,046</td></tr>
<tr><td colspan="4">Partners:<br>N/A</td></tr>
<tr><td>Match Funding:<br>N/A</td><td colspan="2">Match Funding split:<br>N/A</td><td>Funding Mechanism:<br>N/A</td></tr>
</table>

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

**Status Update:**
This project demonstrates three technologies for improving grid reliability:
1-Process Bus
2-Intelligent Alarm processing
3-Substation Testing Tools

**2017 Achievements**

**Process Bus lab demonstration:**
-We documented preliminary lab test results and shared these results at Distributech in January 2018. This information will be included in the final report.
-We procured process bus units from Siemens, SEL, GE, and ABB, installed them in the lab, and substantially completed testing in 2017 per SCE's test plan. Bank differential testing has been delayed while we await vendor product updates.
-SCE leveraged available funding (added scope) and was able to perform and complete optical CT testing in the lab.
-The Functional Design Specification was completed
-Factory Accepting Testing (FAT) has been completed
-Preliminary integration system testing started with SEL and ABB devices.
-Mayberry Substation has been selected for demonstration on a 115KV line.

**Intelligent Alarms:**
Demonstration of Intelligent Alarms Processing was cancelled following a stakeholder meeting in March 2017, where changes to SCE's energy management system architecture were discussed. Intelligent Alarms Processing functionality will be incorporated into SCE's Advanced Distribution Management System.

**Substation Testing Tools:**
-An RFI was issued and Triangle Microworks was identified as a vendor that could meet SCE requirements to provide an automated test tool for Substation HMIs. A PO has been awarded to Triangle-Microworks to configure their Digital Test Manager software to support SCE's end-to-end testing demonstration (PLC, relay, HMI, and EMS simulation and testing).

6. Regulatory Mandates: Submetering Enablement Demonstration - Phase 2

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

**Objective & Scope:**
This project expands on the submetering project from the first EPIC triennial investment plan cycle to demonstrate plug-in electric vehicle (PEV) submetering at multi-dwelling and

commercial facilities. Specifically, the project will leverage third party metering to conduct subtractive billing for various sites, including those with multiple customers of record.

**Deliverables:**

- Manual subtractive billing procedure for multiple customers of record
- 3PE final report
- PEV submetering protocol
- Final project report

**Metrics:**

1d. Number and percentage of customers on time variant or dynamic pricing tariffs
1h. Customer bill savings (dollars saved)
3e. Non-energy economic benefits
4a. GHG emissions reductions (MMTCO2e)
6a. The 3rd Party Evaluator, Nexant, in collaboration with the Energy Division and IOUs, will develop a set of metrics for Phase 2 to be included in the final report
7h. Deployment and integration of cost-effective advanced electricity storage and peak-shaving technologies, including plug-in electric and hybrid electric vehicles, and thermal-storage air-conditioning (PU Code § 8360)
7j. Provide consumers with timely information and control options (PU Code § 8360)
7k. Develop standards for communication and interoperability of appliances and equipment connected to the electric grid, including the infrastructure serving the grid (PU Code § 8360)
7l. Identification and lowering of unreasonable or unnecessary barriers to adoption of smart grid technologies, practices, and services (PU Code § 8360)
8e. Stakeholders attendance at workshops
8f. Technology transfer
9c. EPIC project results referenced in regulatory proceedings and policy reports
9d. Successful project outcomes ready for use in California IOU grid (Path to market)
9e. Technologies available for sale in the market place (when known)

**Schedule:**
Q4 2015 – Q3 2018

| **EPIC Funds Encumbered:** | **EPIC Funds Spent:** |
|---|---|
| $0 | $806,196 |

**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.

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| **Status Update:**<br>Correction. The status provided in the 2016 EPIC Annual Report (provided in February 2017) for this project was for the EPIC I Submetering Project. The 2016 update for this EPIC II project should have read as follows:<br>On October 26, 2016, the Energy Division directed the IOUs to submit a letter to the CPUC Executive Director requesting the following Phase 2 Pilot schedule changes without extending the duration of the Pilot:<br>• Delay the start date for the Phase 2 Pilot from 11/1/2016 to 1/16/2017<br>• Shorten the Exclusivity Enrollment Period from 1/16/2017 to 2/28/2017<br>• Shorten the Open Enrollment Period from 3/1/2017 to 4/30/2017<br><br><u>2017 Update</u><br>This Submetering Phase 2 Pilot project started January 16, 2017 and will end on or about April 30, 2018. A total of 151 submeters are enrolled with three Meter Data Management Agents:<br>1. ChargePoint, 130 submeters enrolled, three submeters terminated early.<br>2. eMotorWerks, 20 submeters enrolled, one submeter terminated early.<br>3. Kitu Systems, 1 submeter enrolled.<br><br>Nexant, the third party Pilot evaluator, will submit their final report to the CPUC on September 1, 2018.<br><br>Subsequently, the CPUC must decide if the Submetering Protocol will be approved. A CPUC decision date is unknown at this time. |

7. Bulk System Restoration Under High Renewables Penetration

| **Investment Plan Period:**<br>2nd Triennial Plan (2015-2017) | **Assignment to value Chain:**<br>Transmission |
|---|---|
| **Objective & Scope:**<br>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:<br><br>* 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.<br><br>* 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 | |

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| 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.<br><br>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:**<br>N/A |
| **Metrics:**<br>N/A |
| **Schedule:**<br>N/A |

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|---|---|
| **EPIC Funds Encumbered:**<br>$0 | **EPIC Funds Spent:**<br>$42,193 |

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| **Partners:**<br>N/A |

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|---|---|---|
| **Match Funding:**<br>N/A | **Match Funding split:**<br>N/A | **Funding Mechanism:**<br>N/A |

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| **Treatment of Intellectual Property:**<br>SCE has no current patents or licensing agreements signed. Future Intellectual Property is to be determined. |
| **Status Update:**<br>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

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| **Investment Plan Period:**<br>2nd Triennial Plan (2015-2017) | **Assignment to value Chain:**<br>Transmission |

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| **Objective & Scope:**<br>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:**<br>N/A |

| **Metrics:**<br>N/A | | |
|---|---|---|
| **Schedule:**<br>N/A | | |
| **EPIC Funds Encumbered:**<br>$0 | **EPIC Funds Spent:**<br>$5,920 | |
| **Partners:**<br>N/A | | |
| **Match Funding:**<br>N/A | **Match Funding split:**<br>N/A | **Funding Mechanism:**<br>N/A |
| **Treatment of Intellectual Property:**<br>SCE has no current patents or licensing agreements signed. Future Intellectual Property is to be determined. | | |
| **Status Update:**<br>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:**<br>2nd Triennial Plan (2015-2017) | **Assignment to value Chain:**<br>Distribution |
|---|---|
| **Objective & Scope:**<br>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:**<br>**Light Duty VAPS Platform – PHEV Pickup Truck:** Purchase Order for PHEV Truck, Test Result Report, Final Report<br>**Class 8 PHEV/BEV:** Purchase Order for Class 8 PHEV/BEV, Test Result Report, Final Report<br>**Medium Duty VAPS Platform – Class 5 PHEV 9ft. Flatbed:** A Plug-in Hybrid Ford F550 Flatbed, Test Result Report, Final Report<br>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:**<br>3a. Maintain/Reduce operations and maintenance costs<br>3e. Non-energy economic benefits<br>4a. GHG emissions reductions (MMTCO2e)<br>4b. Criteria air pollution emission reductions<br>5d. Public safety improvement and hazard exposure reduction<br>5e. Utility worker safety improvement and hazard exposure reduction | |

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| 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)<br>8f. Technology transfer |
| **Schedule:**<br>Q3 2015 – Q1 2019 |

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| **EPIC Funds Encumbered:**<br>$760,503 | **EPIC Funds Spent:**<br>$472,066 |

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| **Partners:**<br>N/A |

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|---|---|---|
| **Match Funding:**<br>N/A | **Match Funding split:**<br>N/A | **Funding Mechanism:**<br>N/A |

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| **Treatment of Intellectual Property:**<br>SCE has no current patents or licensing agreements signed. Future Intellectual Property is to be determined. |
| **Status Update:**<br>2017 Accomplishments<br>**Class 8 EV Project (Heavy Duty Truck):** The International base vehicle was ordered and received in July. US Hybrid used the vehicle to validate the CAD model and begin the vehicle build design. The vehicle was sent to Phoenix and the flatbed was installed on the chassis in December 2017. However, due to schedule delays compounded by resource constraints, it was necessary to cancel this subproject before the drivetrain was converted.<br>**Class 5 PHEV Project (Medium Duty Truck)**: The base vehicle was purchased in July and a potential crew was identified to use the vehicle. The crew provided input on the system features and Odyne completed the vehicle design layout. The vehicle was sent to Valley Power for the system installation in November 2017, and it should be complete and ready for testing in January 2018.<br>**Light Duty PHEV Truck Project:** The stock GMC Sierra was baseline tested and shipped to Efficient Drivetrain Inc. (EDI) for the hybrid upfit in April. EDI provided a detailed system design for review in July. The vehicle conversion was complete in November and EDI performed functionality testing in December. The vehicle will arrive at SCE in January 2018, undergo performance testing and be placed into the field March 2018.<br>**Large VAPS Project:** Freewire received a PO to build a trailer mounted portable energy system (MobiGen) in August 2017. The system was complete in December. It will arrive at SCE in January 2018 and undergo performance and safety testing in Q1 2018.<br>**Medium VAPS Project:** SCE purchased an electric cable pullers from Envoltz. The system was delivered in September 2017 and underwent full performance and capability testing (which it passed without issues). The system is being prepared so that it can be evaluated by field crews in Q1 2018.<br>**Small VAPS Project:** The Altec Jobsite Energy Management System (JEMS) 4E4 Troubleman truck was extensively tested for performance, functionality and safety over seven months. Various system deficiencies were discovered. SCE worked with Altec to rectify the deficiencies, and a report was written documenting the test results ("TR15 – JEMS |

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| Evaluation"). Data tracking units were installed in 22 of the Altec JEMS trucks and the system performance was tracked for six months. We documented the results of the system utilization in a report written in December "TR17 – Field Data Analysis." The vehicle was returned to Transportation Service Department in November to be placed into the field. Additionally, a JEMS 4A base system underwent endurance testing for 600 discharges and charges in an environmental chamber for six months and the battery capacity was documented. The system showed a slight but noticeable decrease in the dedicated 12V battery capacity; this should have a long-term impact on idle mitigation run times over the life of the vehicle. We wrote a report documenting the results ("TR16 – Endurance Test Summary"). |

10. Dynamic Power Conditioner

<table>
<tr><td>Investment Plan Period:<br>2nd Triennial Plan (2015-2017)</td><td>Assignment to value Chain:<br>Distribution</td></tr>
<tr><td colspan="2">Objective & Scope:<br>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.</td></tr>
<tr><td colspan="2">Deliverables:<ul><li>Complete Specification documents for hardware</li><li>Use Cases</li><li>Lab Test Report of the Dynamic Power Conditioner</li><li>Final Project Report</li></ul>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.</td></tr>
<tr><td colspan="2">Metrics:<br>1a. Number and total nameplate capacity of distributed generation facilities<br>1b. Total electricity deliveries from grid-connected distributed generation facilities<br>1i. Nameplate capacity (MW) of grid-connected energy storage<br>2. Job creation<br>3a. Maintain / Reduce operations and maintenance costs<br>3b. Maintain / Reduce capital costs<br>3c. Reduction in electrical losses in the transmission and distribution system<br>5a. Outage number, frequency and duration reductions<br>5b. Electric system power flow congestion reduction<br>5f. Reduced flicker and other power quality differences<br>7a. Description of the issues, project(s), and the results or outcomes<br>9. Adoption of EPIC technology, strategy, and research data/results by others</td></tr>
</table>

| | | |
|---|---|---|
| **Schedule:**<br>Q3 2016 – Q1 2019 | | |
| **EPIC Funds Encumbered:**<br>$782,000 | **EPIC Funds Spent:**<br>$306,938 | |
| **Partners:**<br>N/A | | |
| **Match Funding:**<br>N/A | **Match Funding split:**<br>N/A | **Funding Mechanism:**<br>N/A |
| **Treatment of Intellectual Property:**<br>SCE has no current patents or licensing agreements signed. Future Intellectual Property is to be determined. | | |
| **Status Update:**<br>In 2017, The Advanced Energy Storage Organization partnered with SCE's Supply Management organization to solicit suppliers to support the Dynamic Power Conditioner (DPC) project. The original strategy for the solicitation involved a Request for Information (RFI), which would then lead to a list qualified Bidders for the final Request for Proposal (RFP). The RFI was released to 45 potential suppliers to determine their technical capabilities to support project requirements. The RFI resulted in five responses. Ultimately, the project management team decided that Siemens Industry was the only supplier technically qualified to support project requirements.<br><br>The first milestone was achieved when the Vendor accepted the Purchase Order and received the authority to proceed. The second milestone was achieved in late December, when the vendor provided SCE with the design of the system.<br><br>The project is expected to be completed in Q1 of 2019. | | |

11. Optimized Control of Multiple Storage Systems

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| **Investment Plan Period:**<br>2nd Triennial Plan (2015-2017) | **Assignment to value Chain:**<br>Distribution |
| **Objective & Scope:**<br>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:**<br>N/A | |
| **Metrics:**<br>N/A | |
| **Schedule:**<br>N/A | |

| **EPIC Funds Encumbered:** | **EPIC Funds Spent:** | |
|---|---|---|
| $0 | $3,761 | |
| **Partners:**<br>N/A | | |
| **Match Funding:**<br>N/A | **Match Funding split:**<br>N/A | **Funding Mechanism:**<br>N/A |
| **Treatment of Intellectual Property:**<br>SCE has no current patents or licensing agreements signed. Future Intellectual Property is to be determined. | | |
| **Status Update:**<br>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:** | **Assignment to value Chain:** |
|---|---|
| 2nd Triennial Plan (2015-2017) | Demand-Side Management |
| **Objective & Scope:**<br>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:**<br>Final Report | |
| **Metrics:**<br>3a. Maintain/Reduce operations and maintenance costs<br>5b. Electric system power flow congestion reduction<br>5h. Reduction in system harmonics<br>8d. Number of information sharing forums held<br>8e. Stakeholders attendance at workshops<br>8f. Technology transfer | |
| **Schedule:**<br>Q1 2016 – Q1 2018 | |
| **EPIC Funds Encumbered:**<br>$0 | **EPIC Funds Spent:**<br>$16,847 |

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|---|---|---|
| **Partners:**<br>N/A | | |
| **Match Funding:**<br>N/A | **Match Funding split:**<br>N/A | **Funding Mechanism:**<br>N/A |
| **Treatment of Intellectual Property:**<br>SCE has no current patents or licensing agreements signed. Future Intellectual Property is to be determined. | | |

**Status Update:**

In 2017, we performed a grid impact assessment on several DC Fast Charger locations. The demonstration's goal was to understand the fast charging operations from a grid perspective, and to understand the impact DC Fast chargers had on grid equipment -- both now and in the future. Certain metrics for assessing the impact DC fast chargers have on the grid were based on identifying whether sites were compliant with IEEE 519 Recommended Practice and Requirements for Harmonic Control in Electric Power Systems, and could operate safely within the limitations defined in ANSI C84.1 Electric Power Systems and Equipment — Voltage Ratings (60 Hertz). In addition to power quality, the average DC fast charger site demand was compared to its total circuit demand to quantify its percentage of the maximum demand the fast charging site occupied on its respective circuit.

In 2017, we collected some preliminary results. All Tesla sites evaluated in this study were compliant with IEEE 519, and operated safely within the limitations defined in ANSI C84.1. All Tesla sites evaluated made up 4% to 9% of their circuit's maximum load, and their demand in SCE's territory is expected to double by the end of 2017. Based on the strong correlation in power quality data between sites, and compliance with IEEE 519 and ANSI C84.1, SCE made the decision to reduce the number of sites initially planned to study from 15 to 7 sites. SCE may consider reducing the number of data loggers that SCE plans to install for the EVgo DC Fast charging stations (within the first 5 to 7 installations), if there is the same strong correlation in power quality data between sites, for compliance with IEEE 519 and ANSI C84.1.

In total, the number of sites that are expected to be monitored will have gone from 25 sites, to potentially 13 to 15 sites depending on the results. All data loggers installations for EVgo sites were installed in December 2017. After reviewing the results with SCE's power quality experts, Tesla recommended that more data be collected for several EVgo sites for two reasons. First, a power quality anomaly may have been discovered at these sites, so more monitoring is being performed to confirm this. We will be working with Tesla on diagnosing and reporting on this anomaly. Second, SCE's power quality experts found that, for two sites, an insufficient amount of data was collected to characterize its impact on the grid.  Accordingly, more data is being collected for those sites. Data collection for all existing sites is expected to be completed and reviewed with SCE's experts by March 2018.

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| One mutually beneficial outcome of this demonstration concerned changes made to voltage swell ride-through limits [32]for Tesla's superchargers. This began when an unusual behavior was uncovered at some sites where the superchargers would stop discharging from one, or sometimes two, of the three phases when a voltage swell had occurred. After reviewing this anomaly with Tesla, SCE discovered that this behavior was intentional by the superchargers, and occurred on each phase where a large enough voltage swell occurred. SCE informed Tesla that it was not uncommon to sometimes see brief voltage swells, and recommended that Tesla re-program their de-rating limits for voltage swell ride-through limits according to SAE J2894. Tesla's engineers are now working to adopt these recommended changes, which will help improve their charge times in areas where voltage swells are more common. |

13. Integrated Grid Project II

| **Investment Plan Period:**<br>2nd Triennial Plan (2015-2017) | **Assignment to value Chain:**<br>Cross-Cutting/Foundational Strategies & Technologies |
|---|---|
| **Objective & Scope:**<br>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:**<br>• Evaluation of system performance and field operations performance<br>• Report on market maturity of technologies demonstrated<br>• Final project report (Phase 2) | |
| **Metrics:**<br>1a. Number and total nameplate capacity of distributed generation facilities<br>1b. Total electricity deliveries from grid-connected distributed generation facilities<br>1c. Avoided procurement and generation costs<br>1d. Number and percentage of customers on time variant or dynamic pricing tariffs<br>1e. Peak load reduction (MW) from summer and winter programs<br>1f. Avoided customer energy use (kWh saved)<br>1g. Percentage of demand response enabled by automated demand response technology (e.g. Auto DR)<br>1h. Customer bill savings (dollars saved)<br>1i. Nameplate capacity (MW) of grid-connected energy storage | |

32 Voltage swell ride-through is defined as a device's ability to remain connected to the grid during high-voltage or low-voltage events depending on the duration of the event.

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:**<br>Q3 2016 – Q3 2019 | | |
| **EPIC Funds Encumbered:**<br>$15,851,750 | **EPIC Funds Spent:**<br>$8,676,280 | |
| **Partners:**<br>The CEC and DOE on the EASE ENERGISE project (part of the DOE Sunshot program). | | |
| **Match Funding:**<br>$2.3M Cost Share | **Match Funding split:**<br>N/A | **Funding Mechanism:**<br>Pay-for-Performance Contracts |
| **Treatment of Intellectual Property:**<br>SCE has no current patents or licensing agreements signed. Future Intellectual Property is to be determined. | | |

**Status Update:**

SCE is completing the final stages of the factory acceptance testing (FAT) and preparing the control systems to move to the quality assurance system environment (QAS). This is in preparation for moving the controls to the production environment for field deployment later in 2018. As part of the testing, cybersecurity measures were determined, software bugs fixed, and final architecture updates were made to move the control systems to the QAS environment.

We installed FAN radio network devices on poles in the test area and ran tests to help select the final vendor for field implementation. We also worked to interface the FAN radios to field devices (e.g. capacitor controllers, DESI 2, and microgrid monitoring point). The control code was adapted to run in the FAN radios connected to the field devices; this allowed us to send monitoring and control commands to these devices.

Work continued to secure permission to monitor and control DER devices located on the test circuit. While there is significant DER penetration on the test circuit (>50% DER nameplate/ circuit peak loading), SCE only has the ability to control part of it. Discussions with existing third party DER owners continue and will establish what incentives are necessary to convince them to participate in the demonstration.

Specific accomplishments in 2017 include:

Controllers – Predix UIB – 2030.5 Advanced Technology (AT) lab
- Completed reconfiguration for removal of field agent
- Completed Distribution Management System adapter reconfiguration
- Completed Install of Predix version update
- Completed Factory Acceptance Test (FAT) 2 sandbox testing
- Completed cybersecurity round 1 FAT testing
- Completed FAT 2 (first round)
- Completed Predix upgrade / patch in FAT environment
- Completed integration testing for 2030.5

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| - Completed FAT 2 testing for 2030.5<br>- Completed cybersecurity round 2 (final) FAT testing<br><br>FAN (Field Area Network)<br>- Completed IGP canopy installation (core network + radios) in Johanna / Camden / Central Orange County District Office.<br>- Completed simulation network installation (50 Field Radios in Johanna/ Camden<br>- Completed FAN testing and down select evaluation (2->1) in AT lab<br><br>Microgrid Monitoring Point<br>- Completed switch controller installation with NetComm radio<br><br>DESI2<br>- Release civil construction bid package<br>- Release civil construction purchase order |

## 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, 2017, SCE expended a total of $3,802,219 toward project costs and $69,816 toward administrative costs for a grand total of $3,872,035. SCE's cumulative expenses over the lifespan of its 2012 – 2014 EPIC program amount to $35,185,276. SCE committed $37,723,624 toward projects and encumbered $17,612,776 through executed purchase orders during this period.

SCE continued executing projects from its approved portfolio. Of the 16 projects currently in progress, 4 of these projects were completed during the calendar year 2016 and 7 were completed in 2017. The list of completed 2012-2014 Investment Plan projects is shown below:

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

6. State Estimation Using Phasor Measurement Technologies;
7. Deep Grid Coordination (otherwise known as the Integrated Grid Project).

The following Reports are presented as part of Next Generation Automation:

8. Intelligent Fuses;
9. Remote Intelligent Switcher;
10. Remote Fault Current Indicators; and
11. High Impedance Fault Detection on Distribution Circuits.

Final project reports for projects 5-11 are included in the Appendix of this annual report.

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

For the period between January 1 and December 31, 2017, SCE expended a total of $11,003,917 toward project costs and $775,372 toward administrative costs for a grand total of $11,799,288. SCE's cumulative expenses over the lifespan of its 2015 – 2017 EPIC program amount to $18,063,399. SCE committed $38,212,859 toward projects and encumbered $24,385,306 through executed purchase orders during this period.

SCE stated in its last annual report that "SCE also recently completed the Submetering Enablement Demonstration - Phase 2 project and per the Commission's directives, SCE has included a final report." That statement should have referred to the Submetering Enablement Demonstration – Phase 1 project; EPIC I. That project was indeed completed in 2016 and the report was submitted with the 2016 EPIC Annual Report (which was submitted in February 2017).

SCE began implementing 13 projects from its approved EPIC II Portfolio. As of the date of this report, three projects have been cancelled for reasons described in their respective project updates in section 0 above. Project execution activities continued in 2017 on the remaining 10 projects. Of those 10 projects, the Advanced Metering Capabilities project was completed in 2017 and the final project report is attached in the Appendix. This leaves nine projects in the execution phase.

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

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

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

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

SCE manages its EPIC program through a structured and highly disciplined portfolio management governance framework. In 2017, SCE invested in improving project strategic alignment and stakeholder engagement by developing comprehensive Stage-Gate processes and creating an on-line support tool. Stage-Gate processes govern projects as they move through each phase of the project life-cycle from concept to field demonstration. Gates (at the end of a Stage) help ensure the right stakeholders are engaged, appropriate artifacts are available, and defined criteria are met before projects can move to the next Stage. The on-line (web based) tool supports each stage, helps ensure compliance with Gates, and improves stakeholder communication by providing on-line project status. As of February 2018, EPIC III proposed projects are being vetted through the Stage-Gate processes.

As part of this portfolio management process, SCE performs a critical assessment of all projects on a quarterly basis to A) review the financial and schedule status of EPIC projects vis-à-vis baselined project management plans; and, B) review the technical viability, value proposition and deployment readiness for each EPIC project in light of changing market and industry dynamics.

Given the volatility that characterizes new smart grid technologies, particularly for those in the pre-commercial stage, SCE works to help ensure that its portfolio management process incorporates a real-time feedback loop to address late-breaking market developments and information. Furthermore, launching new corporate or regulatory initiatives[33] after an investment plan has been approved by the Commission may warrant updates to certain EPIC projects as well. As a result of this process, SCE may find it prudent to enhance, revise, or cancel projects in order to accommodate and adapt to emergent regulatory directives, or new industry developments, advances, or guidance with respect to specific technologies.

[33] The Commission's Distribution Resources Plan is one example.

# Deep Grid Coordination
# (aka Integrated Grid Project(IGP))

# EPIC I Final Report

15 February 2018

Developed by
SCE Transmission & Distribution, Advanced Technology
Organization

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# 1 Executive Summary

## 1.1 Project Overview

The objective of IGP is to perform a pre-production demonstration of how the distribution system could be optimized to enable higher penetration of distributed energy resources (DER). This project includes demonstration of next generation grid infrastructure to allow system operators to manage the grid with high levels of DER, testing of controls and protocols to enable effective DER resource interconnection, and demonstration of the ability to optimally manage an integrated distribution system to continue to provide safe, reliable service. The project will also attempt to evaluate how to encourage customers to install and operate DER to provide benefits to the grid.

The project scope includes a field demonstration of many of the capabilities to be implemented as part of SCE's Grid Modernization program. This project is primarily focused on validating specific aspects of SCE's Grid Modernization program, rather than evaluating the appropriateness of SCE's proposed Grid Modernization scope planned for near-term deployment. The project will inform future deployment phases that involve more precise management of distributed energy resources for future distribution markets. This demonstration will lay the foundation needed to reduce the risk and time to implement the Grid Modernization capital projects. Through concepts being demonstrated as part of IGP, control methods will be tested for their ability to facilitate higher penetrations of DER than would have been possible without the controls. The control system will also demonstrate how to better integrate customer DER and utility infrastructure to optimize circuit voltage profile and power flow.

IGP is also the home of SCE's Distribution Resources Plan Demonstration D (Demo D). This demonstration will test how well the system can monitor and operate multiple DERs under various ownership and control arrangements to provide grid benefits. Demo D will also demonstrate the back office and cybersecurity systems needed to manage large penetrations of DER while providing safe, reliable, and affordable service to SCE's customer.

This project began in early 2014 with development of an RFP for a consulting company to assist with overall project planning and systems engineering. During 2014 and 2015 workshops were held with key SCE internal stakeholders and initial project design was completed. In 2016 the controls were integrated with other SCE systems and initial laboratory testing performed. This lab testing extended into early 2017 when the first phase of factory acceptance testing was completed. Under EPIC 2, system acceptance testing and production acceptance testing is being performed to move the control system into the production environment in preparation for field testing in mid-2018. This will be followed by one year of field testing running into mid-2019. This report describes the work performed under EPIC 1 and includes tasks from the beginning of the project through initial factory acceptance testing.

## 1.2 Value of project to CPUC EPIC program and benefit to ratepayers

IGP is designed to demonstrate how the distribution system can be managed with high penetrations of DERs. This demonstration project will be used to better define what measures work best at controlling circuit voltage and optimizing power flow on distribution circuits. These lessons will be used by SCE to provide the requirements for future grid modernization. Many of these lessons have broad applicability to other utilities. A complete list of the lessons learned for this demonstration project is presented in Section 5.2.

Before embarking on a major system upgrade, it is important to demonstrate technologies to confirm system requirements. IGP is demonstrating DER control systems, communications protocols, cybersecurity, field area network (FAN) communications, and methods to work with customers and aggregators. Ultimately, this experience should result in a smoother, better-defined transition to a smarter grid that can operate reliably and safely with high penetrations of DERs. These lessons should inform future modernization efforts.

## 1.3 Key accomplishments & lessons learned

⇨ Key accomplishments:

- Identified a site for utility-owned storage system on the test circuit
- Developed system requirements and completed system design for high penetration DER control systems
- Developed a high-level integration path for aggregators of DERs using IEEE 2030.5
- Integrated the distributed control systems with the distribution management system (DMS) through the integration platform in the lab setting
- Assembled the laboratory test environment based on the DigSILENT PowerFactory simulation system to allow more comprehensive testing of the control systems
- Completed the first series of factory acceptance testing (FAT) of the control systems and the operational service bus
- Tested and evaluated four field area network (FAN) communications systems and down-selected to two systems

⇨ Key lessons learned:

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

- The decision to adopt a systems engineering approach for IGP offered multiple benefits. It provided a disciplined methodology for managing the project lifecycle, including deriving the system requirements, documenting the system design, aligning the requirements with system testing, and ensuring detailed traceability of the technical deliverables to the key business and operational drivers. This approach helped keep the project focused on the overall system requirements during development and testing.
- The IEEE 2030.5 standard for communicating with smart inverters and aggregators is in early stages of deployment and may require changes before it is widely accepted and implemented by DER aggregators.

- To perform thorough laboratory testing of DER control systems, a testing environment that allows system simulation in real-time is needed. This allows controls testing over a broad range of system conditions that would not be otherwise possible.

- Edge computing capability in the FAN field device is vital in allowing the network to be easily adapted to multiple uses (e.g. distributed control, protocol translation, and report by exception)

- Integrating new cybersecurity technologies into the software environment may cause existing systems to malfunction and therefore must be integrated carefully. Should specific cybersecurity capabilities and/or configuration settings be deployed without properly understanding their impacts, existing software control systems may cease to function properly.

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

## 1.4 Direct Contributions to the Grid Modernization Program

The work done so far as part of IGP has delivered the following accomplishments to assist the implementation of SCE's Grid Management System (GMS) project:

- Design and demonstration of implementation of IEEE 2030.5 acceptable to SCE cybersecurity and to be used by a DER Management System (DERMS) (initially for DRP Demo C but extensible to any 3rd party aggregation use cases)
- Demonstration of volt/VAR and power flow optimization for high penetration DER to improve Advanced Distribution Management System (ADMS) request for proposal (RFP) requirements
- Assessment and demonstration of control application integration through an operational service bus
- Completed development of detailed Interface Service definitions for the GE Predix operational service bus, which are now reusable for the DERMS and ADMS implementations
- Assessment of field messaging bus technologies maturity level
- Demonstration of Agile methodologies and their benefits for DERMS and ADMS implementations through the sandbox, factory acceptance, and site acceptance test cycles

IGP has informed and enabled key achievements for the Field Area Network (FAN) as follows:

- New FAN technical design and integration specifications
- Detailed system requirements for the FAN RFP
- Review assessment and scoring criteria for FAN proposals
- FAN vendor product assessment in the SCE's Advanced Technology (AT) lab and in the production environment in the IGP region
- New comprehensive FAN testing equipment setup and procedures in the AT lab
- Complete radio frequency model for the FAN radios derived through the use of automated testing processes

- Selection of final vendor for system wide deployment
- Integration of new FAN with the Common Substation Platform (CSP)
- Design and delivery of the IPv4/IPv6 dual stack solution to increase flexibility of the FAN solution and help with integration with SCE back-office software applications (e.g. advanced distribution management system)
- Enabled FAN testing platform for DERMS and ADMS by integrating new FAN into back-office systems including common shared and security services
- Documentation of new business process flows needed for FAN field deployment

### 1.5 Funding

| | |
|---|---|
| Period of Performance: | Sept 2014 thru April 2017 |
| Dollars Spent: | $18,250,000 |

## 2 Project Summary

### 2.1 Project Objectives

The objective of IGP is to perform a pre-production demonstration of how the distribution system could be optimized to enable higher penetration of distributed energy resources (DER). This project includes demonstration of next generation grid infrastructure to allow system operators to manage the grid with high levels of DER, testing of controls and protocols to enable effective DER resource interconnection, and demonstration of the ability to optimally manage an integrated distribution system to continue to provide safe, reliable service. The project will also attempt to evaluate how to encourage customers to install and operate DER to provide benefits to the grid. To help achieve these objectives, SCE will also demonstrate new FAN equipment, cybersecurity methods, and tools that allow the integration of all these data and control streams. The project is sited in the Santa Ana/ Costa Mesa portion of Orange County and seeks to control DER owned by SCE, customers and third-party aggregators in a coordinated manner. Laboratory testing of IGP systems commenced in the 3rd quarter of 2016 with field deployment scheduled to commence in the 2nd quarter of 2018.

### 2.2 Scope

The project demonstrates capabilities that could inform future system-wide deployments, reducing the risk and time necessary for the associated capital deployments. Through concepts demonstrated as part of IGP, control methods are shown to facilitate higher penetrations of DER than would have been possible without the controls. The control system also demonstrates how to better integrate customer DER and utility infrastructure to optimize circuit voltage profiles and power flows.

IGP is also the home of SCE's Distribution Resources Plan Demonstration D. This demonstration will show a system that can monitor and operate multiple DERs under various ownership and control arrangements to provide grid benefits. Demo D will also demonstrate the back office and cybersecurity systems needed to manage large penetrations of DER while providing safe and reliable service to SCE's customer.

### 2.3 Project Background and Overview

The Electric Program Investment Charge (EPIC) program was authorized by the California Public Utility Commission (CPUC) in late 2013. IGP was started in early 2014, as part of EPIC 1. IGP is demonstrating work that SCE conceptualized through a series of workshops with the California Institute of Technology (CalTech) in 2013. These workshops extended previous work that SCE and CalTech performed for an Advanced Research Projects Agency – Energy (ARPA-E) project on distributed control architecture to manage multiple smart inverters connected to DERs for voltage and VAR control on the distribution grid (Green Electricity Network Integration – GENI program announced April 2011 and project started March 2012).

The primary tasks accomplished in 2014 included developing the RFP to contract with a consulting company to assist with overall project planning and systems engineering, evaluating proposals, contracting with the selected company, and presenting to key internal stakeholders the overall objectives of the project. The successful bidder on these tasks was Navigant Consulting. Towards the end of 2014, the CPUC issued their preliminary guidance on the DRP requirements for the California IOU filings that would be submitted in July 2015. SCE determined at the time that IGP would be an important component of the DRP. This led to the selection of the Johnna Jr. substation as the IGP site since it was anticipated that there would be substantial load growth in the area. This site was also within SCE's Preferred Resources Pilot area that had a procurement mechanism in place for DERs.

The primary tasks accomplished in 2015 included conducting four workshops with key SCE internal stakeholders on specific IGP topics. Each workshop focused on one of the following topics:

- Normal Operations
- Abnormal Operations
- Resource/Infrastructure Planning
- Incentives, Rate Structure, and Market Interface

The stakeholders were selected based on the focus of each workshop. The business requirements identified in the workshops were used to develop high-level use cases and technical requirements. It was also determined that IGP would meet the requirements of the DRP Demo D–managing high penetration of DERs. Towards mid-year 2015 the project structure was formed to include eight sub-projects (SP1-Advanced Substation and Circuit Automation, SP2-Volt/VAR Optimization with DER Participation, SP3-Power Flow Optimization with DER Participation, SP4-High Penetration DER – Virtual Microgrid, SP5-Resource Incentives, SP6-Field Area Network, SP7-Advanced Cybersecurity Detection, and SP8-Integration and Integration Messaging). The project also incorporated two existing EPIC projects (SP9-Distributed Optimized Storage and SP10-Beyond-the-Meter Communication) that were highly synergistic to IGP. Another key 2015 activity was the completion of Proof-of-Concept (PoC) demonstrations for interface messaging using GE's operational service bus. Following this, RFPs were released for a control system capable of managing DERs and for FAN radios. SCE also began to install Remote Fault Indicators (RFIs) in the Johanna Jr. area.

The primary tasks accomplished in 2016 included evaluating the control system vendor proposals, contracting with the two selected companies, and interfacing the vendor systems with the DMS through the interface messaging platform. To manage the testing process, a software tool and hardware environment was developed to support hardware-in-the-loop testing. Another key activity in 2016 was incorporating Camden substation into IGP (*Figure 1*), as there were seven existing large solar PV installations located there. FAN vendors were selected and underwent extensive testing in the lab and limited testing in the field.

Major activities in the first half of 2017 included narrowing the pool of potential FAN vendors to two finalists, deciding on a single distributed control system vendor (Integral Analytics/Smarter Grid Solutions), completing the first round of FAN lab testing, and being awarded funds from the Department of Energy under the Enabling Extreme Real-Time Grid Integration of Solar Energy (ENERGISE) program. Since the IGP lab and field testing environments were already being established, two additional sub-projects were added to the demonstration: Adaptive Protection (SP11) and Grid Edge Data Integration (SP12) which explored the use of advanced metering infrastructure (AMI) data to supplement existing SCADA data.

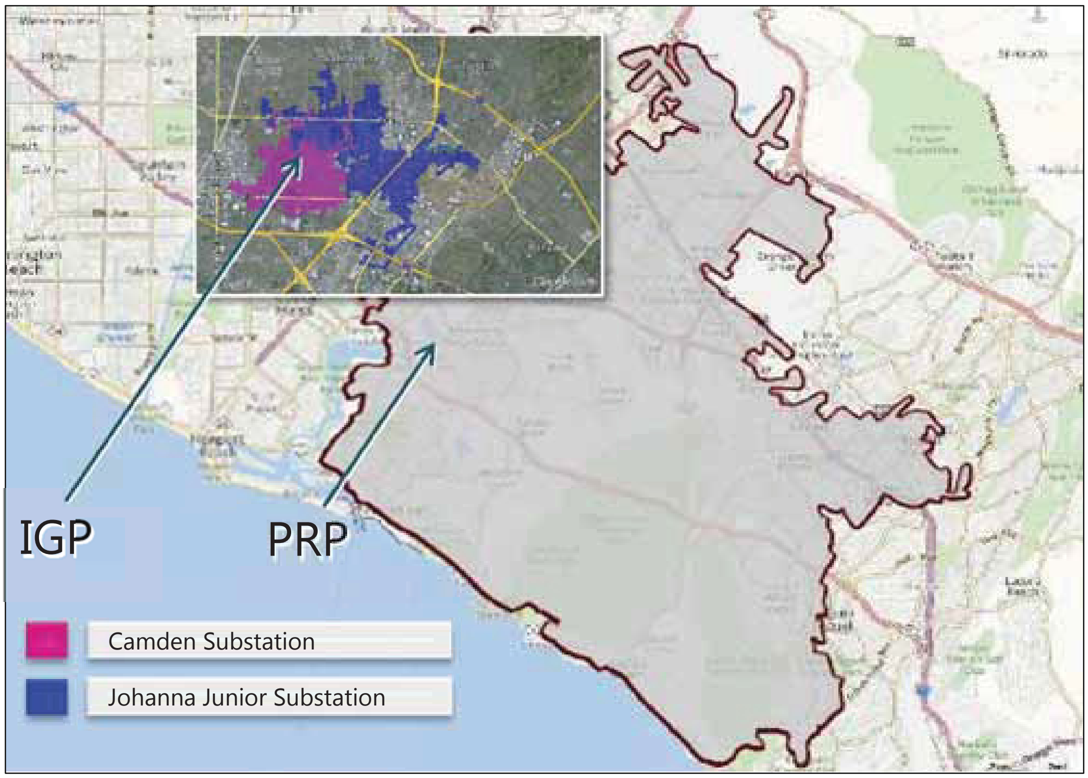



*Figure 1: IGP and Preferred Resource Pilot (PRP) Demonstration Location*

## 2.4 Sub-project Overview

During the IGP planning phase, care was taken to ensure the program was directly aligned with SCE's broader Grid Modernization strategy. To that end, IGP hosted over 20 workshops (Q1 & Q2 2015) with cross-functional representation from key stakeholders in SCE's T&D, Power Procurement, Customer Service, Enterprise Architecture, and Cybersecurity. The end result was a comprehensive set of business requirements and system capabilities for IGP. The requirements and capabilities were grouped into the following categories:

- Advanced Automation and System Reliability
- Grid Optimization and Management (Volt/VAR Optimization, Power Flow Optimization, and Virtual Microgird)
- Resource Incentives
- FAN Communications

– Cybersecurity
– Integration Services

Using the baseline requirements, the IGP team proceeded to identify and select a subset that could serve as the basis for small scale, controlled demonstrations in the production environment. This led to the definition and organization of the scope around eight initial sub-projects that are fully integrated, yet able to demonstrate discrete system capabilities of interest. As the program progressed, new opportunities were identified, resulting in four additional sub-projects. The descriptions for each IGP sub-project are provided in the next section.

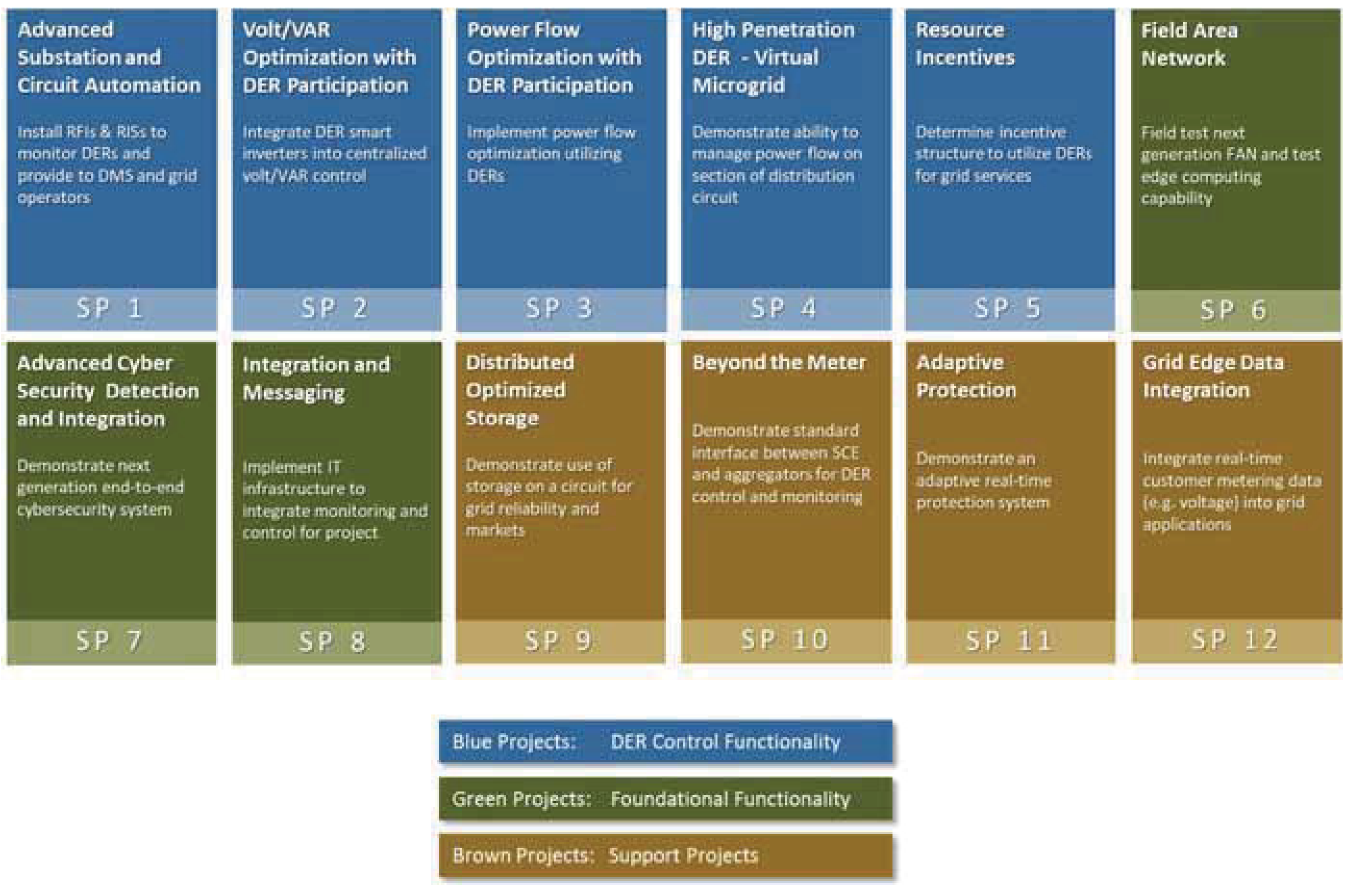



*Figure 2: IGP Sub-Project Organization*

SP1: Advanced Substation and Circuit Automation

Sub-project one (SP1) is focused on increased distribution monitoring, fault detection, and automation to improve reliability and enable resiliency with increasing levels of DERs. SP1 includes the deployment of RFIs and remote intelligent switches (RISs) in the test area, as well as control software to manage those devices.

- SP1 grew out of the need for increased automation and visualization tools to help reduce the frequency and duration of outages and give system operators a better picture of what is happening in the distribution system with higher penetrations of DER (DER installations on the circuit with capacity greater than 15% of the circuit's peak loading).
- The automation component of this sub-project includes demonstrating five RISs in the Johanna Jr. substation area and collecting fault information from RFIs. Both of these types of devices can communicate additional circuit monitoring information (e.g. current, power factor) that will be sent to the DMS to improve operator visibility of the circuits and improve the distribution state estimator results. These devices are part of SCE's Grid Modernization program.
- Another aspect of the sub-project is to collect DER operational data from larger customers—and aggregators of smaller DERs—and forward this generation information to the DMS. This more complete information for operators will help solve the "masked load" problem grid operators face when moving load and generation from one circuit to another. In the past, operators could get into a situation where they thought they were moving a block of load (e.g. 1 MW) to an adjacent circuit only to find it had grown to a larger load (e.g. 2 MW) due to the loss of a DER generator (e.g. 1 MW) on that circuit segment. This "masked load" – load not seen by operators because it is satisfied locally by generation - currently may cause operators to delay load transfer plans until an engineering study is performed to verify the proper switching operations.
- These features will be implemented on SCE's new ADMS when it is put into service in 2019.

| Key Accomplishments | Date |
|---|---|
| Completed installation of 5 new RIS units on Poker / Bingo circuits (using NetComm communications) | Dec 2016 |
| Started integration activities for RIS with new FAN radios | March 2017 |

SP2: Volt/VAR Optimization with DER Participation

Sub-project two (SP2) examines how high penetrations of DERs affect voltage regulation. Specifically, SP2 integrates DER Smart Inverters into volt/VAR optimization schemes to supplement existing capacitor banks and voltage regulators. SP2 includes the procurement of a control application which takes advantage of PV and storage, managing them in conjunction with traditional voltage optimization assets.

- Today, voltage on SCE circuits is mainly controlled through the use of switched capacitor banks and a few transformer tap changers and voltage regulators. SCE has implemented a volt/VAR program called Distribution Volt VAR Control (DVVC) that coordinates the operation of the existing switched capacitor controllers to provide a lower, flatter voltage profile on the circuits. This new profile reduces the amount of energy used by customers and saves them money. With higher penetrations of variable DER starting to show up on circuits, incorporating these DERs into the volt/VAR controls is becoming necessary to manage quicker fluctuations in voltage and help maintain a reliable system. SP2 was conceived to demonstrate controls using these DER devices to absorb and produce reactive power to help control voltage. Once the effectiveness of this volt/VAR control scheme with DER participation is confirmed, it will be implemented as part of the Grid Modernization program.

| Key Accomplishments | Date |
|---|---|
| Identify circuits for demonstrations within the Camden substation area | June 2016 |
| Complete procurement of controller software | July 2016 |
| Complete pre-FAT / sandbox testing | March 2017 |
| Assist SP3 with controller and integration bus testing | April 2017 |

SP3: Power Flow Optimization with DER Participation

Like SP2, sub-project three (SP3) includes the procurement and testing of a control application that coordinates multiple DERs to optimize circuit power flow. This may include balancing load and generation, balancing between phases, optimizing real power flow and avoiding circuit overloads.

- Under today's planning methods, when a circuit is expected to become overloaded due to increasing amounts of load or generation, SCE upgrades conductors and transformers. With the increase in the capacity of PV generation and battery storage being installed on circuits, more upgrades may be required.
- Improved control of DERs on distribution circuits is viewed as a potential way to defer or avoid the need to upgrade some circuit equipment. An added benefit of using control of DER and loads is the ability to optimize the behavior of distribution circuits to help reduce losses and provide better circuit controllability for system operators.
- As with the volt/VAR control with DER participation, this demonstration will help demonstrate the benefits of using DER for power flow optimization.

| Key Accomplishments | Date |
|---|---|
| Complete procurement of controller software | July 2016 |
| Complete AT lab build out | Oct 2016 |
| Complete sprint testing (communication between controllers and integration bus) | Dec 2016 |
| Complete pre-FAT / sandbox testing | March 2017 |
| Complete FAT 1 | April 2017 |

SP4: High Penetration DER – Virtual Microgrid

Sub-project four (SP4) is demonstrating a virtual microgrid. Rather than physically disconnecting and reconnecting a portion of the grid, SP4 uses a control application to keep the net of load and generation power flows at zero at a specific point on a distribution circuit for an extended period of time (measured in hours). SP4 includes the procurement of a control application which can establish and manage the virtual microgrid.

– Managing the real and reactive power flows on circuit sections through the use of DERs is not something SCE does today. As the amounts of DERs on circuits increase, the ability to manage the generation and load on sections of circuits can help limit overloads on these circuit sections. This load and generation management is accomplished by observing power flows at a monitoring point and then sending control signals to DERs to maintain power flow at a set level. While this virtual microgrid is never intended to be isolated from the rest of the grid, it does manage its loading in a manner that allows the circuit section to behave as a controllable load.

| Key Accomplishments | Date |
|---|---|
| Complete procurement of controller software | July 2016 |
| Define circuit segment for microgrid monitoring point | Aug 2016 |
| Finalize design for Distribution Energy Storage Integration (DESI) 2 battery interconnection | Nov 2016 |
| Complete pre-FAT / sandbox testing | March 2017 |
| Complete FAT 1 | April 2017 |

SP5: Resource Incentives

Sub-project five (SP5) evaluates how to encourage customers to install and operate DER to provide benefits to the grid. SP5 includes analysis of the potential for customer adoption of DER and an investigation of potential market designs.

- If SCE is going to start using customer-owned DERs to help provide grid reliability services in the future, there needs to be a process to properly value these grid services and determine how to compensate customers who supply them. This sub-project is looking at various market structures as well as assessing the potential return to these customers if they make their DERs available to provide grid services.
- Examination of customer energy usage patterns reveals that some customers could benefit from the installation of PV or battery storage. These customers could be encouraged to install DER and at the same time sign up to help provide reliability services to SCE's distribution circuits.

| Key Accomplishments | Date |
| --- | --- |
| Complete circuit / locational value analysis | Aug 2016 |
| Complete customer analysis | Sep 2016 |

SP6: Field Area Network

Sub-project six (SP6) is evaluating FAN solutions in the lab and field to replace the aging NetComm solution. This new network will provide field area communications for the other sub-projects, ensuring reliable communications between field devices (including DERs) and back office systems.

- Most new grid services will require better communications. For more than 20 years SCE has used a radio network operating in the 900 MHz unlicensed band. This network provides communications to distribution automation devices and large customer meters. While this system has provided cost-effective communications for many years, it is nearing the end of its useful life. It lacks sufficient bandwidth and proper cybersecurity to continue to support the growing need for communications to new distribution automation technologies and provide control for distribution circuits with high levels of DERs.
- This sub-project is evaluating and field testing new FAN solutions that will enable SCE to move forward with its Grid Modernization plans. This testing, described in section 4.4, includes evaluation of radio communications coverage, data communications capabilities, and ability to handle data flows needed for SCE's future automation plans.

| Key Accomplishments | Date |
|---|---|
| Complete FAN lab build out | April 2016 |
| Complete FAN test plan | April 2016 |
| Complete detailed IGP technical configuration specifications | Sep 2016 |
| Complete FAN round 1 testing (for down select) | Sep 2016 |

SP7: Advanced Cybersecurity Detection and Integration

Sub-project seven (SP7) is evaluating the cybersecurity capabilities of the products procured and deployed as part of the other sub-projects, ensuring that they follow the appropriate industry security standards, such as Institute of Electrical and Electronics Engineers (IEEE) C37-240, IEEE 1686, International Electrotechnical Commission (IEC) 62351, and IEC 61850 90-5. In particular, SP7 focuses on extending foundational, shared cybersecurity services to substation devices to support their unique operating conditions.

- As control systems increasingly interconnect distribution field devices, DER, back-office control systems, and Internet information sources, there is a need for stronger cybersecurity measures. To the extent possible, these cybersecurity measures will utilize the appropriate industry security standards, such as IEEE C37-240, IEEE 1686, IEC 62351, and IEC 61850 90-5. This sub-project will investigate and test a number of cybersecurity systems as part of the IGP control systems. The results of these tests are informing the choices being made as to which cybersecurity measures will be implemented as part of SCE's Grid Modernization plans. This testing will be completed under EPIC 2 in late 2017.

| Key Accomplishments | Date |
|---|---|
| Complete subproject kick-off | Aug 2016 |
| Develop proposed system architecture to satisfy cybersecurity use cases | April 2017 |
| Complete initial Solution Architecture document | April 2017 |

SP8: Integration and Messaging

Sub-project eight (SP8) integrates the other sub-projects. This integration will ensure the different components purchased and implemented by the other sub-projects work together as a unified system. Integration includes the procurement and deployment of technology that facilitates near real-time exchange of messages between different IT and OT systems, such as DMS and the IGP control applications, as well as grid edge devices.

– This sub-project performs the integration of the control system with existing back office applications, distribution automation equipment, and DER (owned by SCE, third parties, or aggregators). To make all of these systems work together smoothly, a significant effort is needed to integrate data exchange protocols, communications technologies, and control systems. This integration ensures the different components purchased from different vendors work together as a unified system. The IGP architecture utilizes an operational service bus technology to tie all these systems together. Lessons learned from this integration effort have been passed to the SCE Grid Modernization efforts and have been used to confirm the requirements used for purchase of the actual production systems.

| Key Accomplishments | Date |
|---|---|
| Develop system requirements | Dec 2015 |
| Identify key architectural components | Feb 2016 |
| Complete use cases | Feb 2016 |
| Develop incremental versions of SDD, SRD, and Interface Catalog documents | Mar 2016 |
| Write test plans / test cases / test procedures | Feb 2017 |
| Complete technical requirements specification | Mar 2017 |
| Manage testing for sprints / sandbox / pre-FAT / FAT 1 | April 2017 |

SP9: Distributed Optimized Storage

Sub-project nine (SP9) demonstrates using distributed optimized storage to address distribution reliability concerns while also using the assets to bid into the wholesale market. This "dual use" maximizes the economic value of the asset, reducing net costs to ratepayers.

- Energy storage is an increasingly important part of the grid as more variable energy resources are installed. The Distributed Optimized Storage (DOS) project will demonstrate how multiple battery systems can be controlled in a coordinated manner while also interfacing with SCE's DMS. Because the objectives of the DOS project were so similar to the objectives of IGP, these two projects were combined. The IGP control system will be used to satisfy the need for a centralized control system to optimize the operation of storage systems. The field demonstration portion of the original DOS project will be satisfied by the field demonstration portion of IGP being conducted in the Camden substation area as part of EPIC 2.
- A high-level use case has been completed that describes how a storage battery would be managed to meet the needs of the wholesale market while also serving the reliability needs of the distribution system. This capability would maximize the economic value of the battery and help reduce costs to ratepayers. Support for multiple battery uses is expected to be an important aspect of future grid operations.

| Key Accomplishments | Date |
|---|---|
| Complete procurement of controller software | July 2016 |
| Acquire site property for DESI 2 battery to be used as part of the demonstration | Aug 2016 |
| Complete pre-FAT / sandbox testing | March 2017 |
| Complete FAT 1 | April 2017 |

SP10: IEEE 2030.5 & Beyond-the-Meter Communication

Sub-project 10 (SP10) evaluates potential interfaces between the SCE DMS and customer-owned DER meters. This metering data can be used to inform grid operators of DER output on a near real-time basis and update the DMS with DER output levels. More details of this sub-project will be provided in a separate EPIC 1 report on the Beyond-the-Meter project.

- As IGP progressed, it became increasingly clear that a way was needed to measure the actual output of various customer-owned DERs. Today, telemetry is not required for DERs less than 1 MW. With increasing amounts of DER with capacities up to the 1 MW telemetry limit, collection of this information for grid system operators is becoming more important. This subproject is looking into how this data might be collected in a near real-time manner at the least cost. For customers with meters on their DER, this might be as simple as installing communications to the existing meter. For others, this information might be obtained through an aggregator who is monitoring the DER installation. The sub-project will determine the best way to obtain this metering information and forward it to the IGP control application so it can be used for optimization as well as help inform grid operators of the state of the distribution system. IGP testing will help influence interconnection standards that might need to be modified to obtain this operational data. The ability to acquire this data will become increasingly important to optimize grid operations and increase reliability through SCE's Grid Modernization plans.

| Key Accomplishments | Date |
|---|---|
| Determine options for collecting customer DER metering data | April 2017 |
| | |
| | |
| | |

Sub-project 10 was started just as EPIC 1 period ended

SP11: Adaptive Protection

Sub-project 11 (SP11) will demonstrate how to adjust relay settings to accommodate varying conditions caused by circuit reconfiguration and large amounts of DERs connected to circuits. This will be a lab demonstration to calculate the new settings based on real-time conditions and communicate (automated or manually) those settings to a relay.

- This sub-project is a recent addition to the IGP scope (EPIC 2 funded) and is a key capability needed to make the protection system more adaptable to changes in distribution circuit configurations as well as new installations of DER. The goal of this sub-project is to demonstrate in the laboratory how protection coordination studies could be run to automatically recalculate relay settings following a significant change in the system topology or DER status. These significant changes would be determined by the ADMS. Methods will also be explored to show how these recalculated protection settings might be automatically downloaded to the relays. With the increasing number of significant changes occurring in the distribution system, this capability will be necessary as we continue to incorporate more DERs into the grid.

| Key Accomplishments | Date |
|---|---|
| Project kick-off | April 2017 |
| | |
| | |
| | |

**Sub-project 11 was started just as EPIC 1 period ended**

SP12: Grid Edge Data Integration

Sub-project 12 (SP12) is a lab demonstration to determine how SCE customer meter data could be used to improve the accuracy of a distributed control system. This data will be obtained from existing AMI meters (less than 200 kW customers) as well as the Real-Time Energy Metering (RTEM) meters used on larger customers.

- Obtaining customer usage and voltage data at their point of connection to SCE is useful for improving the accuracy of volt/VAR controls as well as providing better information for grid state estimation. While today this information is being collected for billing purposes, for most customers, it is only collected once per day. To make this information more useful to the grid optimization applications, it must be retrieved in near real-time. This sub-project, to be executed under EPIC 2 funding, will look at the two systems in use today to retrieve metering data (SmartConnect and RTEM) and investigate how this data could be retrieved more frequently. Once prototype systems are tested in the lab, they may be implemented in the field if it is feasible. The results of this sub-project could inform future approaches to improving SCE's real-time visibility of the distribution system.

| KEY ACCOMPLISHMENTS | DATE |
|---|---|
| n/a | |
| | |
| | |
| | |

Sub-project 12 was started after EPIC 1 period ended

## 2.5 IGP Schedule

The schedule shown in Figure 3 depicts the timing of completed milestones and anticipated timing of future milestones. While SCE did not meet all the milestones set out for this project, significant progress has been made. Most of the delays have occurred in the initial testing phase of the project due to control system integration challenges. As noted in the overall project objective, one of the primary purposes of IGP was to design, test, and refine the integration of new technologies that will assist with modernization of SCE's grid. As such, an essential part of IGP testing is to actively identify problems with these new technologies and develop effective solutions.

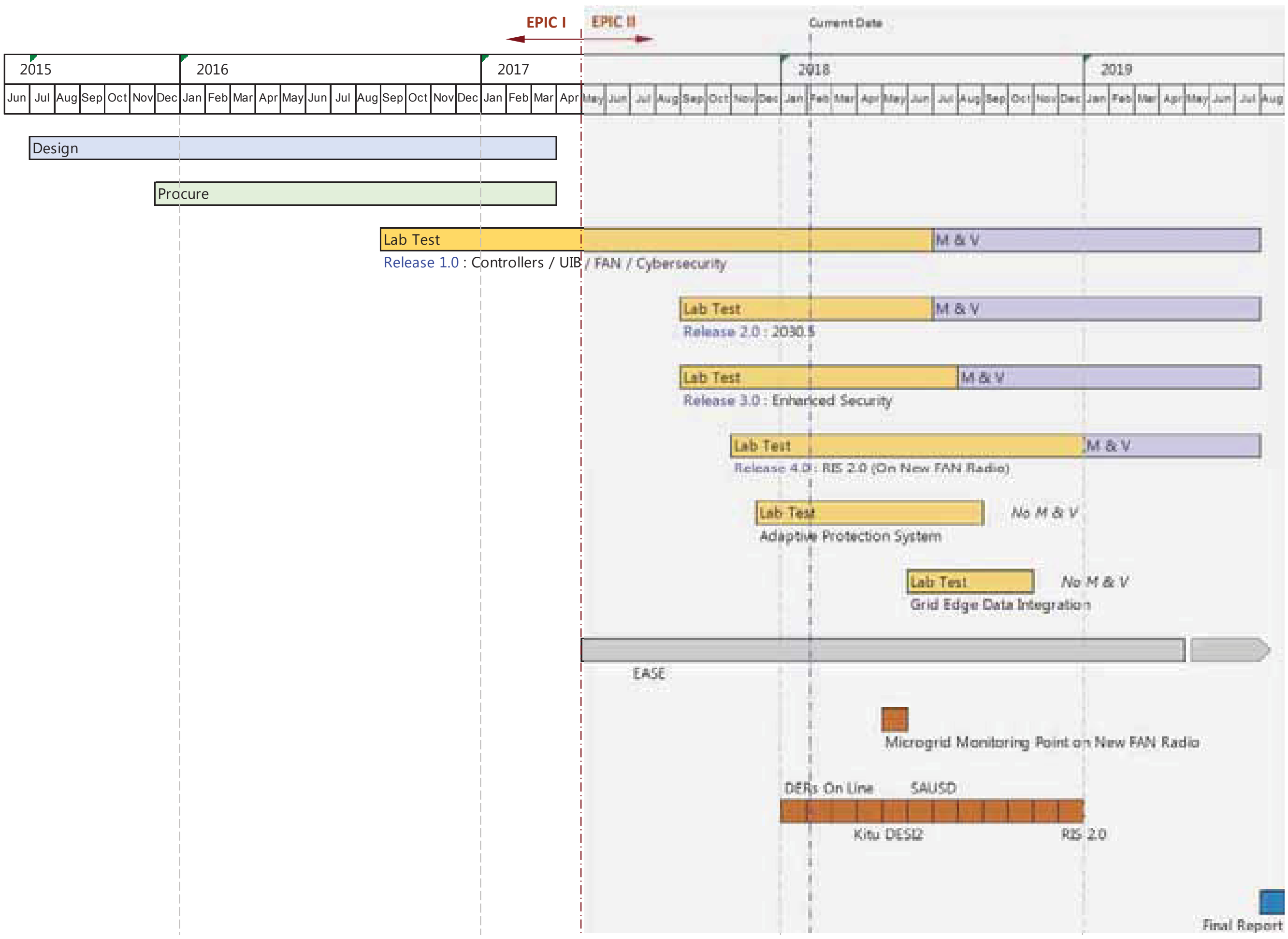



*Figure 3: IGP Top Level Schedule*

# 3 IGP System Design

In order to fulfill IGP's objectives and accommodate the requirements of all the sub-projects, a hybrid design approach has been adopted that combines existing systems and assets already in production with a set of new systems and assets.

- Examples of existing systems and assets include the XA-21 DMS, the NetComm radio network, and edge devices such as RFIs, and RISs already configured for operation over the existing NetComm radio network.
- Examples of the new IGP systems and assets include optimization and control applications, the operational service bus, the common substation platform (CSP), the new FAN, and the set of edge devices that will be configured for operation over the new FAN.
- The design approach leverages SCE's various test facilities to instantiate and prototype each IGP element in a controlled lab environment prior to field deployment.

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

## 3.1 System Requirements / Use Cases

⇨ Requirements Definition

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

⇨ Use Cases

- Use cases were assembled to help determine how the control systems would operate and also derive the functional and non-functional requirements for the system design. A short summary of each of these use cases is included in the following section with more detailed descriptions found in Appendix 6.5.

Use Case 1-1: System Reconfiguration supported by Advanced Monitoring – Scheduled Events

Monitoring information from DERs, RFIs, RISs, and remote controlled switches with monitoring (RCS+s) is collected and used to assist operators in reconfiguration of distribution feeders through the use of power flow simulation/state estimation provided by the ADMS and solar/wind/load forecasting.

Use Case 1-2: System Reconfiguration supported by Advanced Monitoring – Post-Fault

Fault location information from RFIs in combination with monitoring from DERs, RISs, and RCS retrofit devices is collected after a fault and used to provide the operator with a number of potential switching schemes to restore load. The ranking of the schemes will consider priority load as well as solar and storage level forecasts to incorporate potential expected changes in net load on the affected circuits following a reconfiguration.

Use Case 2-1: Voltage Optimization with DER

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

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

At the feeder level, the IGP control system and its optimal power flow (OPF) controller optimizes loads, generation, and storage to shape the load to meet operational requirements at any given time.

Use Case 4-1: Microgrid Control for Virtual Islanding

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

Use Case 9-1: Dual Use of Utility-Controlled Distributed Energy Storage Systems

Utility-Controlled Energy Storage Systems (UCESS) deployed on the distribution grid are integrated, configured, and controlled so as to allow their use for the following two functions:

- Utility distribution grid reliability and optimization needs
- Bidding all or a portion of the power into the wholesale market when not needed for reliability and optimization purposes

The UCESS will be operated, including when bid into the wholesale market, based on constraints driven by the reliability needs of the distribution grid.

## 3.2 Design Considerations

The extent of the IGP sub-projects and their related scopes present sizable complexities and potential operational risks during field deployment. As such, the key design decisions presented below were undertaken to mitigate such risks and minimize integration complexities during implementation. Based on lessons learned from the Irvine Smart Grid Demonstration, the setup and operational maintenance of a separate pilot-production environment for IGP has been deemed too burdensome on SCE's grid operations. As such, the new IGP systems will be integrated into existing production systems and assets wherever possible. Notable examples of these production assets include DMS and common/shared enterprise cybersecurity services such as Active Directory, RSA, and Radius.

Given that the IGP sub-projects are demonstrations, the new IGP systems will not require redundancy. Therefore, the design is such that, if all the new IGP systems were to go offline or become unavailable, the normal existing production operations would be unaffected. The result is that, in the event of failure, Grid Operations will see the same conditions they have known and managed prior to the introduction of the new IGP components.

Some of the IGP sub-projects, including SP2 and SP3, will introduce and demonstrate the new concepts of controlling DER for real and reactive power flow, and microgrid optimization purposes. Other advanced control operations are being considered for later phases of IGP. Given the lack of experience with such control operations, the IGP design provides the ability to maintain operational safety through the use of a battery energy storage system disconnect switch controlled over an alternate communication channel. This capability will provide grid operators with the ability to override the testing environment, should a need arise. Grid operators will also have the ability to disable all automated functions introduced by the new IGP applications.

## 3.3 FAN

SCE has determined that a next generation FAN is needed to replace its aging NetComm system. The wireless communication devices, cybersecurity methods, edge computing, and support tools of the FAN will meet the communications needs of IGP and next generation grid infrastructure. SCE has evaluated several options for the new FAN radio system. Laboratory testing of the two finalists has been completed and more extensive field testing is being conducted in the IGP area. Both finalists' systems have been deployed as test networks and the finalist will be used for the IGP demonstration. Important features of these FAN radios include the ability to run software programs internally that can be used to convert between communications protocols, enable distributed control, and execute modern cybersecurity algorithms.

## 3.4 Logical Context

IGP optimization and control systems will be deployed using existing network infrastructure and cybersecurity components as much as possible. Figure 4 provides a high-level overview of the logical relationships between the various IGP system components. As a demonstration project running in the production environment, the control applications associated with IGP must be of sufficient quality to operate in the production environment without causing problems with existing production applications. This concern informs the overall approach to integrating the IGP control applications with each other, the production DMS, and DER. Specifically, the production DMS must always be aware of any control actions taken by the IGP control applications. Because of this, the operational service bus must connect to both the IGP controls and the production systems. Additionally, security requirements necessitate that the SCE network be divided into different segments, separated by firewalls. Supporting diagrams and material are provided in Appendix 6.1

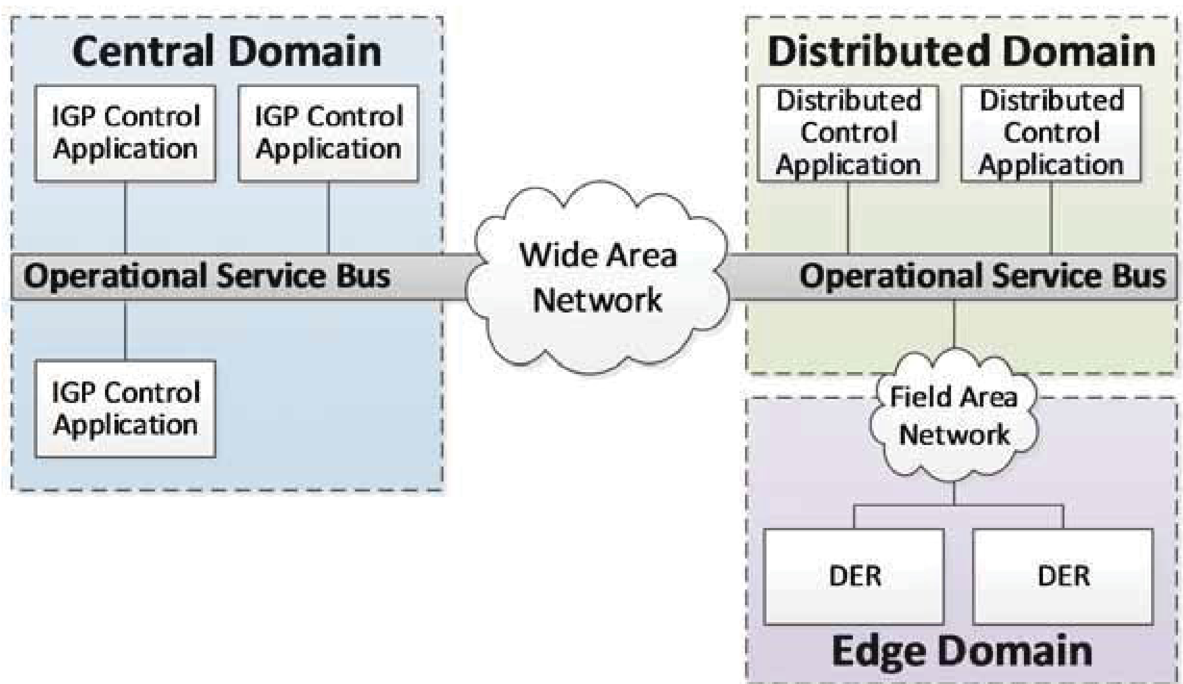



*Figure 4: IGP High Level Logical View*

## 3.5 Determining Project Demonstration Location

The team considered a number of factors when determining the IGP location. Key criteria included system topology, the ability to install field equipment, meeting the DRP Demonstration requirements and, most importantly, having sufficient existing and planned PV and storage installations to qualify as high penetration of DER. The IGP team identified a number of potential locations. Each location was scored based on the criteria in Figure 5 below.

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

*Figure 5: Scoring Criteria for IGP Site Selection*

After thorough analysis, the team decided that a combination of the adjacent Camden and Johanna Jr. substations would satisfy the project criteria. These systems have a mix of overhead and underground circuits with both residential and commercial customers. In addition, the Camden substation area offered several large PV installations already in place with more installations under way to help meet the definition of high penetration of DER. Both of these substations are also located within the PRP area which has actively solicited installation of new DERs in the area over the last few years. These substation areas are sites for the installation of the current generation RFIs, RISs, and the latest version of substation automation (SA-3). These technologies enable IGP to demonstrate the next generation grid and identify any early deployment issues associated with these technologies.

### 3.6 Cybersecurity

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

- Advanced application-level firewalls
- Multi-factor authentication for user access
- Centralized system log collection and aggregation from applications and devices
- Application whitelisting
- Application password vault
- Vulnerability scanning
- Web application firewall to link SCE control systems to third party DER partners over the Internet
- Public key encryption services
- Network access control, visibility, and system profiling capabilities

A cybersecurity risk assessment has been performed on IGP technologies in the lab test environment. This assessment will be repeated as the control systems move into the SCE Quality Assurance System production test environment and again as the control systems are migrated to the formal production system. These efforts have helped resolve issues relating to the proper application cybersecurity requirements and put in place methods to securely interact with DER aggregators over the Internet. This testing has helped lay the ground work for implementation of cybersecurity for SCE's grid modernization applications.

## 4 Lab Testing

### 4.1 Control System Test Lab Design / Setup

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

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

- Show hardware and software operates according to IGP's and manufacturer's specifications.
- Verify field devices could be monitored and controlled by remote command through the control systems.
- Determine if the IGP controller is capable of controlling capacitors and DER to meet circuit voltage requirements.
- Determine if the IGP controller is capable of controlling DER to optimize real/reactive power flow.
- Verify the precision and stability of the real and reactive power control over a range of durations and settings.
- Measure the response speed of the control system.
- Determine DESI 2 battery system's reaction to grid events and control system limits.
- Verify that DER status can be communicated to the DMS and displayed to the operator.

IGP is testing the power flow optimization and volt/VAR controller applications using a controller-in-the-loop test environment. This test environment uses a simulation system to dynamically model circuit conditions as well as simulate dispatch of real and reactive power at multiple resource locations within the modeled distribution substation and its feeders. The testbed has implemented a detailed distribution system model of SCE's Camden substation and its 7 circuits. This model includes cables, conductors, switches, capacitors, and realistic PV and energy storage functionality. The control applications and operational service bus then interact with the modeling environment in real-time to investigate their performance. This testing setup is depicted in Figure 6.

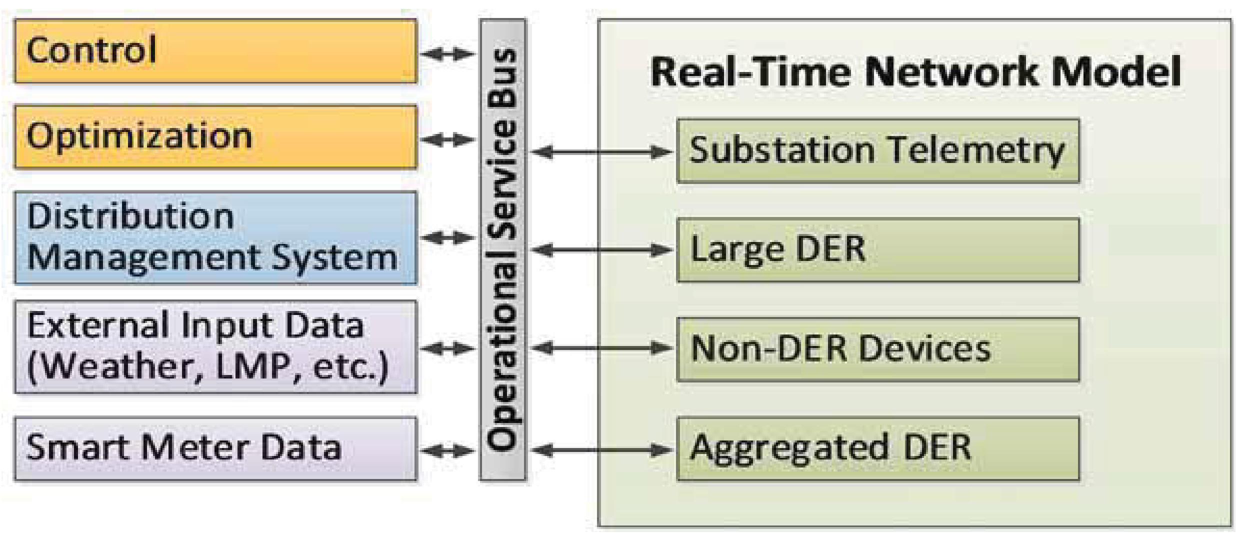



*Figure 6: IGP Control System Test Lab Setup*

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

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

## 4.2 Agile Software Development and Testing

To speed the control system development process, an agile software development method called "scrum" was used. This method is an iterative development approach that uses "sprints" or development iterations to move the process along. Within each sprint, the development team builds and tests a functional part of the software system. Each sprint needs to satisfy a number of "stories" or user requirements. Daily scrum meetings are held to review what was done the previous day and agree on what would be done the coming day. Once this sprint is complete (i.e. the software is functional), the team moves on to the next sprint. This process is repeated until the software system is complete. In the case of IGP, this process was used to develop and ensure software communications paths were operating prior to the start of the FAT. Figure 7 lists the software sprints that were conducted. A total of five development sprints were run. Sprint goals were assigned by the SP8 project owner. Each sprint was scheduled to run for two weeks with all parties participating. A web-based tool was used by all project participants for task assignment and defect tracking. The completion of these sprints signaled when the control software was ready to move to the next lab testing phase.

| Sprint | Goal | Total User Stories | Scope Change | Completed User Stories |
|---|---|---|---|---|
| 1 | Power flow data exchange between SCE's PowerOn Reliance DMS (XA/21 DMS) and control vendors through operational service bus | 18 | +1 | 16 |
| 2 | ▫ CAISO and Weather service wiring completed (all vendors)<br>▫ Control vendor consume the Realtime-PowerFlowSvc<br>▫ Operational service bus components for DERSetPointSvc are ready for Sprint 3<br>▫ Have Field Agent available via the Raspberry Pi setup<br>▫ Control vendor implements the registration process with the GE Field Agent | 24 | +2 | 24 |
| 3 | ▫ MeterDataSvc implemented and consuming sample data<br>▫ Setpoint and SCADA services implemented end to end<br>▫ Everyone using the same sandbox operational service bus instance in the AT lab<br>▫ Having on the ground support for lab issues and deployment<br>▫ Historical weather information distributed to the IGP controller vendors<br>▫ Control vendor integration understood and working<br>▫ Control vendor to implement the weather service | 30 | -10 | 9 |
| 4 | ▫ Control services by control vendors<br>▫ Meter data plumbing in place<br>▫ Historical Weather (15-Month) available<br>▫ DER Schedule Service Design complete<br>▫ PowerFactory simulator talks to a real model<br>▫ CIM 14 to CIM 15 Conversion complete | 30 | -1 | 18 |
| 5* | ▫ Wrap up everything from the last sprint<br>▫ Prove that the controller vendors can use the data<br>▫ Show in this sprint that we can call it a "complete wrap"<br>▫ Demonstration on how to use the data<br>▫ Test bed stood up. BeagleBones with power factory<br>▫ Plumbing in place, model in place testing at full speed | 30 | +7 | 36 |
| ** Sprint 5 lasted six weeks.* | | | | |

*Figure 7: Sprints Conducted by IGP*

## 4.3 Control System Lab Test Cases / Procedures

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

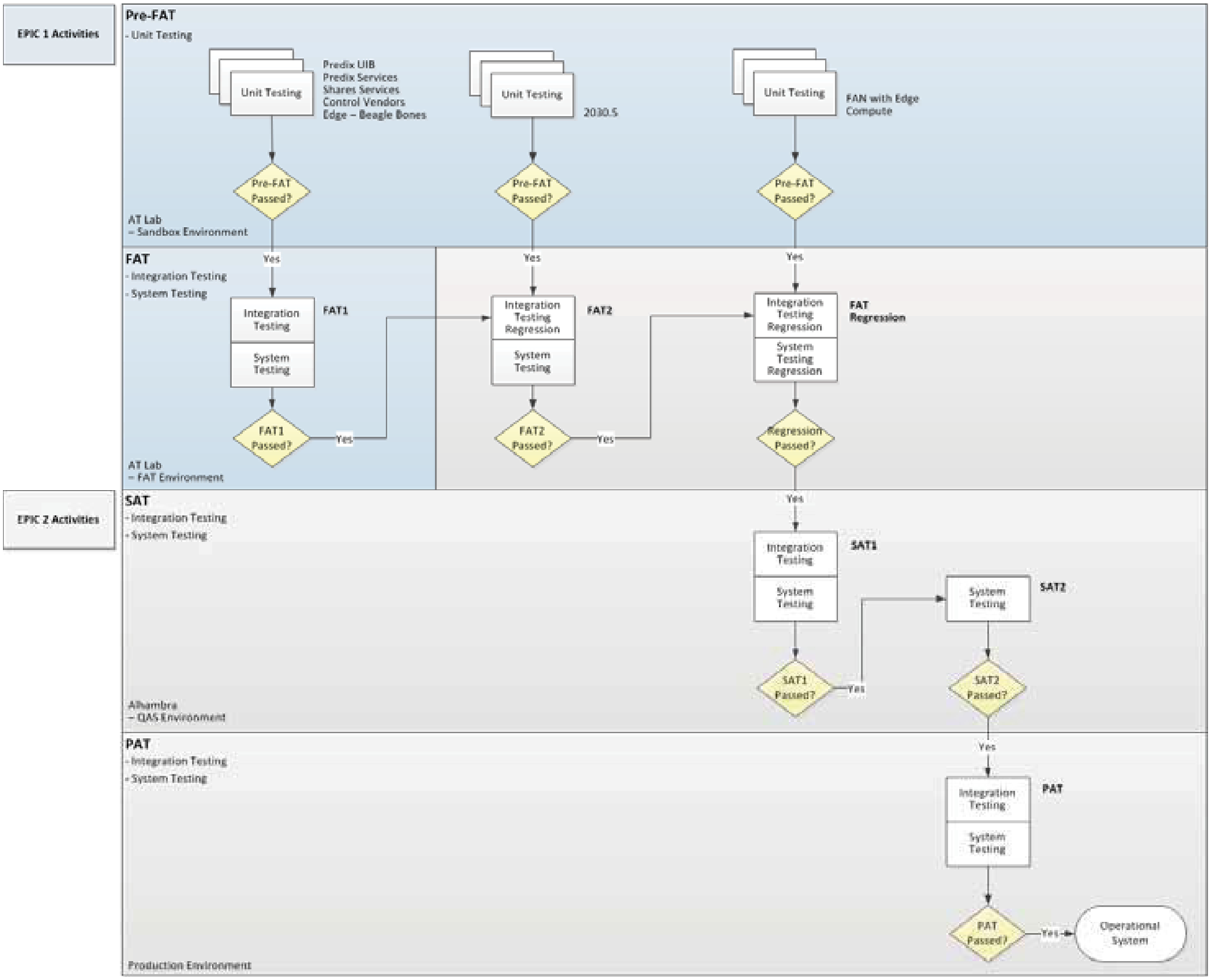



*Figure 8: Overall IGP Test Approach*

For FAT1 testing, a series of system test procedures were created. In total, 49 distinct integration and 45 distinct system test procedures were written to cover the power flow optimization, volt/VAR optimization, and virtual microgrid use cases. The 45 systems test procedures were directly mapped to 100 unique procurement requirements for validation. See Appendix 6.4 for a listing and high-level descriptions of the test cases.

While performing the lab testing as part of system integration and FAT1, progress was reported on daily 8:00 am calls with all pertinent SCE and supplier personnel. In addition, lab testing progress was tracked through the Atlassian Jira software and reports were issued both daily and weekly regarding progress, issues, and status of the resolution of the issues. Jira is a software issue tracking package that provides bug tracking, issue tracking, and project management functions. Jira was accessible to all pertinent SCE and supplier personnel involved in testing. Examples of Jira tracking and reporting are provided in Appendix 6.3.

## 4.4 FAN Test Methods / Procedures

Under IGP, SCE conducted FAN testing to evaluate multiple supplier solutions. These solutions were offered to SCE as part of a competitive RFP issued in November of 2015. SCE has leveraged the AT Grid Edge Solutions Laboratory to conduct the evaluations. Through the evaluations, SCE has selected two finalists from an initial set of seven suppliers. These finalists are being field piloted in the last half of 2017. The final selection is scheduled to be completed by early 2018.

SCE's FAN RFP contained a set of 535 technical requirements that detailed how the solution should work. Figure 9 summarizes SCE's key FAN capability requirements.

| Capability | Definition | Requirement |
|---|---|---|
| Latency | Speed of transmission, measured in latency per hop | 10ms per hop<br>100ms device to device |
| Throughput | Overall capacity of the network, measured in mbps | Greater or equal to 800kbps |
| Coverage | Ability of the network to provide connectivity to end devices | Adaptive modulation |
| Cybersecurity | Device authorization and authentication | Operational certificates, key sovereignty |
| Operations | Tools and system to manage the network | Consolidated management application, zero-touch provisioning, IPv6 support |
| Edge Compute | Compute environment for hosted applications | Environment and application specific OS, 4GB of Flash, 1GB of RAM |

*Figure 9: SCE's Key FAN Capability Requirements*

SCE developed a test plan to verify and evaluate the supplier solutions against the complete set of requirements. This test plan was supported by a set of five different test environments. These test environments focused on physical layer characteristics, network level performance, functional application testing, protocol testing, and field testing. The environments are described further in the following sections.

### Physical Layer Environment

This environment is focused on understanding the physical characteristics of the radio platform, such as radio signal strength, receiver sensitivity, and interference immunity. The testing is done inside a Faraday cage to isolate any outside electromagnetic interference. The radio frequency (RF) signals between the radios and the instrumentation are coupled through coaxial cables with the radios located inside of isolated RF enclosures.

Performance Environment

This environment is focused on validating the performance of the FAN system, specifically, measuring latency and throughput. SCE designed and constructed a wall with nine isolated RF enclosures to simulate a small nine-radio mesh network (Figure 10). This setup also includes a control matrix that can configure the mesh network. The network can be configured in a star mode where eight radios all communicate to one. It can also be configured in a serial mode, where each radio only communicates with an adjacent radio. Testing then measures latency and throughput in both configurations and across multiple hops. Two specific scenarios are represented in Figure 11.

*Figure 10: Radio Performance Environment Test Setup*

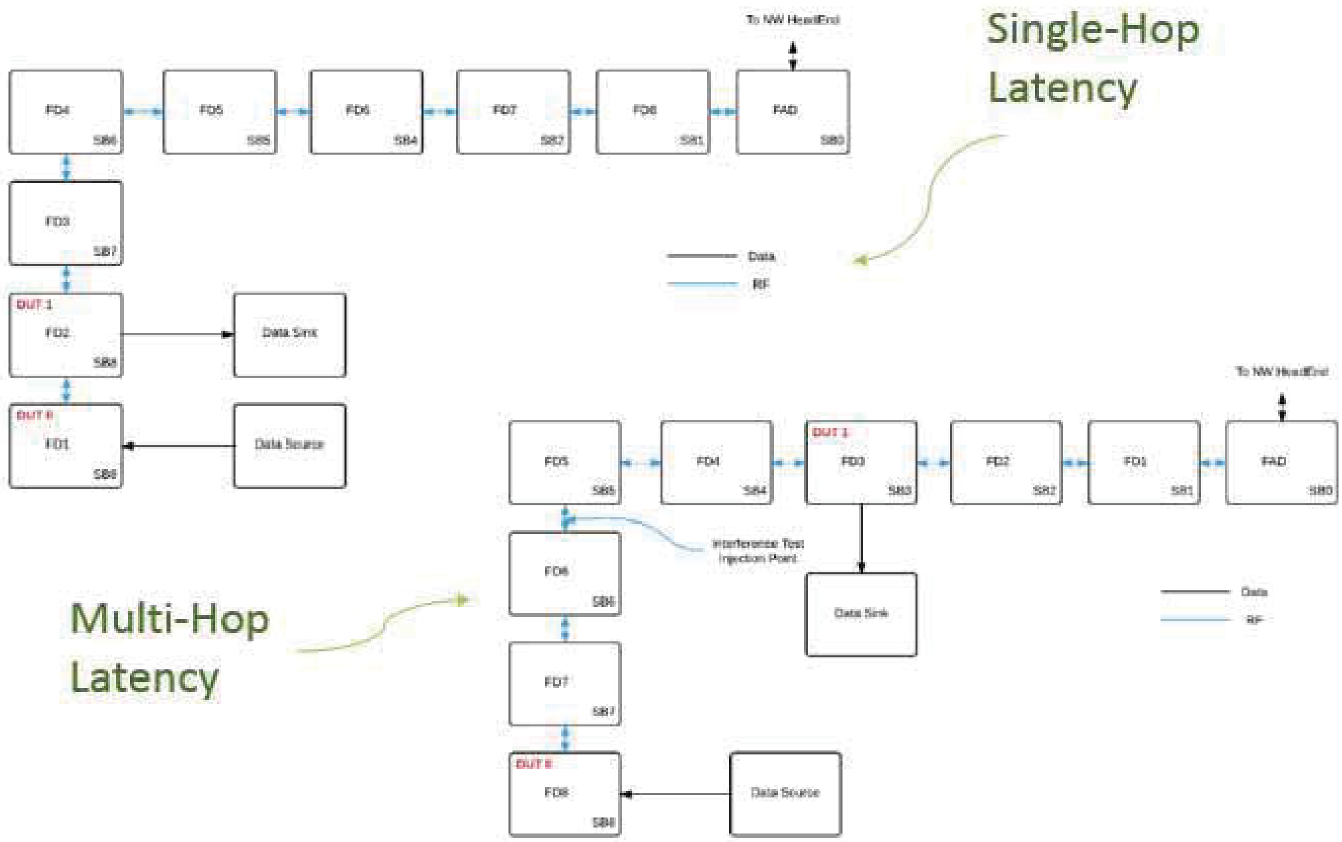



*Figure 11: Radio Test Scenarios in the Performance environment*

Application Testing Environment

This environment is focused on evaluating the network management systems (NMS) offered with each FAN solution. Additionally, this environment supports all the cybersecurity and protocol-focused tests. The NMS test cases evaluate how the network is managed by evaluating configuration management, firmware management, issue reporting, and user interface. Cybersecurity is tested by understanding how devices authenticate and operate on the network. Additionally, the test cases look at how the FAN integrates with SCE's internal cybersecurity services, such as a Public Key Infrastructure. Lastly, the protocol testing validates that the radio platform can support the protocols used by SCE's distribution automation devices, including ModBus, DNP3, and IEC 61850.

Field Testing Environment

Before the official field evaluation, SCE decided to conduct testing using a "drive around" methodology. Two field trucks were used to test the connectivity and range of two radios connected directly to each other. One truck was parked near a substation to simulate a collector point, while another drove pre-determined distances away from the substation. At each location, the radios exchanged packets and the packet success rate was logged. This test was repeated at different locations and distances in five different geographical areas of the SCE service territory. A high level overview of the test setup is presented below in Figure 12.

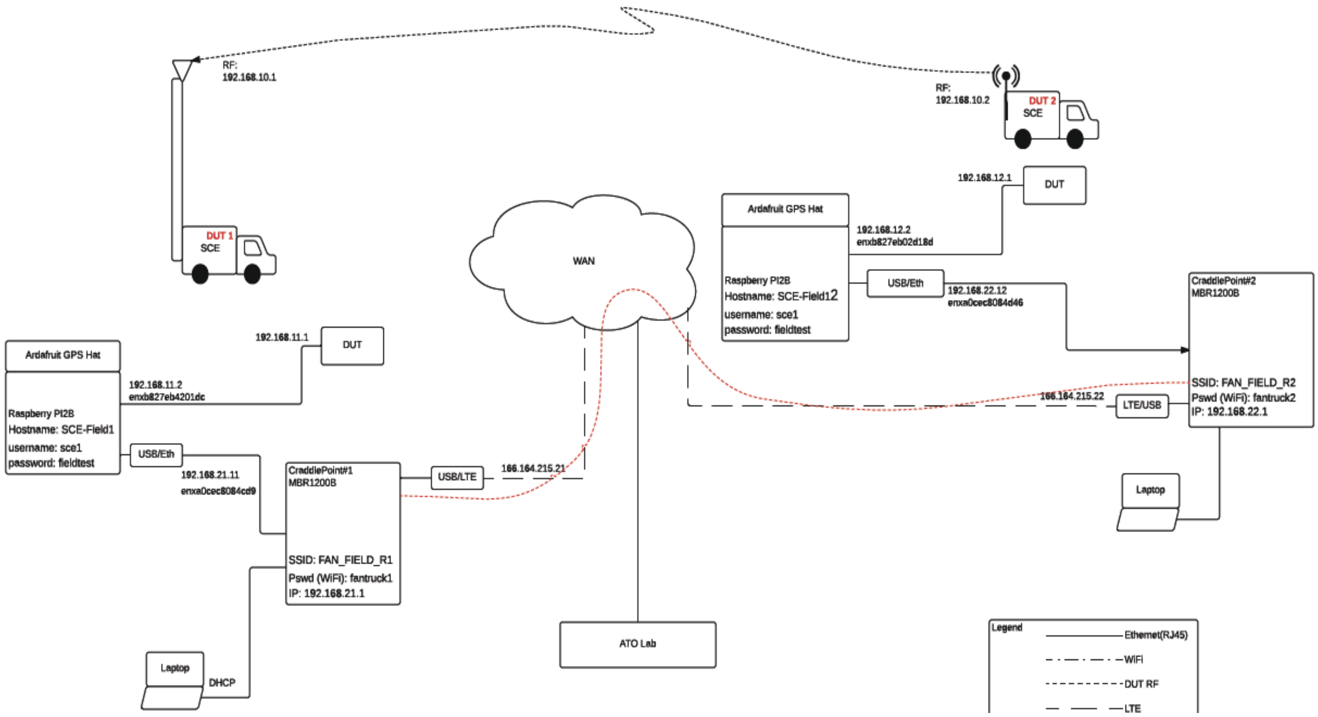



*Figure 12: Field "Drive-around" Test Setup*

Field Demonstration Environment

In September of 2017, SCE began field testing approximately 50 demonstration radios. Two suppliers deployed 25 units each in locations SCE selected. These locations represented places along circuits where distribution automation might be deployed. The goal of the demonstration is to conduct extended testing in an environment that resembles the real world. The radios were installed and commissioned in a manner similar to an operational network. Additionally, the radios are being monitored and managed by the network operations team through a centralized network management system. This not only allows the operations team to learn how to manage the network, but also allows them to evaluate how well the management systems function.

The demonstration also tests the performance of the network by simulating network traffic. Along with each radio, SCE included small computing devices (Raspberry Pi's) to run test scripts. These test scripts used open source tools to inject traffic to determine overall network performance. The test results report overall throughput, latency, and availability of the network. Additionally, the scripting allows for testing of any two or more sets of devices. This allows for specific use cases to be tested. For example, a fault location, isolation and supply restoration (FLISR) scheme with 5 automated switches can be simulated to understand how well the network can support it.

The demonstration continued through the end of 2017, is helping to assist SCE in determining which solutions can best meet the FAN system requirements. In 2018, SCE will begin production implementation with one supplier. The focus in 2018 will be to conduct all necessary testing, integration, and planning in order to begin full scale deployment in Q1 of 2019.

# 5 Project Results

## 5.1 AT Lab Test Results

### Unit Testing (Pre-FAT)

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

### FAT1 Testing

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

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

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

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

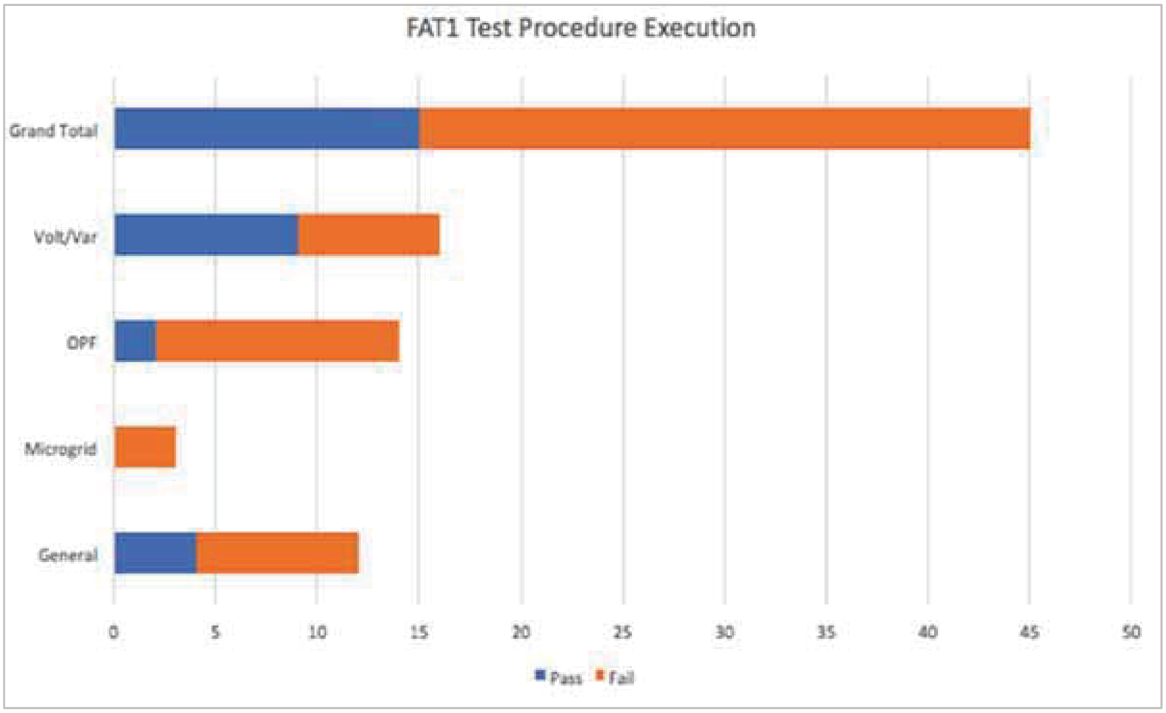
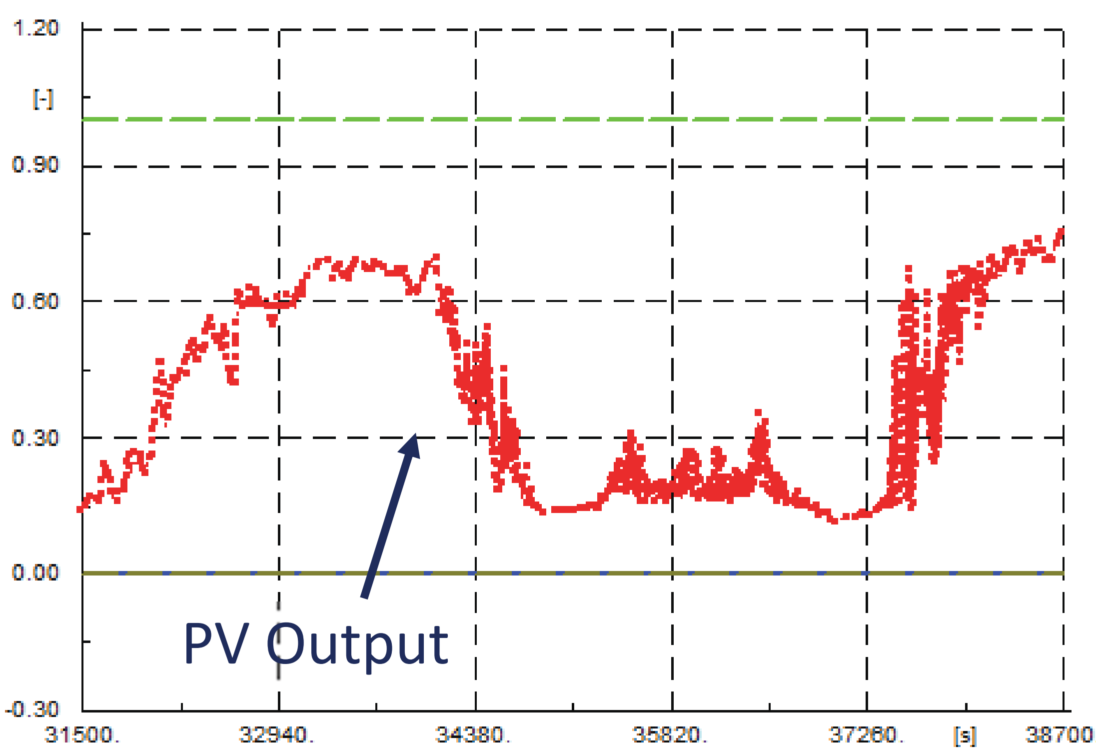



*Figure 13: FAT Test Procedure Results Tracking*

Below (Figure 14), are the results of a sample test case showing centralized control (from the back office) of a PV plus energy storage system where the battery is used to offset change in PV output as well as reduce the higher frequency PV output variations.



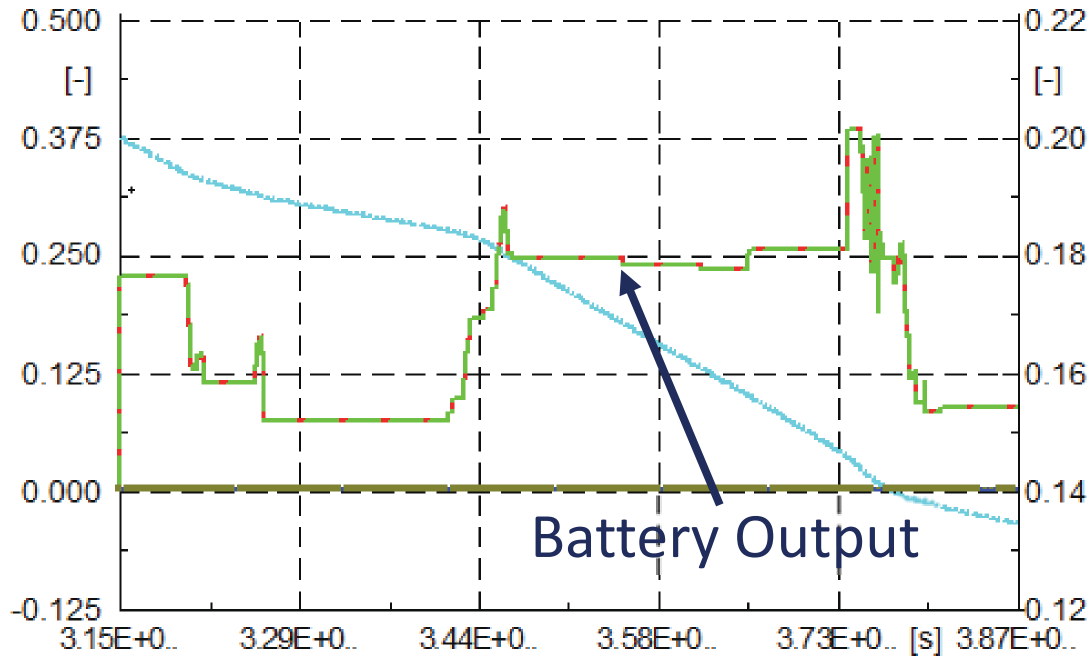



*Figure 14: Sample Control System Lab Test Case Results*

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

– Different control schemes (e.g. optimal power flow, and volt/VAR)

– Software modifications

– Examination of historical events

– What-if scenarios

– Load growth planning scenarios

– DER adoption rate scenarios

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

## 5.2 Findings regarding DERs

One of the more interesting findings was when the project staff approached customers to recruit them to be part of the IGP demonstration. Initially, the strategy was to install monitoring equipment on customer DERs to inform SCE grid operators about DER status (e.g., generation output or state of charge) at any given moment. The team then intended to solicit customers for permission to control the DERs for voltage management and power flow optimization on the distribution circuits. While customers were interested in seeing what control of DER might involve, they typically expressed interest in being compensated for this service. Since this is a demonstration project, there are no rates or programs to compensate customers for using their DERs to provide grid support. The initial plan was to offer to substitute existing customer inverters for smart inverters in exchange for their participation.

However, since most of the customer sites were warrantied and maintained by a 3rd party, this presented contracting challenges. SCE is still in negotiations with several DER owners and is now looking at cash compensation to entice customers to participate. We hope to learn what level of compensation will encourage participation.

Most new DERs being connected to the utility grid are owned by customers or third-party developers. IGP looks to coordinate these resources with utility assets and grid operations. With Business Customer Division and Local Public Affairs, SCE has discussed with customers and the City of Santa Ana how these resources may be better integrated with the utility. Most of the larger PV installations have inverters set to unity power factor and optimized for maximum solar PV output to reduce their overall energy charges. IGP seeks to demonstrate that higher levels of DER penetration will be enabled by increased management of these resources. For DERs to provide the functions necessary to help manage the grid, at times SCE might want to reduce output or produce reactive power that might limit the real power output of the DER. If this control creates higher value for all customers, it will be important to consider how to compensate DER owners for the services they provide in order to incentivize their participation. These incentives can help encourage higher levels of penetration. The project team is working with Pacific Northwest National Lab that has developed several demonstration projects designed to determine optimal incentive structures.

IGP provides the ability to test new California Rule 21 (IEEE 2030.5) communications protocol that communicates information and controls from the device level (smart inverter), whether directly connected or through a third party aggregator, to the traditional back office systems, particularly the Distribution Management System. The IGP allows for an early demonstration of this technology and allows the company to anticipate any implementation issues with this new communication standard and back-office implementation.

## 5.3 Lessons Learned

### Requirements and Analysis Phase

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

### System Design Phase

- The decision to adopt an open standards-based operational service bus architecture with clear service definitions enabled flexibility in integrating software systems from multiple vendors. Unfortunately, the lack of maturity of available service bus products caused project delays.
- Progress with the system design was severely impacted due to lack of sufficient vendor engagement. Future endeavors would benefit from ensuring that the procurement planning can accommodate enhanced vendor participation in the system design phase.

- The IEEE 2030.5 standard for communicating with smart inverters and aggregators is in early stages of deployment and may require changes before it is widely accepted and implemented by DER aggregators. This uncertainty has caused some unwillingness for vendors to adopt the standard at this time.
- The decision to only implement one XA-21 DMS instance in the lab for use by the two control system vendors under test also caused delays. The procedure for vendor switchover meant there were days lost in testing, as well as preventing the non-active vendor from continuing their development procedures in parallel. A second test environment would have speeded the testing of the control systems.

System Development Phase

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

System Integration Phase

- In order to reduce schedule risks, a project should have one dedicated software development environment for each vendor when there are competing solutions. Having to do development work in-series significantly extends the schedule duration.
- Implement formal design reviews for system and unit/component designs in order to elicit more formal engagement by key stakeholders and reduce later technical issues.
- Aligning on an open standards data model for the operational service bus message payloads helps prevent vendor lock-in.

System Testing Phase

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

FAN System

- Edge computing capability in the FAN field device is vital in allowing the network to be easily adapted to multiple uses (e.g. distributed control, protocol translation, and report by exception).
- Standardization is needed to make edge computing even easier to use. Efforts need to be made to determine which forum is most appropriate to drive standardization for edge computing interoperability, portability, and development.
- Provisioning each field device is time consuming, so some form of zero-touch provisioning is required to allow scaling to 500,000 devices.
- The smaller key size required for Elliptic-curve cryptography is valuable for use in narrow-bandwidth 900 MHz channels.
- Mesh IPv6/ IEEE 802.15.4g networks are a good design for peer-to-peer routing and low per-hop latency for real-time applications.

Cybersecurity System

- Integrating new cybersecurity technologies into the software environment may cause existing systems to malfunction and therefore must be integrated carefully. Should specific cybersecurity capabilities and/or configuration settings be deployed without properly understanding their impacts, existing software control systems may cease to function properly.
- Each IT environment (AT lab, QAS, production) has distinct network topologies and existing cybersecurity technologies. It is difficult to discover all scenarios that may be encountered prior to the beginning of testing. Appropriate time for planning, testing, and analysis needs to be set aside as the technologies progress through these environments.

Customer Recruitment

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

## 5.4 Metrics and Benefits Summary

The metrics and benefits table in Appendix 6.2 describes a number of areas where IGP can provide benefits. Some of these describe financial benefits (energy savings, jobs, reductions in capital cost), which are not large for IGP since it only affects a small geographical area. When these technologies are deployed to a larger area, these benefits will grow significantly. Other benefits relate more to safety, reliability, and efficiency. Again, for this specific project, the effects are small, but would be expected to grow as the technologies are deployed more widely. There were significant lessons learned in the area of barriers to widespread deployment of DER controls, optimization, cost-effectiveness, and standards. The final area in the metrics and benefits table is related to how SCE's lessons learned are being disseminated. SCE has published articles in trade magazines, delivered presentations at industry conferences, and shared with other utilities the results of the IGP project. SCE plans to continue these types of external engagement as the project proceeds under EPIC 2 funding.

## 5.5 Technology / Knowledge Transfer

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

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

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

# 6 Appendix

## 6.1 IGP Diagrams

## 6.2 Metrics

## 6.3 Test Report Material/ Diagrams

## 6.4 Test Cases / Procedures

## 6.5 Use Cases

## APPENDIX 6.1 IGP ARCHITECTURE DIAGRAMS

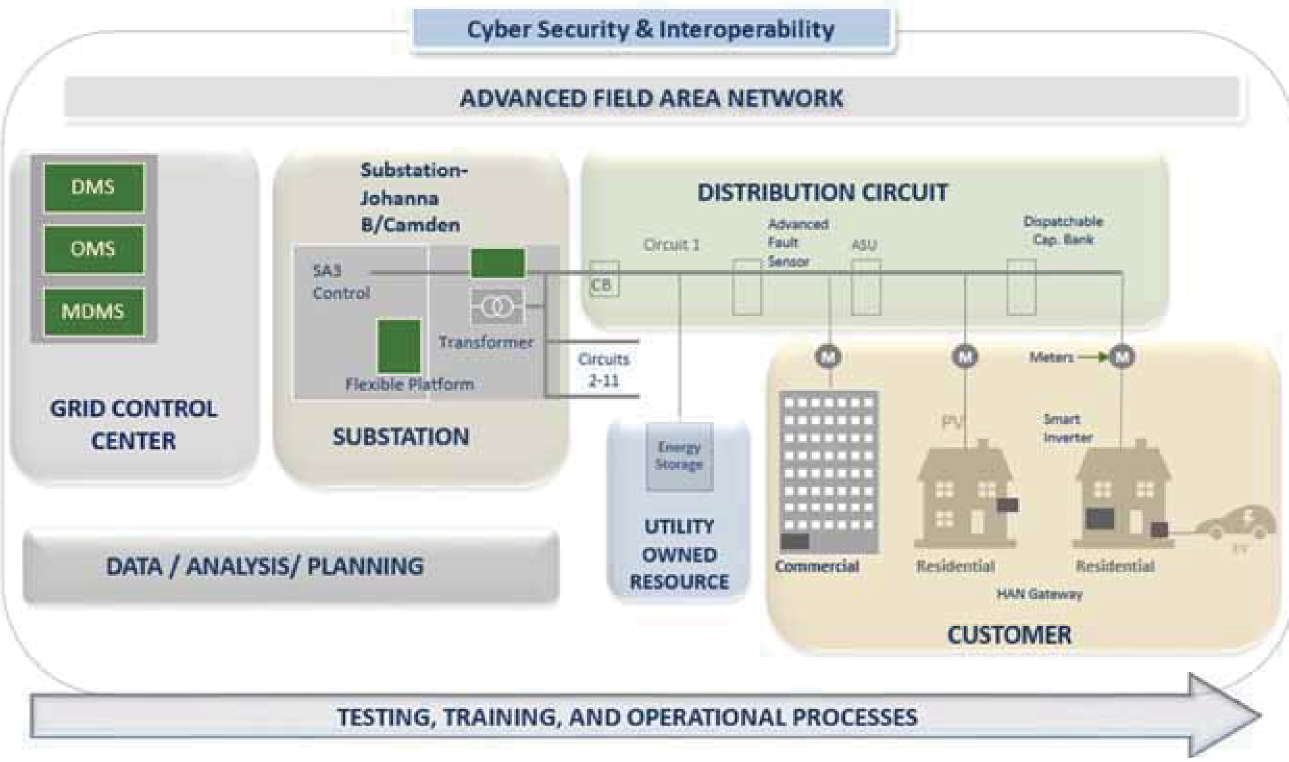



*Figure 15: IGP Structure Diagram*

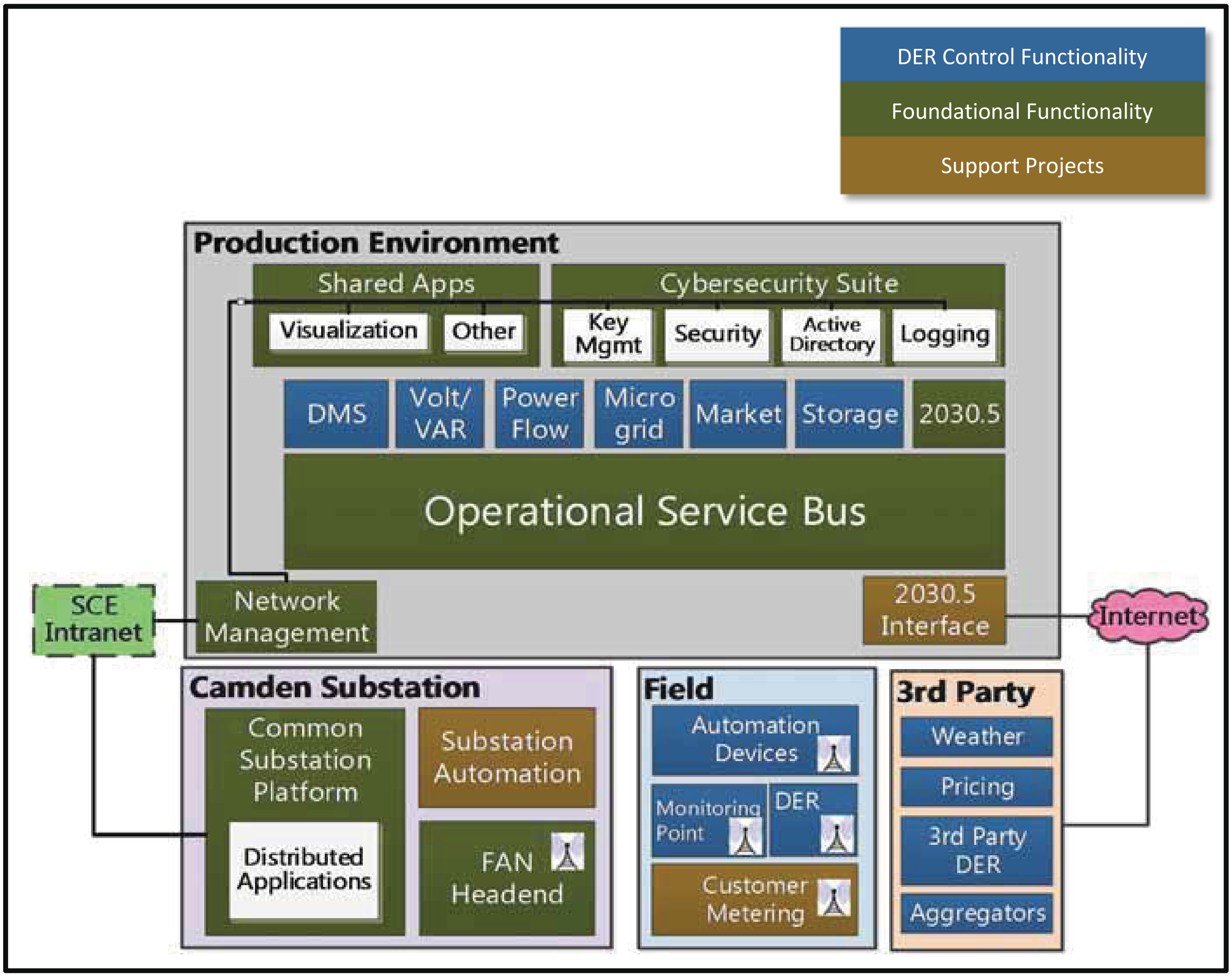



*Figure 16: Top Level IGP Architecture Diagram*

# APPENDIX 6.2 METRICS

Metrics (PS-13-004) - IGP

## 1.0 Potential Energy and Cost Savings

### 1. a. Number and total nameplate capacity of distributed generation facilities

The following is a tabulation of DER capacity in Johanna Jr and Camden substations at the end of the EPIC 1 work (April 30, 2017). Another update will be supplied at the end of the EPIC 2 work.
Number of DER at Johanna Jr substation = 44
Nameplate capacity of DER at Johanna Jr substation = 0.475 MW
Number of DER at Camden substation = 240
Nameplate capacity of DER at Camden substation = 4.758 MW

### 1. b. Total electricity deliveries from grid-connected distributed generation facilities

The following is an estimate of DER energy generation in Johanna Jr and Camden substations over a one year period at the end of the EPIC 1 work (year ending April 30, 2017). These estimates are based on using the NREL PV Watts generation calculator for the PV resources. Another update will be supplied at the end of the EPIC 2 work.
Energy at Johanna Jr substation ~ 700 MWh
Energy at Camden substation ~ 7200 MWh

### 1. c. Avoided procurement and generation costs

The following is an estimate of the avoided procurement and generation costs at Johanna Jr and Camden substations over a one-year period at the end of the EPIC 1 work (April 30, 2017). This estimate is based on the energy generated and the average CAISO daylight price of energy for the year ending April 30, 2017 (approximately $28/ MWh). Another update will be supplied at the end of the EPIC 2 work.
Avoided procurement and generation costs in Johanna Jr substation ~ $20,000
Avoided procurement and generation costs in Camden substation ~ $200,000

### 1. d. Number and percentage of customers on time variant or dynamic pricing tariffs

The following is a tabulation of the number and percentage of customers at Johanna Jr and Camden substations on time variant or dynamic pricing tariffs at the end of the EPCI 1 work (April 30, 2017). Another update will be supplied at the end of the EPIC 2 work.
Number of customers in Johanna Jr substation on time variant or dynamic pricing tariffs = 3130
Percentage of customers in Johanna Jr substation on time variant or dynamic pricing tariffs = 49%
Number of customers in Camden substation on time variant or dynamic pricing tariffs = 2520
Percentage of customers in Camden substation on time variant or dynamic pricing tariffs = 14%

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

The following is a tabulation of the capacity of grid-connected energy storage at Johanna Jr and Camden substations at the end of the EPIC 1 work (April 30, 2017). Another update will be supplied at the end of the EPIC 2 work.
Nameplate capacity of grid-connected storage at Johanna Jr = 0.0 Mw
Nameplate capacity of grid-connected storage at Camden = 0.054 Mw

## 2. Job Creation

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

The following is a calculation of the hours worked and money spent in CA for project during the EPIC 1 period. Another update will be supplied at the end of the EPIC 2 work.
Hours worked in California = 96,518
Money spent in California = $15,058,020

## 3. Economic Benefits

### 3.b. Maintain / Reduce capital costs

While this demonstration project is not deferring any construction of new equipment or circuits at this time, it is expected the DER control capability demonstrated here would be able to delay the need for future circuit upgrades. This metric will be updated at the end of the EPIC 2-funded part of this project when actual field test data would be available.

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

### 5.a. Outage number, frequency and duration reductions

SAIDI and SAIFI indices have been measured for a one year period ending April 30, 2017 (end of EPIC 1 work) as the base year. Data for the following years will be collected and compared to the base year. This comparison will be reported as part of the EPIC 2 report for this project. The following are the baseline indices:
Number of outages in Johanna Jr substation area = 14
SAIDI in Johanna Jr substation area = 20.9 minutes
SAIFI in Johanna Jr substation area = 0.50 interruptions
Number of outages in Camden substation area = 31
SAIDI in Camden substation area = 139.9 minutes
SAIFI in Camden substation area = 0.97 interruptions

### 5.b. Electrical system power flow congestions reduction

Congestion on distribution systems is mostly caused by overloaded circuit and substation equipment. There are also some cases where voltage regulation on circuits will also be the limiter to DER penetration. The controls being demonstrated as part of this project will be used to manage DERs to limit overloads and help maintain proper voltage at customer sites. At the end of the field portion of the project (EPIC 2 funding), an assessment of actual congestion reduction on the test circuits will be conducted and results reported.

### 5.c. Forecast accuracy improvement

Forecast accuracy can be improved through the use of better, more complete information. In the IGP, the project will be obtaining weather data, CAISO pricing, and better circuit flow and voltage measurements that will be used to improve the forecast for the circuit flows and voltage regulation. This allows better utilization of battery systems to balance flows and provide voltage regulation through management of the battery systems charge and discharge cycles. Laboratory demonstrations have shown this forecast function to be important in determining when to charge the battery systems with the least impact on the distribution circuits and at the lowest cost.

### 5.f. Reduced flicker and other power quality differences

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

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

More monitoring points can provide finer detail of how the distribution system is operating. This better information can be used to fine tune the control systems to better control power flow and reduce voltage variations. In the IGP work, additional monitoring points (from DERs and additional line sensors) will be incorporated into the control systems to better estimate power flow and voltage levels. This additional data is expected to provide better control. Actual field measurements will be evaluated in the EPIC 2 portion of the project to prove this out.

## 6.0 Other Metrics*

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

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

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

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

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

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

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

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

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

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

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

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

### 7.d. Deployment and integration of cost-effective distributed resources and generation, including renewable resources (PU Code § 8360)

The IGP project is integrating a number of different DER resources into the grid, some SCE-owned, others owned by third-parties or connected through aggregators. These resources will be connected to SCE circuits and be available for monitoring and control by the software being implemented under the IGP project whenever possible. In laboratory testing, high penetrations of DER have been simulated to show how the control algorithms work. In the field, these resources have not been installed or connected to the control applications as part of EPIC 1 project funding. Negotiations with customers are now underway to connect the IGP controls to as many customer DER devices as possible under the EPIC 2 funding.

| 7.e. | Development and incorporation of cost-effective demand response, demand-side resources, and energy-efficient resources (PU Code § 8360) |
|---|---|

The IGP project is presently investigating sources of demand response that could be connected to the IGP optimization software applications. One source of DR is expected to be 50 residential homes with battery systems in the Camden substation area connected to SCE through an aggregator. The project is putting an IEEE 2030.5 interface in place to exchange status and control information with the aggregator. This interface in now in laboratory testing and will be implemented in the field as part of the EPIC 2 project funding.

| 7.f. | 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) |
|---|---|

While the main focus of the IGP project is to manage high penetrations of DER devices managed by SCE, third parties, and aggregators, some interaction with customer equipment will be explored through interaction with customer-side storage units and PV arrays. This will be done through IEEE 2030.5 communications to an aggregator who will do the actual communications to customer energy storage and PV devices. At this point we have not implemented any direct communications to any other customer appliances.

| 7.g. | Integration of cost-effective smart appliances and consumer devices (PU Code § 8360) |
|---|---|

The main consumer devices being incorporated into the IGP project are storage batteries and PV arrays. The project's goal is to connect with customer or third party owned equipment to provide grid benefits. Another part of the project will investigate the value of these customer devices to the grid as well as what value might accrue to the customers.

| 7.h. | 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) |
|---|---|

The IGP project is integrating customer battery systems and PV arrays into the grid optimizations controls to provide grid benefits through peak shaving. At this time, we do not have any plug-in vehicle or thermal storage as part of the project, but are investigating any resources that might become available during the field demonstration part of the project being executed under EPIC 2 funding.

| 7.j. | Provide consumers with timely information and control options (PU Code § 8360) |
|---|---|

The IGP project is demonstrating two ways to communicate with customers – one through the Internet using IEEE 2030.5 and the other through private, direct communications. IEEE 2030.5 communications will be used to interact with aggregators to provide control of smaller customer DER/DR devices. In this scenario, SCE would send an IEEE 2030.5 message to the aggregator and the aggregator would then forward control requests to the actual customers. Customer response would then be forwarded back to the aggregator who would forward it to SCE. In the second scenario, control messages would be communicated to larger customer DER/DR devices directly through a field area network radio system. This direct communications would generally be reserved for only the commercial and industrial customer DER devices.

| 7.k. | Develop standards for communication and interoperability of appliances and equipment connected to the electric grid, including the infrastructure serving the grid (PU Code § 8360) |
|---|---|

The IGP project is adopting the IEEE 2030.5 communications standard (to be implemented for communications to DER under California Rule 21) as the standard for communicating with DER aggregators. Since this protocol is new, it is taking some time for aggregators to implement it in their systems. SCE is also working on how to implement this protocol through the Internet while maintaining high levels of cyber security.

Communications with grid devices and large DERs is being mainly done through the use of DNP. This communication is through a dedicated field area network radio system. This protocol is commonly used by utility SCADA systems, so implementation is easier than IEEE 2030.5. SCE has also adopted IEC 61850 protocol for substation automation and is looking to extend it use to distribution circuit devices and larger DER installations.

| 7.l. | Identification and lowering of unreasonable or unnecessary barriers to adoption of smart grid technologies, practices and services (PU Code § 8360) |
|---|---|

As DER penetration increases on the distribution system, the need to be able to control these resources to help the grid maintain proper voltage and power flow increases. The control systems being demonstrated as part of the IGP project need to interact with customer-owned and integrator-controlled DER on a minute by minute basis. To date, communications to the DER and willingness of customers/ aggregators to make their system available to support these grid services have been a barrier. The communications issue is being addressed through the Rule 21 smart inverter rules and communications standards such as IEEE 2030.5 and DNP (IEEE 1815-2010). SCE is adopting these protocols as part of IGP. Recruiting customers has been difficult since there are no rates or customer incentives for them to participate. SCE is exploring different forms of compensation to try and get these customers to participate. The field demonstration of the project performed with EPIC 2 finds will test these incentives and see how well they work.

## 8.0 Effectiveness of Information Dissemination

| 8.b. | Number of reports and fact sheets published on-line |
|---|---|

The IGP project was discussed in the IEEE PES magazine, Powergrid International magazine and in the EPIC 1 final report. All of these articles and reports are available on-line as described below. Additional reports and fact sheets will be listed at the end of the EPIC 2 work.

"The Irvine Smart Grid Demonstration Leads the Way to Modernizing California's Electric Grid", Bob Yinger, Jude Schneider, Kevin Clampitt, Megan Remillard, Powergrid International Magazine, October 2015, http://www.elp.com/articles/powergrid_international/print/volume-20/issue-10/features/the-irvine-smart-grid-demonstration-leads-the-way-to-modernizing-california-s-electric-grid.html

"Modernizing the California Grid – Preparing for a Future with High Penetrations of Distributed Energy Resources", Robert Sherick, Robert Yinger, IEEE Power and Energy Magazine, March/April 2017, http://ieeexplore.ieee.org/document/7866943/

Advanced Technology, ID# PS-13-004, Integrated Grid Project (IGP)
EPIC I Final Report
February 15, 2017

| 8.c. | Number of times reports are cited in scientific journals and trade publications for selected projects |
|---|---|

None the project team is aware of at this time. This metric will be reassessed at the end of the EPIC 2 work.

### 8.d. Number of information sharing forums held

The IGP project has been described in several presentations at the DistribuTECH conference and at other presentations. Listed below are the major forums where IGP project information has been shared. Additional presentations will be listed as part of the EPIC 2 work.

"SCE's Integrated Grid Project – Coordination of High Penetrations of DERs", Bob Yinger, Robert Sherick, Erik Gilbert, DistribuTECH Conference presentation, Orlando, FL, February 11, 2016

"SCE's Smart Grid Demonstrations", Bob Yinger, Presentation to the IEEE Industry Applications Society, Los Angeles, CA, May 11, 2016

"SCE's Integrated Grid Project: Demonstrating Coordinated Operations of High-Penetration DERs", Bob Yinger, Dennis Wong, Robert Sherick, DistribuTECH Conference presentation, San Diego, CA, February 2, 2017

"Advanced Distribution Controls and Optimization Testbed at SCE", Renee Cinar, Hector Camacho, Steven Robles, DistribuTECH Conference presentation, San Diego, CA, February 2, 2017

### 8.f. Technology transfer

As the IGP project progresses through the requirements, design, and testing stages, lessons learned are transferred to the group in SCE that is working on the final production DER controls software (DERMS). This is mainly done by involving the production design staff with the design and testing of IGP. Lessons learned from IGP can then be incorporated directly into the production system requirements as soon as they are discovered. This will improve the procurement of the production systems. In addition, lessons learned and observations are documented for others outside of SCE to learn from. This wider audience is communicated to through reports like the EPIC 1 report, trade magazine articles, and conference presentations.

## 9.0 Adoption of EPIC Technology, Strategy, and Research Data/Results by Others

### 9.a. 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

While many of the technologies being demonstrated as part of the Integrated Grid Project are in early stages of commercialization, some of the technologies are now being deployed. A version of distributed volt/VAR control is now being deployed across the SCE service territory. The updated version incorporating DER, being demonstrated as part of IGP, will be deployed after it is proven through IGP field testing. The lessons learned from the demonstration of the grid optimization application (voltage and power flow) are being adopted by the team developing SCE's new DERMS and ADMS products.

| 9.b. Number of technologies eligible to participate in utility energy efficiency, demand response or distributed energy resource rebate programs |
|---|

While the IGP project has not implemented any technologies that have been rebated under the EPIC 1 program, customers in the demonstration area will be eligible for rebates for installation of PV (state solar rebates) and storage system (SCE's Self Generation Incentive Program). These PV and storage systems have not yet been installed, but are planned to be implemented during the time EPIC 2 work is underway.

| 9.c. EPIC project results referenced in regulatory proceedings and policy reports |
|---|

None the project team is aware of at this time. This metric will be reassessed at the end of the EPIC 2 work.

| 9.d. Successful project outcomes ready for use in the California IOU grid (path to market) |
|---|

The objective of the IGP project is to field demonstrate a number of technologies that will be needed to manage the distribution system with high penetrations of DER. In IGP under EPIC 1, the project is laboratory demonstrating voltage control using DER reactive power capabilities and circuit power flow control using DER power control capabilities. While these systems were put in place for demonstration purposes only, they have contributed requirements that are going into requests-for-proposal for the actual production systems including DERMS and ADMS. These outcomes will be updated at the end of the EPIC 2 work.

# Appendix 6.3 Test Report Material / Diagrams

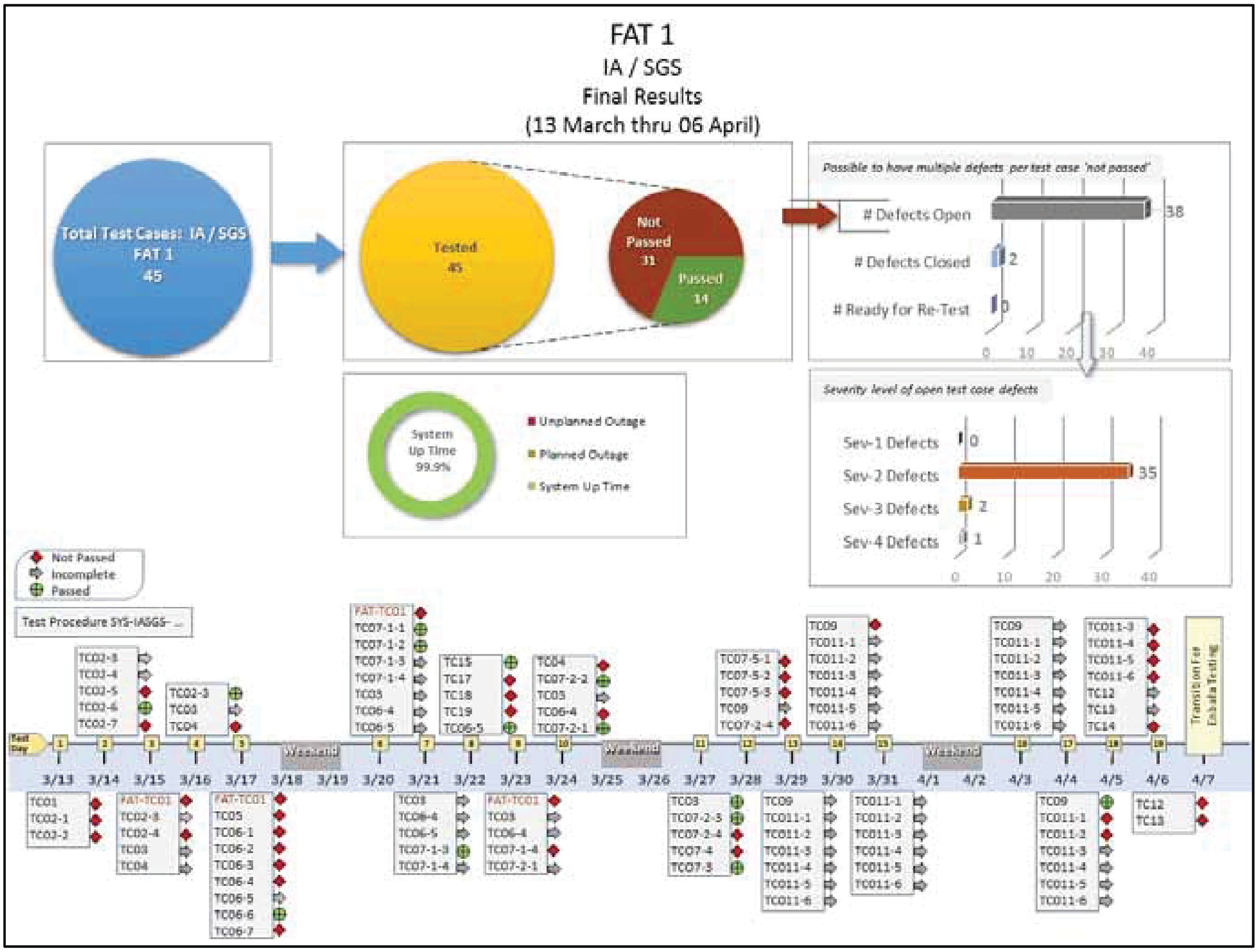



*Figure 17: Overall and Daily Tracking of FAT 1 Results*

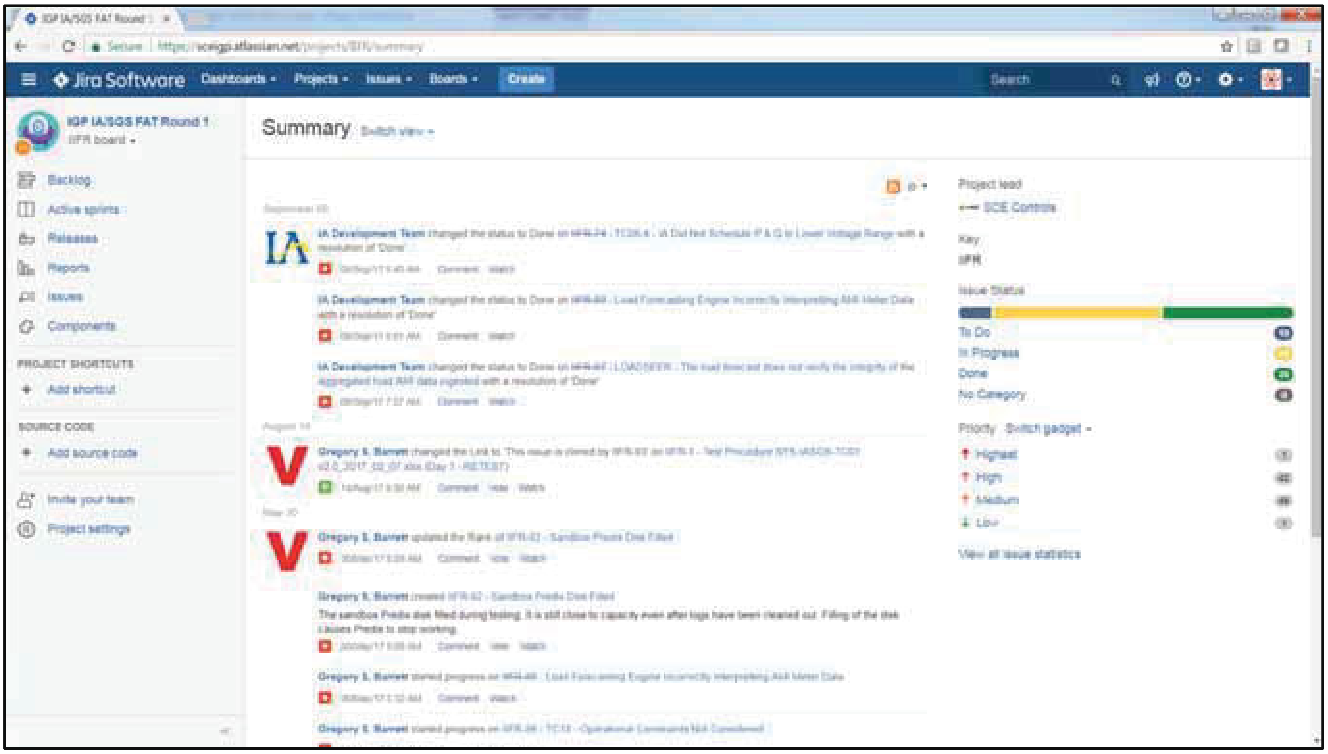



*Figure 18: Sample Screen Shot of Jira FAT 1 Test Tracking*

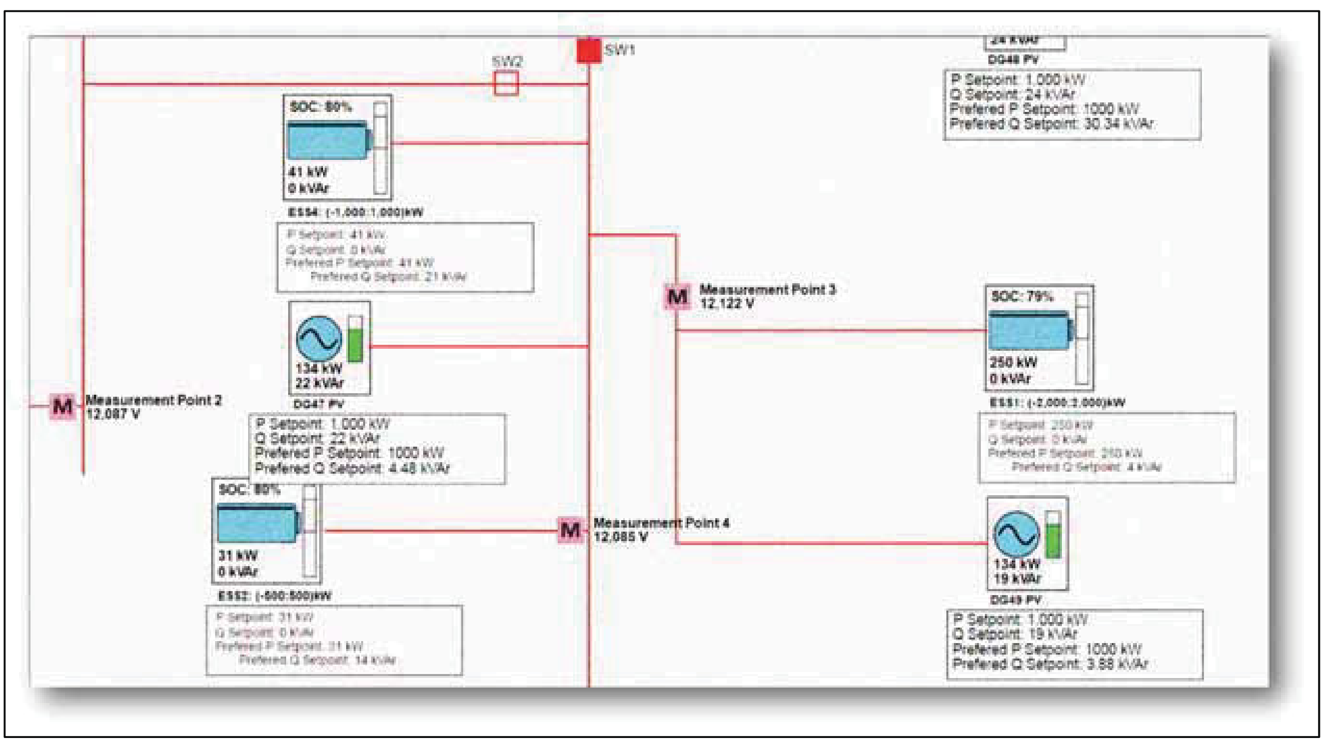



*Figure 19: Sample Screen Shot of Reference Diagram Loaded into Jira to Assist with Testing*

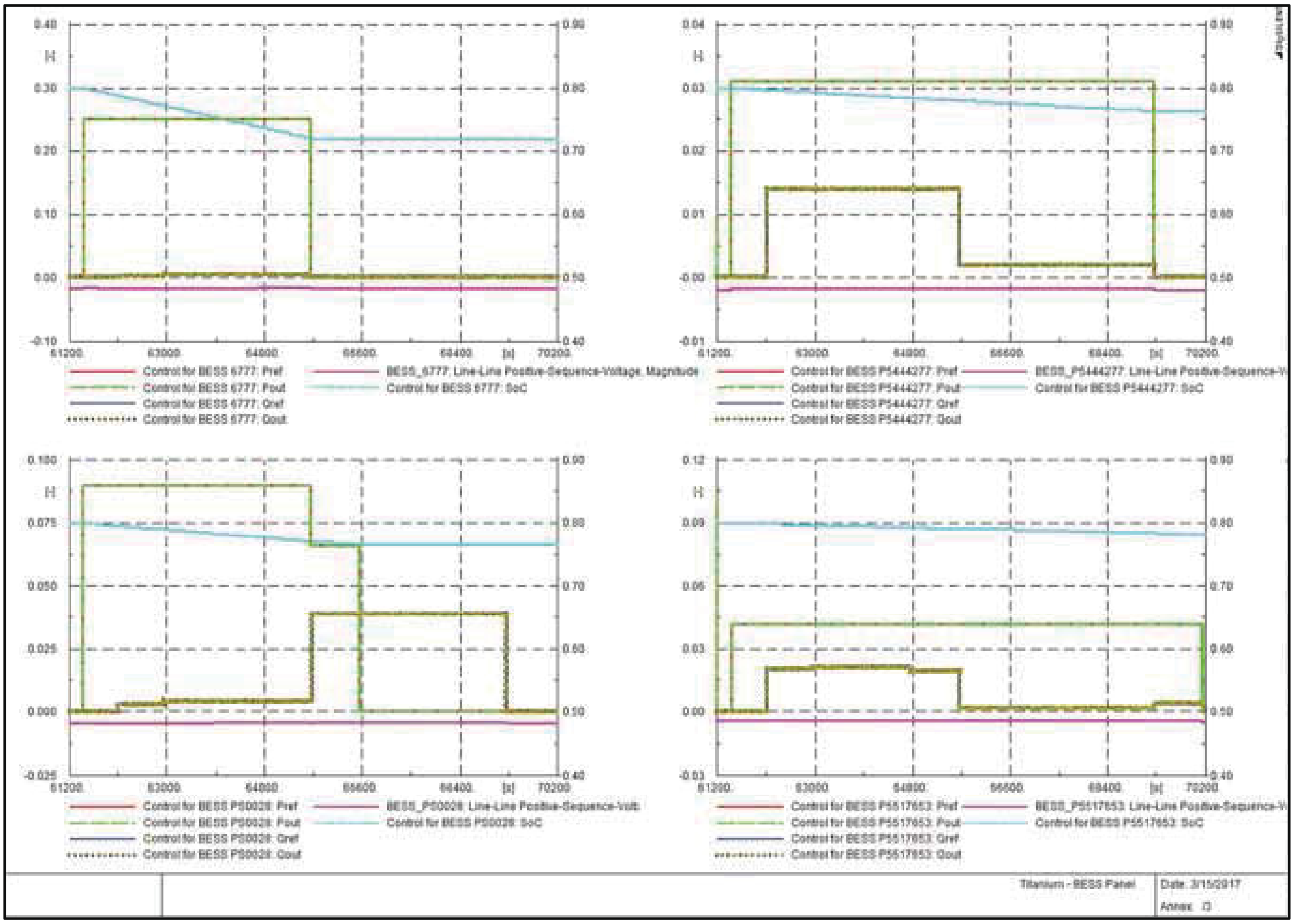



*Figure 20: Sample Screen Shot of Test Chart Loaded Into Jira to Assist with Communicating and Evaluating Results*

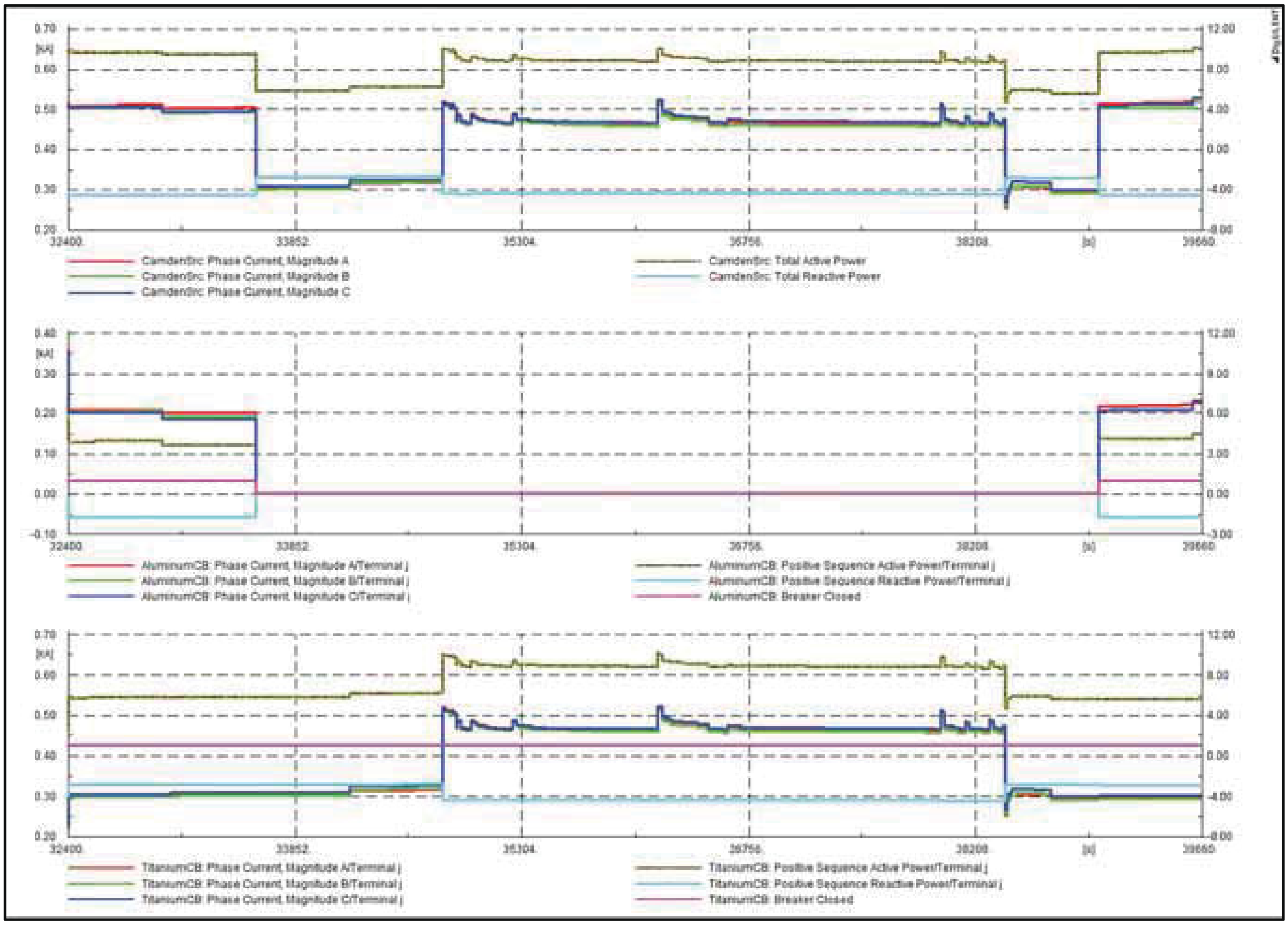



*Figure 21: Sample Screen Shot of Test Chart Loaded Into Jira to Assist with Communicating and Evaluating Results*

# APPENDIX 6.4 TEST CASES / PROCEDURES

Unit Level Test Cases
Unit Testing: Pre-FAT

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

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

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

Integration Testing: FAT / SAT / PAT

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

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| 2030.5 |

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

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| SECURITY |

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

| Test Number | Test Name | Test Description |
|---|---|---|
| Predix/UIB | | |
| INT-UIB-TC01 | Integration Service Performance and Functional Tests | This test case verifies the UIB Integration Service performance and function as described in the associated tests. |
| INT-UIB-TC03 | UIB Management | This test case validates proper operation of the management and monitoring functionality of GE Predix Grid using the management user interface as described in the associated tests. |
| INT-UIB-TC04 | UIB Troubleshooting | This test case verifies the GE Predix Grid's troubleshooting abilities, described in the associated tests, as required by IGP. |
| FAN | | |
| INT-FAN-TC01 | Customer Smart Inverter Control Test | This test case verifies the proper interfacing to a third party control application (FAN connected Distributed Energy Resource (DER)). |
| INT-FAN-TC02 | FAN NMS Connectivity | This test case verifies the proper connectivity of the FAN Network Management System (NMS) to Grid2 for monitoring and control of FAN radios. |
| INT-FAN-TC03 | FAD/WID to CSP | This test case verifies the proper interfacing of the FAN Aggregation/Wide Area Interface Device to Common Substation Platform (CSP) platform. |
| INT-FAN-TC04 | Substation IEDs to CSP | This test case verifies the proper connectivity of substation (SS) IEDs to CSP. |
| INT-FAN-TC05 | Substation Cap Bank to CSP | This test case verifies the proper connectivity of an SS Capacitor (Cap) Bank to CSP. |
| INT-FAN-TC06 | FAD to Field Radios | This test case verifies the proper connectivity of the FAN Aggregation Device (FAD) to field radios at Intelligent Edge Devices (IEDs). |
| INT-FAN-TC07 | FAN RIS Radio to FAN RIS Field Agent | This test case verifies the proper interfacing of a Remote Intelligent Switch (RIS) radio to the field agent. |
| INT-FAN-TC08 | FAN Smart Inverter Radio to Field Agent | This test case verifies the proper interfacing of Smart Inverter radio to the field agent. |
| INT-FAN-TC09 | FAN ESS Radio to Field Agent | This test case verifies the proper interfacing of an Energy Storage (ESS) radio to the field agent. |
| INT-FAN-TC10 | FAN PCC Radio to Field Agent | This test case verifies the proper interfacing of a Programmable Cap Controller (PCC) radio to the field agent. |
| INT-FAN-TC11 | FAN Radio to RIS | This test case verifies the proper interfacing of a FAN radio to a RIS IED. |
| INT-FAN-TC12 | FAN Radio to Smart Inverter | This test case verifies the proper interfacing of a FAN radio to a Smart Inverter IED. |
| INT-FAN-TC13 | FAN Radio to ESS | This test case verifies the proper interfacing of a FAN radio to an ESS IED. |
| INT-FAN-TC14 | FAN Radio to PCC | This test case verifies the proper interfacing of a FAN radio to a PCC IED. |

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| INT-FAN-TC15 | FAN Field Agent to SGSConnect | This test case verifies the proper interfacing of a FAN field agent to the SGSConnect app. |
| INT-FAN-TC16 | FAN Smart Inverter Field Agent to SGSConnect | This test case verifies the proper interfacing of a Smart Inverter field agent to the SGSConnect app. |
| INT-FAN-TC17 | FAN ESS Field Agent to SGSConnect | This test case verifies the proper interfacing of a FAN ESS field agent to the SGSConnect app. |
| INT-FAN-TC18 | FAN PCC Field Agent to SGSConnect | This test case verifies the proper interfacing of a FAN PCC field agent to the SGSConnect app. |
| INT-FAN-TC19 | Legacy NetComm System to Failsafe Switch | This test case verifies the proper interfacing between the legacy NetComm system and the IGP Failsafe switch. |
| INT-FAN-TC20 | FAN Microgrid Control Point Radio to Field Agent | This test case verifies the proper interfacing of the Microgrid Control Point (MCP) radio to the field agent. |
| INT-FAN-TC21 | FAN Radio to Microgrid Control Point | This test case verifies the proper interfacing of a FAN radio to a Microgrid Reference Point (MRP) IED. |
| INT-FAN-TC22 | FAN Microgrid Control Point Field Agent to SGSConnect | This test case verifies the proper interfacing of an MRP field agent to the SGSConnect app. |
| INT-FAN-TC23 | Beaglebone to FAN Radio | This test case verifies the proper interfacing of a Beaglebone to a FAN radio. (Contingency Test) |
| INT-FAN-TC24 | PCC to Beaglebone | This test case verifies the proper interfacing of a PCC IED to a Beaglebone. (Contingency Test) |
| INT-FAN-TC25 | RIS to Beaglebone | This test case verifies the proper interfacing of a RIS IED to a Beaglebone. (Contingency Test) |
| INT-FAN-TC26 | Smart Inverter to Beaglebone | This test case verifies the proper interfacing of a Smart Inverter IED to a Beaglebone. (Contingency Test) |
| INT-FAN-TC27 | ESS to Beaglebone | This test case verifies the proper interfacing of an ESS IED to a Beaglebone. (Contingency Test) |
| INT-FAN-TC28 | Loss of Radio Communications - Single Device | This test case verifies the proper response of the IGP system for a loss of radio communications with a single FAN device. |
| INT-FAN-TC29 | Loss of Radio Communications - Multiple FAN Devices | This test case verifies the proper response of the IGP system for a loss of radio communications with multiple FAN devices. |
| INT-FAN-TC30 | Remote FAN Radio Firmware Upgrade | This test case verifies the proper firmware upgrading of a remote FAN radio. |
| INT-FAN-TC31 | Remote Field Agent upgrade on FAN Radio | This test case verifies the proper upgrading of a remote field agent on a FAN radio. |

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

| Network Infrastructure |
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|---|---|---|
| INT-NET-TC01 | Provisioning of New DER on Network | This test case verifies the proper provisioning of a new DER on the network infrastructure. |
| INT-NET-TC02 | Removal of Existing DER from Network | This test case verifies the proper removal of an existing DER from the network infrastructure. |
| INT-NET-TC03 | Loss of Network COMMs between IGP SS and Back Office | This test case verifies the proper response of the IGP system for a loss of network communications between an IGP substation (SS) and the back office. |
| INT-NET-TC04 | Restoration of Network COMMs between IGP SS and Back Office | This test case verifies the proper restoration of network communications between an IGP SS and the back office. |

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

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

System Testing: FAT / SAT / PAT

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

System Testing: FAT / SAT / PAT

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

System Testing: FAT / SAT / PAT

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

## APPENDIX 6.5 USE CASES

**Use Case 1-1**

Title: System Reconfiguration Supported by Advanced Monitoring – Scheduled Events

Summary: Monitoring information from DERs, RFIs, RISs, and RCS retrofit devices is collected and used to assist operators in reconfiguration of distribution feeders through the use of power flow simulation/state estimation provided by the GMS Scenario Planning Subsystem and solar/wind/load forecasting.

Detailed Narrative:

- With increasing amounts of distributed energy resources (DERs) being interconnected with distribution circuits there is a need for better information to be communicated to system operators to enhance situational awareness in support of circuit reconfiguration. This use case describes how data from new sensors, retrofitted switches, and DER monitoring will be integrated into the GMS system for state estimation and contingency load transfer to give operators a way to more clearly understand the implications of circuit reconfigurations.
- Interfaces will be implemented to allow the GMS to exchange status and control information with DER, DER aggregators, and 3rd party-owned generation. The communications path for the 3rd party-owned DER will be either through the internet, cell data connection or SCE field area network. For aggregators, this communications will most likely be through the internet portal for the aggregator. Additional information will need to be exchanged with the aggregator so each DER resource can be associated with a circuit segment. This will allow the DER data to be integrated into the state estimator.
- Additional data about real and reactive power flow and voltage from remote fault indicators (RFI), remote interrupting switches (RIS), and remotely controlled switch retrofits (RCS+) will enable the GMS state estimator to make better determinations of loading levels on circuit segments. Forecasts of system loading and weather (to forecast generation from renewable resources) on the circuits will help present better options to system operators when they are planning switching operations.
- Example: During a standard road widening job that requires switching during the course of the day, clearly understanding the state of the network including DERs connected to the network will give system operators better situational awareness. This can prevent unintentional overloading of circuit conductors, potential interruption of customer load and better control of voltage and load on the affected circuit segments.

**Use Case 1-2**

Title: System Reconfiguration Supported by Advanced Monitoring – Post-Fault

Summary: Fault location information from RFIs in combination with monitoring from DERs, RISs, and RCS retrofit devices is collected after a fault and used to provide the operator with a number of potential switching schemes to restore load. The ranking of the schemes will consider priority load as well as a solar and storage level forecasts to incorporate potential expected changes in net load on the affected circuits.

Detailed Narrative:

- Increasing amounts of distributed energy resources (DER) being interconnected with distribution circuits results in a need for better information in order to effectively perform fault location and service restoration. This use case describes how data from remote fault indicators, new sensors, and DER monitoring will be integrated into the grid management system (GMS) and its contingency load transfer application (CLT) to account for DER installed on circuits and leverage the improved situational awareness facilitated by the monitoring capabilities of DERs, remote fault indicators (RFIs), remote intelligent switches (RISs), and remotely controlled switch retrofits (RCSs). Furthermore, the addition of RISs will increase the reconfiguration flexibility of the circuit and allow for a reduction in SAIDI and CAIDI as larger portions of the faulted circuit can be restored in an automated or semi-automated manner.
- Interfaces will be implemented to allow the GMS to exchange status and control information with SCE-owned DERs, DER aggregators, and 3rd party-owned DERs. The communication path for the SCE-owned DERs, RFIs, RISs, and RCSs will be the SCE field area network (FAN). The communication path for the 3rd party-owned DERs will be either through the Internet, cell data connection or FAN. For aggregators, this communications will most likely be through the Internet portal for the aggregator. Additional information will need to be exchanged with the aggregator so each DER resource can be associated with a circuit segment. This will allow the DER data to be integrated into the CLT.
- Initial actions by the RIS on the circuit will allow quick isolation of faulted circuit sections. Real and reactive power flow data before the fault will be forwarded to the GMS from RFIs, RISs, and RCSs. This data combined with status and output information from DER devices will allow forecasts of system loading and renewable resources output. Utilizing the CLT and other applications, options will be presented to operators to quickly restore load in a safe and reliable manner based on optimization criteria such as 'maximum number of customers', 'critical loads', etc.
- Example: A fault occurs within the IGP study area. RISs automatically isolate the faulted portion of the circuit. Data collected from RFIs, RISs and DER devices is collected by the GMS system. Utilizing the CLT, DER forecast, and load forecast, circuit reconfiguration options are presented to the system operator to restore as much load as possible. The system operator selects an option to restore service to customers.

**Use Case 2-1**

Title: Voltage Optimization with DER

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

Detailed Narrative:

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

**Use Case 3-3**

Title: DERs Managed Shape Feeder Load

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

Detailed Narrative:

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

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

**Use Case 4-1**

Title: Microgrid Control for Virtual Islanding

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

Detailed Narrative:

- Increasing interest in microgrids coupled with greater amounts of distributed energy resources (DER) being connected to distribution circuits may provide an opportunity to investigate islanding portions of the SCE distribution system. These microgrids are different than most others because they are on the utility side of the meter and involve utility assets and multiple customers. While the microgrid contemplated as part of this use case will not be able to island, it will show how a distribution grid operator (DGO) with support from the grid management system (GMS) could control the load and generation on a circuit segment. This control of load and generation will enable shaping of the circuit load pattern to minimize losses and defer the need to upgrade circuit infrastructure. This use case describes DER can be controlled to reduce the real and reactive power flow on a portion of a circuit to zero. Since the microgrid will not be islanded, there is no risk of dropping customer loads due to imbalance of load and generation. Load control and DER (e.g. photovoltaics (PV) and battery storage) used in this subproject will be owned by SCE and 3rd parties so it is important to keep in mind that contracts with these 3rd party resources need to allow for these functions.
- In addition to the monitoring capability added to the distribution circuits by installation of remote fault indicators (RFIs), remote intelligent switches (RISs), and remotely controlled switch retrofits (RCSs) another reference point may be installed on the selected circuit to act as a control point. Data from this control point will be used by the GMS and its optimization system (OS) and/or, if a microgrid controller is installed, the microgrid controller software to balance load and generation. All of the monitoring data will be communicated using the SCE field area network (FAN) or other communication channels. This data could flow to the OS or, if applicable, directly to the microgrid controller. In either case the DGO would have to be informed on the state of the distribution circuit. The intent of this use case is to be able to control current at the reference point to a low value that is below a pre-set threshold.
- The choice of the reference point will depend upon the amount of connected load and available DER and distributed storage (DS) required to balance it. Temporary monitoring of the circuit at several locations will provide information to select the reference point. If an RIS is installed at the right location, a separate reference point will not need to be installed. While it would be ideal to control real and reactive power on a second-by-second basis, the need for this high-speed control is unclear. The use case will establish the timing needed for this control function.
- Example: Load and sufficient PV generation and DS are located beyond a reference point on a distribution circuit segment. A microgrid controller polls the reference point to determine the real and reactive power flows. It then issues commands to modify the set points for demand response, PV generation and battery storage to reduce the flows to zero. This process is repeated on a regular basis to keep the flows at the reference point below the pre-set low threshold. Status information is forwarded to the DGO on a regular basis to maintain situational awareness.

**Use Case 9.1**

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

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

- Use of UCESS by the utility for distribution grid reliability and optimization needs.
- Bidding of UCESS assets (or portion of) to the wholesale market when not needed for reliability and optimization purposes.
- Operationally, the UCESS will be operated, including when bid into the wholesale market, constrained by the reliability needs of the distribution grid.

Detailed Narrative:

- In October 2013, the CPUC issued Decision 13-10-040, which adopts an energy storage procurement framework and establishes an energy storage target for independently owned utility companies including SCE. Per the CPUC decision, SCE now has an energy storage procurement requirement of 580MW, with procurement required no later than 2020 and installations no later than 2024. SCE may elect to own and operate ESS or procure the service of third-party ESS to serve the two described functions.
- This use case will accomplish this goal by utilizing UCESS for (1) improving grid reliability and optimization resulting in upgrade deferral of grid assets and (2) generating revenue through UCESS participation in wholesale energy markets. The following sections elaborate on this dual use concept. This use case applies to any energy storage system (ESS) that is under full utility control, whether it is own by the utility or under a service contract.

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

- SCE's priority is to use the UCESS to improve grid reliability and mitigate the cost of distribution system upgrades. UCESS will be a key component of the overall utility's Distributed Energy Resources (DER) and will be used/leveraged for the following control applications for which dedicated use cases exists:
    1) Volt/VAR Control described in the document "IGP Use Case: 2.1 Voltage Optimization with DER"
    2) OPF control described in the document "IGP Use Case: 3.3 DER Managed to Shape Feeder Load"
    3) Virtual Microgrid described in the document "IGP Use Case: 4.1 - DER Microgrid Control for Virtual Islanding"
- For this utilization scenario phase, the ESS under utility control will be integrated with centralized and/or distributed control applications and will be managed by a hierarchical control methodology based on the entire DER composition. Given the distributed nature of the UCESS, adequate and reliable communications infrastructure and network availability will be required.
- The IGP control application will forecast the output of the various DER resources, as well as the load on the connected customers, starting with the closest DER resources to the UCESS and the closest customers and working outward. Once this forecast is created, the IGP controller can determine the optimal capacity and schedule for the UCESS to charge and discharge. Because of the difference in

operational life, and other characteristics of each UCESS, the forecasting system has to take into account the associated operational cost (including life degradation) by the UCESS for each operation and assess the system true operating cost. The second optimization may cause a divergence from a pure technical optimization.

- Once a converged schedule is created that maximizes the production of DER, creates manageable ramp rates, and manages the costs of using storage and demand response, the IGP control application can finalize the storage schedule and release it for operation. Typically, the schedule will be for day ahead operation. The UCESS needs to be monitored as the day progresses, to see that the actual forecasts are being realized and that the UCESS schedule continues to be within the parameters (e.g., charging rates, discharge times, etc.) set for the specific UCESS unit.
- Should the UCESS or the forecast deviate beyond the limits set by the schedule, an updated schedule will be calculated and, if necessary, distributed generation or demand response schedules will be changed. The monitoring and adjustments will be made as needed, and operate within the parameters set by the characteristics of the UCESS.
- Typically, the process for using UCESS for grid reliability and optimization could be summarized as follows:
  1) IGP control application will forecast the output of the various DER resources, as well as the load
  2) The IGP controller will determine the optimal capacity and schedule for the UCESS to charge and discharge
  3) UCESS will be monitored as the day progresses, to see that the actual forecasts are being realized
  4) Should the UCESS or the forecast deviate beyond the limits set by the schedule, an updated schedule will be calculated

Utilization Scenario Phase 2: Manage UCESS Wholesale Market Participation

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

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

2) Provide generation and load capacity, and additional constraints to the wholesale market
3) Upon reception of a dispatch command from the wholesale market.
4) a. Allocate the dispatch command between the various aggregated UCESS based on optimization model or current condition
   b. Send appropriate commands to each individual UCESS
5) Adjust aggregated UCESS capacity available to the wholesale market based on current grid condition (e.g., unexpected event, drift in forecast)

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

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

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

# Beyond the Meter: Customer Device Communications, Unification, and Demonstration
# Final Project Report

Developed by

SCE Transmission & Distribution, Grid Technology & Modernization

January 2018

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# Acknowledgments

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# 1 Executive Summary

The Beyond the Meter Customer Device Communications, Unification, and Demonstration Project (BTM hereafter) successfully demonstrated the integration of customer and third-party meters that 1) monitor photovoltaic (solar power) and energy storage systems; 2) collect measurement data; and 3) communicate with SCE's Distribution Management System (DMS) to improve situational awareness of the distribution grid.

To leverage common demonstration resources (thus Electric Program Investment Charge dollars), the BTM project was conducted in concert with Southern California Edison's (SCE) Integrated Grid Project (IGP). IGP's overall objective is to "demonstrate, evaluate, analyze, and propose options that address the impacts of Distributed Energy Resources (DER) penetration and increased adoption of Distributed Generation (DG) owned by consumers."[1] BTM contributed significantly to IGP objectives through lab validation of approaches and technologies that can be exercised later in the field. In addition, BTM laboratory work set the stage for field testing and validation of new Field Area Network (FAN) technologies used to collect customer load and generation data that can be utilized to evaluate and mitigate the impacts of customer-owned DER.[2]

# 2 Project Summary

The objective of the Beyond the Meter (BTM) Project was to prove, in a laboratory environment, the ability to integrate new FAN radios with customer-owned or -sited distributed energy resources (DER). The radios and related FAN technologies, from two separate vendors, are intended for deployment in the IGP demonstration territory (Johanna Junior and Camden substations) in 2018 to support both monitoring and control of customer- and SCE-owned DER and distribution assets. Schneider meters were chosen for the project because these models are currently used by selected IGP customers (in the same territory) for monitoring their behind-the-meter photovoltaic and energy storage systems. Negotiations are underway with these customers (or their providers) to allow the IGP to integrate the FAN systems with their meters for monitoring and possible future control purposes, or for SCE to deploy similar meters in available meter sockets.

The ability to monitor the growing amount of customer-owned DER is critical for customer integration onto SCE's distribution grid. Thus the BTM project supports the improvement of grid reliability, which is a strategic goal under the Electric Program Investment Charge (EPIC) Investment Framework for Utilities (see Figure 1). In addition, the demonstration of technologies under this project that allow customers to support SCE Grid Operations' reliability objectives using their behind-the-meter photovoltaic or energy storage also contributes to SCE's various Grid Modernization initiatives addressed by the EPIC framework. These include the Distribution Resources Plan (DRP), Preferred Resources Pilot (PRP), and Energy Storage Deployment initiatives.

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[1] See http://on.sce.com/2niOWAA and http://on.sce.com/2DMmgud

[2] The Electric Power Research Institute defines DER as "smaller power sources that can be aggregated to provide power necessary to meet regular demand." DER can include energy storage and advanced renewable technologies.


**Figure 1. EPIC Investment Framework for Utilities**

## 2.1 Problem Statement

Recent regulatory and market mechanisms are driving the rapid deployment of distributed generation onto California's electric grid. While these distributed energy resource (DER) systems provide clear and significant environmental and financial benefits, they are connected to grids designed for one-way power flows, and thus may impact the stability, reliability, and efficiency of the distribution system. The new California Energy Commission Rule 21-defined smart inverter control and communications[3] are intended to resolve these impacts and support more DERs. However, photovoltaic and energy systems deployed prior to the implementation of these new requirements still can cause significant impacts. Thus, it is imperative that distribution operators receive insight into the operations of these legacy systems, and do so without expensive retrofits or software updates.

## 2.2 Project Scope

The scope of this project involved demonstrating in the lab methods, including serial communication (RS-232 or RS-485) and Transmission Control Protocol (TCP)/Internet Protocol (IP), to integrate existing customer-owned and -configured off-the-shelf meters with SCE's test Field Area Network (FAN) radios. It also intended to demonstrate the ability to collect key distributed energy resource (DER) monitoring data (frequency, active power, reactive power, and voltage) via SCE's Distribution Management System (DMS) and the Distributed Network Protocol (DNP3) standard. In addition, the project intended to support 2018 Integrated Grid Project (IGP) field deployments of FAN equipment at select customer sites.

[3] http://www.energy.ca.gov/electricity_analysis/rule21/

### 2.2.1 Test Equipment

Selected customers for the 2018 IGP/FAN demonstration have both the Schneider PowerLogic® ION8600 and ION8650 meters in use. However, during project procurement it was discovered that the ION8600 meters had been deprecated by Schneider, and thus the project team procured two ION8650 meters.[4] One Form 9s meter socket was acquired from SCE's Metering Services Organization (MSO), and a second was wired up by SCE lab personnel.


**Figure 2. Meter Sockets Used for Testing**

Testing occurred within the DER and the Grid Edge Solutions (GES) Lab at SCE's Westminster, CA, Grid Technology & Modernization facility. The DER Lab contains load banks, photovoltaic simulators, grid simulators, and lab network connections. It was used to establish basic Transmission Control Protocol (TCP)/Internet Protocol (IP) connectivity from the meter to the lab network, as well as to demonstrate the ability to poll meter data without the FAN radios.[5] The GES Lab is staged for the FAN testing, and has a variety of networking and test equipment as well as the vendor FAN technologies being evaluated. This lab was used to establish connectivity between the meter and the radios and to confirm the ability to poll meters from the DMS through the FAN in a controlled setting.[6]

[4] From a literature review, it appears that the major difference between the two meter models that would affect the 2018 demonstration is the number of Communication (COM) ports that are active at any one time on the ION8600 versus the ION8650. For example, COM1 RS-232/RS-485 is not available if the ION8600 meter version ordered includes modem AND Ethernet options.
[5] As FAN vendors/technologies are currently under procurement and evaluation processes, this report will not mention specific names or products.
[6] The FAN radios were previously connected to the lab network that hosts an instance of SCE's Distribution Management System software.

The meters come with multiple configuration and connectivity options, most of which are pre-configured out of the box. The ION8650A meters acquired included RJ45 (Network/Ethernet); DB9 (RS-232); optical and RJ11 (Modem) connections[7] and support Modbus remote terminal unit (RTU); Distributed Network Protocol (DNP) over Transmission Control Protocol (TCP); File Transfer Protocol (FTP); Simple Mail Transfer Protocol (SMTP); International Electrotechnical Commission (IEC) 61850; and Schneider's ION protocol.[8] The BTM Project used Ethernet/RS-232.

| | Port connection | Wire or connector | Connect to |
|---|---|---|---|
| COM breakout cable | COM1 (RS-232)[1] | DB9 connector (from breakout cable) | computer RS-232 serial port |
| | COM1 (RS-485)[2] | White wire (from breakout cable) | RS-485 Data + |
| | | Black wire (from breakout cable) | RS-485 Data - |
| | RS-485 common shield | Bare wire (from breakout cable) | RS-485 shield (COM1 and COM4) |
| | COM4 (RS-485) | Red wire (from breakout cable) | RS-485 Data + |
| | | Black wire (from breakout cable) | RS-485 Data - |
| | COM 2 (modem) | RJ11 connector | modem telephone line |
| | Ethernet | RJ45 connector | LAN/WAN Ethernet port |
| | IRIG-B[3] | Red wire | IRIG-B (+) |
| | | Black wire | IRIG-B (-) |

[1] Refer to the section, "RS-232 connections" on page 28 for additional information on RS-232 connections.
[2] For RS-485 communications, use an Ethernet to RS-485 or RS-232 to RS-485 converter. Refer to the communications converter documentation for details.
[3] IRIG-B cannot be configured via the meter's front panel. See the *IRIG-B GPS time synchronization* technical note for configuration procedures

**Figure 3. Connectivity Options from the ION8650 Socket Install Guide[9]**

### 2.2.2 Testing Approach

Once the meters were installed in the socket and powered up, project personnel configured them. This included determining which protocols to use for which Communication (COM) port (Distributed Network Protocol (DNP) over Transmission Control Protocol (TCP) for Network port and DNP/RS-232 for COM1 port), as well as the meter IP address, subnet mask, and gateway address. This was done using both the front panel display and meter setup software. Some configuration, including current transformer (CT) ratings, had to be modified while the meter was in Test Mode. Putting the meter in Test Mode either required removing the anti-tamper pin and the front cover in order to press a button, or connecting a PC to the meter via Ethernet and using the freely available ION Setup software.[10] Figure 4 shows the front panel setup, where removing the tamper pin revealed the Test Mode and Master Reset Button (F and G).

Aside from setting the meter to Test Mode, making all configuration changes, as well as viewing the current settings, was done using the front cover/LCD. The remaining settings, including the default DNP point map,[11] did not need to be modified.

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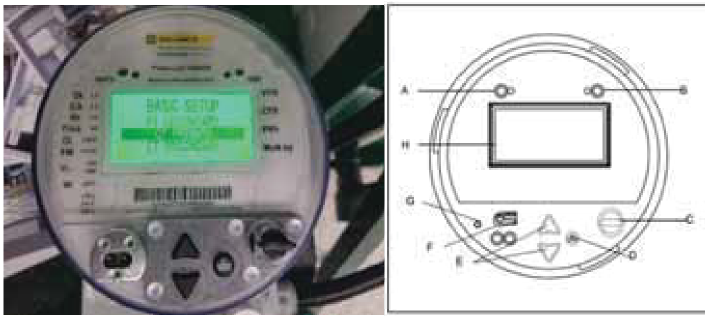
[7] Depending on the meter version, these cannot all be enabled (e.g., for 8650A meters, only the optical and two COM ports can be used simultaneously).
[8] These are all supported by Ethernet. Not all are supported by the other connection options. Note that supported and enabled options, including communications, are able to be determined by looking at the model number on the front of the meter.
[9] http://bit.ly/2Gqbt6h Besides meter versioning, installation, and wiring, the guide includes information on using the front panel to set up communications, security, and other settings as well as out-of-the-box configurations (including IP ports).
[10] http://bit.ly/2nmrhyu
[11] http://bit.ly/2rN9JAU




| | |
|---|---|
| A | Watt pulser: A set of LEDs (infrared, red) used for real energy pulsing. |
| B | VAR pulser: A set of LEDs (infrared, red) used for reactive energy pulsing. |
| C | Demand reset switch: Resets the peak demand values logged in the meter. Can be activated with the cover on or off. |
| D | Round button (Alt/Enter): Press to select a highlighted option. Also used to toggle between Norm and Alt display modes. Press and hold for 3 seconds to access Setup menu. |
| E | Navigation buttons: Press the up or down buttons to scroll and highlight a different menu item or to increase/decrease the value of a highlighted number. Press and hold the up button for 3 seconds to move the cursor to the left. Press and hold the down button for 3 seconds to move the cursor to the right. |
| F | Test mode button: Located under the front label, this places the meter into Test mode, ceasing accumulation of billable quantities. |
| G | Master reset button: Located in a recessed pinhole under the front label to prevent accidental activation. You must remove the meter cover and its label to access it. |
| H | Meter LCD screen |

**Figure 4. Front Panel Setup**

### *2.2.2.1 Distributed Energy Resources Lab*

The DER Lab setup was used to confirm the ability to connect the meter to an IP network and collect Distributed Network Protocol (DNP) measurement data via the Distribution Management System (DMS). To accomplish this, the meter's Ethernet port was connected to a switch, which in turn was connected to a lab network port. The IP address, mask, and gateway were set on the meter (the meters unfortunately do not support Dynamic Host Control Protocol-DHCP) after determining the correct network settings by connecting a laptop to the switch. Confirmation of the connection was achieved by pinging the meter from a second laptop connected to a different subnet. Note that for an undetermined reason, it can take a while (up to 5 minutes were noticed) for a Transmission Control Protocol (TCP) connection to be set up. After a connection was confirmed, the meter was polled via a third-party DNP master software and Wireshark software on a tester's laptop to ensure settings and configuration. Next the DMS was configured with the IP address, DNP port number (Default 20000), transport protocol (TCP is only supported by the meter), and DNP station address (Default 100). DMS polling was successful.

Figure 5 shows a screenshot of the DMS successfully polling the meter (right). The points mapped (left) are 1,3046294 = communications channel status; 2,8 = frequency; 2,9 = active power; 2,10 = reactive power; and 2,11 = voltage. Note that the load/photovoltaic simulators were not active when the screenshot was taken.

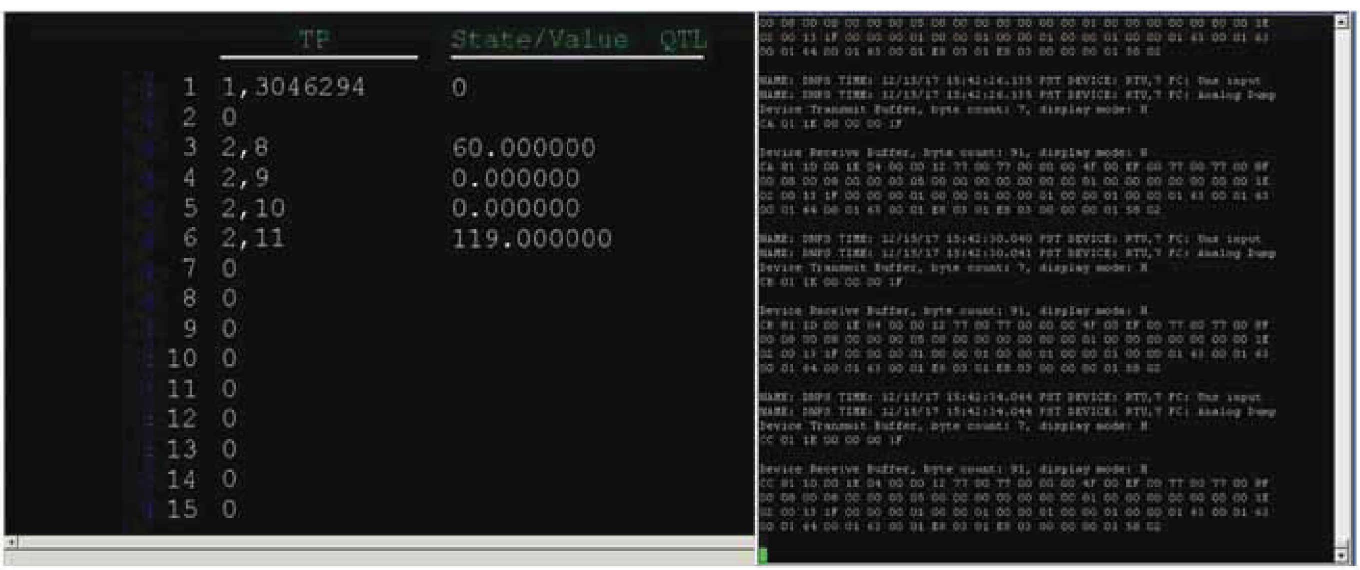



**Figure 5. Screenshot of the DMS Successfully Polling the Meter**

#### 2.2.2.2 Grid Edge Solutions Lab

Following basic network testing in the DER Lab, the remaining testing was completed in the Grid Edge Solutions Lab with the Field Area Network (FAN) technologies. Initially, project personnel attempted to replicate the previously successful testing by connecting to each radio via a switch and Ethernet (TCP/IP), and configuring the meter's IP address, mask, and gateway appropriately. However, this was not possible. Upon further investigation with Wireshark software, it was seen that the radios were establishing connections with the DNP master, but traffic was terminating there and not reaching the meter.

The next step was to work with each vendor to configure the radios and resolve the issues. For vendor A, the solution was to configure the static route (IP address) of the meter on the radio itself. Once this was done, testers were able to ping and poll the meter at its IP address (the radio was transparent). Unlike vendor A's radio, vendor B's radio had a Distributed Network Protocol (DNP) slave/master application whereby the meter's static IP/route was entered on the radio. Polling was done between the Distribution Management System (DMS) and the radio itself (by entering the IP of the radio, not the meter, into the DMS), and separately between the radio and the meter.

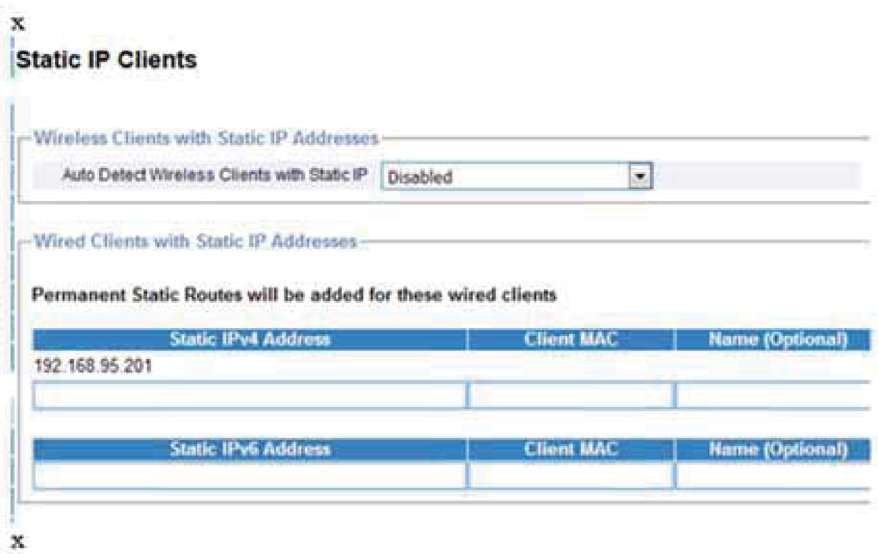



**Figure 6. Static IP Configuration Page on Vendor A's Radio**

The final test collected DNP data via serial Communication (COM) ports (RS-232) on the meter. Both vendors support RS-232; however, one radio provides a DB9 connector, while the other provides an RJ45. Both were configured on the radios and tested, but only vendor B's radio was successfully used to collect DNP data from the meter prior to the project's conclusion.

Figure 7 shows the successful RS-232 testing setup used with vendor B's radio and the meter. From left to right: Meter RS-232 Connector (DB9 Female), RS-232 Tester, Gender Changer, Null Modem Adapter, RS-232 to Ethernet Adapter.

Given that FAN work will continue in 2018, Beyond the Meter project personnel will work with vendors and the FAN team to demonstrate and document the correct use of serial pin assignments for RS-232 communications for each meter (and necessary adapters).


Figure 7. Successful RS-232 Testing Setup Used with Vendor B's Radio and the Meter

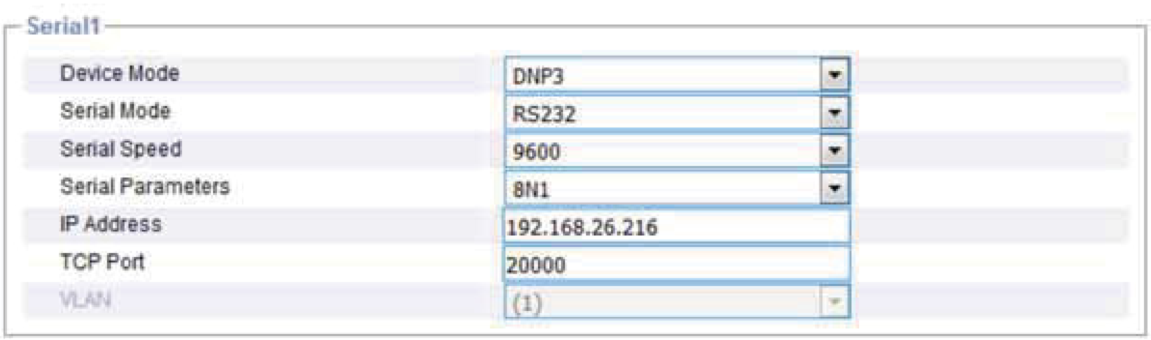



Figure 8. Serial Setting on Vendor A's Radio

## 2.3 Schedule and Milestones/Deliverables

The table below shows project milestones.

| Milestone | Proposed Completion Date | Actual Completion Date |
|---|---|---|
| Procurement of equipment (meters, radios) installed at SCE labs in Westminster, CA | September 1, 2017 | November 15, 2017 |
| Lab testing completed | October 31, 2017 | December 21, 2017 |
| Field testing | December 1, 2017 | N/A |
| Final report | December 31, 2017 | December 31, 2017 |

# 3 Project Results

## 3.1 Achievements and Next Steps

The Beyond the Meter Project learnings/successes included the following.

- The project demonstrated and documented how to configure meters and radios to support the collection of Distributed Network Protocol (DNP3) data over Transmission Control Protocol (TCP)/Internet Protocol (IP).
- The project demonstrated the capability to collect DNP3 data over the RS-232 interface for one of the two radios.
- Project personnel consulted with Field Area Network (FAN) radio vendors to improve their products for SCE and others users.
- Project results informed SCE's FAN procurement.

The project team recommends lab and field testing in 2018 prior to deployment for a larger field demonstration. Suggested continuation of work includes the following.

- Complete RS-232 testing and documentation for both radios. It is important to note that serial communications would be necessary if the meter's TCP/IP Communication (COM) port is already used by the customer.
- Continue with field evaluations in order to understand site-specific issues (such as meter locations) that may affect radio frequency communications.
- Work with internal cybersecurity experts to evaluate issues related to the integration of customer-owned equipment with SCE communications and control systems.

## 3.2 Metrics

| Metric | Outcome |
|---|---|
| Increased use of cost-effective digital information and control technology to improve reliability, security, and efficiency of the electric grid | The ability to integrate to-be-deployed Field Area Network (FAN) technologies and existing distributed energy resources (DERs) will be necessary for optimization of the electric distribution grid. The same communications that were used to collect measurement data for the Beyond the Meter Project could be extended to control information in the future. |
| Technology transfer | Throughout the Beyond the Meter Project, team personnel coordinated with the FAN vendors, SCE Distribution Management System users, and Integrated Grid Project (IGP)/FAN engineers and project managers. They will separately document specific radio and meter configurations, as well as be present during the 2018 IGP/FAN demonstration, to support the integration of meters in the field. |

## 3.3 Procurement

The only items procured for the project were the meters. The costs aligned with the original estimates. Outside of the lengthy procurement time, the only issue encountered was that the ION8600 meter had been deprecated.

# List of Acronyms

| | |
|---|---|
| BTM | Beyond the Meter |
| CT | Current Transformer |
| DER | Distributed Energy Resources |
| DG | Distributed Generation |
| DHCP | Dynamic Host Configuration Protocol |
| DMS | Distribution Management System |
| DNP | Distributed Network Protocol |
| EPIC | Electric Program Investment Charge |
| FAN | Field Area Network |
| FDEMS | Facility Distributed Energy Management System |
| GES | Grid Edge Solutions |
| IGP | Integrated Grid Project |
| IP | Internet Protocol |
| SCE | Southern California Edison |
| TCP | Transmission Control Protocol |

# SCE State Estimation Using Phasor Measurement Technologies Final Project Report

Developed by

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# 1 Executive Summary

Southern California Edison (SCE) has installed Phasor Measurement Units (PMUs)[1] at 13500-kV and 230-kV substations to measure voltage and current phasors. These PMUs transmit data at 30 frames per second to SCE's centralized Phasor Data Concentrator (PDC). SCE also receives external PMU data from the California Independent System Operator, which maintains reliability and accessibility for the state's power grid.

One PMU alone does not provide real-time grid insightt, however a group of PMUs properly distributed through the system can allow SCE dispatchers to make immediate operational decisions. Such accurate and timely data on the state of the power system is essential for understanding grid system health and providing the basis for corrective action that could help avoid failures and outages. To evaluate the ability to provide real-time insight into power grid dynamics, SCE undertook the Synchrophasor Demonstration Project.

The overall project objectives were to make the PMU data useful for real-time operations at SCE's Grid Control Centers (GCCs), and enable transmission system reliability coordinators to immediately see any power grid issues throughout the Western Electricity Coordinating Council (WECC) region – most of the Western United States and Canada, as well as northern Baja California, Mexico. Given this "Western Interconnection," real-time grid insight would enable SCE to immediately coordinate with other utilities to avoid system impacts and thus improve reliability for customers.

Utilities and Independent System Operators (ISOs) across North America have been deploying synchrophasor[2] technology for use in their control centers and for offline analytics for more than 10 years. Many of the larger ISOs and utilities have progressed to production-grade systems in their control centers, including multiple deployments for high availability and redundancy, as well as deployments in staging and development environments.

SCE's Synchrophasor Demonstration Project was successful in achieving the project objectives. The technology and the benefits of using synchrophasor technology and applications in real-time operations were validated.

Based on the success of this project, and the current state of industry adoption of synchrophasor technology, SCE is assessing the next steps of adopting system-wide use of synchrophasor-based applications in real-time operations.

[1] From the U.S. Department of Energy's smartgrid.gov website: "PMU measurements record grid conditions with great accuracy and offer insight into grid stability or stress."

[2] From the U.S. Department of Energy's smartgrid.gov website: "Synchrophasor technology is used for real-time operations and offline engineering analyses to improve grid reliability and efficiency and lower operating costs."

## 2 Project Summary

For this project, SCE deployed synchrophasor applications from the Electric Power Group (EPG, project vendor) that use PMU data to provide real-time insight into grid dynamics. EPG's applications provide information on wide-area situational awareness; oscillations caused due to the increased use of renewable generation and changes in system topology; phase angle information for monitoring grid stress; and assistance with line reclosing.

Following are the key project accomplishments and associated benefits:

| | PROJECT ACCOMPLISHMENT | BENEFIT/VALUE |
|---|---|---|
| 1. | Provided wide-area situational awareness of the Western Electricity Coordinating Council region to SCE operators | Detect events outside of SCE's footprint and enhance the ability to take timely corrective actions to prevent extreme events (such as the Pacific Southwest Blackout of 2011 and the Western Interconnection Blackout of 1996) |
| 2. | Expanded synchrophasor observability to 49 substations using data from the Phasor Measurement Units installed at 13 substations | Achieve expanded observability via the Electric Power Group's *enhanced* Linear State Estimator, without the need for additional Phasor Measurement Unit installations – creating the potential for substantial cost savings |
| 3. | Provided real-time phase angle information to SCE operators | Assist in line reclosing, monitoring grid stress, and detecting islanding conditions (when distributed (on-site) generation continues providing power to a location even though the electric utility grid is down) |
| 4. | Monitored oscillatory behavior in the grid | Identify locations and root causes of oscillations, such as malfunctioning of wind plant controllers |

Based on this information, synchrophasor applications that use PMUdata can address both the reliability and affordability strategic goals in the Electric Power Investment Charge (EPIC) Framework for Utilities (Figure 1), plus contribute to Grid Modernization and Optimization.


**Figure 1. EPIC Investment Framework for Utilities**

## 2.1 Problem Statement

SCE has invested heavily in installing PMUs at substations and the associated communications and hardware infrastructure. The PMUs are installed at thirteen 500-kV and 230-kV substations measuring voltage and current phasors. These PMUs transmit data at 30 frames per second to SCE's centralized Phasor Data Concentrator (PDC). In addition, SCE receives external PMU data from the California Independent System Operator, which maintains reliability and accessibility for the California power grid.

However, the existing PMUs alone do not provide real-time grid insight, and thus SCE grid operators do not receive accurate, timely, and synchronized data on the state of the power system. Operators need advanced tools to understand system health in real time as the basis for corrective action that could help avoid failures and outages.

To address these issues, and improve system reliability and optimize grid operation, SCE undertook the Synchrophasor Demonstration Project. This project involved investigating the possibility of using PMU data in real-time applications to:

- Monitor grid stability using phase angle differences;
- Assess transmission line reclosing using phase angles;
- Provide wide-area situational awareness of the Western Electricity Coordinating Council region for SCE operators;
- Alert operators to power system oscillations caused as a result of renewable power resources (such as wind and solar generation);
- Monitor inter-area oscillations; and
- Detect islanding conditions.

## 2.2 Project Scope, Schedule, and Milestones/Deliverables

For this project, SCE worked with the Electric Power Group (EPG) on power system state estimation using Phasor Measurement Units (PMUs) to demonstrate the *enhanced* Linear State Estimator (*e*LSE) at SCE's Grid Control Centers (GCCs). (*e*LSE is EPG software for obtaining the best estimate of the real-time state of the power system utilizing only synchrophasor data). This work involved performing data validation and conditioning on the synchrophasor stream, and generating an estimate of phasors of nearby substations at the same synchrophasor rate to increase observability of the power system. In addition, as part of this project, EPG's Real-Time Dynamics Monitoring System (RTDMSR®) [3] was deployed to provide the GCCs with an advanced analytics and visualization system in order to better extract information from synchrophasor data for use in real time.

Following is a summary of the tasks performed for completion of the SCE Synchrophasor Demonstration Project:

- Provided synchrophasor applications and tools to operators for use in real-time operations.
- Deployed EPG's RTDMS platform, including Visualization Clients at GCC, with the portfolio of 15 synchrophasor applications in the Quality Assurance (QAS) environment.
- Integrated and implemented EPG's *e*LSE technology for expanded system visibility.
- Conducted Site Acceptance Testing (SAT).
- Migrated RTDMS from the QAS environment to the DMZ environment (a production-level network at SCE) for use by SCE operators.
- Deployed Visualization Clients on operator desks for access and daily use of synchrophasor data.
- Held hands-on training on the use of RTDMS for:
  - Monitoring real-time grid dynamics such as phase angles, oscillations, damping, and voltage sensitivities;
  - Diagnosing system events and stressed conditions to assess the system state; and
  - Planning actions based on system state diagnostics.

9 training sessions took place for operators, 5 in September/October 2016 and 4 in January/February 2017. The GCC demonstration system has been in continuous operation since January/February 2017.

### 2.2.1 Phase 1: RTDMS Deployment at GCC in QAS Environment

The main objective of Phase 1 was to install, configure, and deploy an initial instance of the RTDMS in the SCE GCC QAS environment. At the end of Phase 1, which took place from June 21, 2016, to August 18, 2016, the RTDMS platform was up and running in the QAS environment using real-time data from SCE's PMUs.

In addition, the RTDMS platform in the QAS environment was available for training. This included five orientation sessions for SCE operators, engineers, and Information Technology personnel to help familiarize them with synchrophasor technology and its use cases in real-time operations. The topics included 1) Synchrophasor Overview: Fundamentals; 2) Synchrophasor Metrics: Phase Angle Differences and Their Use in Real-Time Operations; 3) Power System Oscillations: Monitoring Using Synchrophasors; 4) Power System Oscillations Detection and Voltage Sensitivity: Monitoring Using Synchrophasors; 5) Using Alarms and Events in RTDMS; and 6) RTDMS Configuration and Monitoring.

[3] Built upon GRID-3P® platform. US Patent 7,233,843, US Patent 8,060,259, and US Patent 8,401,710. ©2015 Electric Power Group. All rights reserved.

### 2.2.2 Phase 2: RTDMS and *e*LSE Integration/Implementation for Expanded Visibility

The main objective of Phase 2 was to include validated and conditioned data results as well as expanded visualization through use of EPG's *e*LSE in RTDMS visualization. This phase occurred from August 19, 2016, to October 21, 2016.

Using data from the 13 substations where SCE deployed PMUs, *e*LSE increased the visibility to 49 substations at 500-kV and 230-kV voltage levels when all 13 substations were reporting data. The real-time circuit breaker status information was obtained using SCE's Inter-Control Center Communications Protocol (ICCP) for updating the *e*LSE network model in near real time for accurate phasor estimations. At the end of this project phase, RTDMS visualization included validated and conditioned data results, as well as expanded visualization through use of the *e*LSE.

Phase 2 also included multiple training sessions for SCE operators on using RTDMS for real-time operations. During training, the Electric Power Group provided each operator with a laptop with the RTDMS running using recorded SCE PMU data. Five of these training sessions were provided for SCE operators (4 to 6 operators per session) at SCE's Grid Control Center in Alhambra, CA, with each session about 3 hours long.

### 2.2.3 Phase 3: RTDMS and *e*LSE Migration to GCC DMZ Environment

The main objective of Phase 3 was the migration of the RTDMS platform from the QAS environment at SCE to the DMZ (a production-level network at SCE) environment. By the end of this phase, which took place from October 14, 2016, to December 31, 2016, operators had access to the RTDMS with the *e*LSE in the GCCs.

Phase 3 also included Site Acceptance Testing (SAT) at the GCCs for RTDMS and *e*LSE applications. SAT included functional testing of RTDMS applications and validation testing of the *e*LSE application against SCE's state estimator and Supervisory Control and Data Acquisition (SCADA) systems.

### 2.2.4 Phase 4: Real-Time Operations Training with the RTDMS

The main objective of Phase 4, which took place from January 1, 2017, until December 31, 2017, was to work with EPG on support and maintenance for the RTDMS and EPG's *e*LSE in SCE's GCC DMZ environment.

This phase included detailed full-day training sessions for SCE operators on using the RTDMS for real-time operations. The operators accessed real-time PMU data by accessing the RTDMS installed in the GCC DMZ environment. In addition, the operators were trained on SCE-specific events by leveraging the Phasor Simulator for Operator Training (PSOT) deployed by EPG in 2015 at the GCCs. PSOT's event library includes key simulated events in SCE's footprint, such as the Magunden Separation and South of Lugo N-2 Remedial Action Scheme.

The event files were streamed during the trainings and the operators learned and practiced on the RTDMS. Areas of focus included the event signatures, event alarms, various metrics associated with the event, and corrective actions.

# 3 Project Results

As noted in the Project Summary (Section 2), the following lists the key project accomplishments and the benefits provided to the Western region power grid (including the State of California's and SCE's), as well as to SCE customers. The Achievements portion of this document (under Section 3.1) provides additional details.

| | PROJECT ACCOMPLISHMENT | BENEFIT/VALUE |
|---|---|---|
| 1. | Provided wide-area situational awareness of the Western Electricity Coordinating Council region to SCE operators | Detect events outside of SCE's footprint and enhance the ability to take timely corrective actions to prevent extreme events (such as the Pacific Southwest Blackout of 2011 and the Western Interconnection Blackout of 1996) |
| 2. | Expanded synchrophasor observability to 49 substations using data from the Phasor Measurement Units installed at 13 substations | Achieve expanded observability via the Electric Power Group's *enhanced* Linear State Estimator, without the need for additional Phasor Measurement Unit installation – creating the potential for substantial cost savings |
| 3. | Provided real-time phase angle information to SCE operators | Assist in line reclosing, monitoring grid stress, and detecting islanding conditions (when distributed (on-site) generation continues providing power to a location even though the electric utility grid is down) |
| 4. | Monitored oscillatory behavior in the grid | Identify locations and root causes of oscillations, such as malfunctioning of wind plant controllers |

## 3.1 Achievements

### 3.1.1 Availability of SPM Data/Applications in GCC for Use in Real-Time Operations

SCE's Synchrophasor Demonstration Project leveraged the deployed Phasor Measurement Units (PMUs) at SCE's 500-kV and 230-kV substations and the phasor data measured by these PMUs. The PMUs can measure substation bus voltage phasors (voltage magnitude and voltage angle); transmission line current phasors (current magnitudes and angles); and substation bus frequencies. The project made the data usable for real-time operations through key synchrophasor -based applications in the Real-Time Dynamics Monitoring System (RTDMS). Following is a list of these applications:

1. Wide-area situational awareness
2. Phase angle and grid stress monitoring
3. Automated event analyzer
4. Voltage stability monitoring
5. Oscillation stability analysis and monitoring
6. Oscillation detection
7. Frequency stability monitoring
8. Angular stability analysis and monitoring
9. Flow gate and inter-area power transfer

10. Generation trip detection
11. Load trip detection
12. Islanding detection
13. Intelligent alarms
14. Advanced built-in data validation

#### *3.1.1.1 RTDMS Customization and Configuration at GCC*

RTDMS deployment at SCE's Grid Control Centers (GCCs) included customization and configuration based on discussions with SCE operators. RTDMS Clients were installed at five operator consoles in the GCC in Alhambra, CA, and at four operator consoles in the GCC in Irvine, CA. The configured RTDMS visualization included:

1. Phase angle difference calculations between key SCE substations overlaid on geo-spatial maps;
2. Bus voltage and bus frequency visualization for key substations;
3. Power flow visualization for key transmission lines/corridors;
4. Oscillation monitoring and oscillation detection visualization;
5. Voltage sensitivity visualization; and
6. Configuration of alarm thresholds for angle differences, voltages, and frequencies.

Figure 2 and **Error! Reference source not found.** show screenshots from the RTDMS deployed at the GCCs, with Figure 2 indicating the RTDMS Dashboard. This dashboard provides the operator with the overall health of the system in terms of information such as real-time alarms and frequency trend charts. Figure 2 also denotes key voltage angle difference pairs as arrows overlaid on a geo-spatial map of Southern California. An arrow points toward the general direction of power flow and the arrow color changes in real time with an increase in grid stress, providing a visual indication to the operator. The blue squares represent the observable substations via PMUs or the *enhanced* Linear State Estimator (*e*LSE). The alarm panel provides the real-time alarm information. Lastly, the display shows the system frequency plotted as a high-resolution trend chart and as numeric values in real time.

Figure 3 shows a regional display for the Los Angeles Basin area. Key regional angle difference pairs are shown on the map on the left, and voltage trend charts for key 230-kV substations are shown on the right. Note that some previously unobservable substations (which do not have PMUs) are now observable via the Electric Power Group's *e*LSE. Such substations in the figure are Center, Eagle Rock, Rio Hondo, and Walnut, and are identified by the suffix _LSE in the display name.

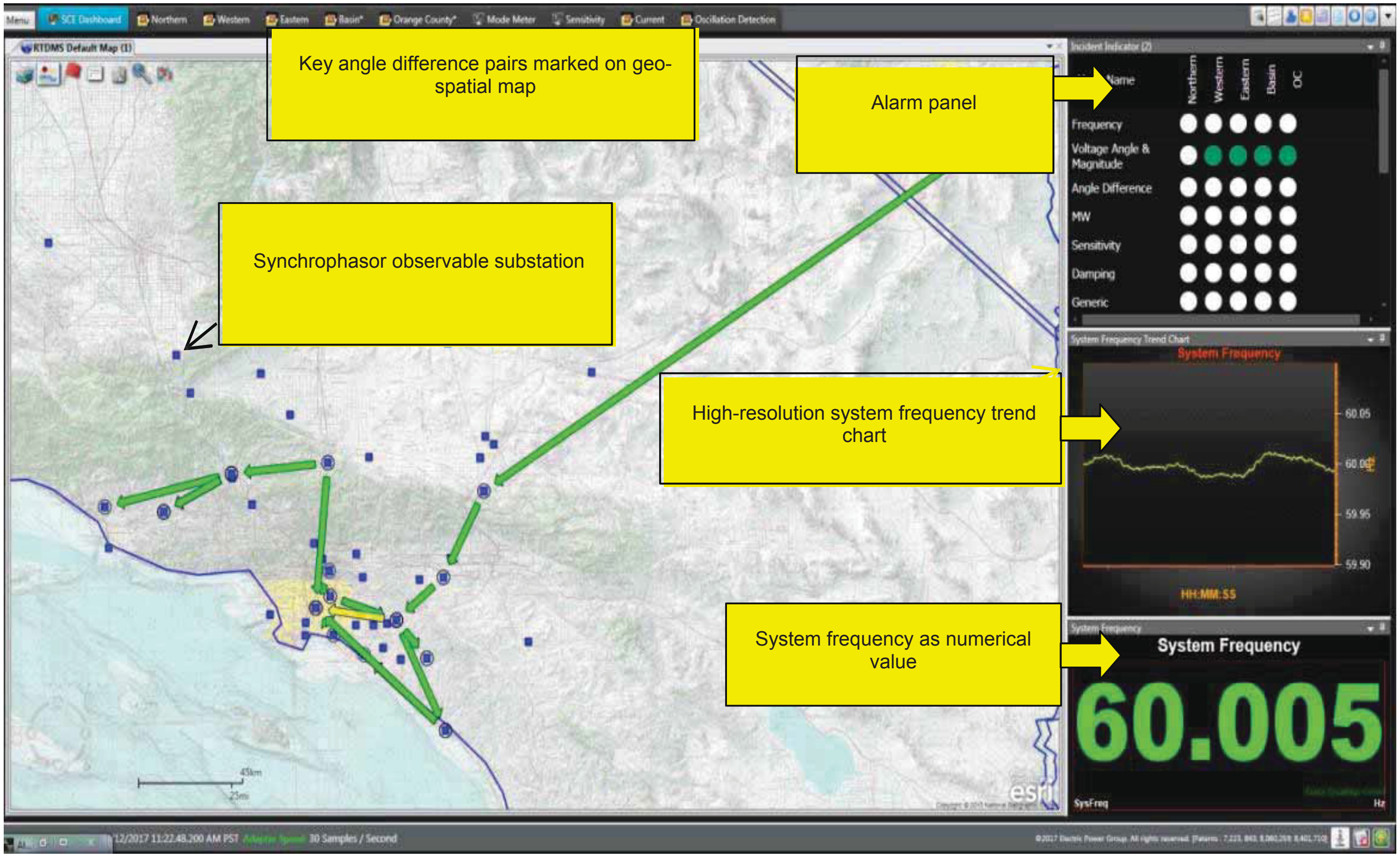


**Figure 2. RTDMS Dashboard at GCC**

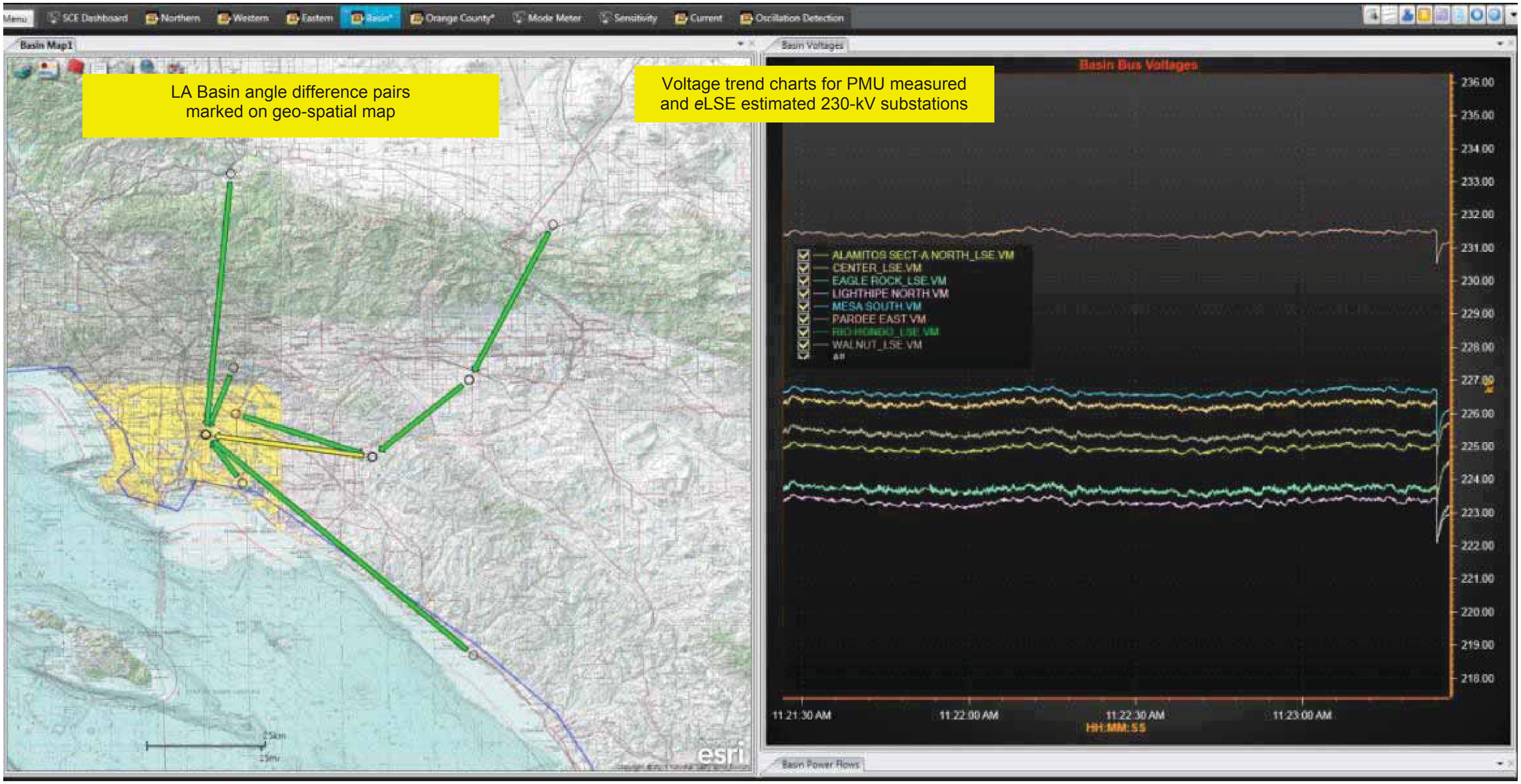


Figure 3. LA Basin Display Showing Regional Metrics

#### 3.1.1.2 RTDMS and eLSE System Architecture and Data Flow at GCCa

Figure 4 shows the system architecture and data flow diagram for Electric Power Group (EPG) applications in SCE's Grid Control Centers (GCC). EPG applications are deployed across four physical servers in the GCC DMZ (an SCE production-level network) environment. The servers and a description of the corresponding applications are listed here.

**LSE (Linear State Estimator) Server**

- ***enhanced* Linear State Estimator (*e*LSE):** Provides synchrophasor data values estimated using the Phasor Measurement Unit (PMU) data stream; power system network model; and real-time breaker status from the Energy Management System (EMS) via the Inter-Control Center Communications Protocol (ICCP).
- **Network Model Builder:** Allows the user to convert the EMS Common Information Model (CIM) to the *e*LSE readable network model to run the *e*LSE using real-time synchrophasor data.
- **ICCP Gateway:** Allows *e*LSE to receive breaker status information from the EMS for updating the *e*LSE network model in near real time for accurate phasor estimations.
- **DataNXT Server (a master program):** Integrates the *e*LSE and ICCP Gateway, and conducts data validation and conditioning.

**Real-Time Dynamics Monitoring System (RTDMS) Server**

- **RTDMS Server:** Receives a real-time phasor data stream from the DataNXT Server and performs a variety of calculations for use in the control center, such as phase angle differences, power flows, alarming, etc.
- **RTDMS Advanced Calculation Engine (ACE):** Performs calculations for modes, oscillation detection, and sensitivities in real time using synchrophasor data.

**RTDMS Database (DB) Server**

- **RTDMS PMU/Signal DB:** Archives all real-time PMU data as well as data values that were calculated at the second level by the RTDMS Server; also stores all advanced calculations such as sensitivities, oscillation damping, and modal frequency and energy values.
- **RTDMS User Control DB:** Stores the user profile information data for RTDMS Visualization Clients.

**RTDMS Data Access Server**

- **RTDMS Intelligent Synchrophasor Gateway (ISG) (a middleware application):** Provides an interface for data exchange between RTDMS Visualization Clients and the RTDMS Database; also manages sessions, authentications, and access based on security settings.
- **RTDMS Access Manager (RxM):** Manages PMU-level role-based access control on phasor data and alarms, including user accounts, roles, privileges, and permissions; also utilized to manage user profiles and preferences, access to displays, global alarms, and event configurations.
- **RTDMS GridSmarts (an online reporting website):** Provides ad hoc and periodic reporting capabilities; also can generate and automatically email pre-configured reports.

During the project, RTDMS Visualization Clients were installed at operator consoles in SCE's GCCs in Alhambra, CA, and Irvine, CA. RTDMS Client enables users to visualize phasor measurement data by providing a wide range of displays to monitor real-time dynamics and system events within the grid. It also provides operators and engineers with real-time wide-area monitoring, visualization, situational awareness, metrics, alarms, and events in power systems.

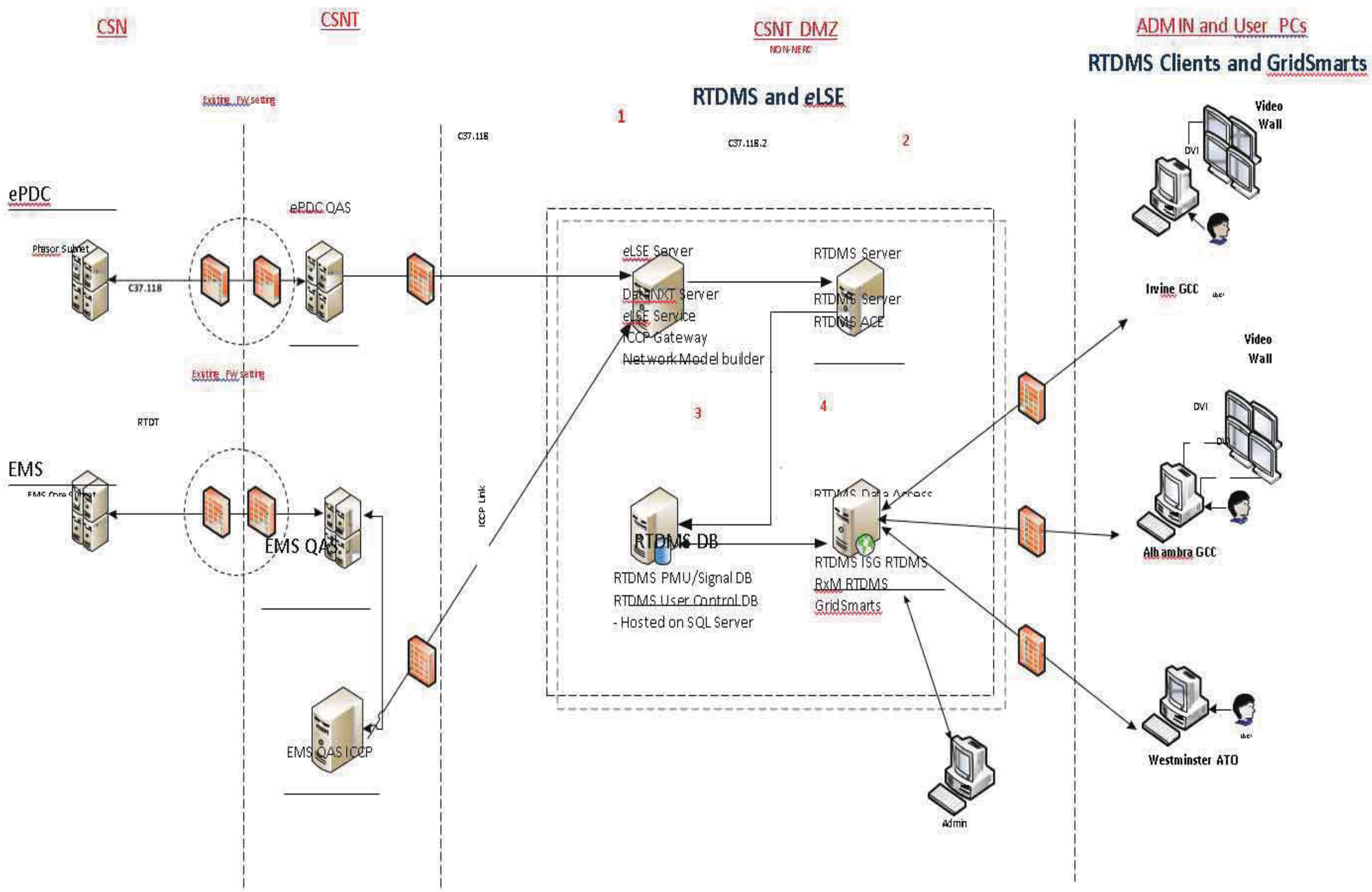


**Figure 4. RTDMS and eLSE Solution Deployment at GCC DMZ**

### 3.1.2 Expansion of Synchrophasor Observability in SCE Using *e*LSE

Another key goal of the project was to expand synchrophasor observability using measurements from existing PMUs in SCE's service territory footprint. PMU installation involves substantial capital and man-hour expenditures. The Electric Power Group's *enhanced* Linear State Estimator (*e*L*SE*) technology can result in substantial savings in PMU installation for SCE, as PMUs installed at strategically located substations can provide observability of neighboring substations in terms of voltage magnitude and voltage angle information. SCE has PMUs deployed at 13 substations to date. Using data from these sites, *e*LSE increased the visibility to 49 substations at 500-kV and 230-kV voltage levels when all 13 substations are reporting data. Table 1 below lists the SCE substations with installed PMUs.

| | | | | | |
|---|---|---|---|---|---|
| 1. | Lugo | 500, 230 | 8. | Mesa | 230 |
| 2. | Mira Loma | 500, 230 | 9. | Moorpark | 230 |
| 3. | Serrano | 500, 230 | 10. | Pardee | 230 |
| 4. | Vincent | 500, 230 | 11. | Santiago | 230 |
| 5. | Alamitos | 230 | 12. | Victor | 230 |
| 6. | Kramer | 230 | 13. | Viejo | 230 |
| 7. | Lighthipe | 230 | | | |

**Table 1. List of SCE Substations with Installed PMUs**

With *e*LSE integration, the synchrophasor observability has been extended to 8 additional 500-kV substations (Table 2) and 28 additional 230-kV substations (Table 3).

| | | | | | |
|---|---|---|---|---|---|
| 1. | Antelope | 500 | 5. | Rancho Vista | 500 |
| 2. | Eldorado | 500 | 6. | Valley | 500 |
| 3. | Midway | 500 | 7. | Victorville | 500 |
| 4. | Mohave | 500 | 8. | Whirlwind | 500 |

**Table 2. Additional Observable 500-kV Substations with eLSE**

| | | | | | |
|---|---|---|---|---|---|
| 1. | Bailey | 230 | 15. | Ormond | 230 |
| 2. | Barre | 230 | 16. | Pastoria | 230 |
| 3. | Blm West | 230 | 17. | Pisgah | 230 |
| 4. | Caldwell | 230 | 18. | Pearblossom | 230 |
| 5. | Center | 230 | 19. | Redondo | 230 |
| 6. | Chino | 230 | 20. | Rio Hondo | 230 |
| 7. | Cool Water | 230 | 21. | Santa Clara | 230 |
| 8. | Eagle Rock | 230 | 22. | Saugus | 230 |
| 9. | Ellis | 230 | 23. | SONGS | 230 |
| 10. | Hinson | 230 | 24. | Sylmar | 230 |
| 11. | Johanna | 230 | 25. | Villa Park | 230 |
| 12. | Lewis | 230 | 26. | Walnut | 230 |
| 13. | Long Beach | 230 | 27. | Water Valley | 230 |
| 14. | Luz LSP | 230 | 28. | Windstar | 230 |

**Table 3. Additional Observable 230-kV Substations with eLSE**

Figure 5 illustrates the synchrophasor observability for SCE after *e*LSE Implementation. The red squares represent the substations with installed PMUs and the blue diamonds represent the additional observable substations.

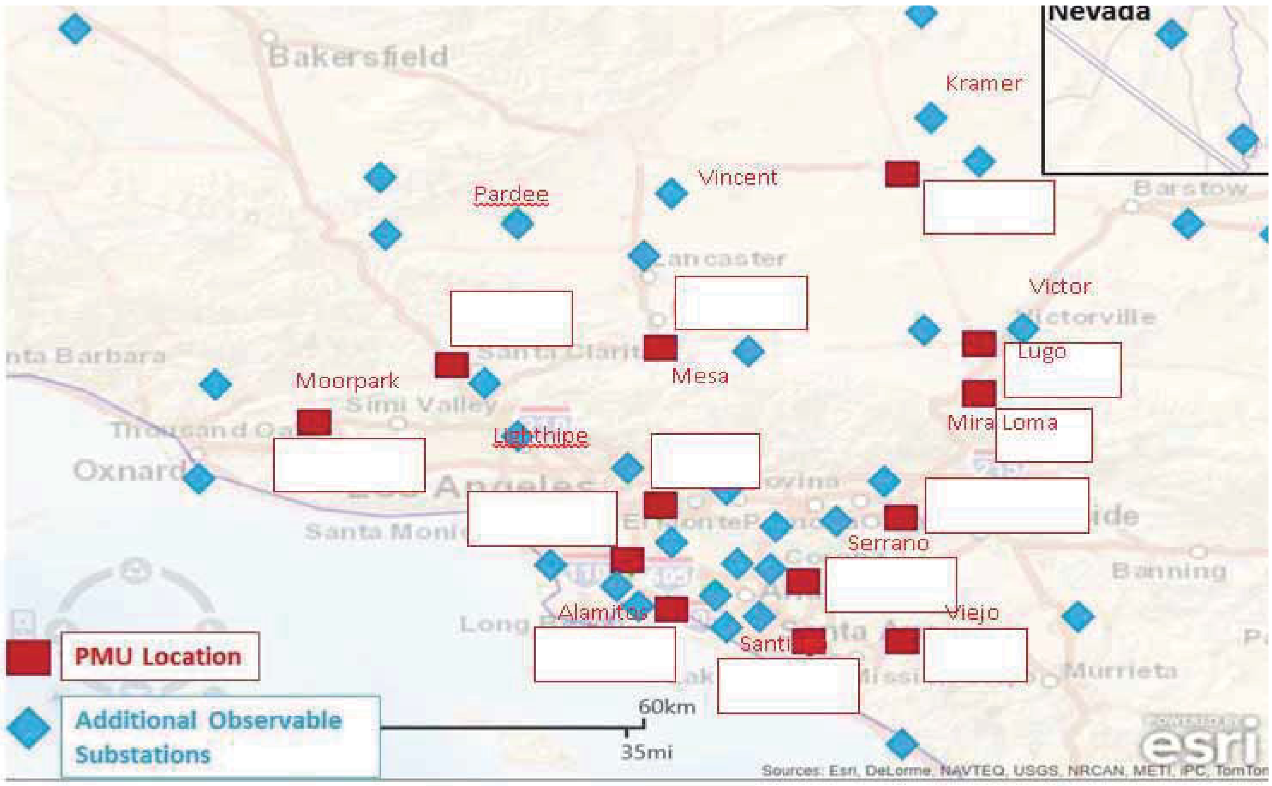


Figure 5. SCE Map Showing Synchrophasor Observability After *e*LSE Implementation

### 3.1.3 Validation of eLSE Data for Operator Confidence

For acceptance of the Electric Power Group's (EGP) *enhanced* Linear State Estimator (*e*LSE) technology at SCE's Grid Control Centers (GCCs), the project team conducted validation testing of the output results from *e*LSE. The validations were performed for voltage magnitude estimations (500-kV and 230-kV substations) and angle difference estimations for key pairs. This took place in early January 2017 at the GCC in Alhambra, CA, as part of the Site Acceptance Testing (SAT). A detailed report on *e*LSE validation by EPG was submitted by EPG to SCE in February 2017. This section provides a brief summary of the validation process and findings.

#### 3.1.3.1 eLSE Validation Criteria

The following test criteria were deemed sufficient for validation purposes based on the recommendations by Peak Reliability[4] and EPG's experience with *e*LSE validation at other entities:

- Voltage magnitude estimates within ±1% of actual voltage measurements
- Voltage angle estimates within ±1° of actual voltage angle measurements

#### 3.1.3.2 Summary of Key Findings and Conclusions

- Validations were performed for voltage magnitudes and angle differences.
- Voltage magnitude validation:
  - For 230-kV and 500-kV Phasor Measurement Units (PMUs), *e*LSE results were within 1% of raw measurements.
- Angle difference validation:
  - *e*LSE results were within 1° of the measured values for key angle difference pairs.
  - *e*LSE results were also validated against SCE state estimator results and were within 1°.
- *e*LSE validations were within the criteria for validation.

#### 3.1.3.3 eLSE Validation Examples

**230-kV Voltage Magnitude Comparison:** The first comparison was performed for the bus voltages at 230- kV substations. The estimated voltages were compared against the PMU voltage magnitudes by plotting both using the Electric Power Group's Phasor Grid Dynamics Analyzer offline analysis tool. Figure 6 shows a 1-hour comparison plot for the Lighthipe 230-kV substation.

[4] The Western Electricity Coordinating Council was bifurcated in 2014, with Peak Reliability formed as the Reliability Coordinator for the area including most of the Western United States and Canada, as well as northern Baja California, Mexico. www.peakrc.com

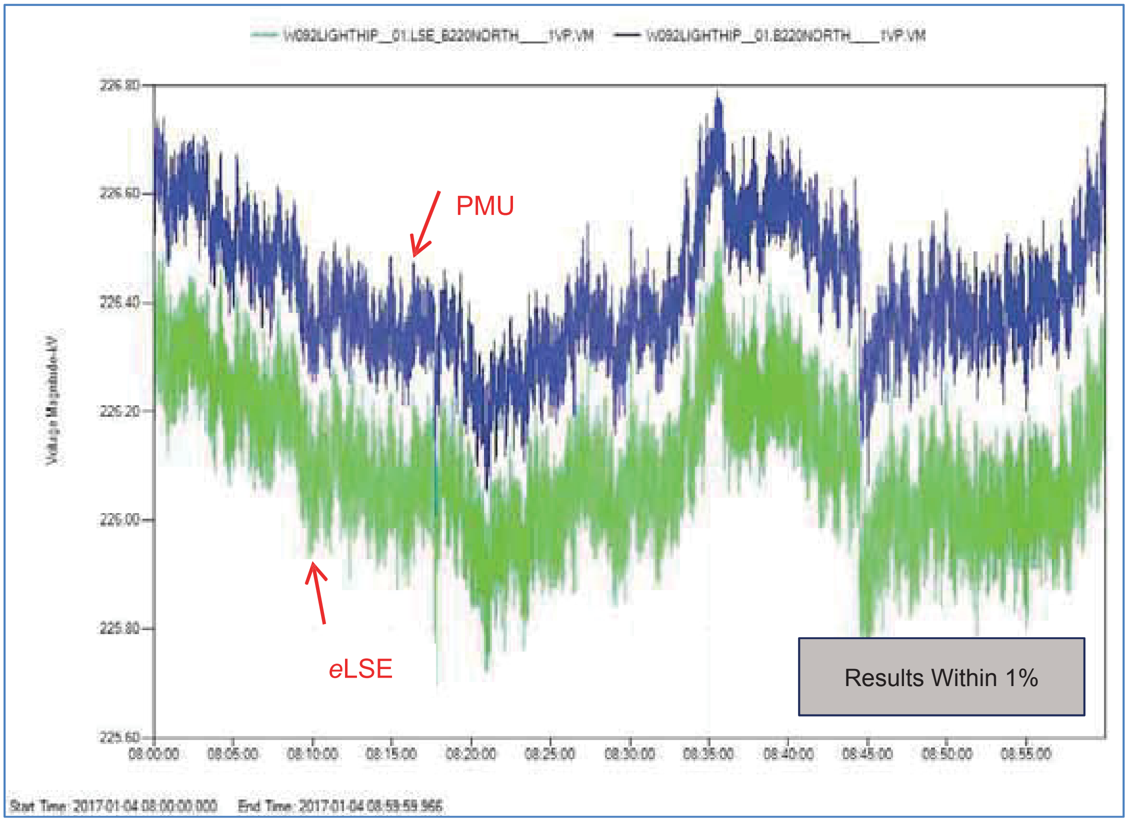


**Figure 6. Lighthipe 230-kV North Bus Comparison**

**500-kV Voltage Magnitude Comparison:** Another comparison was conducted for the bus voltages at 500-kV substations, and the estimated voltages were compared against the Phasor Measurement Unit voltage. Figure 7 below shows a comparison plot for the Lugo 500-kV substation in the Real-Time Dynamics Monitoring System.

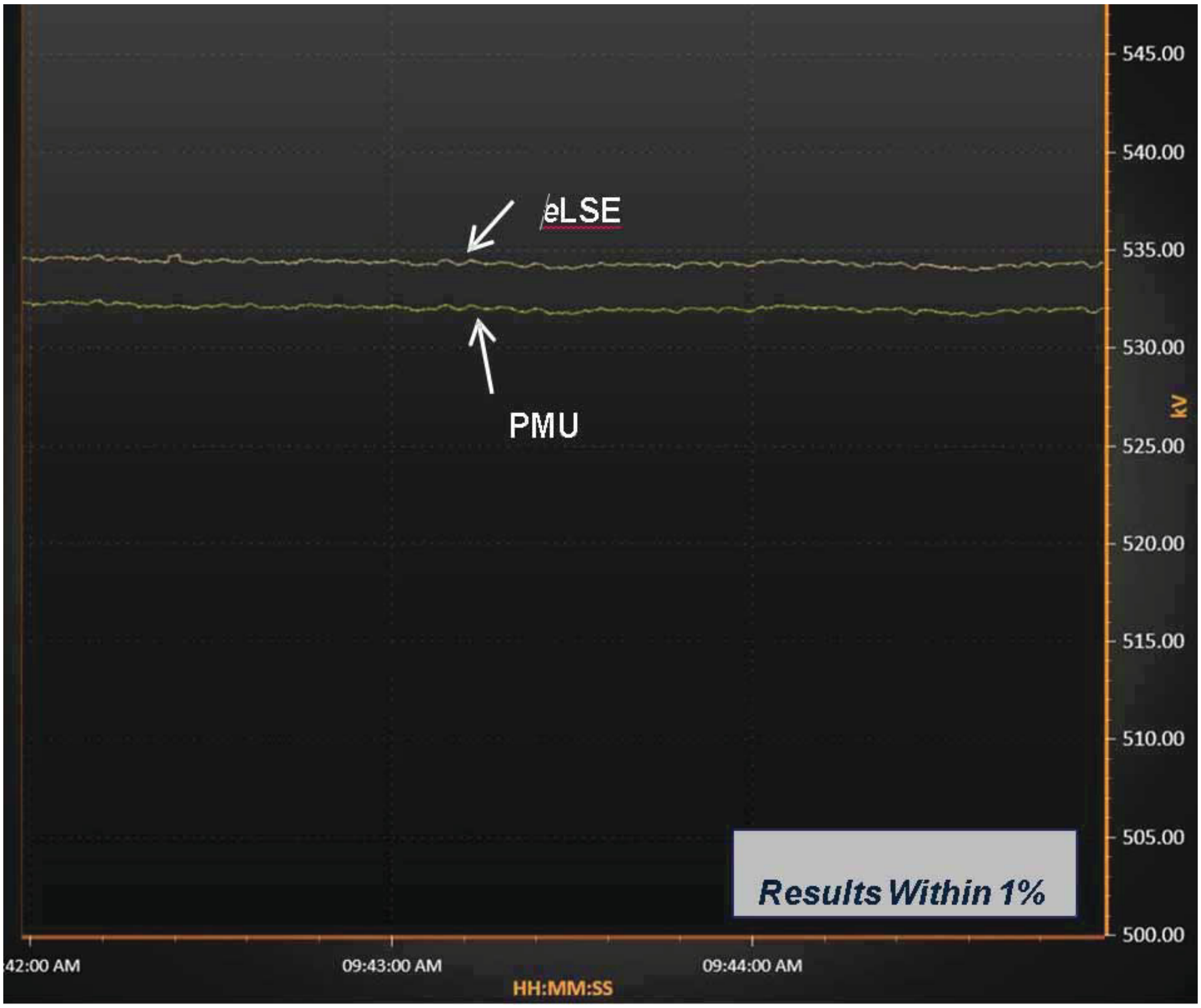


Figure 7. Lugo 500-kV West Bus Comparison

**Angle Difference Comparison:** The next comparison was done for the voltage angle differences from PMU measured, *e*LSE estimated, and SCE's state estimator values. Figure 8 below shows a comparison plot for the Vincent-Lugo 500-kV angle difference pair in Phasor Grid Dynamics Analyzer.

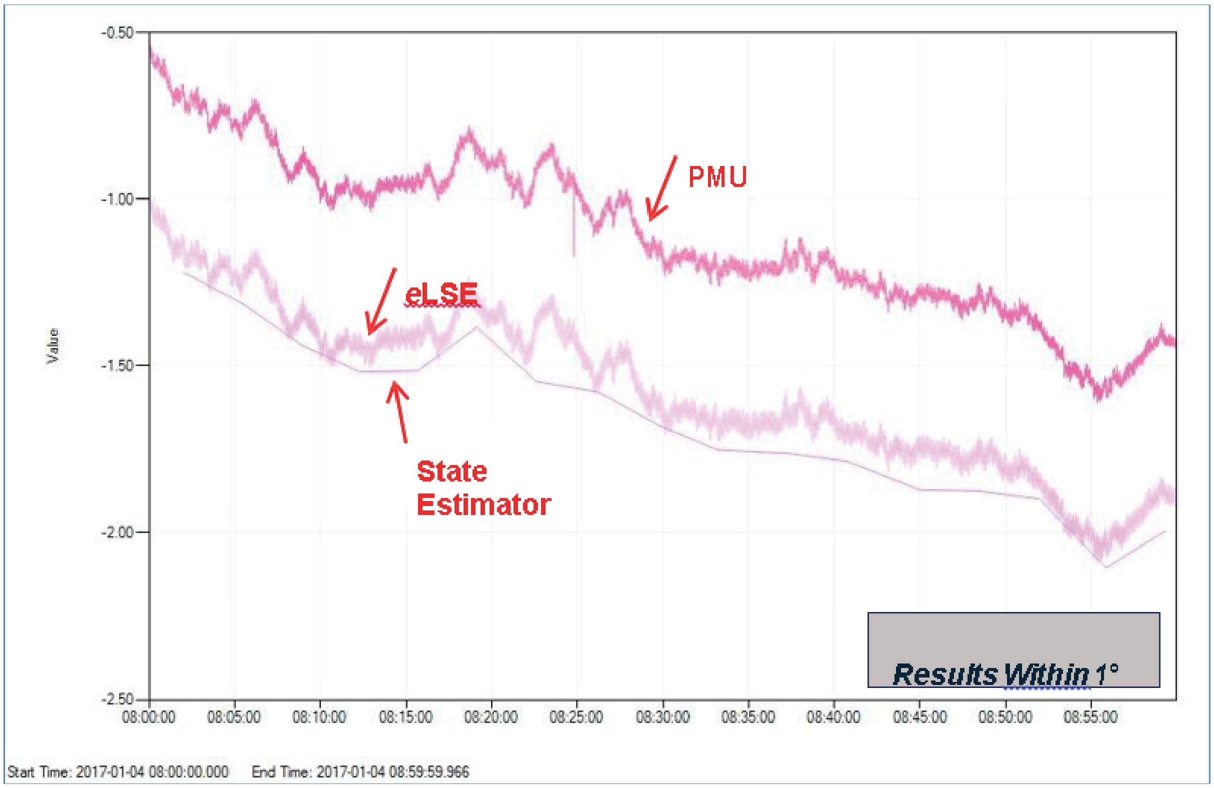


**Figure 8. Vincent-Lugo 500-kV Angle Difference Comparison**

## 3.2 Metrics

**Enhanced grid monitoring and online analysis for resiliency**
The project enabled SCE Grid Control Center dispatchers to see data in real time and make decisions based on online tools that provide wide-area situational awareness to enhance SCE and Western region grid operations.

**Increased use of cost-effective digital information and control technology to improve reliability, security, and efficiency of the electric grid (Public Utilities Code § 8360)**
Using data from sites shown in Table 1, the *enhanced* Linear State Estimator increased the visibility to 49 substations at 500-kV and 230-kV voltage levels when all 13 substations (with Phasor Measurement Units installed) are reporting data.

**Number of information sharing forums held**
Every other week, meetings were held with members of the Grid Control Centers to discuss the various synchrophasor-based applications.

**Technology transfer**
For acceptance of the synchrophasor technology in real-time operations, SCE operators were provided orientations and hands-on trainings on using various synchrophasor-based applications in the Real-Time Dynamics Monitoring System. In addition, Power System Control and Information Technology Grid Services personnel were trained to enable them to support the Grid Control Centers in synchrophasor technologies. See Project Scope, Schedule, and Milestones/Deliverables (Section 2.2) for more details.

**Successful project outcomes ready for use in California's investor-owned utility grid (path to market)**
If the other California investor-owned utilities have the required software and tools, they also would be able to perform this demonstration.

**Technologies available for sale in the marketplace (when known)**

- The Real-Time Dynamics Monitoring System is currently available in the marketplace. The Bonneville Power Administration is the first utility to implement comprehensive adoption of syncrophasors in its wide-area monitoring system.
- The *enhanced* Linear State Estimator is also currently available in the marketplace, with the Electric Power Group.
- The Phasor Measurement Units are available from any commercial vendor that is properly certified.
- The communication network to supply the interconnection between the Phasor Measurement Units and Phasor Data Concentrators can be a wired connection, a serial, or Ethernet cable. These networks are readily available through several communication providers across the United States.

## 3.3 Procurement

As part of the project, SCE procured servers and hardware to install the Real-Time Dynamics Monitoring System (RTDMS) platform, RTDMS Clients, and *enhanced* Linear State Estimator (*e*LSE) applications at SCE's Grid Control Centers. The project Purchase Order to Electric Power Group (EPG) consisted of two parts:

- Software license cost (RTDMS platform, RTDMS Clients, and *e*LSE), and
- Professional services cost.

All software licenses and professional services procured by SCE from EPG were delivered on time and within budget.

## 3.4 Stakeholder Engagement

The SCE project stakeholders were SCE's Grid Modernization Organization, the Grid Control Centers (GCCs), and Power System Control (PSC).

The Grid Modernization Organization's project expectations were to explore how Phasor Measurement Unit (PMU) data could be used in real-time operations, and these expectations were accomplished by deploying the Real-Time Dynamics Monitoring System (RTDMS) and the Electric Power Group's *enhanced* Linear State Estimator (*e*LSE) applications in the GCCs. Personnel from the Grid Modernization Organization participated in each project phase, signed off upon completion of each milestone, and participated in the orientation and training sessions. They also took part in the Site Acceptance Testing (SAT) and signed off on the final SAT report, as well as on a separate *e*LSE data validation report after *e*LSE was successfully deployed.

The GCCs' expectations from the project were to understand how to use PMU data in real-time operations. The expectations were accomplished by providing multiple orientation and training sessions to system operators on synchrophasor technology and applications available via the RTDMS and *e*LSE. These sessions were held at the GCC in Alhambra, CA, and the GCC in Irvine, CA, to ensure that all of the system operators had the opportunity to participate.

# List of Acronyms

| | |
|---|---|
| DB | Database |
| CAISO | California Independent System Operator |
| CIM | Common Information Model |
| *e*LSE | *enhanced* Linear State Estimator |
| EMS | Energy Management System |
| EPG | Electric Power Group |
| EPIC | Electric Program Investment Charge |
| GCC | Grid Control Center |
| ICCP | Inter-Control Center Communications Protocol |
| ISG | Intelligent Synchrophasor Getaway |
| ISO | Independent System Operator |
| kV | Kilovolt |
| PDC | Phasor Data Concentrator |
| PGDA | Phasor Grid Dynamics Analyzer |
| PMU | Phasor Measurement Unit |
| PSC | Power System Controls (SCE organization) |
| PSOT | Phasor Simulator for Operator Training |
| QAS | Quality Assurance |
| RTDMS | Real-Time Dynamics Monitoring System |
| RTDMS ACE | RTDMS Advanced Calculation Engine |
| RTDMS ISG | RTDMS Intelligent Synchrophasor Gateway |
| RTDMS RxM | RTDMS Access Manager |
| SAT | Site Acceptance Testing |
| SCADA | Supervisory Control and Data Acquisition |
| SCE | Southern California Edison |
| WECC | Western Electricity Coordinating Council |
| SPM | Synchronized Phasor Measurement |

# Advanced Grid Capabilities Using Smart Meter Data Final Project Report

Developed by

SCE Transmission & Distribution, Grid Technology & Modernization

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# Acknowledgments

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# 1 Executive Summary

Southern California Edison (SCE) has installed 5 million smart electric meters in its service territory, which covers 50,000 square miles. The meters are connected to more than 4,500 distribution circuits and are mainly installed at residential and small commercial (<200 kW demand) customer sites. They collect meter events and exceptions, as well as time-series consumption and voltage data.

This meter data is invaluable in improving the accuracy of existing records. For example, improved accuracy of meter-to-transformer connectivity helps in outage notifications, outage duration reporting, trouble response operations, local planning for load additions, and asset condition. Connectivity information also enables SCE to effectively evaluate the connected load on a transformer and predict the risk of failure, voltage degradation along a circuit, overloaded transformers and circuits, and more. The value of accurate phase information can improve load balancing, power flow modeling, state estimation, and other factors.

There were two objectives of this project, called Advanced Grid Capabilities Using Smart Meter Data:

1. Demonstrate and evaluate solutions that correlate meters to their respective service transformer. This would enable better outage management and more accurate customer notifications while providing the benefits stated above.
2. Demonstrate and evaluate solutions that correlate meters to an electrical phase. This would optimize the efficiency of the grid through improved load balancing, power flow modeling, etc.

The solutions primarily employed statistical algorithms that used historical meter data to perform the correlations. The accuracy of the algorithms' results was determined by comparison with field-verified data.

In the first part of the project, several approaches were demonstrated to improve transformer-to-meter correlations. The project team evaluated the ability of a solution to correctly identify an incorrect correlation (mismatch) of a meter to a transformer in the existing database and correctly associate (remap) it with a transformer. Using historical time-series voltage data, an Electric Power Research Institute (EPRI) algorithm was first demonstrated on two distribution circuits. This was followed by demonstration and evaluation of a vendor's solution that used both historical meter voltage data and outage events in stand-alone and combined algorithms to successfully confirm and/or map meters to their respective service transformers. The following table lists the different solutions demonstrated, along with their maximum accuracies.

| Solution Description | Max Accuracy | |
|---|---|---|
| | Mismatch | Remaps |
| EPRI solution (setup, testing, and optimization) | 20% | 8% |
| Single-transformer outage event solution | 95% | 95%[1] |
| Voltage Signature Analysis solution | 85% | 85% |
| Hybrid solution (transformer outage with Voltage Signature Analysis) | 95% | 85% |

**Table 1. Accuracy of Transformer-to-Meter Correlation Solutions**

In the second part of the project, several solutions were demonstrated and evaluated to predict phase-to-meter correlations. Again using historical time-series voltage data, the project team first demonstrated an EPRI algorithm. This was followed by demonstration and evaluation of a vendor's solution of two data-driven statistical models of unsupervised and supervised machine-learning algorithms. The unsupervised algorithm was further developed to provide an enhanced version that improved the accuracy of the results. The EPRI algorithm was evaluated on two distribution circuits and performed below expectations. The vendor's solution provided better results and therefore was evaluated on 23 additional circuits that were selected based on 7 categories that could impact algorithm performance. These categories included customer distributed energy resources (DER), circuit phase type, system voltage, meters per transformer, overhead or underground, maximum load, and circuit imbalance.

A month's worth of meter data at a time was processed through the solutions for each circuit. Each circuit's highest accuracy was determined by processing several months of data; the averaged accuracy was established by taking the maximum accuracy determined for each circuit and averaging it over the 23 circuits. The following table displays the performance of the solutions.

| Algorithm Type | Maximum Averaged Accuracy (%) |
|---|---|
| EPRI | 50% |
| Unsupervised | 66% |
| Enhanced Unsupervised | 80% |
| Supervised | 86% |

**Table 2. Summary of Maximum Averaged Accuracy of EPRI Algorithm and a Vendor's Machine-Learning Algorithms**

[1] This remap accuracy is based only on incorrect mappings because the meters lost power when the transformer had an outage, and the meters were mapped to a different transformer. Meters that were mapped to a transformer but did not have an outage when the transformer went out were set aside for other correlation methods such as voltage signature analysis.

Of the seven circuit categories, those with six possible phase combinations had the largest detrimental impact on these accuracies. Alternately, high imbalance between phases on a given circuit was beneficial because it enabled more distinct group separations. This is discussed further in the report.

With the successful conclusion of the Advanced Grid Capabilities Using Smart Meter Data Project, the processes and algorithms used for meter-to-transformer and meter-to-phase correlations are scheduled to be deployed in SCE's production environment.

# 2 Project Summary

Smart meter data is invaluable, as it can be utilized in many use cases including outage notifications, outage duration reporting, trouble response operations, local planning for load additions, and asset condition. Additionally, it can be used in improving connectivity information to allow SCE to effectively evaluate the connected load on a transformer and predict the risk of failure, voltage degradation along a circuit, overloaded transformers and circuits, etc. The basis for any of these use cases is to have good records of transformer-to-meter associations (correlation). Good phase information allows SCE to benefit significantly due to the ability to conduct effective load flow studies and avoid power quality issues. It also enables effective utilization of load data available from smart meters to define the most accurate condition of the distribution system. This load information, in conjunction with phase information, can be very useful in load switching during emergent operating conditions. As with most other large electric utilities, SCE's records of these associations were inaccurate. This project demonstrated solutions that could improve the accuracy of the existing records.

The first part of the project demonstrated transformer-to-meter correlation solutions. An Electric Power Research Institute (EPRI) solution was first demonstrated using a correlation algorithm to determine voltage trends between pairs of meters and meters marked as being on the same transformer. Upon completion, another vendor's solutions were demonstrated. The vendor's solutions employed two techniques that complemented each other. The first technique used outages to establish meter-to-transformer correlations. Single-transformer power outages and restorations were identified and then correlated to meters that also had outages and restorations at approximately the same time. The second technique demonstrated the establishment of transformer-to-meter connectivity by correlating the voltage signature of meters on the same transformer. For meters that did not correlate to the transformer they were mapped to, the algorithm would attempt to find a correlation with other meters on surrounding transformers. The third technique was a hybrid of the highly accurate outage event correlation technique for identifying mismatched meters, combined with the voltage signature technique to remap only the mismatched pool of meters to their respective transformer.

The second part of the project demonstrated technologies that were capable of mapping the voltage signature of the smart meter to the unique characteristics of the phase. Again, an EPRI solution was first demonstrated, followed by a vendor's solutions. The solutions demonstrated the establishment of the phasing information for distribution circuits by correlating the voltage signature at the meter and transformer level with the connectivity model of the circuits. These solutions employed different statistical methods to identify the electrical phase at the meter with varying degrees of accuracy.

This project is one of the Foundational Strategies and Technologies that has the potential to improve reliability. It is foundational for other analytic solutions that use smart meter data. Building on this foundational technology, reliability can be improved through proper transformer and phase loading that leads to better distribution system and asset management. The project therefore meets strategic goals in the Electric Program Investment Charge (EPIC) Investment Framework for Utilities, as shown in Figure 1.


**Figure 1. EPIC Investment Framework for Utilities**

## 2.1 Problem Statement

SCE has developed analytics solutions that provide important information for distribution system planning, system reliability, outage notification to customers, etc. The smart meter is used as a sensor with meter data as the primary input to the analytics solutions. A key requirement on the use of this data is knowledge of the location of the meters on the distribution circuit. The accuracy of the meter association to its respective transformer and electric phase is therefore essential. SCE estimates that records with the meter/transformer associations are approximately 84% accurate.

Additionally, whenever an outage (planned or unplanned) occurs, customer notifications are based on records of service connections (meters) to their respective transformers affected by the outage. Any record inaccuracy results in miscommunication to some customers. It also affects incorrect transformer loading calculations.

Accurate electric distribution system phase information can help SCE operate the distribution network in a more efficient and reliable manner. Specifically, accurate phasing information is crucial to a set of analytic and operational tools and applications in the electric power distribution system, including 1) load balancing, 2) three-phase power flow modeling, 3) state estimation/situational awareness, and 4) early damage detection. However, electric phase connectivity information is typically missing or inaccurate in SCE's circuit maps and databases. Some circuit maps have phase information, but only in cases where field crews fed back this information to the circuit mappers. Since the information is rarely updated, its accuracy is questionable, and therefore mostly disregarded by engineers and planners for load balancing and in power flow studies.

SCE's service territory has a mix of phase-to-phase (Ph/Ph)-connected and phase-to-neutral (Ph/N)-connected distribution transformers and various primary voltages (4 kV, 12 kV, 16 kV, etc.).

Typically, until a field check is performed, a random assignment (guesstimate) of phases to transformer structures or laterals is used. Random assignments result in low default accuracies. For circuits with three possible phase combinations, either Ph/N or Ph/Ph, the default accuracy is 33%, meaning there is a 33% chance that the phasing assignments/associations are accurate. For circuits with six possible phase combinations (Ph/Ph and Ph/N), the default accuracy is even lower at 16%.

This project was designed to address these issues to enable better outage management and more accurate customer notifications, and to optimize the efficiency of the grid through improved load balancing, power flow modeling, and other factors. It aimed to provide a single solution to cover the range of variables in SCE's distribution system.

## 2.2 Project Scope

This project demonstrated several statistical methods and algorithms that improve the accuracy of transformer-to-meter and electric phase-to-meter correlations. Algorithms obtained from the Electric Power Research Institute were initially demonstrated, followed by other vendor solutions.

### 2.2.1 Solution Description: Transformer-to-Meter Correlation

#### *2.2.1.1 Electric Power Research Institute (EPRI) Solution*

Most of the algorithms demonstrated and evaluated for transformer-to meter correlations used the one-hour average time-series voltage from the smart meter as input data. The EPRI solution used a correlation algorithm to determine voltage trends between pairs of meters and meters marked as being on the same transformer. The algorithm was a two-step process. The first step was to identify mismatched meters, and the second step was to associate the mismatched meters to the correct transformers. Mismatched meters were those that that the records showed to be associated with the wrong transformer. A meter was flagged as a possible mismatch if the median correlation coefficient of the known meter-to-transformer association was sufficiently less than the median correlation coefficient of the meter to another transformer grouping. Using a similar methodology, the next step of the algorithm linked the mismatched meter to an alternate transformer. The accuracy of identifying the mismatches was approximately 20%, while the accuracy of correlating the mismatched meters to their correct transformers was approximately 8%.

#### *2.2.1.2 Vendor Solution 1*

The next demonstration showed the vendor's solution using single-transformer outages to identify mismatched meters and remap them to the correct transformer. Three years of historical single-transformer outage data was used for this portion of the project. This solution was based on the concept that in a single-transformer outage event, only meters that were correctly associated with that transformer would have a power outage. This would identify mismatched meters as well as the correctly mapped meters. Mismatched meters that had an outage with the transformer, but were incorrectly associated (mapped) to a different transformer according to existing records, were easily identified and remapped to the correct transformer. This method demonstrated >95% accuracy in identifying incorrect associations and enabling correction of the records. There also were meters that were incorrectly mapped because they did not go out when the transformer had an outage. Remapping these meters to the correct transformer was set aside for field verification because the other alternative (using proximity analysis for remapping these meters to an adjacent transformer) would introduce a greater likelihood of errors.

The analysis of the mismatches was less straightforward than expected. Not all meter outage events were being extracted from the meters and stored in the meter database. After further analysis, it was discovered that in ~30% of the cases, the meter did in fact experience an outage despite the fact that no outage events were retrieved for the meter. To avoid this problem, a secondary validation was conducted given the fact that the smart meters have status flags associated with each consumption interval. A few of these flags were discovered to be associated with outages. Therefore, customers originally identified as mismatches were run through this secondary analysis to confirm whether or not they were in fact mismatches.

This secondary analysis provided strong results, which were incorporated in the hybrid solution discussed below. However, this solution could only be effectively applied to single-transformer outages. It did not work in cases where multiple transformers on a circuit went out at the same time, except to identify meters that were mismatched.

#### 2.2.1.3 Vendor Solution 2

This solution demonstrated the use of a meter Voltage Signature Analysis algorithm. Like the EPRI solution, it included a two-step process, except that it used a different statistical model for predicting the meter-to-transformer association. First, the algorithm had to discover mismatched meters on transformers and then remap those meters to adjacent transformers on the same circuit. It limited the search for transformer remaps to a 500-foot radius from the meter. Variables used in the model were the correlation value and the distance between each meter and potential transformer candidates. These variables were then used in logistic regression to create the predictive model. This solution presented many concerns, namely the potential to falsely identify mismatched meters and introduce additional error into existing connectivity records. Therefore, multiple trials and iterations were performed to optimize the model in order to minimize the number of errors. With each trial, the algorithm accuracy improved, starting as low as 18% and ending with an accuracy in the upper 80% range. This solution was initially tested on the same two circuits used to test the EPRI solution, and then expanded to include three additional circuits.

#### 2.2.1.4 Hybrid Solution

The final demonstration focused on a hybrid combination of the single-transformer outage solution and the meter Voltage Signature Analysis solution. While the single-transformer outage analysis proved to be highly successful in identifying meter mismatches or confirming correct associations, it was dependent on single-transformer outages. The Voltage Signature Analysis was able to achieve accuracies upward of 80% and had no dependency on outages. However, this came with the risk of introducing new association errors that could potentially worsen the state of the connectivity model. Therefore, a hybrid combination was demonstrated that parsed the pool of mismatched meters identified by single-transformer outages through the Voltage Signature Analysis algorithm. This provided a way to remap the incorrectly mapped meters from the outage solution while eliminating the risk of introducing additional errors, since the meters were already identified as incorrectly mapped. The Voltage Signature Analysis part of the solution could also be used alone on multi-transformer outages when only applied to the mismatched meter pool.

This hybrid solution is being implemented at SCE. Figure 2 shows the process flow.

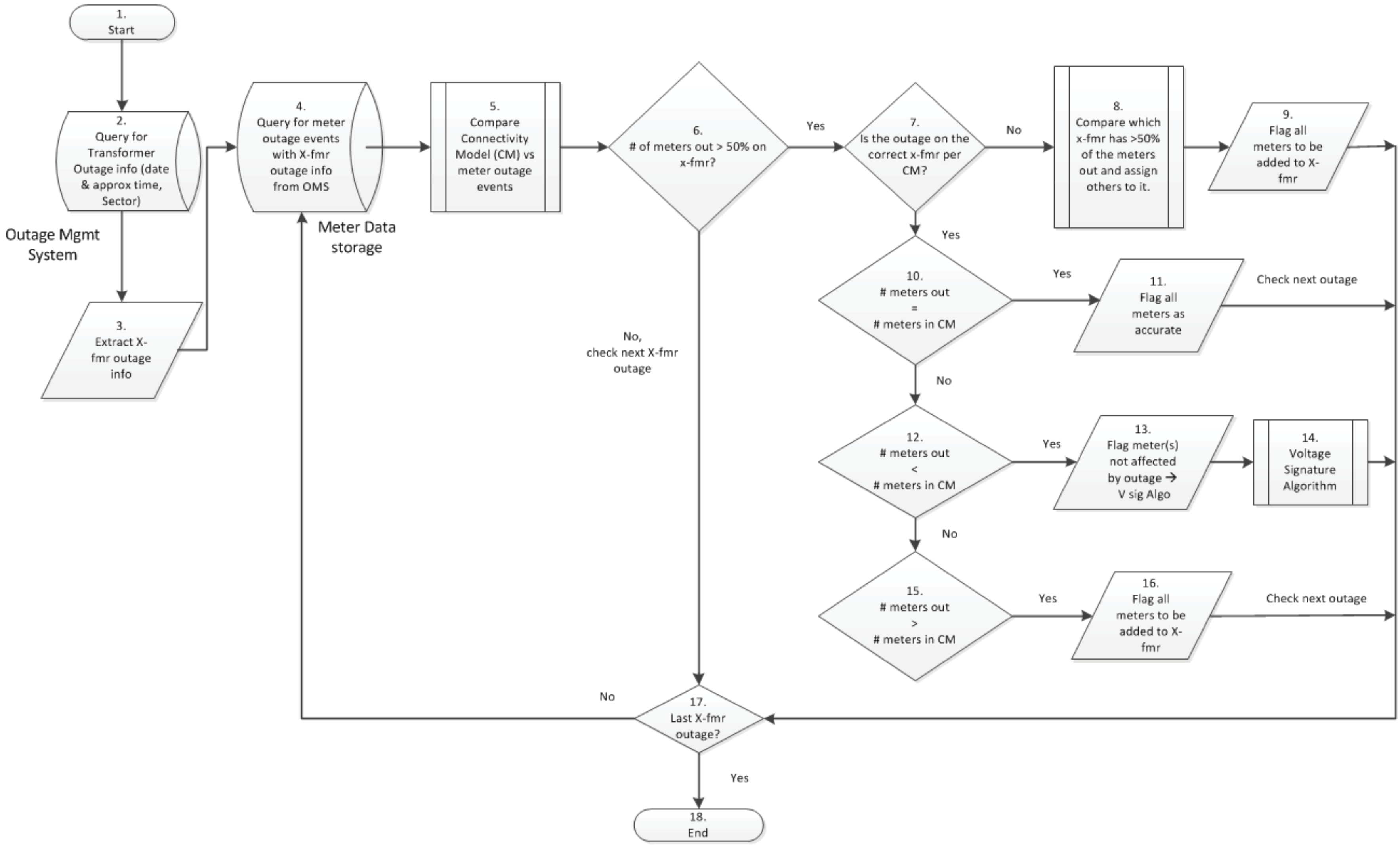



**Figure 2. Hybrid Solution Flow Diagram**

#### *2.2.1.5 Data Description and Test Circuit Selection*

**Data Description**

The transformer-to-meter correlation solutions used a combination of connectivity, smart meter, and Supervisory Control and Data Acquisition (SCADA) data:

1. Connectivity data: Network connectivity of the distribution system
2. Smart meter data: Hourly smart meter voltage and consumption readings along with meter outage exceptions, events, and geo-coordinates
3. SCADA data: Circuit current readings, circuit load readings, and substation capacitor bank voltage readings

**Test Circuit Selection**

Two 12-kV distribution circuits emanating from the same substation were used in the demonstration and evaluation of the transformer-to-meter correlation solutions. These circuits had predominantly phase-to-phase (Ph/Ph)-connected transformers on the primary side and approximately 3,400 service points combined of residential and commercial customers. Both circuits had rooftop photovoltaic (PV) installations and additional customer-owned distributed generation. The PV installations were small and were primarily associated with residential customers. These circuits included meters that do not provide voltage data.

Based on the performance of the vendor's solutions, the demonstration was expanded to include additional circuits ranging from 4 kV to 16 kV, with a predominance of either Ph/Ph-connected or phase-to-neutral (Ph/N)-connected service transformers.

To establish an accurate assessment of the different solutions, the connections of all of the meters to their respective transformers were field-verified with a few exceptions. These included parts of the circuit that were buried underground and where safety hazards existed.

### 2.2.2 Solution Description: Phase-to-Meter Correlation

#### *2.2.2.1 Electric Power Research Institute (EPRI) Solution*

The second part of the project was conducted to demonstrate and evaluate phase-to-meter correlation solutions. The EPRI solution used two distinct statistical approaches to predict the phase connection of non-three-phase meters. The first approach utilized a regression model of circuit loads for each phase that accounted for metered loads, unmetered loads, and losses. The concept behind this approach was to use the energy consumption data of the meters and a related measurement, such as the current readings by phase, at the substation. A regression model could be fitted to estimate the phase connection of individual meters based on their time-series energy-consumption patterns, versus the three energy-consumption-related patterns at the head of the circuit serving the meters. The model can be estimated as long as the number of intervals over which the smart meter and circuit data is observed is greater than the number of phase predictions for the circuit plus the number of model parameters used to control for unobserved (unmetered) loads and losses.

The second approach utilized voltage in combination with energy consumption to predict the phase of the meter, and consisted of a series of correlation and regression statistical methods to predict the connection of each meter. This method compared time-series voltage measurements from each meter to the three voltage measurements at the substation bus. By comparing the differences in the voltage measurements over time, the phase connection of the meter can be parsed out using simple correlation methods to match the meter voltage profile to the best matching profile of the three measurements at the substation bus.

Both of the EPRI statistical approaches were tested on two circuits. The first approach was quickly abandoned because of the large discrepancy between the aggregated meter loads and the substation energy measurements for the circuits. In the second approach, prediction accuracy rates depended significantly on the ability to aggregate metered loads to service transformers and to the circuit node level of two-phase taps off the main line. Due to the results, the demonstration and evaluation of the second approach was limited to the two initial circuits (see Project Results, Section 3, for more information).

#### 2.2.2.2 Vendor Solution

This solution used a toolbox of machine-learning algorithms to provide comprehensive solutions to the phase identification. The toolbox included unsupervised machine-learning and supervised machine-learning algorithms.

**Unsupervised Algorithm**

In this solution, a constrained clustering algorithm of smart meter data was used. The unique features were first extracted from the voltage time-series of smart meters instead of directly utilizing the voltage time-series data. The meter phase constraints were defined based on known information about line configurations in the network connectivity model. For example, meters on the same single-phase transformer must share the same phase, so a constraint was created to map all meters on such a transformer to the same phase. In the final step, a constrained clustering algorithm was applied to accurately identify the phase connection of each meter.

The flow diagram in Figure 3 shows the process from data collection, consumption by the unsupervised algorithm, and comparisons of results with reference (field-verified) data.

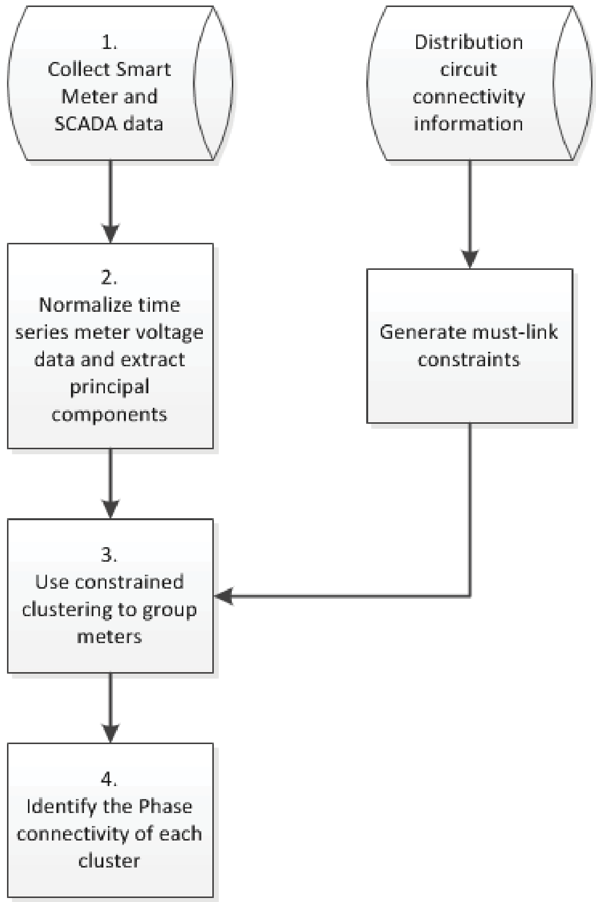



**Figure 3. Diagram of the Unsupervised Machine-Learning Process**

In the first step, voltage measurements were collected from smart meters and the Supervisory Control and Data Acquisition (SCADA) system. In the second step, the meter voltage time-series were normalized by their standard deviations, and principal component analysis (PCA) was applied on the normalized time-series to extract the top principal components. In the third step, the constraints were defined in the clustering process by inspecting the network connectivity data. The meters on the same laterals were put into a subset, and then an augmented clustering algorithm was performed on the subsets to obtain the full partition. It was difficult to find the optimal result(s) only through clustering. To obtain a relatively good result, the clustering algorithm was performed multiple times with different sets of random initial cluster centers. The clustering result with the smallest sum of squared distances was selected in the end. Finally, the phase of each cluster was solved by identifying a one-to-one match between the set of clusters and the set of possible phase connections. The accuracy of the results was then compared to field-verified phase information.

The benefits of this unsupervised machine-learning solution were:

1. It utilized the known information about line configurations in the network connectivity model to avoid mislabeling of the meters on the same secondary feeder, which could occur with other methods.
2. It was computationally efficient.
3. It could identify phase connections with high accuracy in distribution circuits where the majority of transformers are phase-neutral connected.
4. It could still determine the phase connections of metered customers even when the distribution circuit had some unmetered customers.

**Supervised Algorithm**

In this solution, an extension of the Mapper algorithm was developed using Topological Data Analysis. Mapper transforms an input metric space into an easily visualized representation called an abstract simplicial complex. From this simplicial complex, subsets of similar data points were identified. In this sense, Mapper is akin to a human-aided clustering algorithm. Here, Mapper was extended to a human-aided classification algorithm. This extension was performed by learning the algorithm’s two most critical parameters from training data, building a base simplicial complex from that training data, and defining how new data is classified from this base simplicial complex. The two critical parameters were the size of a covering and the distance metric.

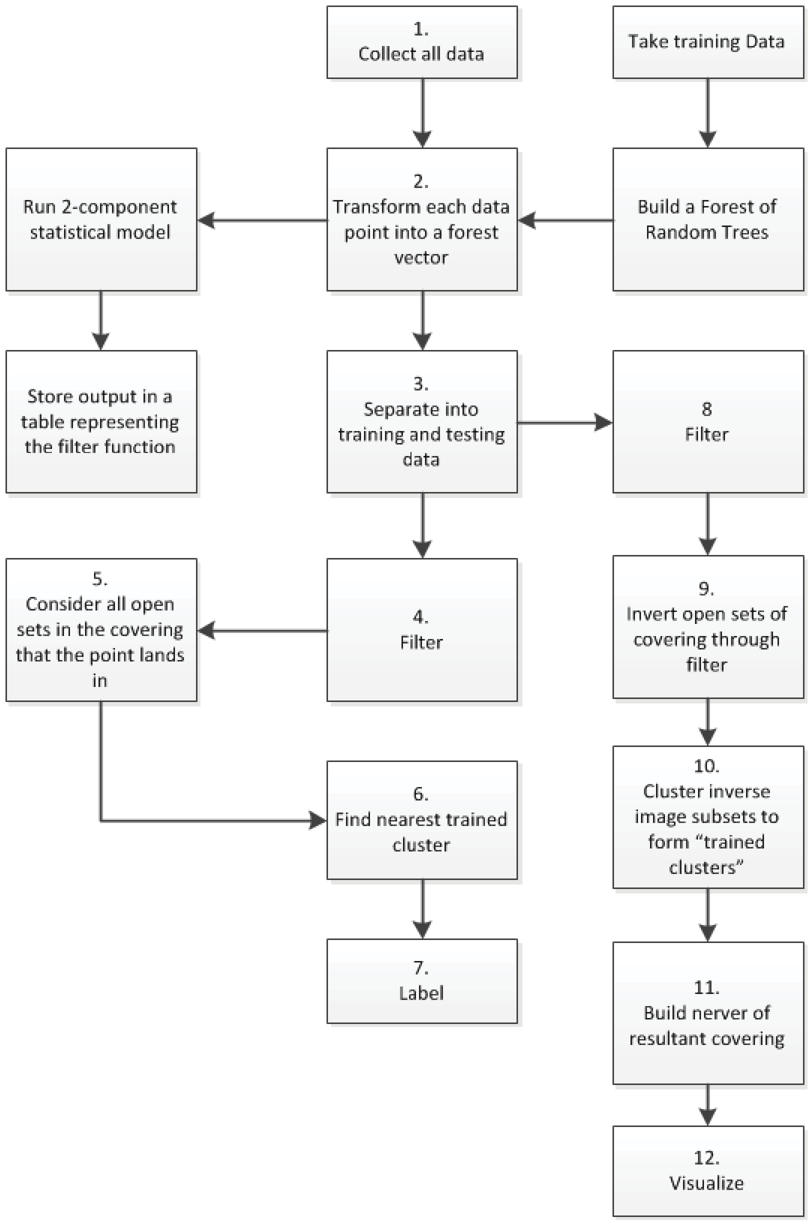



**Figure 4. Diagram of the Supervised Machine-Learning Process**

The flow diagram of the supervised machine-learning procedure is summarized in Figure 4. First, training data was used to build a forest of random trees, and this forest was used to transform each data point into a forest vector. Next, the two-component statistical algorithm was run on the entire ensemble, and the numerical results were stored (for each data point) in a table that represents the filter function. The ensemble was then split into training and testing data, and the training data was put through Mapper to build a base simplicial complex. Finally, new data was classified by filtering that point and grouping it to the nearest appropriate cluster.

The meter voltage and phase label data $X$ was partitioned by training data and test data. The training data are those data points for which the phase information is known, and the test data are those data points for which the phase information is not known. The intent is to obtain accurate phase information for the test data given only a small amount of training data. This cannot be achieved with Mapper alone. Mapper can form a simplicial complex that visualizes connections between similar data points, but a rule must be set for labeling the test data points from the complex. Furthermore, to achieve high accuracy, the complex itself needs to represent connections related to the phase information. To ensure such connections are represented, it is reasonable to build the simplicial complex from only the data in which the information is known.

This solution exhibited the following unique benefits:

1. It had high accuracy with little infrastructure and phase information.
2. It did not require any modeling of the network. For example, branch impedances did not need to be known.
3. It was robust with respect to missing data.
4. The implementation and tuning of the algorithm was very user-friendly.
5. It handled any type of phase (phase-to-phase, phase-to-neutral) connectivity without additional changes.

However, the main drawback was that it needed accurate training data for all phases on a given circuit, which currently can only be obtained from field measurements.

**Enhanced Unsupervised Algorithm**

Building on the unsupervised algorithm discussed above, the enhanced unsupervised model was developed to leverage a different dimensionality reduction technique. The fundamental difference between this technique and the original principal component analysis (PCA) is that this technique is a nonlinear dimension reduction method, whereas PCA is a linear dimension reduction method. Another enhancement is specific to circuits with six possible phase (phase-to-phase and phase-to-neutral) combinations. Leveraging data about each individual transformer on a circuit, the analysis was split into two separate analyses where phase-to-phase connections were analyzed separately from phase-to-neutral connections. Therefore, each transformer was assigned to one of three either phase-phase combinations or phase-neutral combinations. Those circuits with mixed phase-phase and phase-neutral combinations were separated into the two clustering problems, and then the results were recombined to give the phasing for the entire circuit. These enhancements improved the accuracy of the results.

#### *2.2.2.3 Data Description and Test Circuit Selection*

**Data Description**

The raw data collected to test the phase identification algorithms included:

1. Connectivity data: Network connectivity of the distribution system
2. Smart meter data: Hourly smart meter voltage and consumption readings
3. Supervisory Control and Data Acquisition (SCADA) data: circuit current readings, circuit load readings, and substation capacitor bank voltage readings

**Test Circuit Selection**

The vendor's solutions were initially demonstrated on the same two circuits used in the EPRI demonstration. However, based on its performance, the demonstration was expanded to include 23 additional circuits to assess consistent performance of the algorithms across representative (test) circuits in SCE's service territory. Therefore, all of the circuits were split into seven categories, with many of the circuits overlapping two or more categories. The categories were further split into subcategories in order to test the impact of varying the magnitude of each category. A cross-section of typical SCE circuits were identified that either fit into these categories or a combination of two categories from which a short list of 23 test circuits was developed. Note that approximately 70% of SCE's circuits have phase-to-phase-connected service transformers. This results in much smaller voltage variations at the meter and substation bus than with phase-to-neutral-connected transformers.

#### *2.2.2.4 Category Identification*

Since smart meter voltage was an input data to the algorithms, anything that could affect voltage fluctuations was a primary driver for selecting the first four categories. For this reason, high to low distributed energy resources (DER) penetration; circuit phase type; system voltages (4 kV, 12 kV, etc.); and meters per transformer were selected as individual categories. An additional three categories were chosen, including overhead versus underground circuits; maximum kilowatt-hours (kWh); and unbalanced circuits from the SCE Field Engineering list, bringing the total to seven. Following are descriptions of each category.

**Customer DER:** This is a measure of the amount of distributed (on-site) generation on a particular circuit. Generation from the customer side can impact voltage levels at customer locations on a given circuit.

**Circuit Phase Type:** SCE's distribution circuits may have one of three primary connections to their transformers: phase-to-neutral, phase-to-phase, or a combination of both. The phase connection type can greatly impact the voltage variance between phases on a given circuit.

**System Voltage:** This is the primary voltage level of a given circuit. This can be associated with certain phase connection types, as well as the size of a circuit, both of which can impact voltages on each respective circuit.

**Meters Per Transformer:** Different distribution circuits have different numbers of meters attached to each transformer. The number of meters per transformer can impact voltage reads on the secondary side of transformers for a given circuit.

**Overhead Versus Underground:** This is a measure of the number of overhead (OH) transformers versus underground (UG) transformers on a circuit. OH and UG equipment have different properties, which may affect voltages of meters on a given circuit.

**Maximum kWh:** This is the maximum amount of single-phase customer load based on meter data for a given circuit. Light single-phase loading can increase the likelihood of less voltage variation on a given circuit.

**Unbalanced Circuits from Field Engineering List:** As part of its duties, Field Engineering prioritizes circuits that have high loading imbalances to rectify. Large loading imbalances lead to large voltage imbalances on a given circuit.

## 2.3 Schedule and Milestones

The Advanced Grid Capabilities Using Smart Meter Data Project began in June 2015 with the demonstration of the Electric Power Research Institute's (EPRI's) solution for transformer-to-meter correlation. It concluded in June 2017 with the demonstration of a vendor's solution for phase-to-meter correlation. The following table shows the solutions evaluated in the transformer/meter correlation part of this project, with approximate durations.

| Solution Description | Duration |
|---|---|
| EPRI solution evaluation (setup, testing, and optimization) | 8 months |
| Single-transformer outage event solution evaluation | 2 months |
| Voltage Signature Analysis solution evaluation | 5 months |
| Hybrid solution (transformer outage with Voltage Signature Analysis) evaluation | 3 months |

**Table 3. Solution Demonstration Durations for Transformer-to-Meter Correlations**

Following the transformer/meter correlation demonstrations, the phase/meter correlation demonstrations were initiated, and concluded in July 2017. The following table shows the phase/meter correlation solutions evaluated, with approximate durations.

| Solution Description | Duration |
|---|---|
| EPRI solution evaluation (setup, testing, and optimization) | 3 months |
| Vendor solution using unsupervised machine-learning algorithm | 2 months |
| Vendor solution using supervised machine-learning algorithm | 2 months |
| Vendor solution using enhanced unsupervised machine-learning algorithm | 2 months |

**Table 4. Solution Demonstration Durations for Phase-to-Meter Correlations**

Note: The reason for demonstrating and evaluating the transformer-meter correlation solutions first was because the phase-meter correlation solutions were dependent on good transformer-to-meter associations.

# 3 Project Results

## 3.1 Transformer-to-Meter Correlation

The Electric Power Research Institute (EPRI) algorithm was the first solution demonstrated and evaluated on two of SCE's distribution circuits. Based on field inspection of both circuits, the accuracy of the algorithm to predict meter-to-transformer association mismatches for the two circuits combined was determined to be 20%. The accuracy to link a mismatched meter to its actual connected service transformer was 8%.

The next solution demonstrated and evaluated was the single-transformer outage algorithm, which proved to be highly successful. An analysis was performed on a sample of 100 cases where a meter was identified as a remap to a new transformer. Out of the 100 cases, 95 were deemed correct, giving the algorithm a 95% accuracy rate. However, the accuracy in remapping a meter to the correct transformer was less impressive.

The third solution demonstrated was the meter Voltage Signature Analysis algorithm. It used a statistical model for predicting the meter-to-transformer association. Based on a comparison with field verifications, the algorithm's ability to identify mismatched meters and remap them to the correct transformer was 85% accurate.

The last solution demonstrated was the hybrid solution, which was a combination of the meter outage analysis and the meter Voltage Signature Analysis algorithm. The comparison with field-verified data yielded an accuracy of 95% for identifying mismatched meters, and 85% in remapping them to the correct transformer.

The transformer-to-meter correlation solutions' results are listed in the table below.

| Solution Description | Max Accuracy | |
|---|---|---|
| | Mismatch | Remaps |
| EPRI solution (setup, testing, and optimization) | 20% | 8% |
| Single-transformer outage event solution | 95% | 95% |
| Voltage Signature Analysis solution | 85% | 85% |
| Hybrid solution (transformer outage with Voltage Signature Analysis) | 95% | 85% |

**Table 5. Accuracy of Transformer-to-Meter Correlation Solutions**

## 3.2 Phase-to-Meter Correlation

To measure the accuracy of the solutions, an accurate reference had to be established. Field crews were therefore dispatched to each of the test circuits to identify the phase(s) associated with transformers on the circuits. In some cases, not all transformers were phased due to an inability to retrieve the actual phasing in the field. This was due to wireless communications issues based on SCE's method used for circuit phasing as well as safety concerns. However, since the majority of transformers on the test circuits were phase-verified in the field, it provided sufficient information for determining the accuracy of the algorithms' results in this demonstration. The field personnel marked up circuit maps as they verified the phase(s) of transformers on each circuit. Once this task was completed, the maps were converted into Excel format to enable comparison with the algorithms' results.

While the field verifications were being performed, the meter voltage data was extracted for each test circuit. The algorithms were readjusted to fluidly perform the larger-scale analysis. A calendar month's worth of meter voltage data associated with each circuit was parsed through the algorithms. This was repeated so that results for each circuit were generated for several calendar months for each algorithm.

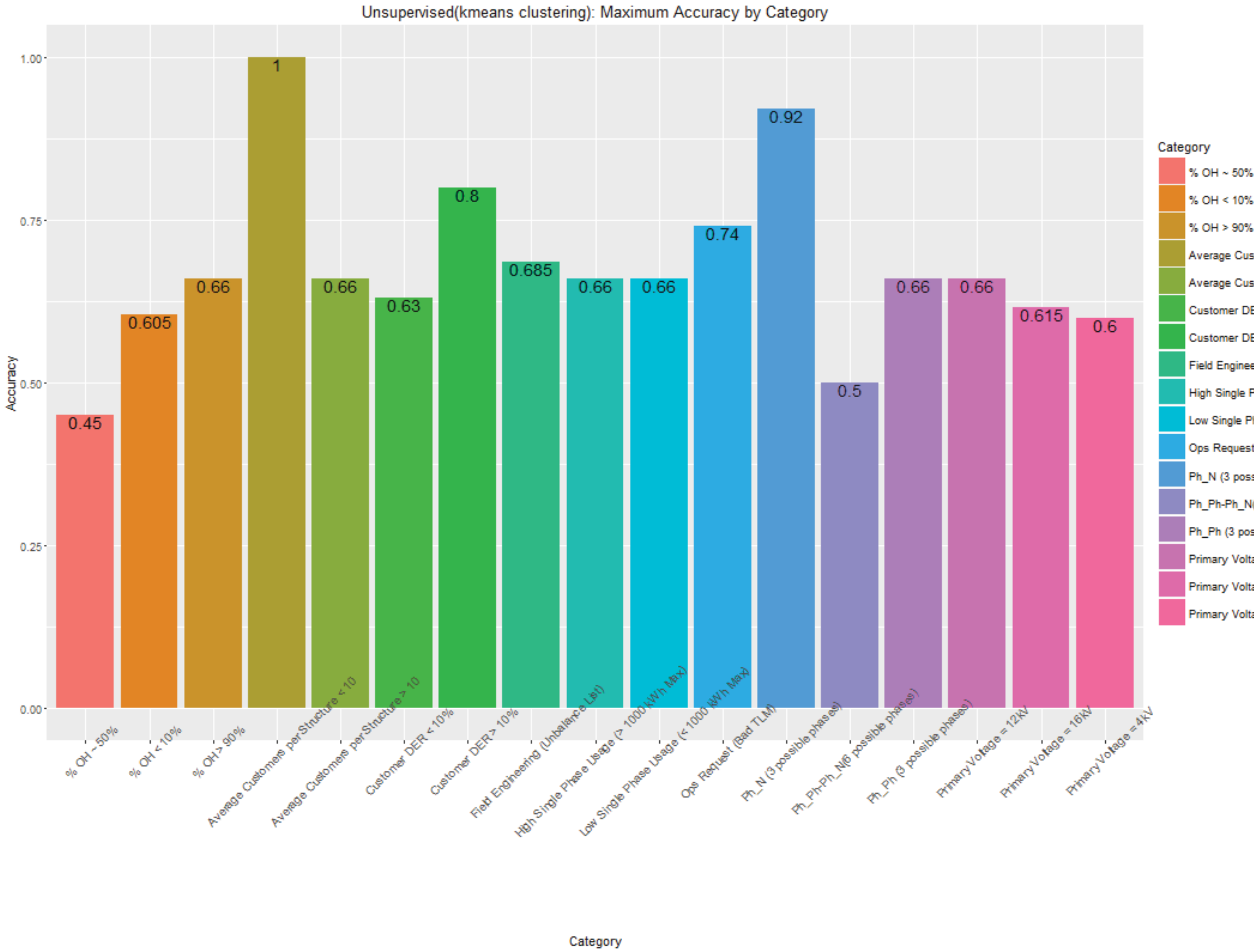
#### 3.2.1.1 EPRI's Phase-to-Meter Correlation Algorithm

The Electric Power Research Institute (EPRI) algorithm was evaluated on two distribution circuits. When aggregated at the node level (two-phase tap off the main line), the accuracy rate of predicting the phase connection of a meter was 69% and 74%, respectively, for the two circuits. At a more granular level, the accuracy rates dropped to 48% and 52%, respectively, for the two circuits when aggregated at the service transformer level.

The accuracy rate of the phase connection predictions tended to rise as the number of meters whose energy consumption was aggregated together increased. This trend was observed at both the transformer and at the device level, a two-phase tap off the main three-phase line. For one circuit, the accuracy rate ranged from 40% to 75% for 10 or fewer meters grouped together at a service transformer, versus 100% when there were groupings of 70 or more meters at the device level. For the other circuit, the accuracy rate ranged from 11% to 50% for 49 or fewer meters grouped together at either the transformer or 2-phase tap, versus 100% when there were groupings of 50 or more meters on a 2-phase tap.

### 3.2.1.2 Vendor's Algorithms

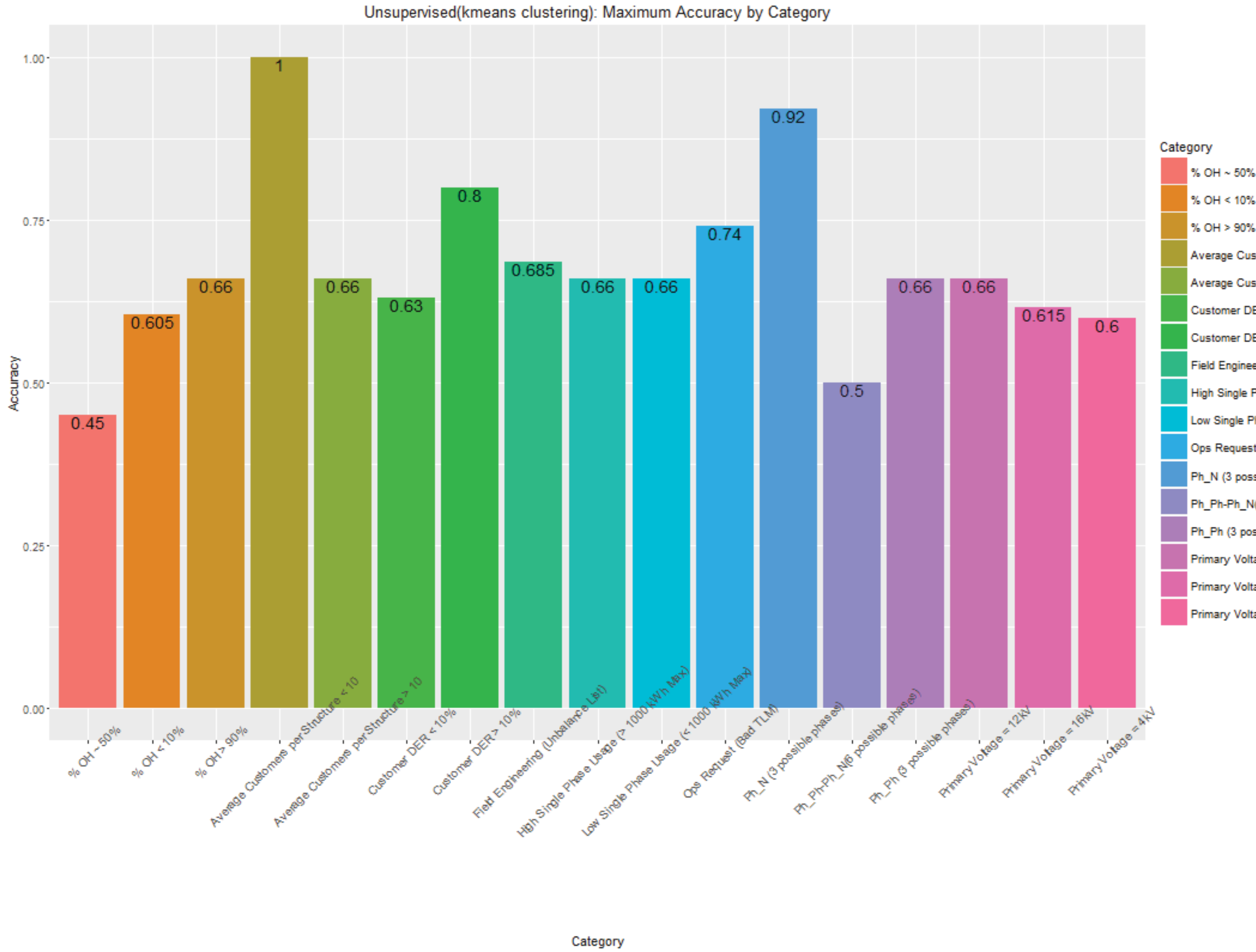
The vendor's solution used supervised and unsupervised machine-learning algorithms. These algorithms were evaluated on 23 distribution circuits. The accuracy of the results for each test circuit varied because of the algorithms' dependency on meter data for each month used. For some months, the results had higher accuracy than for other months for the same circuit. Therefore, only the maximum accuracy levels achieved per circuit and category are reported.



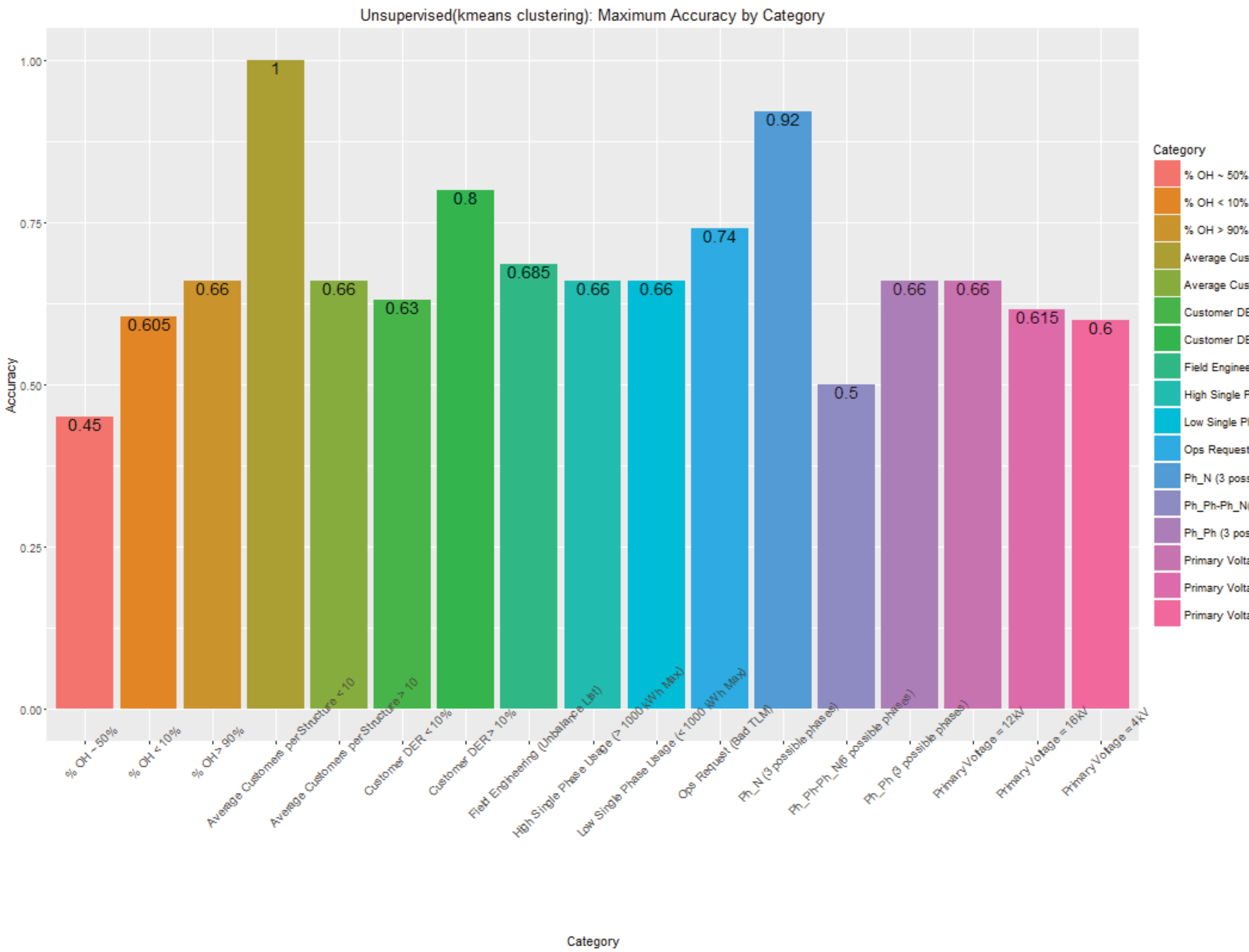

shows the maximum averaged results of the 23 test circuits across the 7 categories and category combinations.

**Unsupervised Machine-Learning Algorithm**

As can be seen in




, the unsupervised algorithm had accuracy levels ranging from 45% all the way to 100%. However, the average accuracy across all circuits was calculated to be 66%. Although this is better than SCE's current default level of 33% for circuits with three possible phase combinations, it still did not achieve the results desired.




also indicates that the majority of categories had a similar average maximum accuracy, with a few exceptions. On the low end, one exception was the circuits in the category with a mixture of overhead and underground (50/50) circuits, and also under the 6 possible phase connections. In this category, it was more difficult for the algorithm to accurately identify the phasing due to two factors: 1) the additional number of grouping possibilities; and 2) the fact that the voltages are less independent, which causes extremely similar voltages. On the high end, it can be seen that the phase-to-neutral (Ph/N) with average number of customers per structure of <10 performed well. Evaluated separately, the Ph/N category performed well due to the independence of phase voltages, making it easier to distinguish between phases. The average number of customers per structure <10 category also had some high performers, which could be attributed to a lower chance for data errors due to a smaller population.

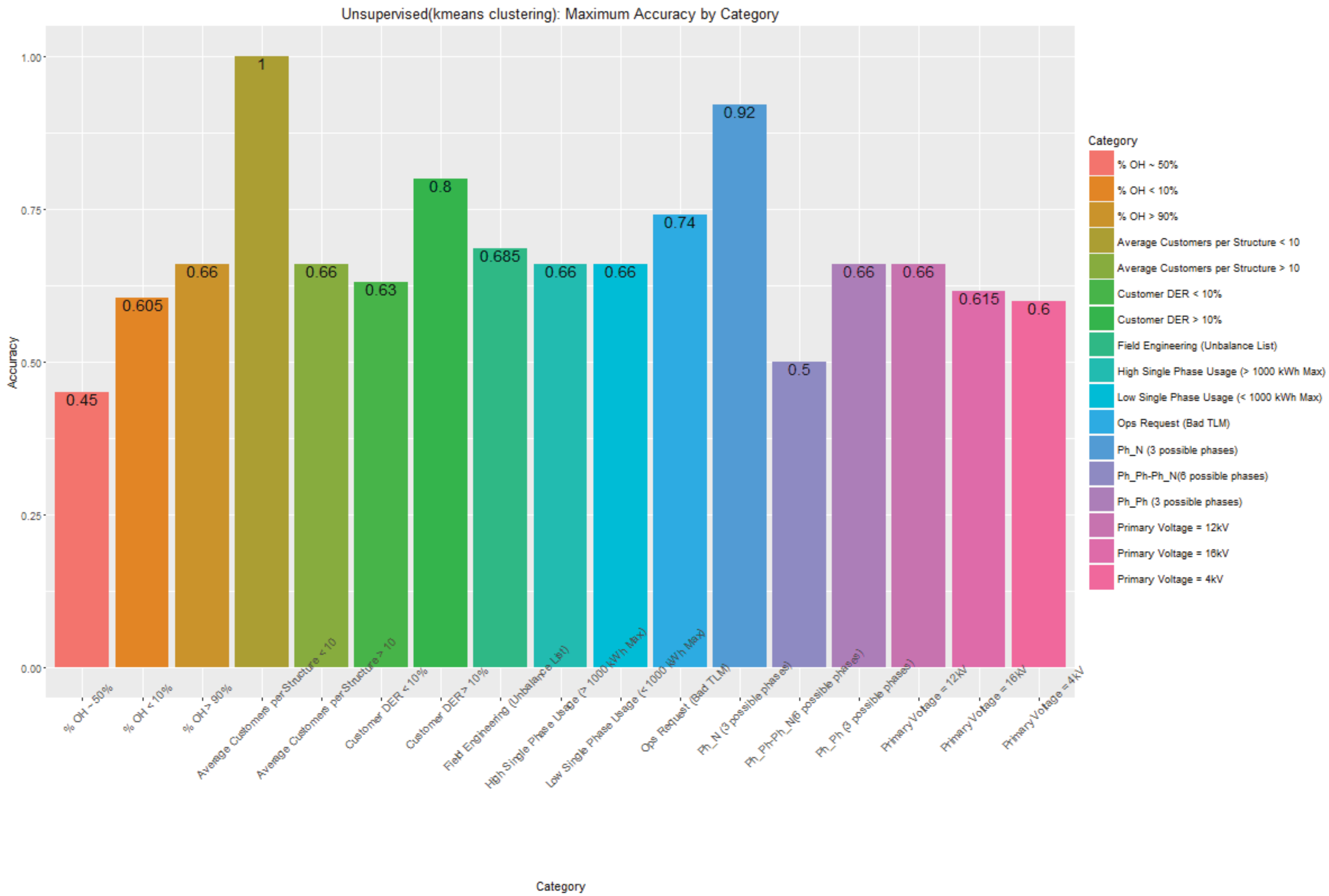



**Figure 5. Unsupervised Algorithm Results of 23 Test Circuits Across Seven Categories**

**Supervised Machine-Learning Algorithm**

Figure 6 shows the accuracy of the supervised algorithm results. As can be seen, it performed better than the unsupervised approach, achieving an average maximum accuracy across all circuits of 86%. The chart also shows that the supervised algorithm performed consistently well across the categories with one main exception, similar to the exception in the unsupervised model. The six-phase (phase-to-phase and phase-to-neutral) combination category had the lowest accuracy, at 52%. This speaks to the interdependency of the phases and the similarity of their voltages. The other key aspect to note about the supervised algorithm is that it requires training data. The results shown were generated using 10% training data derived from field verification. The training data must be highly accurate or the results will have very low accuracy.

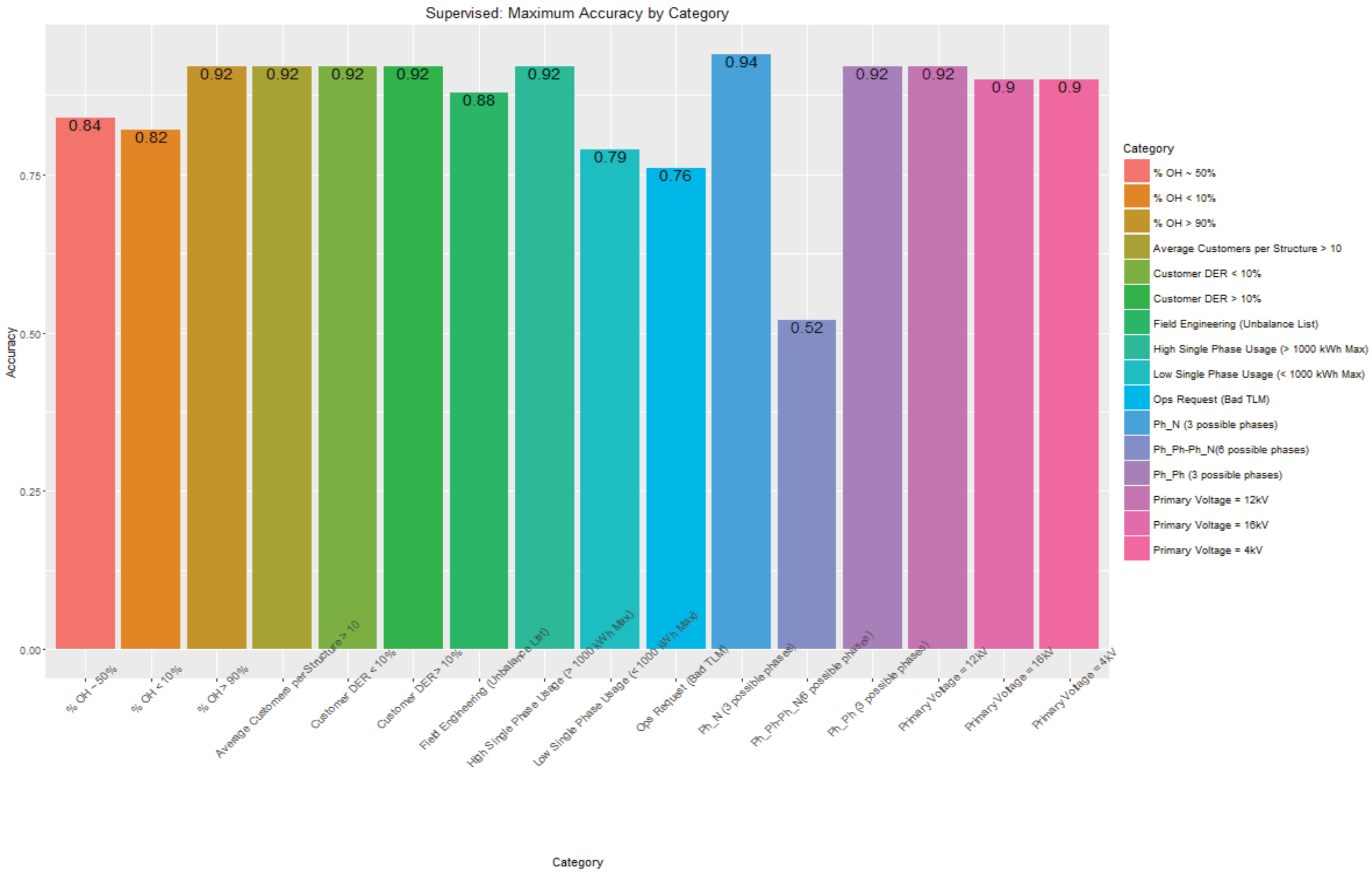



Figure 6. Supervised Algorithm Results of 23 Test Circuits Across Seven Categories

**Enhanced Unsupervised Machine-Learning Algorithm**

Considering the results for the unsupervised and supervised algorithms, the focus turned to improving the unsupervised algorithm. The driver for this was the fact that it is much easier to implement since it does not depend on training data. Therefore, effort was spent on improving the lower average performance of the unsupervised algorithm, which was 66% averaged across the 23 circuits.

The enhanced unsupervised model using a dimensionality reduction technique produced far better results. A visual comparison is shown below.

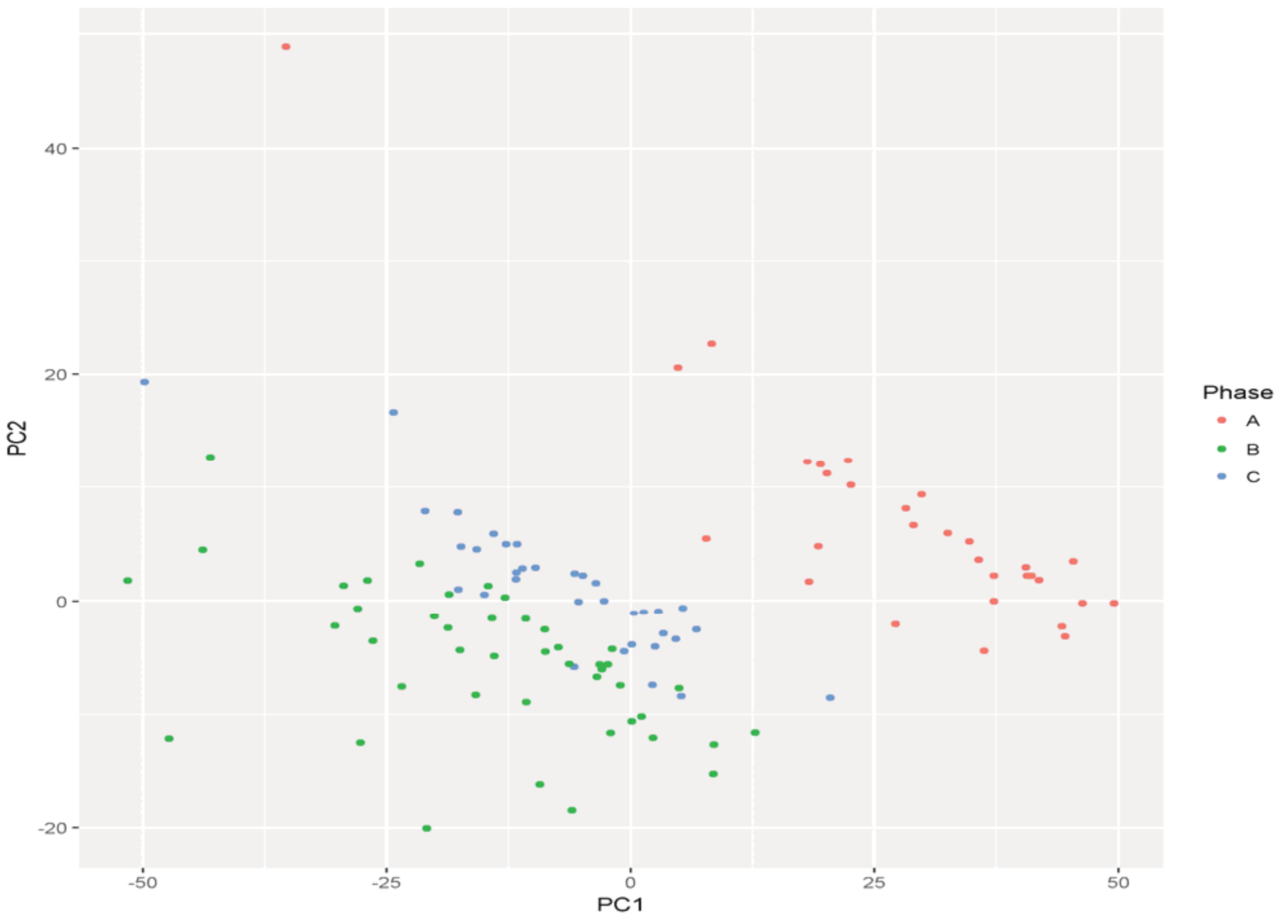



**Figure 7. Example of an Unsupervised Plot for a Circuit**


Figure 8. Example of an Enhanced Unsupervised Plot for the Same Circuit in Figure 7

As can be seen by the figures above, the plot using a dimensionality reduction technique in Figure 8 makes a much more distinct separation between the appropriate phase groupings versus principal component analysis in Figure 7.

In addition, leveraging transformer/circuit connectivity information, circuits with six possible phase combinations were split into two separate analyses. Smart meter data for the phase-to-phase (Ph/Ph)-connected transformers were run through the algorithm separately from phase-to-neutral (PH/N)-connected transformers for each circuit. Therefore, each transformer was assigned to one of three possible phase combinations (Ph/Ph or PH/N). The results then were recombined to give the phasing for the entire circuit.

Based on Figure 9, it can be seen that the new methodology enhanced the performance of the unsupervised algorithm. The enhanced unsupervised algorithm achieved an 80% averaged maximum accuracy across the 23 test circuits. This was a 14% overall improvement over the original unsupervised model. Once again, the Ph/N circuits performed well, achieving a 90% averaged accuracy. The unbalanced circuits along with the 4-kV circuits also achieved accuracies of over 90%. In addition, others such as the Ph/Ph and Ph/N mixed category saw improvement, reaching an accuracy of 81%.

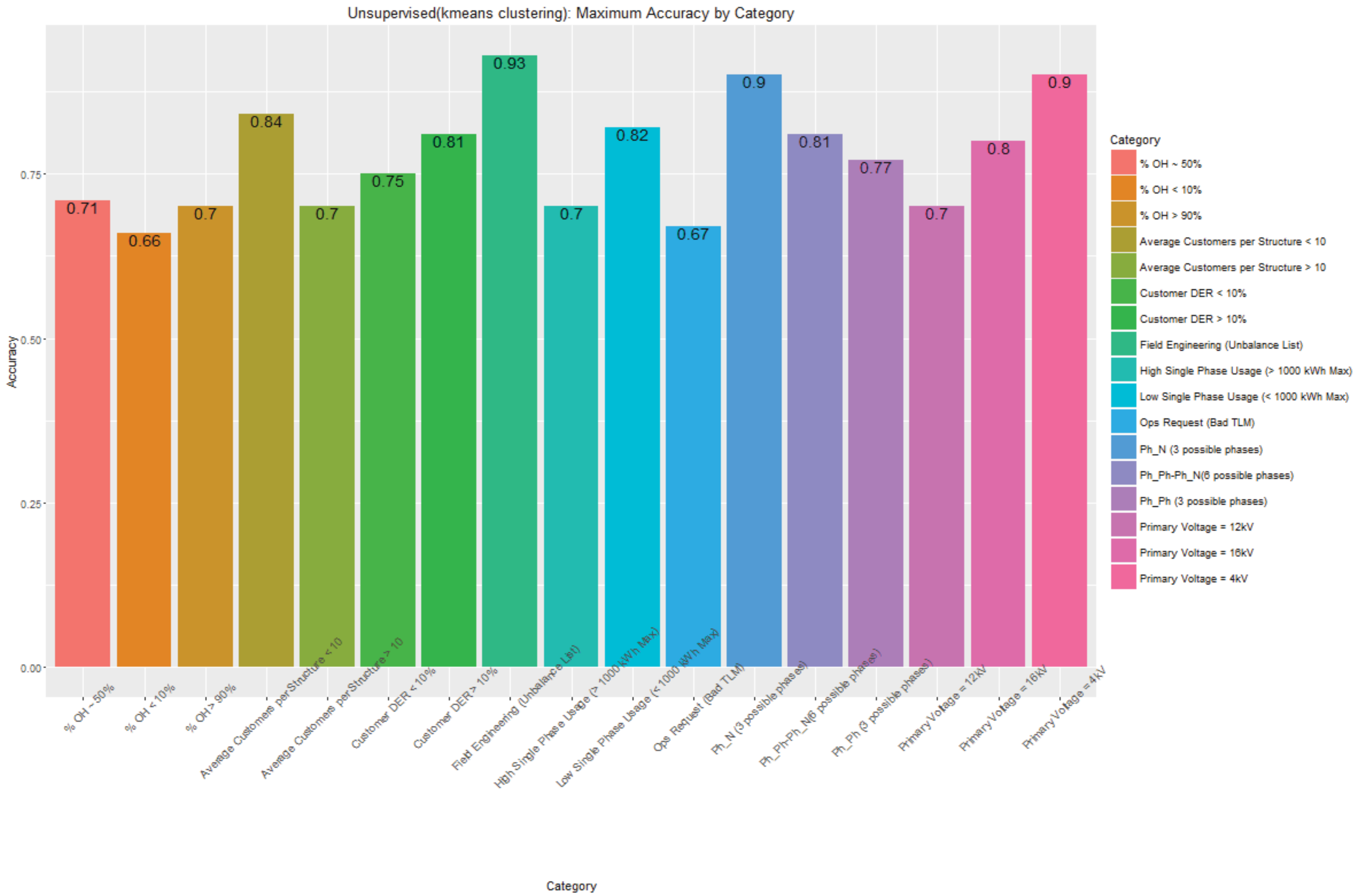



**Figure 9. Enhanced Unsupervised Algorithm Results of 23 Test Circuits Across Seven Categories**

Overall, the supervised and enhanced unsupervised algorithms provided a substantial improvement over the current state of phasing information for SCE's distribution system, with both algorithms achieving an averaged 80% accuracy or more. The project results, based on the previous analysis discussed above, also indicated that the algorithms were largely unaffected by the circuit category with two major exceptions. The first involved circuits with a mixture of Ph/Ph and Ph/N connections, while the second involved highly balanced circuits. These categories saw accuracies as low as 45% to 52% for both the original unsupervised and supervised algorithms. In both cases, there was little voltage separation, which is the fundamental basis on which the algorithms operate. Therefore, these categories are slightly more challenging than the others. Despite the challenges, the enhanced unsupervised algorithm brought the accuracies up to the 70% to 80% range.

The table below summarizes the averaged accuracy of the results of the Electric Power Research Institute's (EPRI's) algorithm and the vendor's supervised, unsupervised, and enhanced unsupervised algorithms.

| **Algorithm Type** | **Maximum Averaged Accuracy (%)** |
|---|---|
| EPRI | 50% |
| Supervised | 86% |
| Unsupervised | 66% |
| Enhanced Unsupervised | 80% |

**Table 6. Summary of the Accuracy of the Phase-to-Meter Correlation Algorithm Results**

## 3.3 Technical Lessons Learned and Recommendations

There were several important findings identified in this demonstration project. They were mostly related to considerations that need to occur in the implementation of the algorithms in a production environment. Following are some of the key findings.

### 3.3.1 Transformer-to-Meter Correlation

1. Missing data was an issue. During the outage event analysis it was discovered that in ~30% of the cases, the meter <u>did</u> in fact have an outage, although no outage events were in the database for the meter. This problem was solved by a secondary validation of status flags associated with each consumption interval of mismatched meters only.
2. Both the Electric Power Research Institute (EPRI) solution and the vendor's Voltage Signature Analysis algorithms depend on an assumed transformer voltage that is derived from the majority of the existing meters associated with it. Therefore, transformers need three or more meters associated with them in the database.
3. Data quality also was an issue. During the demonstration of the Voltage Signature Analysis algorithms, it was discovered that some transformers were not in the database, making it impossible to identify the correct mapping. In other cases, while the transformer was in the database, there were no meters associated with it and thus no assumed transformer voltage could be made. This problem was solved through changes in processes for installing new or replacement transformers.

4. Some meters had inaccurate geo-coordinates. This inaccuracy affected remapping of these meters, especially when a 500-foot radius from the meter was used in the search for potential transformers. In addition, the variation in geography in SCE's service territory affected the distance relationship between a meter and a transformer. For example, in rural areas, the 500-foot radius to remap mismatched meters had to be increased because in some cases service drops from a transformer were more than 500 feet away.

### 3.3.2 Phase-to-Meter Correlation

1. A factor affecting the algorithms is voltage imbalance between phases, where the larger the imbalance, the higher the accuracy. Therefore, to achieve the best phase identification accuracy, a time period/month should be chosen when the distribution circuit is heavily unbalanced.
2. Two other factors affecting the algorithms' accuracy are the number and type of phase connections. Circuits dominated by phase-to-neutral-connected transformers perform well due to the independence of the phase voltages. Circuits dominated by phase-to-phase-connected transformers may or may not perform as well depending on the loading of each phase. This is due to a strong interdependency between the phases, causing them to be less separable by voltage and hence impacting algorithm performance.
3. Since the supervised and unsupervised algorithms rely on meter voltage data, the location of the meter on the circuit is important, along with the group of meters it belongs to.
4. The enhanced unsupervised algorithm does not require training data, and so it is the preferred solution over the supervised algorithm.
5. The algorithms do not work on circuits with large populations of meters that do not provide voltage information.

## 3.4 Value Proposition

The Advanced Grid Capabilities Using Smart Meter Data Project provided considerable benefits to both SCE and its customers. It enabled the use of existing data sources and infrastructure, including Advanced Metering Infrastructure, circuit asset information, Supervisory Control and Data Acquisition, etc., to improve records of both transformer-to-meter correlations and electric phase-to-meter correlations. Utilization of the project solutions' algorithms eliminated labor-intensive activities such as field verification of phase-to-meter and transformer-to-meter associations for planning and load switching operations. The algorithms also improved transformer load management, timely and accurate customer notifications about power outages and restorations, etc. In addition, other analytics such as transformer loading, load switching, power flow modeling, etc., are highly dependent on good transformer-to-meter and phase-to-meter correlations.

## 3.5 Metrics

**Maintain/Reduce Operations and Maintenance Costs**

The improvements in transformer-to-meter and phase-to-meter mapping can reduce operations and maintenance costs from improved efficiencies in grid management and reduction in field work. Since these solutions are software applications that draw on and use existing data, they can improve connectivity records without human intervention. Accurate transformer/meter mapping helps planners and engineers better manage transformer loads and potentially extend transformer life. It also improves outage management, customer notifications, and reliability reporting. One direct cost that can be avoided is the payment made when customers are not notified prior to a planned outage. Better transformer/meter mapping can reduce this cost.

Accurate phase/meter mapping can greatly improve load flow modeling, load balancing on feeders, optimization of distribution asset use, state estimation, etc.

**Increased Use of Cost-Effective Digital Information and Control Technology to Improve Reliability, Security, and Efficiency of the Electric Grid (Public Utilities Code § 8360)**

Both the transformer/meter and phase/meter solutions are a highly cost-effective method of using digital information to improve connectivity records. The solutions are primarily derived from smart meter data to provide fairly accurate results that then can be used to improve the reliability and efficiency of the distribution grid.

**Number of Information Sharing Forums Held**

SCE participated in many information-sharing engagements for this project. Project staff coauthored a technical paper on phase identification[2] that was published by the Institute of Electrical and Electronics Engineers (IEEE), and also discussed the phase identification and transformer/meter correlation solutions with utilities both inside and outside of California. Separately, the EPRI prepared and published a project report[3] on its transformer-to-meter and phase-to-meter correlation solutions and findings for this project. SCE also supported a presentation of the phase identification solution at the DistribuTECH utility industry conference.

**Technology Transfer**

The project's solutions successfully demonstrated that they could improve transformer-to-meter and phase-to-meter connectivity records. As a result, SCE plans to implement the vendor's solutions in the production environment for use by Grid Operations and Field Engineering staff. Note that the vendor solutions demonstrated are propriety and contain intellectual property owned by the vendor. Any technology or knowledge transfer to other utilities or grid analytics vendors is the vendor's sole responsibility.

[2] IEEE paper: *Phase Identification in Electric Power Distribution Systems by Clustering of Smart Meter Data*, by Nanpeng Yu, Joshua Davis, dated 2017.

[3] EPRI Report: *Data Analytic Methods and Demonstration to Link AMI Meters to a Transformer and to a Phase*, by Jared Green, dated 2015.

# Glossary

| Term | Definition |
|---|---|
| Averaged accuracy | It is calculated by taking the maximum accuracy achieved for all test circuits using several months of meter data and averaging it over all the test circuits. |
| Mismatched meter | Incorrect mapping of a meter to a transformer in existing records |
| Mismatch accuracy | Ability of the algorithm to correctly identify meters that do not match the referenced transformer |
| Remap | Association of a meter to a new transformer |
| Remap accuracy | Ability of the algorithm to correctly remap mismatched meters to the correct transformer |

# List of Acronyms

| | |
|---|---|
| DER | Distributed Energy Resources |
| EPIC | Electric Program Investment Charge |
| EPRI | Electric Power Research Institute |
| IEEE | Institute of Electrical and Electronics Engineers |
| kV | Kilovolt |
| kWh | Kilowatt-Hours |
| OH | Overhead Circuit |
| PCA | Principal Component Analysis |
| Ph/Ph | Phase-to-Phase |
| Ph/N | Phase-to-Neutral |
| PV | Photovoltaic |
| SCADA | Supervisory Control and Data Acquisition |
| SCE | Southern California Edison |
| UG | Underground Circuit |

# Remote Intelligent Switcher Final Project Report

Developed by

SCE Transmission & Distribution, Grid Technology & Modernization

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# Acknowledgments

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# Table of Contents

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# 1 Executive Summary

Recent improvements in electric utility distribution automation system technologies have occurred at the individual device or component level. However, a gap currently exists in addressing these individual technologies at the integrated system level for capabilities such as advanced wireless communication; intelligent controller and protection devices; and state-of-the art sensing devices.

To help address this gap, the Remote Intelligent Switch (RIS) Project included the use of a new automated distribution circuit switching scheme. This work was undertaken to demonstrate the ability of the RIS to aid in troubleshooting efforts that minimize the number of customers impacted by faults and also provide faster customer load restoration.

# 2 Project Summary

The Remote Intelligent Switch (RIS) represents an important component of Southern California Edison's (SCE) Grid Modernization Plan. This technology offers advanced automation for fault detection, isolation, and auto circuit reconfiguration. It also provides bi-directional protection and incorporates a greater level of automatic data measurement and communication (telemetry).

The RIS solution needs to be scalable, where more than two fault interrupters are embedded per circuit and more than two circuits are included in the scheme.

SCE's key objectives for the project, all successfully accomplished, were to:

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

This project also initially included work to integrate advanced control systems, modern wireless communication systems, and the latest breakthroughs in distribution equipment and sensing technology to demonstrate a complete system design that would be a standard for distribution automation and advanced distribution equipment. In December 2016, five RIS devices were commissioned for a pilot demonstration at SCE's Johanna Substation on the Poker 12-kV and Bingo 12-kV circuits. SCE will continue to monitor the results and consider this for future deployment.

Per the Electric Program Investment Charge (EPIC) Investment Framework for Utilities (Figure 1), this project addresses system safety and reliability by providing an automated fault sectioned and restoration system. Project testing demonstrated that the system can reduce outage durations, bring substation-style protection to the distribution system, and provide improved situational awareness of the grid through automatic data measurement and communication (telemetry).

The RIS project work also supports the Grid Modernization and Optimization strategic goals by demonstrating the next generation of grid technology that aims to implement the "self-healing" circuit concept. The system utilizes the latest generation of controller hardware technology that integrates Programmable Logic Controller (PLC), protection relay, and communication functionality (supporting multiple protocols) into one unit. This enables automated switching decisions without operator intervention and brings SCE one step closer to the future of grid operations.


Figure 1. EPIC Investment Framework for Utilities

## 2.1 Problem Statement

SCE's current distribution automation technology relies heavily on human intervention and an aging technology architecture. During a fault condition, it can take several minutes (or longer during storm conditions) to isolate one or more faults. The current automated switching scheme, switch-and-a-half (1.5), is only capable of automatically isolating half of the load on an affected circuit. In addition, the technology architecture used by SCE's electric system assets is nearing the end of its life cycle, and needs re-engineering for the modern era of grid technology.

The Remote Intelligent Switch (RIS) Project demonstrated an advanced distribution automation switching system that provides circuits with self-healing capabilities without operator intervention. This system is capable of reducing System Average Interruption Duration Index (SAIDI) and Momentary Average Interruption Frequency Index (MAIFI), and providing improved situational awareness through increased telemetry.

## 2.2 Project Scope

To better understand the Remote Intelligent Switch (RIS) Project, it is valuable to briefly explain SCE's distribution system design and how it responds to fault conditions.

SCE's electric distribution system employs a radial feeder design from the substation bus. Each circuit is typically designed with open tie switches to neighboring radial circuits. The number of ties is sufficient to prevent overload of the tie circuits during load transfers under abnormal conditions. Use of these tie switches can occur for maintenance, faulted circuit scenarios, and under storm conditions. Networked, or parallel, circuit operation is not typically employed.

**When a fault occurs on the existing primary system**, in most situations the circuit's CB (circuit breaker) interrupts the fault, resulting in an entire circuit outage (temporary or permanent). When a fault occurs on a circuit equipped with an RIS system, it is intended that the nearest interrupting device – which could be an RIS – acts to clear the fault, thus minimizing the amount of load interrupted.

**For a fault in the zone nearest to the feeder's CB**, the fault is interrupted by the CB using the traditional time-over-current protection curves method. Fault interrupters embedded on the feeders will not have seen the fault, so they will not operate. In this scenario, the feeder's CBs perform reclose operations to test the circuit, and SCE investigates use of a loss-of-voltage feature in the downstream interrupters to trigger isolation activities. Once fault isolation occurs, the Instantaneous Capacity Restoration Check (ICRC) algorithm is triggered, utilizing SCE's existing low-speed communication system, to determine subsequent restoration activities available. The tie switch is used to accomplish the load restoration recommendation. After any tie switch closing action for load restoration purposes, the tie switch and closed downstream interrupters reverse their fault sensing to address the new (temporary) circuit reconfiguration.

**For a fault in a zone downstream from an interrupter**, the fault is interrupted by either a traditional time-over-current protection curves method or a fixed-time current limit method. In this scenario, SCE investigates use of multiple communication systems for isolation actions to be taken by downstream interrupters. SCE also investigates use of a loss-of-voltage feature in the downstream interrupters to trigger isolation activities. In addition, the interrupting fault interrupter performs test operations. Once fault isolation occurs by whichever method, the ICRC algorithm is triggered to determine subsequent restoration activities available. The tie switch is used to accomplish the load restoration recommendation. Again, after any tie switch closing action for load restoration purposes, the tie switch and closed downstream interrupters reverse their fault sensing to address the new (temporary) circuit reconfiguration.

In the RIS project, SCE demonstrated an advanced distribution automated switching scheme from Siemens utilizing various communication configurations that govern the RIS' feature set. All demonstrations consisted of the same circuit configuration and parameters. SCE is evaluating plans to expand the existing demonstration installation from 5 to 11 devices. This expansion would include an operational group consisting of SCE's Poker 12-kV, Bingo 12-kV, and Yahtzee 12-kV circuits. The remaining three devices would establish a new operational group consisting of the Pistachio 12-kV and Tetris 12-kV circuits.

### 2.2.1 Project Tasks and System Testing Demonstrations

The Remote Intelligent Switch (RIS) Project consisted of the following major tasks and testing demonstrations. All of these were successfully completed.

- System configuration to include the RIS operational scheme, controller programming, and overall scheme testing
- Factory hardware configuration and testing of integrated system components
- Factory Acceptance Testing (FAT) demonstration of RIS components at the vendor's facility
- SCE laboratory initial setup and configuration, including Supervisory Control and Data Acquisition System (SCADA) communication and Distribution Management System (DMS) integration
- Site Acceptance Testing (SAT) demonstration at SCE's laboratory
- SCE laboratory support for laboratory testing of alternative network topology scenarios
- SCE Equipment Demonstration Evaluation Facility (EDEF) initial setup and configuration, including SCADA communication and DMS integration
- SCE EDEF field testing and demonstration
- Commissioning for RIS pilot demonstration on select SCE distribution circuits

### 2.2.1.1 Factory Acceptance Testing (FAT)

FAT was held at Siemens' Wendell, N.C., facility. FAT lasted approximately 3 days and included 20 SCE subject matter experts (stakeholders) representing 7 cross-functional groups. During this testing cycle, the project team attempted 31 structured tests and 4 unstructured tests. Altogether, the system successfully completed 27 tests.

The FAT configuration consisted of five pre-prototype RIS units in an operational group of two circuits. Siemens utilized an Omicron software setup that provided coordinated injections for each RIS unit and supplied pre-programed post-fault results. While not an ideal test setup, this test cycle allowed the team to uncover system programming gaps.

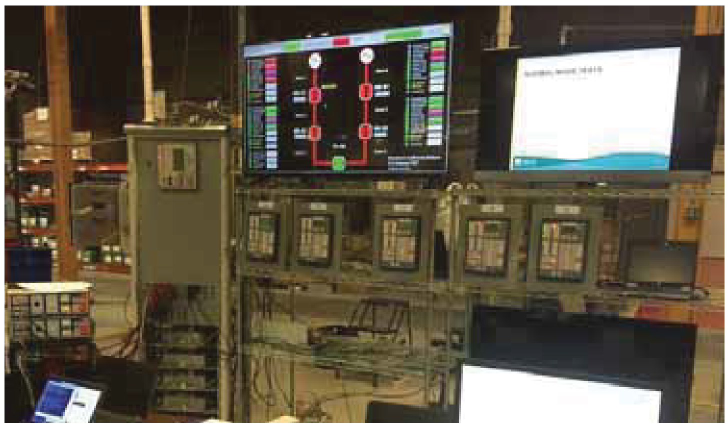

**Figure 2. Test Setup for Factory Acceptance Testing**

### 2.2.1.2 Site Acceptance Testing (SAT) 1

SAT Demonstration 1 took place at SCE's Equipment Demonstration Evaluation Facility in Westminster, CA. SAT 1 lasted approximately 5 days and included 28 company subject matter experts (stakeholders) representing 8 cross-functional groups. During this testing cycle, the team attempted 39 structured tests. Altogether, the system successfully completed 27 tests.

The SAT configuration included five prototype RIS units in an operational group of two circuits. These units were installed in real-world conditions on a test circuit within a controlled environment. Similar to Siemens' Omicron setup, SCE utilized individual Dobles (current amplifiers) that provided injections for each RIS unit and coordinated the injections between units. A centralized software operator manipulated injections based on system conditions and response. This testing cycle allowed the team to perform a full end-to-end test, incorporating all RIS hardware and support systems.

Figure 3. RIS Devices Installed for Site Acceptance Testing

#### *2.2.1.3 Site Acceptance Testing (SAT) 2*

SAT Demonstration 2 took place at SCE's Integrated Innovation and Modernization Laboratory in Westminster, CA. This SAT lasted approximately 10 days and included 30 company subject matter experts (stakeholders) representing 8 cross-functional groups. During this testing cycle, the team attempted 81 structured tests. Altogether, the system successfully completed 79 of them.

This testing cycle's configuration consisted of five second-generation RIS prototypes in an operational group of two circuits. These units were installed in the SCE laboratory, where they were connected to a real-time load flow simulator supplied by RTDS Technologies Inc. Dobles (current amplifiers) were used to amplify the Real-Time Digital Simulator (RTDS) signals to represent field conditions, and to act as a breaker simulator. Impedance models of SCE's Poker and Bingo circuits (the RIS pilot circuits) were used in the RTDS. This testing cycle allowed the team to evaluate the ability of the RIS logic to address complex scenarios associated with fault types and system conditions.

**Figure 4. Initial RIS and RTDS Laboratory Setup**

## 2.3 Milestones and Deliverables

The Remote Intelligent Switch (RIS) Project completed all scheduled deliverables. SCE successfully demonstrated the RIS concept utilizing decentralized logic on a low-speed communication system.

### 2.3.1 Milestones and Deliverables

- Milestone 1 (January 2015): Controller/Communication System Integration including development of radio Device Code Word (DCW), and successful demonstration of end-to-end communication utilizing SCE's NetComm system
- Milestone 2 (September 2015): Factory Acceptance Testing (FAT) Demonstration 1 of vendor solution, and acceptance based on SCE's criteria
- Milestone 3 (October 2015): Field and substation hardware delivery
- Milestone 4 (November 2015): FAT Demonstration 2 of vendor solution, and acceptance based on SCE's criteria, including any enhancements or resolution of issues identified following FAT Demonstration 1
- Milestone 5 (December 2015): System firmware updates

- Milestone 6 (December 2015): Controller/Distribution Management System (DMS) integration, including DMS database and graphical user interface (GUI) configuration and implementation
- Milestone 7 (January 2016): Site Acceptance Testing (SAT) Demonstration 1 of vendor solution, and acceptance based on SCE's criteria
- Milestone 8 (February 2016): SAT Demonstration 2 of vendor solution, and acceptance based on SCE's criteria, including any enhancements or resolution of issues identified following SAT Demonstration 1
- Milestone 9 (March-May 2016): Demonstration at SCE's Equipment Demonstration Evaluation Facility, and acceptance of vendor solution to include all hardware on an energized 12-kV distribution system

Additional milestones included deliveries of the system logic addressing RIS technical specifications; control cabinet hardware design and prototyping; RIS system training; and RIS project documentation.

Also, the project team prepared technical manuals, operational bulletins, and job aids, and provided them to SCE organizational groups involved with field operations.

**Figure 5. RIS 3422 Installed on the Poker 12-kV Circuit**

# 3 Project Results

## 3.1 Achievements

In December 2016, the project team successfully commissioned the Remote Intelligent Switch (RIS) pilot system on SCE's Poker 12-kV and Bingo 12-kV circuits. The system demonstrated the ability to automatically identify a fault condition, isolate the fault condition within a load block, and automatically restore power to affected load blocks without the intervention of Grid Operations. This served as the culmination of this project by demonstrating the RIS concept on a live distribution system. It thus displayed the self-healing circuit concept and its ability to benefit customer reliability, a key strategic goal under the EPIC Investment Framework for Utilities (Figure 1).

From a technical standpoint, the project accomplishments highlight the Grid Modernization and Optimization strategic goals outlined by EPIC. The team identified and implemented a hardware/software combination that supports extensive distributed processing capabilities while incorporating standardized relay functionality. In addition, the team overcame limitations of SCE's Netcomm communication system, a serial Distributed Network Protocol (DNP)-based system with a limited 9600 bps transfer rate, utilizing the DNP Router concept. The DNP Router acts as an intermediary device, coordinating communication between RIS end-points and mimicking publisher-subscriber communications on the DNP protocol.

Additional demonstrations are needed to refine the low-speed architecture, evaluate high-speed architecture, and expand on supported circuit topology. However, the RIS system is currently capable of being deployed by SCE or other utilities in a manner similar to the existing Poker 12-kV and Bingo12-kV circuit pilots. Based on the positive results of this project, SCE is considering future work to incorporate a Computer-Aided Design (CAD) module into the demonstration to support more complex system deployments.

## 3.2 Value Proposition

The Remote Intelligent Switch (RIS) Project demonstrated the value of RIS technology to SCE and its customers through the ability to:

- Provide circuits with self-healing capabilities without operator intervention;
- Increase system reliability and thus decrease the frequency and duration of power outages; and
- Improve operators' awareness of conditions on the entire system through a greater level of automatic data measurement and communication (telemetry).

These capabilities represent an important component of SCE's Grid Modernization Plan and support key elements included in the EPICInvestment Framework for Utilities (Figure 1).

## 3.3 Metrics

The Remote Intelligent Switch (RIS) Project addressed the following metrics:

- **Maintenance/reduction of operations and maintenance costs:** The project demonstrated that the RIS provides advanced automation for fault detection, isolation, and auto circuit reconfiguration, thus reducing the need for operator intervention and for field support to perform switching operations.
- **Outage number, frequency and duration reductions:** The RIS system met the project objectives of 1) ensuring that one-third or greater of circuit load can be quickly restored after overcurrent conditions occur; and 2) when possible, ensuring that one-third or greater of circuit load never experiences service interruptions as a result of a fault condition.

## 3.4 Technical Lessons Learned and Recommendations

### 3.4.1 De-Centralized RIS Logic

Configuration of the Remote Intelligent Switch (RIS) logic was a challenging and extensive process. In early 2016, during initial project activities, new stakeholder engagement resulted in additional system requirements. After reviewing the complexity of the various conditions, it became apparent to the project team that the initial logic approach was insufficient. Ultimately, the team redesigned the logic approximately 10 times.

For the first system logic attempt, the team focused on basic fault scenarios where the system started from an initial pre-defined, ideal configuration. However, during pre-Factory Acceptance Testing (FAT) evaluations with stakeholders, the team realized that the system needed the ability to adapt to various initial/starting conditions, as well as support greater fault complexities. For example, a variation of an initial/starting condition preceding a fault could consist of Zone 4 being temporarily transferred to Circuit A where Switch B1 acts as the circuit tie switch. To address these new operational conditions, it was clear that the situational-based logic approach (where programming consisted of situations and the corresponding resultant) was insufficient.

The team determined it needed a system design that could support dynamic configurations while maintaining operational consistency. This change in direction led to a rules-based logic. To support dynamic circuit topologies, the rules-based logic is governed by process control flags generated by real-time telemetry and circuit conditions. The resulting flags trigger corresponding pre-defined operational rules, based on standardized grid operation practices, which limit RIS outcomes. For example, these rules control the coordination limits, zone isolation, zone transfer limits, and reserve capacity determination. This approach provides Grid Operations with a consistent and predictable RIS operation/response that can be determined via several key self-directed questions.

Throughout the remainder of project activities, the logic was continuously enhanced to address system issues and incorporate additional functionality. For instance, during FAT, it was determined that the system needed to include a feature referred to as the “V Check Rule,” which prevents closure of an open/tripped RIS between two de-energized lines. Various system demonstrations also resulted in specific logic to address and correct operational errors due to miscoordination between protection elements on devices.

Lessons learned throughout the demonstrations resulted in significant changes to the RIS concept. The logic gates that compose the system grew from 831 for the initial concept to 1,581 for the last logic iteration. The shift to a rules-based logic design expanded system capabilities, while making system operations predictable and consistent.

### 3.4.2 DNP Router

In order to leverage SCE’s Netcomm system and perform peer-to-peer data exchange over the Distributed Network Protocol (DNP), the project team developed a new DNP Router concept. A DNP Router allows a DNP-based communication system to mimic a publisher-subscriber communication mode. It does this by polling individual controllers in the field and sending (publishing) the acquired information back to assigned (subscribed) system components via commands. However, the legacy Netcomm communication system has a number of limitations, which include packet size and bandwidth capacity. These factors minimized the ability to use unsolicited response from the field devices. Unlike conventional Remote Terminal Units (RTUs), the DNP Router should have the capability to dynamically determine which devices to poll and in what sequence.

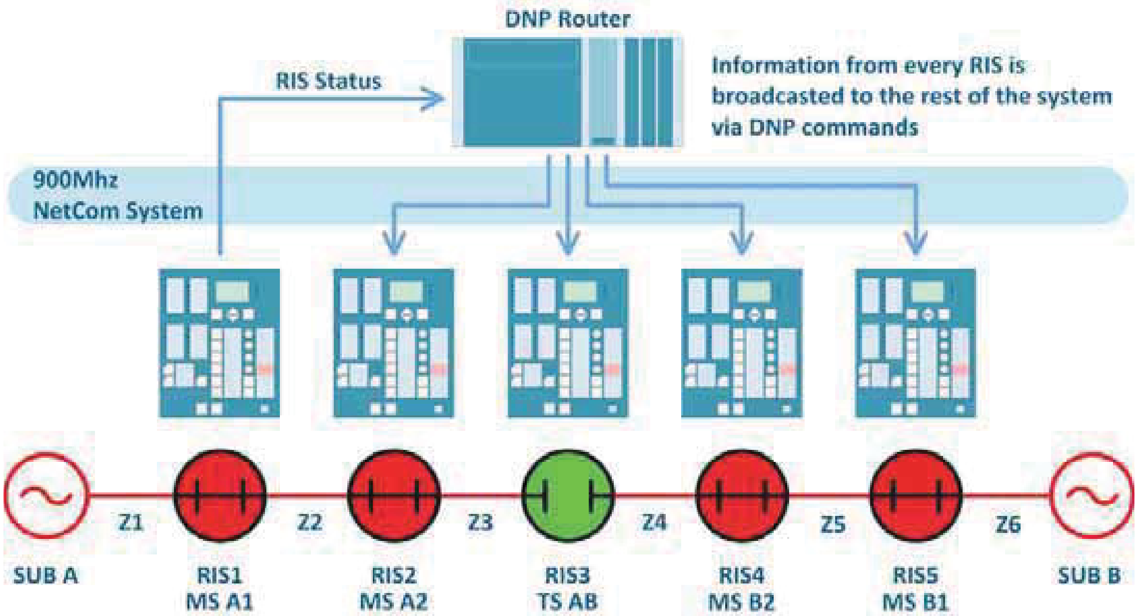


Figure 6. DNP Router Concept

The first version of the DNP Router application incorporated a conventional RTU configuration. This design established a connection to all individual Remote Intelligent Switch (RIS) controllers and received unsolicited responses. Then the router application resent the previously received status to the rest of the system via DNP commands. While this approach worked for hardwired connections, when device communication was switched to radio, the router could not communicate to the RIS controllers. This failure was a result of the packet size required to perform an integrity data poll.

The next DNP Router application iteration, called the Sequential Poll-Broadcast approach, polls only certain bits at a time, and does not rely on spontaneous polling or transmission of data packets. While this approach did work, the total processing time did not meet project requirements.

After a series of tests, the project team realized that the data exchange mechanism could be improved to skip unnecessary steps in data processing, leading to improved system flexibility by autonomously self-adjusting to system conditions. Communication and fault supervision parameters were added to the DNP Router's applications in an effort to make the sequential process more dynamic and based on current system conditions. While this improved the data processing time, the average time still ran longer than acceptable levels.

To improve the processing speed, the router logic needed to be more intelligent and perform the minimum number of steps required to exchange fault data. To accomplish this, the team provided RIS controllers with the ability to govern the router's processing. This enabled the router to accept direction from the RIS controllers on which steps to execute next, and provided the needed boost in data processing and system response time. The system now exceeds SCE's acceptable performance levels, with an average operation time under 3 minutes.

## 3.5 Technology/Knowledge Transfer Plan

The Remote Intelligent Switch (RIS) Project successfully demonstrated next-generation grid technology, part of the Grid Modernization and Optimization strategic goals outlined in EPIC Investment Framework for Utilities (Figure 1). While additional demonstrations are required to refine the RIS low-speed architecture, evaluate high-speed architectures, and expand on supported circuit topology, currently the RIS system is capable of being deployed by SCE or other utilities in a manner similar to the existing Poker and Bingo pilot.

During the RIS pilot deployment, technical manuals, operational bulletins, and job aids were prepared and provided to SCE organizational groups involved with field operations.

## 3.6 Stakeholder Engagement

Starting with the Request for Information (RFI) process, stakeholders served as an integral component of the project, providing input on everything from the technical specifications to hardware design, logic functionality, and operational characteristics.

The project team relied on multiple subject matter experts from numerous cross-functional groups, including:

- Distribution Appartus Engineering
- Distribution Automation
- Field Engineering
- Grid Operations
- Substation Construction & Maintenance (SC&M) Distribution Apparatus, SC&M Relay Test
- IT – Power Systems Control
- Technology Integration (T&D Training)
- Huntington Beach District
- Santa Ana District

The project team held standing meetings to capture and respond to stakeholder expectations. During the twice-monthly technical “Issues/Resolutions” meetings, the project team worked to resolve numerous issues documented in an online ticket tracker. As an example, the Integrated Innovation and Modernization organization resolved concerns raised by field personnel by re-designing the RIS control Human Machine Interface (HMI) to incorporate a “modes” concept, thus simplifying device operation. During twice-monthly administrative meetings, the project team focused on coordinating project tasks assigned to stakeholders and their respective organizations. The majority of collaboration occurred during stakeholder participation at Factory Acceptance Testing (FAT), Site Acceptance Testing (SAT), and pilot demonstrations.

# List of Acronyms

| | |
|---|---|
| CAD | Computer-Aided Design |
| CB | Circuit Breaker |
| DCW | Device Code Word |
| DMS | Distributed Management System |
| DNP | Distributed Network Protocol |
| EPIC | Electric Program Investment Charge |
| EDEF | Equipment Demonstration Evaluation Facility |
| FAT | Factory Acceptance Testing |
| GUI | Graphical User Interface |
| HMI | Human Machine Interface |
| ICRC | Instantaneous Capacity Restoration Check |
| kV | Kilovolt |
| MAIFI | Momentary Average Interruption Frequency Index |
| RFI | Request for Information |
| RIS | Remote Intelligent Switch |
| RTDS | Real-Time Digital Simulator |
| RTU | Remote Terminal Unit |
| SAIDI | System Average Interruption Duration Index |
| SAT | Site Acceptance Testing |
| SC&M | Substation Construction & Maintenance |
| SCADA | Supervisory Control and Data Acquisition System |
| SCE | Southern California Edison |

# Intelligent Fuses
# Final Project Report

Developed by

SCE Transmission & Distribution, Grid Technology & Modernization

January 2018

An *EDISON INTERNATIONAL*® Company

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# Acknowledgments

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# 1 Executive Summary

Southern California Edison's (SCE) Integrated Innovation and Modernization Organization is tasked with investigating and evaluating future grid technologies – including the Intelligent Fuse (I-Fuse) – to help reduce System Average Interruption Duration Index (SAIDI), one of the electric utility industry's customer outage reliability indicators.

The goal of the I-Fuse Project involved utilizing a functional, simple, and cost-effective demonstration device, combined with wireless communication, for remote monitoring to assess the ability to improve power system reliability and thus reduce SAIDI.

Project laboratory and vendor factory testing demonstrated the I-Fuse's capability to reclose automatically after it opened, enabling isolation of a downstream fault (meaning a circuit interruption). Testing also indicated that the device would be able to automatically restore impacted customers within seconds in field use. In the event of a permanent fault, the biggest benefit identified was that the fuse would not need to be replaced, but just closed.

Depending on the success of any future field testing of the I-Fuse device, it potentially could become SCE's primary solution for protection and automation of branch line fuses, which protect sections of circuits.

# 2 Project Summary

This project evaluated a lateral (non-mainline) circuit protection strategy using the vendor's custom-designed singe-phase circuit breaker (the Intelligent Fuse, or I-Fuse). Laboratory and vendor factory testing showed this can dramatically improve the way troublemen and field crews respond to lateral faults.

Currently, when a fault occurs on a branched line, fuses are the only type of protection device SCE utilizes. If the current exceeds the fuse's amp rating for a period of time, the fuse blows and isolates the fault. This function works well, but customers' electric service cannot be restored until the fuse is replaced.

Project testing demonstrated that for a temporary fault, the I-Fuse design reclosed to clear the momentary outage, minimizing lost customer outage interruption minutes. For a permanent outage, the testing showed that the I-Fuse design opened and isolated the faulted section. It performed one reclosure before locking out, and if that occurred, the Remote Fault Indicator (RFI) installed beyond the I-Fuse detected the outage and sent an alarm to the Distribution Management System (DMS).

Based on testing the I-Fuse could effectively improve the capability to isolate faulted or degrading system conditions. In doing so, the device could enhance the reliability of the distribution grid by automating branch line protection, and in the event of temporary faults could restore customer service within seconds.

Future plans call for using I-Fuses in SCE service territory regions identified with elevated levels of downed wire events and on long lateral (non-mainline) circuit segments. In addition, SCE circuit application criteria include installation of I-Fuses on lateral circuit segments with ferroresonance limitations for branch fuse applications.

In terms of the Electric Program Investment Charge (EPIC) Investment Framework for Utilities (Figure 1), the I-Fuse addresses customer and circuit reliability because of the potential to reduce SCE's SAIDI and thus increase customer satisfaction. In addition, the probability that the I-Fuse device could save money on labor and equipment associated with replacing blown branch line fuses for momentary outages offers an opportunity to contribute to the affordability strategic goal.

Looking forward, the I-Fuse's potential to also improve the ability to connect distributed generation, or DG (meaning on-site generation) on the distribution system represents one of the key drivers and policies under the EPIC Renewables and Distributed Energy Resources Integration strategic goal.


**Figure 1. EPIC Investment Framework for Utilities**

## 2.1 Problem Statement

SCE currently has thousands of branch line fuses on its distribution system. In the event of a fault, the fuses open and require a field worker to manually replace them. They do not have telemetry (automatic data measurement and communication) capabilities to remotely notify system operators or field crews when and where a branch line fuse is blown.

With Intelligent Fuses (I-Fuses), all faults still would be isolated, but in the event of temporary faults the I-Fuse could restore customer service in seconds, and the fuse would not need replacement.

## 2.2 Project Scope

The I-Fuse Project scope included testing and evaluation at the vendor's (G&W) factory, where it was manufactured. It also was tested to the Institute of Electrical and Electronics Engineers (IEEE) C37.60 Standard at Powertech Lab (one of the largest research and testing labs in North America). Testing at both facilities was successful in indicating that the I-Fuse could improve the reliability of the distribution grid by automating branch line protection.

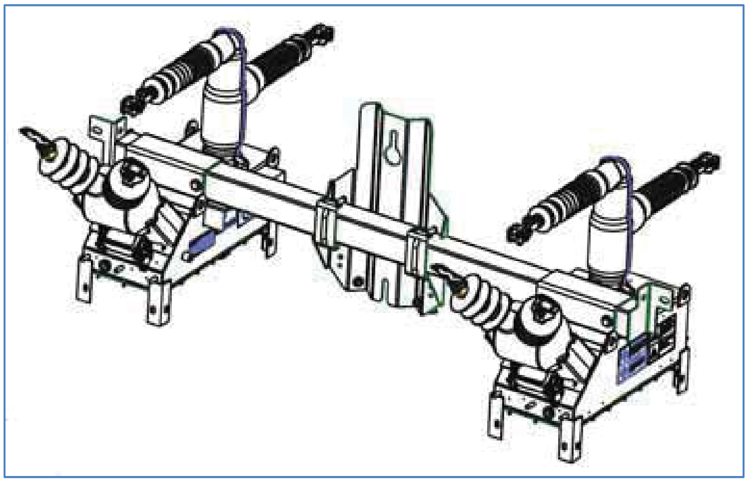

Figure 2. Intelligent Fuses Mounted on Crossarm

### 2.2.1 Project Testing Scenarios

**Scenario 1: Simulated Temporary Fault**

- T (time) = 0: Fault occurs
- T = 100 milliseconds: I-Fuse opens and isolates the fault, and sends an open alarm to the Distribution Management System (DMS)
- T = 15 seconds: I-Fuse recloses, the customers come back online, and the I-Fuse sends a close status

**Project Testing Scenario 2: Simulated Permanent Fault**

- T = 0: Fault occurs
- T = 100 milliseconds: I-Fuse opens
- T = 15 seconds: I-Fuse recloses and locks out due to a permanent fault, and the device sends a lockout status

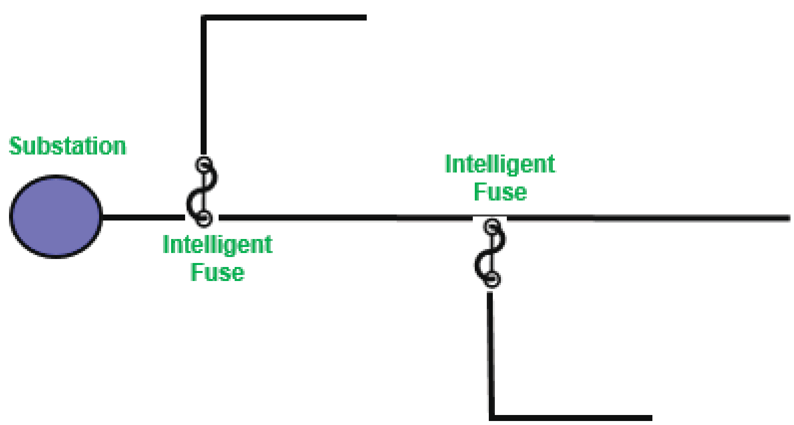


Figure 3. Diagram Showing No Fault on a Lateral Circuit

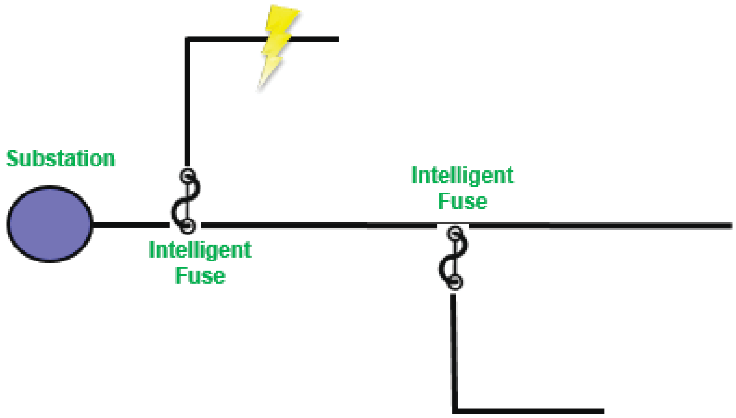


Figure 4. Diagram Showing a Fault on a Lateral Circuit

**Operating Curves for Circuit Protection**

- Solid Material Universe (SMU)-20 Slow (15E, 25E, 40E, 50E, 80E, 100E, 150E, 200E) (E is a fuse rating)
- Relay Curves (101, 105, 133, 135)
- Institute of Electrical and Electronics Engineers (IEEE)/American National Standards Institute (ANSI) Curves
- U Curves
- International Electrotechnical Commission (IEC) Curves

### 2.2.2 Tests Performed

**Controller Operation**

1. Local operation of OPEN/ CLOSE contact positions was successfully tested.
2. Remote command via Wi-Fi of OPEN/CLOSE contact positions was successfully tested.

**Lockout Operation**

1. Local lockout operation was triggered and verified the indicator to show lockout.
2. Remote command via Wi-Fi of lockout operation was triggered and verified status.

**Automatic/Solid Reclosing Relay Status Operation**

1. Sent remote command to automatic reclosing and verified control on automatic mode.
2. Sent remote command to block reclosing and verified control on block mode.

**Communications Protocol Testing**

1. Distributed Network Protocol (DNP) 3.0: The controller was tested with DNP3 Serial and LAN/WAN outstation protocol communications. The controller successfully communicated to Distribution Management System (DMS) using DNP3.
2. International Electrotechnical Commission (IEC) 61850: The controller was not tested for IEC 61850, Manufacturing Message Specification (MMS), and Generic Object Oriented Substation Event (GOOSE).

**DMS Integration**

1. The DMS was tested by SCE's Power System Control Organization.

**Rechargeable Battery**

1. Upon loss of AC (without 120 VAC), the controller was able to operate (OPENED/CLOSED) via Wi-Fi more than 50 times, while DMS communication was enabled and received operation status change.
2. 120 VAC was applied to the controller and verified that the voltage divider charged the supercapacitor.
3. After 120 VAC was applied, the following features were available in minutes. This test verified that the I-Fuse will have telemetry after 20 minutes of energization.
   a. Charge for 1 minute to be able to close and trip after the line is energized
   b. Charge for 10 minutes to enable reclosing
   c. Charge for 20 minutes to enable Supervisory Control and Data Acquisition (SCADA)
   d. Charge for 30 minutes for full supercapacitor back-up capacity

**Wi-Fi Operational Testing**

1. Open the device
2. Close the device
3. Open status
4. Closed status
5. Lockout status
6. Automatic/block status
7. Upload settings
8. Read existing settings
9. Time-current characteristic (TCC) curve
10. AC or DC power status
11. Percentage back-up time available
12. Direction of power flow
13. Current
14. Voltage
15. Communication status (blue light-emitting diode, or LED)
16. Event report
17. Operations counter

### 2.2.3 Additional Functionalities

The following functionalities were included as optional items in the initial I-Fuse Request for Proposal (RFP). However, during project execution, SCE stakeholders requested that these functionalities be requirements of future I-Fuses to ensure they can be utilized throughout SCE's power system.

- **Gang operation:** Ability to operate three separate fuses at the same time using a single control to avoid any potential ferroresonant condition that may occur while energizing and de-energizing the circuit. This can prevent a situation where, if one phase of a lateral (two-phase) wire goes down, the current still travels from the other wire down that line, jumps the transformer, and loops back to the downed wire side.
- **Reclosing scheme with fast curve as the initial trip, and configuration of the reclose to coordinate with the individual transformer fusing:** Capacity to help protect overhead wires from arcing fault damage. Arcing faults can rapidly (in less than 10 cycles, or 0.167 milliseconds) degrade and melt through a conductor, causing a separation. With a fast time-current characteristic (TCC) curve, SCE believes that temporary arcing fault-caused downed conductor events can be reduced.

- **Residual ground protection:** A function that enables an increase in sensitivity for ground faults beyond the branch circuit, and also provides the ability to set upstream protection as sensitively as possible while still properly coordinating the I-Fuse.
- **Automation for remote I-Fuse monitoring:** Capability to allow SCE to respond to fault conditions as they are reported by the device, thus reducing the amount of time the public is exposed to energized power lines. During specific system conditions, it may be desirable to block reclosing and modify the operating scheme in high-fire-danger areas. Automation can allow the widespread application of these devices where it may not be appropriate to dispatch crews for manual block reclosing.
- **Operating TCC curve:** A graphical display with lines representing the average fuse melting time in seconds for a range of overcurrent conditions.

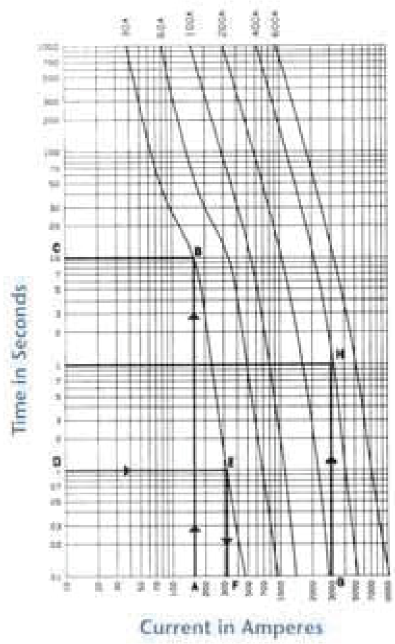


**Figure 5. Sample Time-Current Characteristic Curve**

## 2.3 Schedule, Milestones, and Deliverables

Work on the I-Fuse Project began in January 2016. A competitive procurement was held and one purchase order was issued for the delivery of three devices. While Factory Acceptance Testing (FAT) showed that the vendor's device met SCE's stated requirements for the project, company stakeholders identified additional functionalities (originally included as optional in the Request for Proposal) as necessary. (See Additional Functionalities, Section 2.2.3, for more details.) In addition, field crews indicated that the vendor's product was too heavy and not practical for installation on existing branch line fuse poles.

The vendor delivered one I-Fuse device in July 2017 and the project ended without the delivery of the other two, given the new requirements identified by stakeholders. The project did successfully meet the goal of demonstrating, via laboratory and factory testing, that the I-Fuse could improve the reliability of the distribution grid by automating branch line protection. Any future projects SCE undertakes will address the additional functionalities requested by internal stakeholders, plus the device weight concern.

| Intelligent Fuse Schedule | Description | Date |
|---|---|---|
| Finalize Hardware Design | Intelligent Fuse hardware design has been accepted based on SCE's criteria | July - 2016 |
| FAT (Factory Acceptance Test) | FAT demonstration of vendor solution and acceptance based on SCE's criteria | September - 2016 |
| Finalize Software with Fonox | Intelligent Fuse software design has been accepted based on SCE's criteria | March - 2017 |
| Equipment Delivery for Lab Testing | Delivery of first Intelligent Fuse prototype | July - 2017 |

**Table 1. Project Deliverable Timeline**

# 3 Project Results

Laboratory and vendor factory testing of the I-Fuse device was successful in meeting SCE's project goal by demonstrating that the I-Fuse could improve the reliability of the distribution grid by automating branch line protection. As noted in the Executive Summary (Section1):

> *Project laboratory and vendor factory testing demonstrated the I-Fuse's capability to reclose automatically after it opened, enabling isolation of a downstream fault (meaning a circuit interruption). Testing also indicated that the device would be able to automatically restore impacted customers within seconds in field use. In the event of a permanent fault, the biggest benefit identified was that the fuse would not need to be replaced, but just closed.*

However, when the device was demonstrated for SCE field personnel, they indicated that the I-Fuse is too heavy and not practical to install on existing branch line fuse poles. (See Technical Lessons Learned and Recommendations, Section 3.4.)

## 3.1 Achievements

Some of the key project benefits/deliverables during project testing included:

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

See Project Scope (Section 2.2) for more information and details.

## 3.2 Value Proposition

This project demonstrated the value of the I-Fuse based on its ability to improve distribution grid reliability by automating branch line protection, and to improve the capacity to isolate faulted or degrading system conditions. Project testing indicated that when a temporary fault occurred, the I-Fuse design reclosed to clear the momentary outage. It also showed the capability to automatically restore customers impacted by a momentary power outage within seconds in field use. Given these results, the project achieved its goals of successfully demonstrating the I-Fuse's ability to increase power system reliability and thus reduce SAIDI, a utility customer outage reliability indicator.

## 3.3 Metrics

See the Project Summary (Section 2) for an overview of project work and accomplishments and how the I-Fuse work addresses key elements of the EPIC Investment Framework for Utilities (Figure 1).

## 3.4 Technical Lessons Learned and Recommendations

The I-Fuse device was demonstrated for field personnel for feedback. The responses were that the I-Fuse design was too heavy and not practical to install on existing branch line fuse poles. Use of the vendor's device (weighing 1,000 lbs.) would require a change-out to larger-sized poles to hold its weight, which would be very costly. Based on field crew input, the weight of an I-Fuse should not exceed 200 lbs. Weight requirements were not included in initial specifications and will be for any future I-Fuse projects.

## 3.5 Technology/Knowledge Transfer Plan

The project team collaborated with SCE stakeholders (namely Distribution Apparatus Engineering and field crews) and maintained open lines of communication with the project vendor. This enabled the exchange of information about commercially available Intelligent Fuse (I-Fuse) products, their features and capabilities, and any modifications needed to meet SCE system requirements. Looking ahead to any future projects, this cooperative approach will allow a more efficient, cost-effective procurement of devices that meet SCE's needs.

## 3.6 Procurement

A competitive procurement was held to procure three I-Fuse devices. One I-Fuse device was acquired and tested. Procurement of the other two was deferred due to the concerns raised by SCE field personnel about the weight of the vendor's product. (See Technical Lessons Learned and Recommendations, Section 3.4.)

## 3.7 Stakeholder Engagement

During the project, the project team worked and met with the SCE stakeholders listed below:

- Distribution Apparatus Engineering (the primary stakeholder, which also was invited to observe project device testing)
- Field Apparatus
- Troublemen
- Grid Operations
- Distribution Automation Engineering
- Power System Control
- Netcomm Wireless Engineering
- Construction Methods
- Construction Engineers
- Distribution Engineers

# List of Acronyms

| | |
|---|---|
| AC | Alternating Current |
| ANSI | American National Standards Institute |
| DG | Distributed Generation |
| DMS | Distribution Management System |
| DNP | Distributed Network Protocol |
| EPIC | Electric Program Investment Charge |
| FAT | Factory Acceptance Testing |
| GOOSE | Generic Object Oriented Substation Event |
| IEC | International Electrotechnical Commission |
| IEEE | Institute of Electrical and Electronics Engineers |
| I-Fuse | Intelligent Fuse |
| LAN | Local Area Network |
| LED | Light-Emitting Diode |
| MMS | Manufacturing Message Specification |
| PSC | Power System Control |
| RFI | Remote Fault Indicator |
| RFP | Request for Proposal |
| TCC | Time-Current Characteristic |
| SAIDI | System Average Interruption Duration Index |
| SCADA | Supervisory Control and Data Acquisition |
| SCE | Southern California Edison |
| SMU | Solid Material Universe |
| VAC | Volts Alternating Current |
| WAN | Wide Area Network |

# Remote Fault Indicators
# Final Project Report

Developed by

SCE Transmission & Distribution, Grid Technology & Modernization

January 2018

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# Acknowledgments

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Appendix 2, Death Valley On-Ramp Wireless Communication Demonstration Project Report

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# 1 Executive Summary

Remote Fault Indicators (RFIs) can minimize the time spent by field crews to identify and isolate faults on the distribution grid, thus shortening outage times for customers. Specifically, when there is a power interruption, RFIs send a signal with an estimated location of the malfunction to grid operators, allowing them to quickly map the location, isolate the outage, and dispatch a crew.

Currently, Southern California Edison (SCE) places mechanical fault indicators on its distribution lines. An indicator light in these devices comes on when a disruption triggers a power outage. An SCE troubleman alerted to the outage drives through the area to look for the indicator light on the line. Until the disruption is localized, the entire line, and sometimes much of a neighborhood, might remain without power.

Based on the benefits of RFIs, this evaluation project focused on demonstrating the technology of low-cost RFIs from various vendors to determine the next-generation devices for wide-scale SCE system deployment over the coming decade. The demonstration showed that wireless communications from the devices can assist in rapid fault location for SCE troublemen, and provide monitoring of operating currents for distribution grid planning purposes.

The RFI design selected is cost-effective, simple to install, and maintenance cost is low.

# 2 Project Summary

This project assessed Remote Fault Indicator (RFI) technology through both SCE laboratory testing and installation of overhead RFIs on field circuits. Overhead RFIs can serve as a key component of the future distribution grid by quickly and accurately locating faults. This, in turn, can reduce the System Average Interruption Duration Index and thus improve reliability for customers – a goal identified in the Electric Program Investment Charge (EPIC) Framework for Utilities (see Figure 1).

The project also showed that RFIs can communicate with SCE's Distribution Management System, or DMS (which monitors and controls the power distribution network) via a cost-effective wireless communication system with the ability to measure the magnitude of current on power lines and alarm-on faults. As part of SCE's next-generation distribution automation initiatives, RFIs can support Grid Modernization and Optimization, also part of the EPIC Framework.


**Figure 1. EPIC Investment Framework for Utilities**

## 2.1 Problem Statement

SCE currently has thousands of existing mechanical fault indicators on its distribution lines. These sensors do not have telemetry (automatic data measurement and communication) capabilities to notify system operators or troublemen when and where a fault occurs on a line. This means that crews must take extra time to identify and isolate faults.

## 2.2 Project Scope

In March 2014, a Request for Information with SCE specifications and requirements was sent to various vendors. SCE screened responses for sensor capabilities and functionalities, and performed an initial evaluation of each vendor. As a result, two vendors were selected for Remote Fault Indicator (RFI) demonstration evaluation: Schweitzer Engineering Laboratories (SEL) and Sentient Energy.

The objectives of this project evaluation were to demonstrate and evaluate the following nine functional and operational features: 1) fault detection logic; 2) load monitoring; 3) power harvesting; 4) bidirectional load flow; 5) data collection; 6) wireless communication; 7) environmental (for example, temperature and ultraviolet rating); 8) hardware; and 9) ease of installation and deployment.

The Institute of Electrical and Electronics Engineers (IEEE) 495-2007 standard was used as a guide for testing fault circuit indicators. The American National Standards Institute/International Society of Automation (ANSI/ISA)-82.01 standard was applied for safety requirements for electrical equipment measurement, control, and laboratory use.

See Project Results (Section 3) for details on the testing results.

*Note:* Initially, the project included evaluation of both overhead and underground RFIs. However, over the course of the evaluation, the project team learned that the underground sensors are a very immature technology, and vendors do not yet have a complete solution for them. In the future SCE plans to specifically evaluate underground sensors.

## 2.3 Schedule, Milestones, and Deliverables

This project evaluation was conducted from June 2013 to December 2015. The Sentient Master Monitor 3 (MM3$^{TM}$) was selected by the evaluation team as the successful candidate for Remote Fault Indicator SCE system deployment.

| RFI Task Schedule | | | | |
|---|---|---|---|---|
| # | Task | Duration (Days) | Start Date | End Date |
| 1 | Stakeholders meeting to gather project requirements and support | 30 | 1/6/2014 | 2/6/2014 |
| 2 | Determine project scope and objectives with stakeholders | 8 | 1/8/2014 | 1/17/2014 |
| 3 | Budget discussion - obtain estimated budget approval | 3 | 1/13/2014 | 1/17/2014 |
| 4 | Project schedule development | 2 | 1/14/2014 | 1/17/2014 |
| 5 | Identify pilot locations, targeted Worst Performing Circuits | 7 | 1/20/2014 | 1/28/2014 |
| 6 | Distribution Engrs and Troubleman to provide site locations for pilot | 25 | 3/10/2014 | 4/5/2014 |
| 7 | RFI - Send Request For Information to vendors | 21 | 3/12/2014 | 4/3/2014 |
| 8 | PO to sensor vendors and OnRamp Wireless vendor | 3 | 6/2/2014 | 6/6/2014 |
| 9 | SEL WSO & 8301a prototype lab functional testing | 65 | 7/21/2014 | 9/25/2014 |
| 10 | Senitent MM3 prototype lab functional testing | 85 | 8/1/2014 | 10/26/2014 |
| 11 | Wireless communication testing for all vendors | 15 | 8/18/2014 | 9/3/2014 |
| 12 | DMS integration development | 15 | 9/5/2014 | 9/21/2014 |
| 13 | Training Job Aid for field crew | 30 | 8/2/2014 | 9/2/2014 |
| 14 | Sensor field installation | 50 | 10/1/2014 | 11/21/2014 |
| 15 | Monitor and track installed sensors performance | 310 | 10/1/2014 | 8/8/2015 |
| 16 | Firmware modifications on field sensors to correct issues | 15 | 6/6/2015 | 6/22/2015 |
| 17 | Develop deployment process flow | 8 | 8/10/2015 | 8/19/2015 |
| 18 | Present Lessons Learned to Standard Review Team | 1 | 9/15/2015 | 9/17/2015 |
| 19 | Published SCE Distribution Overhead Construction Standard DOH AP-604 | 15 | 11/2/2015 | 11/18/2015 |
| 20 | Published White Paper | 4 | 11/9/2015 | 11/14/2015 |
| 21 | Close RFI pilot program | 1 | 12/31/2015 | 1/1/2016 |

**Table 1. Project Schedule**

# 3 Project Results

Below are the test results for key product features for Schweitzer Engineering Laboratories and Sentient Energy.

## 3.1 Schweitzer Engineering Laboratories (SEL) Sensors Evaluation

SEL offered Remote Fault Indicator (RFI) solutions with both the overhead WSO-11 model and underground 8301a model.

### 3.1.1 SEL Wireless Sensor Overhead–11 (WSO-11)

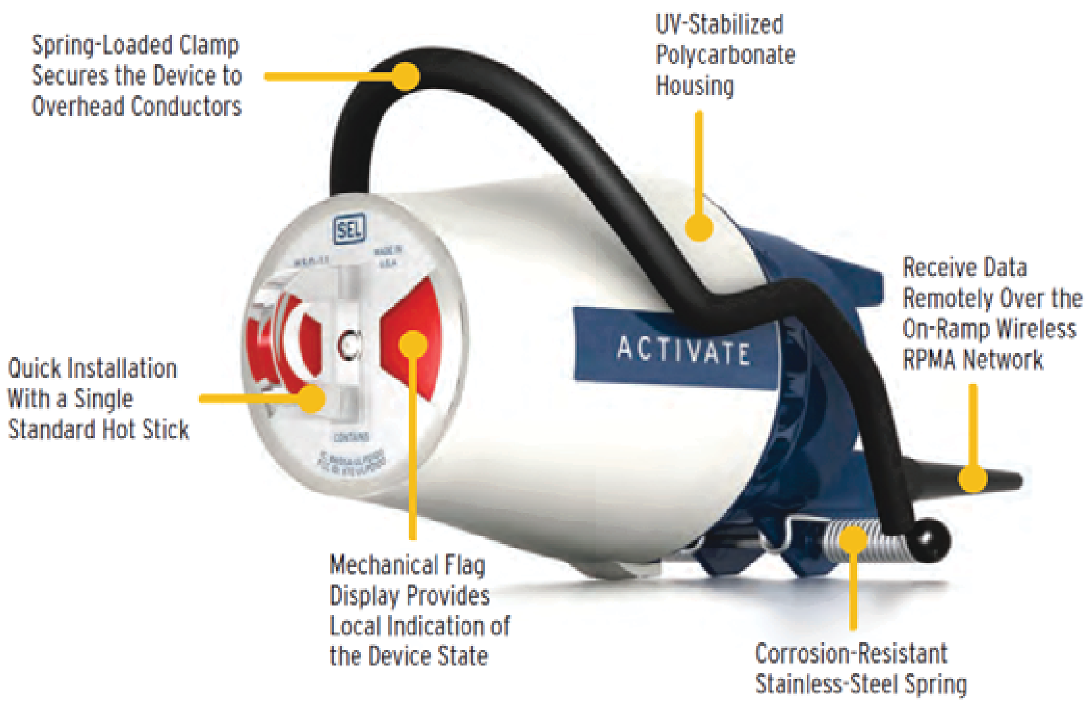


**Figure 2. SEL WSO-11 Wireless Sensor for Overhead Lines**

- **Fault Detection Logic:** The WSO-11 has eight distinct trip thresholds and can automatically select the best-fit fixed thresholds based on measured load current. However, SCE's requirements included capturing the actual fault magnitude value. The trip threshold only provides the fixed maximum value if the fault exceeds the predefined fault values.

- **Load Monitoring:** The WSO-11 includes monitor circuit loading and records on an hourly basis. But due to the onboard battery management, the load data is reported once a day, which includes 24 values. SCE required receipt of a load profile every 5 minutes instead of every hour. The hourly scan cannot provide the granularity data necessary for circuit analysis.

- **Power Harvesting:** The WSO-11 does not offer a power harvesting feature, and it uses its battery to maintain operation. The vendor indicates that the battery has 10 years of life expectancy.

- **Bidirectional Load Flow:** The WSO-11 does not offer bidirectional sensing.

- **Data Collection:** During the evaluation monitoring phase, the WSO-11 maintained a highly reliable current measurement accuracy and fault alarm measurement, with less than a 2% error rate.
- **Wireless Communication:** The WSO-11 is integrated with On-Ramp Wireless Radio (whose name was changed to Ingenu after the project evaluation). On-Ramp uses the free 2.4 GHz Industry, Scientific and Medical (ISM) frequency band to send data packets from the sensors to the Distribution Management System (DMS). The technology uses a proprietary protocol called Ultra-Link Processing (ULP) communication to transport data packets. On-Ramp developed its own Human Machine Interface (HMI) called On-Ramp Wireless Total View application, which only communicates to its field monitoring devices.

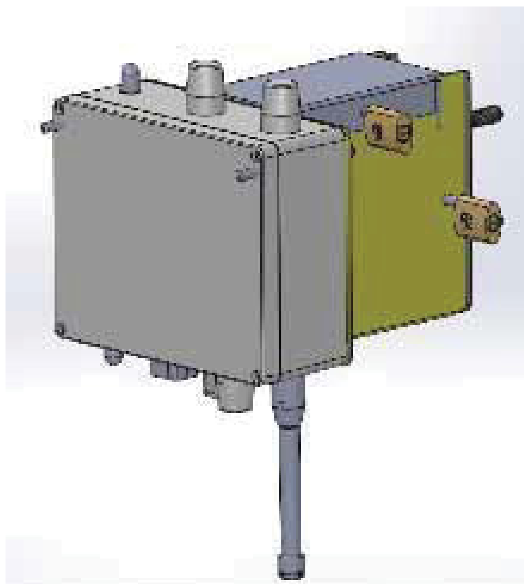

Figure 3. On-Ramp Wireless Radio Access Point (drawing provided by On-Ramp Wireless)

- **Wireless Communication Evaluation:** Fifteen On-Ramp WSO sensors (five sites) were evaluated in Death Valley. Since there was no reliable communication in Death Valley, SCE made use of commercially available satellite communications to transmit data and to backhaul the data packets. The feedback from Grid Operations, Power System Control/Distribution Management System (PSC/DMS), Information Technology, and NetComm Wireless Engineering was not positive due to the high cost of back-office integration and a lack of DMS integration capabilities. (See Section 4.2.2 under Appendices for more information.) The On-Ramp HMI also does not integrate with SCE's existing NetComm network. System operators would need to use a separate screen (On-Ramp Total View application) to monitor the RFI, which could create confusion for users.

- **Environmental:** The WSO-11 was installed in multiple regions throughout SCE's service territory to verify that the sensors would meet Institute of Electrical and Electronics Engineers (IEEE) 495-2007 standard requirements. For example, the WSO-11 was installed:
  - In regions with varying climates, such as coastal areas with high salinity;
  - In a desert area (Death Valley) with a high ultraviolet (UV) rating and extremely high temperatures;
  - Around high, dense vegetation; and
  - Underneath transmission lines (to test for corona discharge, which can degrade the integrity of the sensor's plastic cover after time).

  The 15 WSO-11 sensors in the Death Valley evaluation failed in the in the harsh, extreme heat environment. The WSO-11 comes with an integrated mechanical fault display that rotates when it detects a loss of current. After nine months of evaluation, including the summer period, the mechanical plastic components froze up and would not rotate. Ten of the 15 WSO-11 sensors failed on communication due to their electronic components and antennae being affected by the 33-kV line corona discharge.
- **Hardware:** The WSO-11 weighs 1.6 lbs., which allows it to be installed on the smaller overhead #2 conductor. This low weight also enables troublemen to install it at any radial section required. However, testing showed that the WSO-11 has a weak spring mechanism, resulting in the sensor disengaging from the power lines under fault conditions with high-fault duty. For example, on a circuit with high loading at approximately 350 amps, if the sensors are installed within a mile of the substation, during a fault the conductors could whiplash and might cause the sensors to disengage from the lines.
- **Ease of Installation and Deployment**: The WSO-11 is designed to be installed via a single-person operation. The device self-identifies to the On-Ramp Access Point when it detects a load current above 5 amps.

### 3.1.2 SEL Underground Distribution Sensor: 8301a

*Note:* The link below shows the SEL-8301 model. However, during this project, the 8301 model was not available for purchase. SCE purchased the 8301a prototype model instead.

**Figure 4. SEL-8301 Underground Distribution Sensor**

- **Fault Detection Logic:** The 8301a has a similar fault detection logic as the WSO-11.
- **Load Monitoring:** The 8301a has a similar load monitoring method as the WSO-11.
- **Power Harvesting:** The 8301a harvests power using the 8302 current transformer (CT). The CT performs two functions: 1) It is used to monitor the circuit loading; and 2) It is used as a power harvester. The 8301a also utilizes an integrated battery to maintain operation during extended power outages. According to the vendor, the battery has a 10-year life expectancy.
- **Bidirectional Load Flow:** The 8301a does not offer bidirectional sensing.
- **Data Collection:** The 8301a has a similar data collection method as the WSO-11.
- **Wireless Communication:** The 8301a also uses On-Ramp Wireless Radio communication.
- **Environmental:** The 8301a was tested for Ingression Protection (IP68) submergibility with seawater at SCE's Newport vault. After three months, the unit failed to communicate and was extracted for inspection. Upon inspection, the unit was half-filled with seawater.
- **Hardware:** The 8301a has the capability to monitor up to 4 positions (12 current sensing ports) on an underground switch, with each port connected to a CT.
- **Ease of Installation and Deployment:** The 8302 CT was designed to be installed using rubber gloves. The SEL 8301a module includes several status light-emitting diode (LED) indicators, which assisted in the installation process.

## 3.2 Sentient Energy Master Monitor 3 (MM3™) Sensor

In late 2013, the Sentient MM3 product added Landis+Gyr radio integration. With its enhanced features, the Sentient MM3 met most of the SCE Request for Information requirements and specifications for the Remote Fault Indicator (RFI) Project. Therefore, the SCE evaluation team decided to perform a more thorough laboratory test. The following sections describe this testing, with information on scope, methodology, results, and lessons learned regarding the deployment process.

Figure 5. Sentient MM3 Sensor

### 3.2.1 Scope

- **In Scope:** All testing that was conducted for sensor functionality is covered in detail in this report. Testing conducted by SCE's Integrated Innovation and Modernization Organization, Distribution Apparatus Engineering, Distribution Automation, Power System Control/Distribution Management System (PSC/DMS), and Netcomm Wireless Engineering is mentioned, but not in detail.
- **Out of Scope**: Detailed radio communication testing conducted by Integrated Innovation and Modernization, PSC/DMS, and Netcomm Wireless Engineering is not covered in this report, as it relates more to wireless communication and DMS sync.

### 3.2.2 Methodology

The following subsections describing the MM3 sensor testing review the hardware used, sensor Distributed Network Protocol (DNP) settings, firmware, and the testing procedure for both the laboratory and the field installations.

#### 3.2.2.1 Hardware

Four main pieces of equipment were used for laboratory testing: 1) Doble Test Set; 2) high-current range (HCR), low-current range (LCR), and full-current range (FCR) models of the MM3 sensor; 3) Sentient Energy Loop Charger; and 4) a Fluke voltage meter.

- **Doble F6150SV** (used to simulate field conditions): The Doble Test Set was used to create configurable currents to simulate steady-state load current and fault conditions.
- **HCR, LCR, and FCR Sensor Models:** Three different models of the Sentient Energy MM3 were tested throughout this project. Initially, two models were needed for different amperage ratings: the HCR (20A-800A) and the LCR (10A-100A). A third model, the FCR (10A-800A), was manufactured by the vendor to eliminate the need for different models based on current rating.
- **Sentient Energy Loop Charger:** The loop charger's purpose is to create enough current to power up the sensor.
- **Fluke 355 True RMS 2000A Clamp Meter:** This clamp meter is used for the current readings from the Doble Test Set and the Sentient Energy Loop Charger, and for validation between MM3 current readings.

#### 3.2.2.2 DNP Settings

All DNP points were tested and validated in the laboratory.

#### 3.2.2.3 Firmware Versions

Throughout this evaluation, several different firmware versions were tested to meet SCE's requirements: 1.3, 1.42, 2.0, 2.02, and 2.1. Version 2.1, the production version, was installed for deployment.

#### 3.2.2.4 Functionality Testing/Acceptance Criteria

The following seven tests verified the functionality and integration viability of the Remote Fault Indicator (RFI) sensor into SCE's system: 1) power harvesting; 2) fault alarms; 3) current measurement accuracy; 4) Netcomm radio communication; 5) Distribution Management System integration; 6) supercapacitor testing; and 7) "Call Home" Device Code Work.

- **Power Harvesting:** This test validated at what amperage the MM3 sensor turned on. A Doble (used to simulate field conditions) was utilized to configure the current output to turn on the sensor. Testing started at the specified amperage (10A) and specified time (~20 minutes). <u>*Acceptance Criteria:*</u> The sensor had to turn on with a minimum amperage of 10A and report to the DMS within 20 minutes.
- **Fault Alarms:** The MM3 has three different fault algorithms for fault indication: 1) fault threshold, 2) percent change, and 3) Di/Dt (derivative of current over time).
    1. The fault threshold algorithm is the simplest, as it indicates a fault once the defined current is exceeded. However, it also needs the most time to implement because it requires field engineers to determine the fault setting for the particular location.
    2. The percent change algorithm is a little (but not significantly) more complicated. For this algorithm to work, the sensor needs to see a minimum 50A (configurable) of fault current with an additional 200% (configurable) change for 160 milliseconds (configurable). Seventy-two hours (configurable) also are required to establish a baseline peak load before alarming. For example, an RFI with a peak current of 200A during a 72-hour period needs to see at least 450A (50A + 200*2) for at least 10 cycles to minimize temporary alarms and/or false alarms.

3. The Di/Dt algorithm was never considered based on a recommendation from the vendor and the inability to test the algorithm, which is based on the change of current over time. (The “slope” is configurable.) The vendor only intended to use this algorithm for special studies/cases.

The project team conducted laboratory testing using the percent change algorithm. The baseline peak current (~30A) was established using the loop charger after the 72-hour period. The sensor was then installed on the Doble and a fault condition was simulated with 225A lasting 10 cycles. *Acceptance Criteria:* The test procedure with varying fault current needed to produce a fault alarm. The fault alarms were to be validated locally (in the field) from the light-emitting diode (LED) indication light, as well as remotely from the DMS. Based on the testing, the sensors were to be set to use the percent change algorithm with SCE’s Distributed Network Protocol (DNP). Fault alarming validation was to be conducted locally (via the LED indication light) and remotely (via the DMS). SCE was to set test conditions and validate correct operations.

- **Current Measurement Accuracy**: This test validated the electrical current accuracy of the sensor. Testing was limited, as the project team was only able to test for current ranges (10A-50A) for steady state and up to 225A for fault conditions. *Acceptance Criteria:* Current accuracy was accepted if the sensors met specifications in the field that are restricted by the Doble output limitation (up to 50A).
- **Netcomm Radio Communication:** With an integrated Landis+Gyr radio, testing communication between the sensor and SCE’s Netcomm system was essential. The majority of the testing was completed by SCE’s Netcomm Wireless Engineering and Power System Control. *Acceptance Criteria:* The sensor needed to seamlessly integrate into SCE’s Netcomm network.
- **Distribution Management System (DMS) Integration**: Integration of the Distributed Network Protocol (DNP) points between the sensor and SCE’s DMS also was essential. This involved joint testing collaboration with SCE’s Integrated Innovation and Modernization Organization, Distribution Apparatus Engineering, and Power System Control/Distribution Management System. *Acceptance Criteria*: The sensor needed to seamlessly integrate into SCE’s DMS system.
- **Supercapacitor Testing**: This test met SCE’s requirement to maintain LED light operation and radio communications for at least 30 minutes when the sensor detected loss of current. *Acceptance Criteria:* The sensor needed to last at least 30 minutes when the current fell below 10A, with constant radio communication.
- **“Call Home” Device Code Word (DCW)**: This is a custom-designed script developed by Sentient/Landis+Gyr to automatically self-identify and self-configure to deploy itself onto the SCE NetComm network. Using an integrated Global Positioning System (GPS) chip, the sensor can capture the latitude and longitude coordinates that are necessary for the Netcomm radio system. The DCW was tested in SCE’s Netcomm Wireless Engineering group to verify functionality. *Acceptance Criteria:* Testing had to be verified and accepted by Netcomm Wireless Engineering.

#### 3.2.2.5 Field Hardware

- **High-Current Range, Low-Current Range, and Full-Current Range MM3 Sensors:** These three different RFI models were tested in the laboratory and also installed in the field at various locations.
- **Grip-All Hotstick:** The hotstick (an insulated pole that protects from electric shock) was used to install the sensors on energized distribution lines.

- **Phase Identification Tool:** The phase identification tool used in the project is a standard tool and available to all SCE crews. Phase identification is necessary when installing the sensors, and correct phasing is required for an accurate reflection of what is in the field compared to what the DMSshows.

### 3.2.3 Acceptance Criteria

During this project, field installs were completed by Distribution Automation, which then validated the radio frequency communications and the device's functionalities by performing the endpoint test.

### 3.2.4 Vendor Selection

After this Remote Fault Indicator (RFI) evaluation, SCE selected the Sentient Energy MM3 for the following reasons:

- Integrated Landis+Gyr radio
- Power harvesting technology (no batteries)
- Maintenance-free life span
- No pole-mounted equipment
- Ease of installation
- Ability to stay on the conductor during fault conditions
- Accuracy of measurements
- Global Positioning System and pre-loaded "Call Home" Device Code Work
- QR code with future use case
- Large range of conductors (1/0 – 653 ACSR, meaning aluminum conductor steel reinforced cable)

SCE worked with Sentient to correct two issues: 1) no alarm within 72 hours of start-up time because of baseline peak load, and 2) the need for a copper versus aluminum model. SCE continues to work with Sentient to address: 1) the product weight (6.2 lbs., which is too heavy for laterals, or non-mainlines); and 2) possible false alarms due to load transfers.

## 3.3 Achievements

The benefits realized from this Remote Fault Indicator (RFI) Project include:

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

The Sentient Energy MM3 can be utilized for SCE Grid Modernization and Optimization. It also can be deployed through the normal request channels from the Technical Planning, District Planning, and District Engineering departments. With integrated Landis+Gyr radios, each installed sensor can enhance the mesh network, thereby increasing the overall reliability of the communication network and ultimately reducing the System Average Interruption Duration Index (SAIDI) for customers. This specifically addresses the Reliability strategic goal in the Electric Program Investment Charge (EPIC) Framework for Utilities (Figure 1).

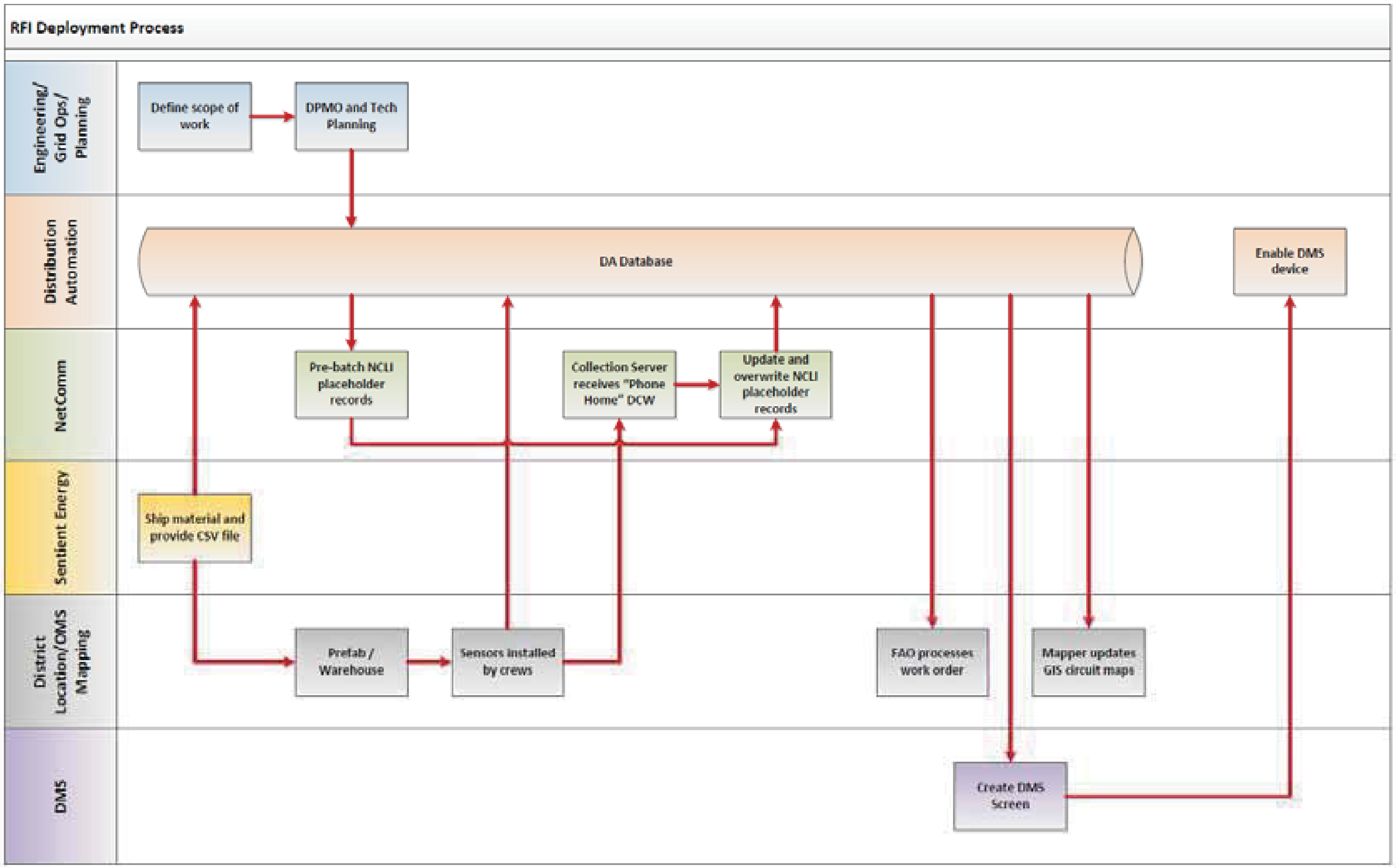


Figure 6. RFI Swim Lane Deployment Process

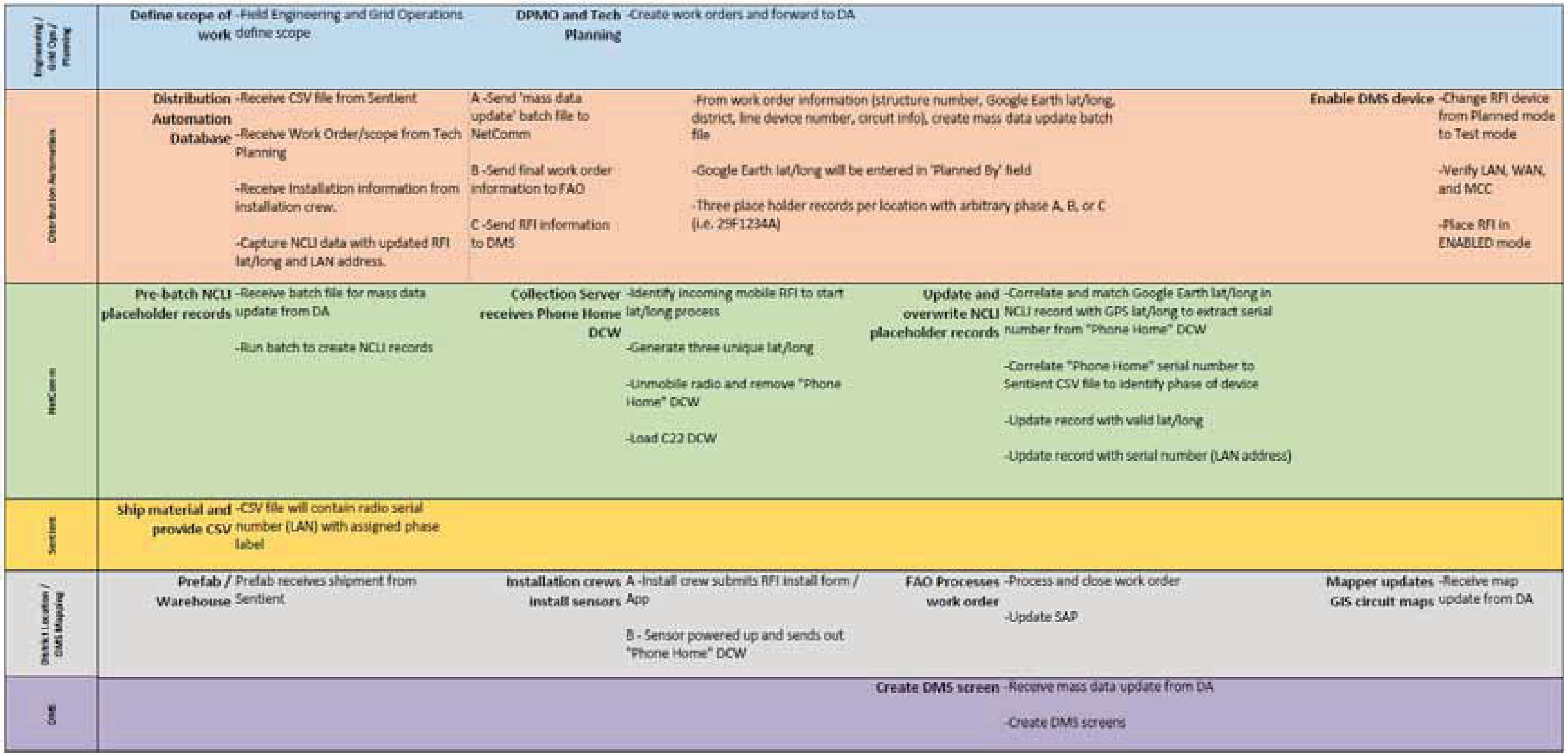


**Figure 7. RFI Deployment Process with Swim Lane Details**

## 3.4 Value Proposition

This Remote Fault Indicator (RFI) Project demonstrated that this technology meets the requirements for wireless communication capabilities that can assist in rapid fault finding for SCE troublemen, as well as monitoring of operating currents for distribution grid planning purposes. This can provide significant value to SCE, other utilities, and customers by reducing the duration time of localized power outages. It also can offer value through Distribution Management System integration to support continued modernization and optimization of SCE's power system grid.

## 3.5 Metrics

See Executive Summary (Section 1) and Project Summary (Section 2) for an overview of the ability of Remote Fault Indicators to enhance system reliability, lower the System Average Interruption Duration Index, and support SCE's next-generation distribution automation initiatives.

## 3.6 Technical Lessons Learned and Recommendations

### 3.6.1 Laboratory Observations for the Sentient Energy MM3 Sensor

- **RFI Functionality/Issues/Settings: Power Harvesting, Humming:** When the project team installed a sensor on a current transformer/loop charger, a loud humming sometimes occurred. This could be explained in various ways: 1) the low-current range sensor was installed with currents greater than 100A; 2) the sensors were not fully closed; or 3) there were dirty cores/debris on the cores that caused enough separation for the sensor to hum.
- **RFI Functionality/Issues/Settings: Power Harvesting, Locking:** There were several instances where the lock screw would not latch onto thread, causing the screw to fail to lock. Sentient made a manufacturing change to spot weld the troubled area.
- **Fault Alarms:** During initial tests of the percent change algorithm, there were multiple cases of the fault alarm not triggering. This was caused by the fault duration timing between the Doble (a current amplifier) and sensor being off by a few milliseconds. The sensor was looking for current to exceed its fault threshold for at least 10 cycles, and the Doble was only powered on for 10 cycles. Because the Doble takes a short period of time to reach its specified current, this accounted for the fault alarm not triggering.
- **Backup Power Test:** This test showed that assuming the supercapacitor is fully charged when no current is available, the sensor will stay on from 30 minutes (with heavy radio communication) up to 2 hours (with light radio communication).

### 3.6.2 Field Observations for the Sentient Energy MM3 Sensor

- **RFI Functionality/Issues/Settings: Power Harvesting, Humming:** When the project team installed a sensor in the field, a loud humming sometimes occurred. This could be explained in various ways: 1) the low-current range sensor was installed with currents greater than 100A; 2) the sensors were not fully closed; or 3) there were dirty cores/debris on the cores that caused enough separation for the sensor to hum.
- **RFI Functionality/Issues/Settings: Power Harvesting, Locking:** There were several instances where the lock screw would not latch onto thread, causing the screw to fail to lock. Sentient made a manufacturing change to spot weld the troubled area.
- **Fault Alarms:** During the evaluation project duration, the sensors experienced false alarms. The majority of these occurred due to the capacitor bank switching ON and the sensor failing to detect the current change quickly enough. A sensor experiencing this

issue was removed and sent to back to Sentient for investigation. A new firmware was developed, tested, and verified.

- **Distributed Network Protocol (DNP) Points:** The DNP settings were tested and verified with SCE's Power System Control Department. During this evaluation, DNP settings were modified to take into account some of the false fault alarms. The loss-of-voltage alarm also was completely disabled due to "chattering" (constant on and off). There was no solution that fixed the issue.
- **Radio Communication:** The majority of the sensors tested during this evaluation were pre-programmed by SCE's Netcomm Wireless Engineering group. Over time some of the sensors stopped communicating. Some of these issues were caused by "spurious" data killing the Device Code Work. Other possible causes were due to insufficient current and radio frequency noise interference.
- **Backup Power Test:** This test was not verified in the field, because SCE cannot stage an outage to de-energize a conductor.
- **Device Code Work (DCW) Test:** "Call Home" DCW was tested. This determined that the sensors needed to acquire two solid links to satellites to acquire Global Positioning System (GPS) latitude/longitude.

## 3.7 Technology/Knowledge Transfer Plan

SCE's Integrated Innovation and Modernization organization worked with the Distribution Apparatus Engineering, and Integration Technology groups to update SCE's Equipment Standard publications, as well as to prepare installation job aids and a self-directed program for engineers, planners, troublemen, and field crews.

## 3.8 Procurement

The project cost ran 3% higher than the estimated costs due to additional communication hardware required to complete the project with custom configuration. With adjustments made during device evaluation, the technology is more mature and ready for the marketplace.

## 3.9 Stakeholder Engagement

Project stakeholders consisted of Integrated Innovation and Modernization, Distribution Apparatus Engineering, Power System Control/Distribution Management System, NetComm Wireless Engineering, Distribution Automation, and Grid Operations. The project started with a larger list of requirements or specifications identified by these stakeholders. The team reviewed and prioritized the requirement list based on "must-have" or "nice-to-have." The team met twice monthly to discuss any project status updates, identify new topic areas that required reporting, and obtain new requirements or specifications to meet specific needs.

# List of Acronyms

| | |
|---|---|
| ACSR | Aluminum Conductor Steel Reinforced Cable |
| ANSI | American National Standards Institute |
| CT | Current Transformer |
| DCW | Device Code Work |
| DMS | Distribution Management System |
| DNP | Distributed Network Protocol |
| EPIC | Electric Program Investment Charge |
| FCR | Full-Current Range |
| GHz | Gigahertz |
| GPS | Global Positioning System |
| HCR | High-Current Range |
| HMI | Human Machine Interface |
| IEEE | Institute of Electrical and Electronics Engineers |
| ISA | International Society of Automation |
| ISM | Industry, Scientific and Medical |
| kV | Kilovolt |
| LED | Light-Emitting Diode |
| LCR | Low-Current Range |
| MM3 | (Sentient Energy) Master Monitor 3 |
| ms | Milliseconds |
| PO | Purchase Order |
| PSC | Power System Control |
| RF | Radio Frequency |
| RFI | Remote Fault Indicator |
| RFI | Request for Information |
| SAIDI | System Average Interruption Duration Interruption |
| SCE | Southern California Edison |
| SEL | Schweitzer Engineering Laboratories |
| ULP | Ultra-Link Processing |
| UV | Ultraviolet |
| WSO | Wireless Overhead Sensor |

## Appendix 1, Remote Fault Indicator Installation Form

Submit | Save As | Print Form | Reset Form

☎ Distribution Automation Hotline: (714) 285-4325 ✉ E-mail: emaildap@sce.com

# Remote Fault Indicator (RFI) Installation Form

**Work Order #:** **Date:**

**District #:** **Device #:**

**Circuit:** Search is case sensitive. (i.e. Lighthipe, El To **Substation:**

**Structure:** New Installation Replacement

**Installed: Overhead** Source Side Load Side **Underground** 1 2 3 4 5 6

**Latitude:** ° ' " N — Degrees (33–39), Minutes (0–59), Seconds (0–59)

**Longitude:** ° ' " W — Degrees (114–121), Minutes (0–59), Seconds (0–59)

| **Phase(s)** *(Click box next to Phase to enter data)* | | |
|---|---|---|
| **A** ☒ | **B** ☒ | **C** ☒ |
| Serial Number: | Serial Number: | Serial Number: |
| R E | R E | R E |
| LAN Address: | LAN Address: | LAN Address: |
| 91 . . . | 91 . . . | 91 . . . |
| Current: | Current: | Current: |
| Field A | Field A | Field A |

**Comments:**

**Name:** Phone Number:

Business Days: Monday–Friday (Excluding SCE Holidays) Business Hours: 7:00 am – 4:00 pm

Updated 10/26/2015

## Appendix 2, Death Valley On-Ramp Wireless Communication Demonstration Project Report

# Death Valley On-Ramp Wireless Communication Demonstration Report

December 2017

Developed by

SCE Transmission & Distribution, Grid Technology & Modernization

Southern California Edison
2131 Walnut Grove Avenue
Rosemead, CA 91770

# Acknowledgments

The following individuals contributed to development of this document:

| | |
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| Victor Tran | Project Lead |
| Michael Gonzales | Project Engineer |
| Bryan Pham | Senior Manager, Engineering |
| Mindy Berman | Tech Editor, Mindy F. Berman Communications |

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# 1 Demonstration Project Objective

The objective of this demonstration project was to demonstrate On-Ramp Wireless (ORW) communication over satellite backhaul at Death Valley on the Furnace Creek 33kV circuit. *(Note: On-Ramp Wireless Radio's name was changed to Ingenu after the demonstration project completion).* Standard installations of devices that employ ORW utilize cellular communication to backhaul data. The alternative method uses satellite communication to backhaul the data if there is no cellular coverage. To evaluate the radio technology, ORW collaborated with Schweitzer Engineering Laboratories (SEL) to install its small-form factor radio into SEL's WSO-11 (Wireless Sensor for Overhead Lines) sensory devices.

These SEL Remote Fault Indicators (RFIs) were used as endpoint devices to communicate to an ORW Access Point (AP). In the demonstration, the ORW communication system was limited to monitoring capabilities with the use of 15 SEL WSO-11 devices. The use of these RFIs allowed Southern California Edison's (SCE) Integrated Innovation and Modernization Organization to demonstrate the communication capabilities of ORW in this communication-challenged location with minimal to no impact on the distribution system under any potential communication failures.

# 2 Locations

The On-Ramp Wireless (ORW) Access Point (AP) was installed on the tallest Death Valley area mountain at 3,000 feet elevation and had coverage to communicate with 15 Remote Fault Indicators (RFIs). The different colors in Figure 1 show the percentage probability of communication between the AP and the RFIs. The AP has a range of up to 24.4 miles with >= 75% coverage (shown in yellow).

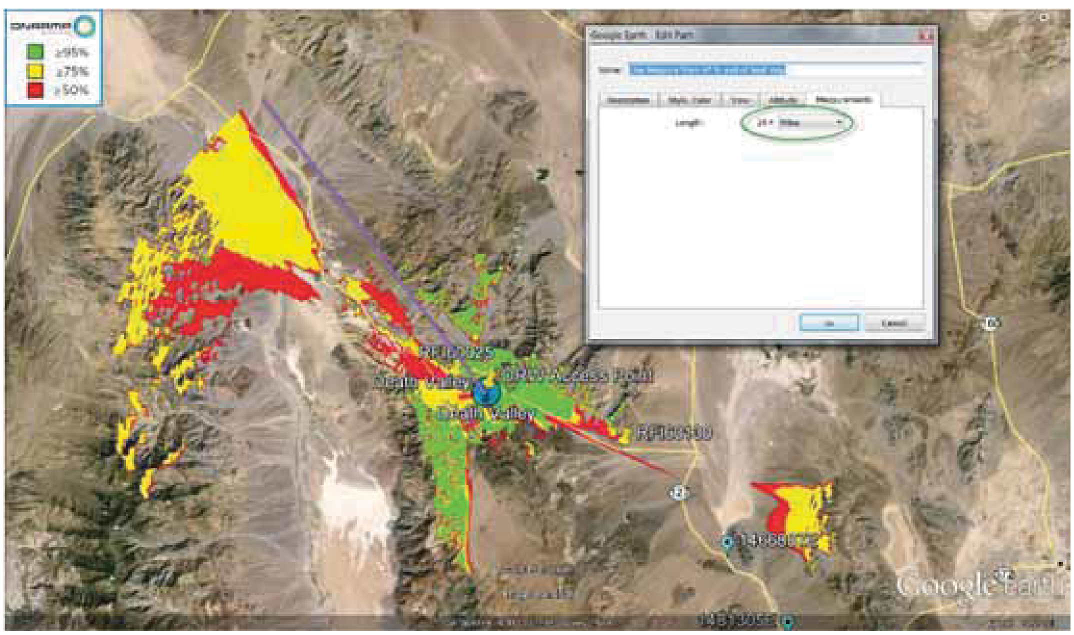


**Figure 1. On-Ramp Wireless Heat Map**

Figure 2 (below) depicts the Furnace Creek 33kV circuit single-line diagram showing the five site locations with Schweitzer Engineering Laboratories (SEL) RFIs.

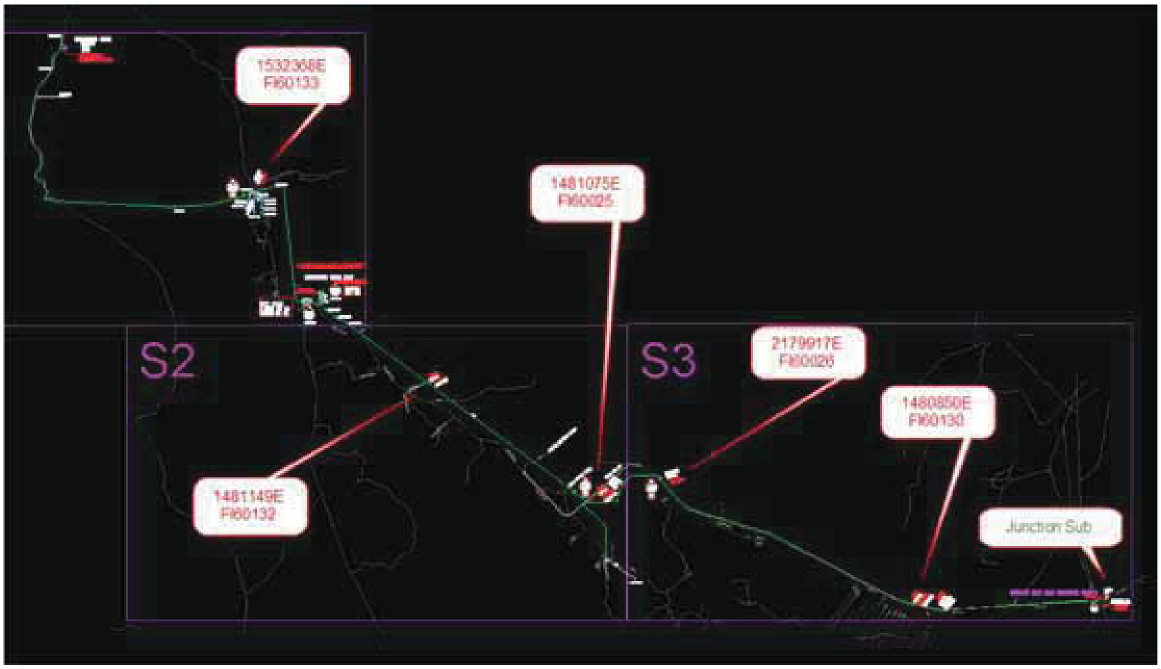


Figure 2. Furnace Creek 33kV Circuit Map

# 3 Communication Network

In Figure 3, the test hub portion reflects the Remote Fault Indicator (RFI) installation at Alhambra, CA. The yellow boxes represent the SatCom hardware; the magenta represents the hardware than creates the virtual private network (VPN) tunnel; the blue represents the On-Ramp Wireless and backhaul equipment; and the red-lined box represents the RFI endpoints.

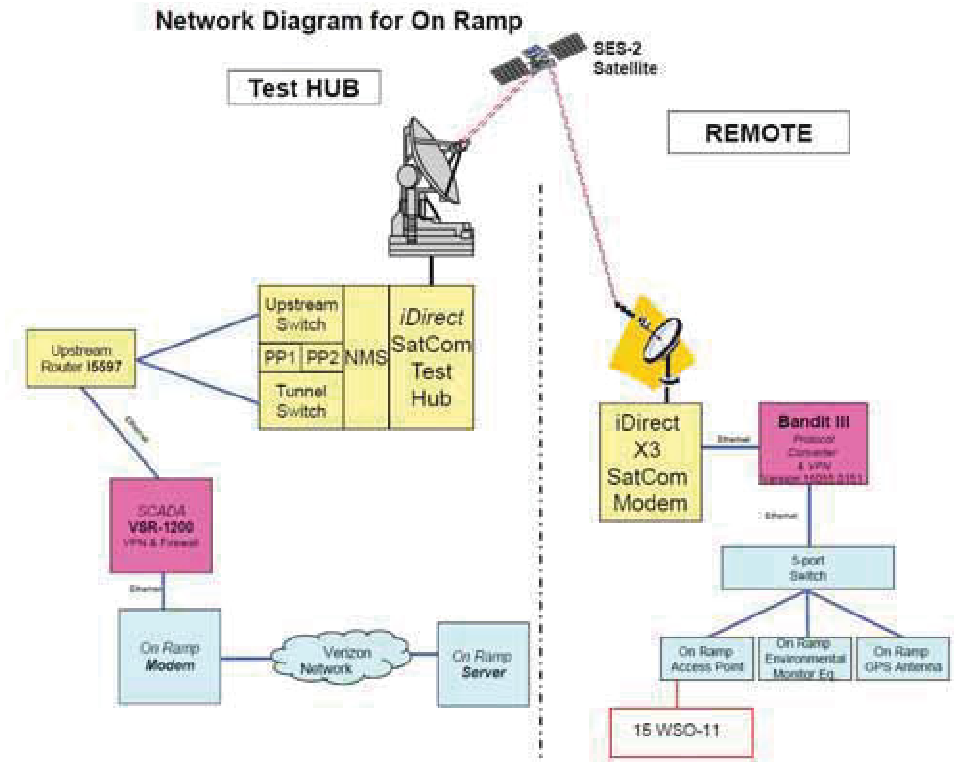


**Figure 3. Network Architecture Diagram for the On-Ramp Wireless Over Satellite Integration**

## 3.1 Hardware

- On-Ramp Wireless Access Point Radio - Boxer
- iDirect Satellite at Furnace Creek 33kV Circuit
  - iDirect X3 SatCom Modem
  - Cordex CXRC 24-400W Power Module
  - TRIMM 757 Fuse Panel Device
  - Encore Networks Bandit III Protocol Converter and Virtual Private Network (VPN)
- iDirect Satellite at Alhambra Test Hub
  - iDirect SatCom Test Hub
  - NMS – Network Management Services
  - Upstream Switch
  - Tunnel Switch
  - Supervisory Control and Data Acquisition (SCADA) Encore Networks Virtualized Service Router (VSR) -1200 VPN and Firewall
  - Digi Modem 3G Cellular Backhaul
- Endpoint Devices
  - 15 SEL WSO-11 Sensors

Figure 4. iDirect Satellite with Wireless On-Ramp Access Point

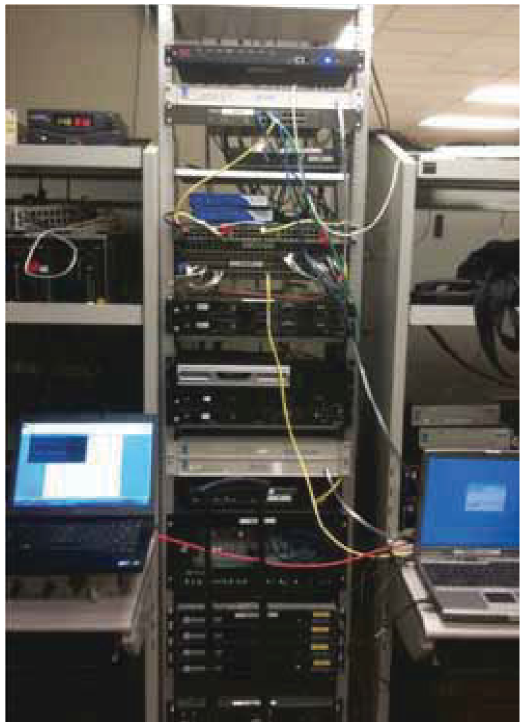

Figure 5. iDirect Satellite at Alhambra Test Hub (both top and bottom photos)

**Figure 6. Schweitzer Engineering Laboratories WSO-11 Sensors**

# 4 Testing

## 4.1 Pre-Field Testing/Mock-Up

A number of tests/mock-ups were completed before installation to verify the functionality of the various system components. Communication between the Remote Fault Indicators and Access Point was verified in the lab. Communication between the Alhambra iDirect system and On-Ramp Wireless server also was verified, and it was confirmed that a secure and reliable link was established. A mock-up installation was performed in SCE's Chino Training Yard utilizing all equipment that was to be used in the field.

## 4.2 Testing Criteria

The main criterion evaluated during this demonstration was the reliability of the On-Ramp Wireless system over satellite. The percentage of received packets over expected packets from the Remote Fault Indicators (RFIs) was calculated to give an indication of reliable communication. The RFI hardware also was evaluated to see how it would perform in the harsh desert environment.

## 4.3 Field Performance Issues

In December 2013, the system was installed and communication was established from the RFIs to the On-Ramp server using the satellite backhaul. The link was removed in May 2015.

A number of issues arose during the demonstration. Two major ones involved the RFI hardware and the satellite. Five RFIs needed replacement due to communication issues, and the satellite faced environmental issues that required a special firmware upgrade. A more detailed description follows below.

### 4.3.1 WSO-11 RFI Devices

By the second quarter of 2014, five of the 15 RFIs in the demonstration project had stopped communicating. The units were replaced and the root cause reports indicated low radio power output. During the demonstration, all RFIs experienced time-out alarms due to either lost packets or possible issues with the iDirect SatCom tunnel test hub. A time-out alarm notification occurs when the RFI data fails to communicate with the On-Ramp Wireless server after 2,940 minutes (49 hours). There were a total of 204 time-out alarms during the demonstration project.

### 4.3.2 Satellite Communication

The satellite equipment included different pieces of equipment, which added to potential points of failure. Some of this equipment included 1) a Virtualized Service Router (VSR) device (an integrated security gateway that supports high-performance security and Virtual Private Network (VPN) solutions over satellite); and 2) a TRIMM fuse array device that provides alarm status and power loss indication remotely, and also displays local relay contacts status.

Some of the issues that occurred were due to the extreme heat environment. In this heat, the VSR and the TRIMM device failed to operate and needed to be rebooted locally, which required manual intervention. A better satellite status monitoring method should have been set up from the beginning of the demonstration, since the test hub is not actively monitored by SCE's Telecommunications Control Center. To resolve this, the firmware was updated and modified in the VSR to automatically reboot when the VSR hung up on operation.

The Death Valley satellite link was connected to the Alhambra iDirect SatCom test hub (test network). Backhaul interruptions occurred when new hardware or firmware was introduced to the test hub for testing.

Multiple firmware upgrades at the iDirect SatCom test hub caused the tunnel to drop randomly 17 times. The backhaul interruptions varied from 20 seconds to nine days (see Table 1).

| Backhaul Down | Backhaul Recovery |
|---|---|
| 3/10/2014 10:35 | 3/10/2014 13:37 |
| 3/17/2014 11:49 | 3/17/2014 13:21 |
| 3/17/2014 14:01 | 3/17/2014 17:35 |
| 4/13/2014 5:58 | 4/13/2014 6:58 |
| 5/10/2014 20:32 | 5/19/2014 20:31 |
| 6/27/2014 22:14 | 6/27/2014 23:14 |
| 7/4/2014 6:27 | 7/4/2014 7:27 |
| 10/20/2014 23:12 | 10/21/2014 10:22 |
| 10/25/2014 9:22 | 10/25/2014 11:02 |
| 10/25/2014 13:37 | 10/25/2014 14:42 |
| 10/26/2014 10:22 | 10/26/2014 12:07 |
| 12/11/2014 5:37 | 12/11/2014 10:57 |
| 12/12/2014 3:17 | 12/22/2014 4:07 |
| 2/6/2015 5:02 | 2/6/2015 7:02 |
| 2/6/2015 11:47 | 2/6/2015 13:47 |
| 2/6/2015 18:37 | 2/6/2015 19:52 |
| 2/6/2015 21:17 | 2/7/2015 0:52 |

**Table 1. Backhaul Interruption Times at iDirect SatCom Test Hub**

# 5 Conclusion

The iDirect equipment withstood the rough weather conditions at Death Valley, as called for in the RFI project technical specifications. The satellite link disconnection issues experienced were mostly due to bugs in the satellite modem software. A better satellite status monitoring method should have been set up from the beginning of the demonstration, since the test hub is not actively monitored by SCE’s Telecommunications Control Center.

However, even with the disconnection issues, On-Ramp Wireless (ORW) was able to collect data from the RFIs, thus showing that ORW may be a viable solution for data collection over long distances.

# List of Acronyms

| | |
|---|---|
| AP | Access Point |
| NMS | Network Management Services |
| OWR | On-Ramp Wireless |
| RFI | Remote Fault Indicator |
| SCADA | Supervisory Control and Data Acquisition |
| SCE | Southern California Edison |
| SEL | Schweitzer Engineering Laboratories |
| VPN | Virtual Private Network |
| VSR | Virtualized Service Router |
| WSO | Wireless Sensor for Overhead Lines |

# High-Impedance Fault Detection on Distribution Circuits
# Final Project Report

Developed by

SCE Transmission & Distribution, Grid Technology & Modernization

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Southern California Edison

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# Acknowledgments

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# Table of Contents

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# 1 Executive Summary

Southern California Edison (SCE) and the rest of the electric utility industry continue to experience incidental high-impedance (HiZ) faults in large distribution or feeder line systems. These faults occur when a fallen conductor touches a high-resistance surface such as asphalt. The faults do not generate high enough current to trip traditional protection devices (e.g., a substation circuit breaker). Because HiZ faults may not be detected and isolated by conventional means, downed power lines can remain energized and represent a hazard to bystanders and utility workers.

Before beginning this project, SCE funded a laboratory-based project on HiZ faults. SCE contracted with the Southwest Research Institute (SwRI) for consulting services based on SwRI's previous experience with a measurement technique called Spread Spectrum Time Domain Reflectometry (SSTDR). The work used proof-of-concept laboratory bench testing to demonstrate that SSTDR can be used to locate HiZ faults on a de-energized distribution circuit. The testing sufficiently validated the robustness and reliability of localization techniques for identifying impedance changes, enabling SCE to proceed to more detailed demonstrations and expanded testing in energized distribution line test environments.

In the High-Impedance Fault Detector Project, SCE leveraged the successes of its previous work to further investigate SSTDR's capabilities to detect and locate HiZ faults through a signal transmission and response monitoring process. This work, funded by the Electric Program Investment Charge 1 (EPIC 1), established by the California Public Utilities Commission, included:

- Demonstrating the ability to detect a broken-phase anomaly between a transformer and the power source;
- Incorporating multi-conductor (three-phase) monitoring;
- Testing the system on energized conductors;
- Identifying and documenting a design for building a field prototype; and
- Further refining and enhancing the system.

The project saw several accomplishments in the demonstration of an SSTDR HiZ system when assessed on an outdoor conductor line. The results indicated that the HiZ system is capable of identifying anomalous impedances on energized circuits in a wide variety of system conditions, benefitting electric utilities by:

- Improving the ability to detect energized conductors that have fallen to the ground;
- Decreasing the number of false alarms;
- Increasing resolution and accuracy in the detection and localization of HiZ faults; and
- Enhancing public safety through the reduction of HiZ fault detection time.

While additional work is required to continue system performance refinement, SCE believes that the SSTDR HiZ technology can proceed to prototyping and field testing. SCE is now focused on bringing an SSTDR HiZ system to a successful pre-production stage. Any work beyond that would involve validating an SSTDR HiZ system for commercialization and mass production.

# 2 Project Summary

The overall goal of the project's Spread Spectrum Time Domain Reflectometry (SSTDR) high-impedance (HiZ) system is to minimize injury risk to the public and utility workers in the event of contact with one or more downed wires. Project results showed that this system conceptually can identify and notify Grid Operations quickly of a wire anomaly, resulting in appropriate action to de-energize the wire manually or automatically.

Per the Electric Program Investment Charge (EPIC) Investment Framework (Figure 1), the High-Impedance Fault Detector Project's benefits include increasing electric system safety and reliability by providing a reliable and accurate warning system to identify one or more broken/fallen energized conductors. This project also supports Grid Modernization and Optimization strategic goals by identifying failed aging infrastructure.


**Figure 1. EPIC Investment Framework for Utilities**

## 2.1 Problem Statement

The electric utility industry continues to experience high-impedance (HiZ) faults due to aging hardware such as conductors, poles, crossarms, and insulators. Many downed distribution power lines are still energized when utility workers arrive at the scene – presenting a safety risk to both them and the public. Existing solutions focus on current and voltage, but none of the technologies used to date have been able to reliably and securely detect HiZ faults. Current commercially available solutions also cause many false alarms. As a result, a new method is necessary. SCE believes a reflectometry-based solution represents an innovative and promising approach.

## 2.2 Project Scope

The scope of this project included:

- Refining techniques and algorithms for signal generation, reflection processing, map building, and reflection mapping;
- Evaluating in-line coupling technology, identifying an existing technology in the market suitable for the project's needs;
- Preparing a draft test plan for un-energized and energized testing;
- Conducting repeated single-phase testing on various exterior un-energized power lines utilizing the selected in-line (capacitive) coupler;
- Evaluating methods to translate circuit maps from SCE geographic information systems (GIS) into workable data structures for anomaly localization;
- Evaluating self-learning techniques for reacting to power flow configuration changes;
- Converting the system from a manual control to an automated operational system with continuous monitoring;
- Identifying a controllable switch box that allows one set of computing and signal hardware to control signal input and signal receipt on three independent line couplers;
- Conducting extensive field testing on energized lines, starting at 120 VAC up to 12 kV three-phase distribution;
- Performing testing of signal propagation through a phase-to-phase transformer connection;
- Conducting initial conductive coupling testing on underground conductors; and
- Completing testing of impedance discontinuities with placement before and after the transformer connections, as well as on the phase not connected to the transformer.

In this project, a design document for a field prototype was created. Finally, the monitoring process was demonstrated at the SCE-owned Equipment Demonstration Evaluation Facility, which is located at the Shawnee Substation in Westminster, CA, and features an energizable test environment.

Based on the achievements of the project, SCE is assessing whether testing eventually will transition from a simulated environment to a demonstration project on a real-world energized distribution system. If SCE conducts that work with successful results, and determines that a prototype system is ready, it may consider conducting a limited pilot demonstration on an actual 12-kV or 16-kV distribution circuit to determine the system's performance in a real-world environment.

The following sections list the project goals, all of which were successfully completed.

### 2.2.1 Project Goal 1: Transformer Backfeed Detection Investigation

**Goal:** Demonstrate a high-impedance (HiZ) system's ability to detect an impedance discontinuity on a phase connected to a potential transformer, when the impedance is located between the transformer and the power source.

**Approach:** Electrical backfeed through a phase-to-phase transformer to a broken line between the transformer and the power source represents a significant safety issue. It would be a major accomplishment if the HiZ system could detect this condition through its monitoring and provide an alert that the condition exists. Work associated with this goal involved analysis of signal propagation through a phase-to-phase transformer connection, and methods that the HiZ system could implement to accurately detect and report this dangerous condition.

### 2.2.2 Project Goal 2: Multi-Phase Monitoring and Anomaly Detection

**Goal:** Enhance the system from single-phase monitoring to three-phase monitoring.

**Approach:** Distribution lines at the medium-voltage level are typically three phase from the substation. The HiZ system needs the ability to monitor and detect anomaly impedances on any of these phases. This capability improvement in the project expanded the system to three-phase detection by incorporating line couplers placed on each phase, with appropriate system hardware to extend monitoring and detection to all three phases.

### 2.2.3 Project Goal 3: Expanded Field Testing

**Goal:** Test the system on energized circuits and on three phases.

**Approach:** The focus of this goal was to expand testing to energized power lines, as well as to test the system's ability to monitor all three phases of a medium-voltage distribution line.

### 2.2.4 Project Goal 4: Prototype Design

**Goal:** Finalize a prototype design and prepare a bill of materials to ready for future work.

**Approach:** Based on work including three-phase monitoring and detection, a prototype design document outlined how the system will be reduced to a field-deployable unit from the current laboratory-grade equipment.

### 2.2.5 Project Goal 5: Continued Improvements

**Goal:** Enhance and refine specific areas of system performance.

**Approach:** The focus of this task was to continue to improve the system in the areas of signal transmission, reflection processing, anomaly detection, and other areas based on outcomes from the expanded field testing.

## 2.3 Schedule and Deliverables

Originally, the project was scheduled for completion in seven months, from March 2015 to October 2015.

While significant progress was made during the first seven months, many unforeseen project challenges extended the schedule to a May 2016 completion date (resulting in a 14-month project).

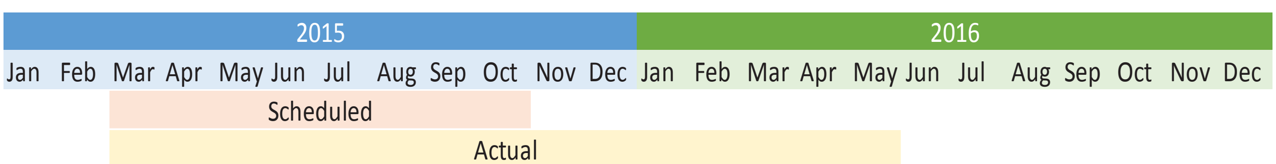


**Figure 2. Project Duration**

The project delivered the following:

1. Initial draft test plan for the Spread Spectrum Time Domain Reflectometry
2. Interior and exterior laboratory design drawing, pictures, and procedure
3. Prototype design schematics
4. Southwest Research Institute (SwRI) project demonstration to the SCE team at SwRI's Texas facility
5. An end-of-project demonstration of technical accomplishments, focusing on line coupling technology and methodology, and immunity to noise on the line
6. A final project report containing test results, outcomes, and recommendations, as well as a final presentation on all activities
7. A plan for all testing activities at the SCE Equipment Demonstration Evaluation Facility and the SwRI (Sabinal, Texas) sites

# 3 Project Results

This section describes the results achieved during the project.

## 3.1 Achievements

### 3.1.1 Goal 1: Transformer Backfeed Detection Investigation

Testing in the laboratory on a phase-to-phase distribution transformer determined that the high-impedance (HiZ) signal cannot effectively transmit through the transformer. The signal attenuated too much for effective detection through the non-signal transmitted phase connected to the transformer.

However, testing indicated that the HiZ system can effectively detect a broken line between the transformer and the power source. It did this because it was monitoring all three phases of the power line independently through its round-robin detection scheme. Testing showed that the system detected an impedance discontinuity on any phase, no matter where it was located.

### 3.1.2 Goal 2: Multi-Phase Monitoring and Anomaly Detection

A coupler switch box was incorporated and tested that allowed one set of computing and signaling hardware to interact with three couplers in a round-robin manner. The box contained a digitally controlled switch to control which coupler sent the transmit signal. Testing on a three-phase circuit proved that the box can successfully control transmission and receipt of HiZ signals to a coupler on each phase of the circuit.

The HiZ system software was modified for three-phase monitoring. The ability to continually monitor each phase of the circuit also was implemented.

### 3.1.3 Goal 3: Expanded Field Testing

Multiple field tests were conducted at energized voltages up to 12 kV. As predicted through earlier analysis, there was no significant impact to the HiZ signal or its ability to detect anomaly impedances when the line was energized.

### 3.1.4 Goal 4: Prototype Design

Based on the work completed, the project team prepared a design document for a prototype HiZ device. This design incorporates the coupler switch box as a system component. The document also identifies the design of the computing, signal processing, and anomaly processing components needed to move the system from laboratory-grade equipment to less-expensive and more rugged equipment suitable for field deployment.

### 3.1.5 Goal 5: Continued Improvements

As an element of the three-phase monitoring, the anomaly detection component was upgraded to utilize long-term and short-term averages to look for changes in the line that may indicate impedance anomalies. The implementation of these trend windows will be important to reduce or eliminate false positive readings as the system matures and moves to more complex line environments. Such false positives may be caused by weather, capacitor banks, switchgear, or other short-term events that may look like anomalies but, in fact, are not.

## 3.2 Value Proposition

The project efforts documented in this report successfully demonstrated the ability of a Spread Spectrum Time Domain Reflectometry (SSTDR) high-impedance (Hiz) system to quickly identify and notify grid operators of wire anomalies so they can de-energize a downed wire manually or automatically to minimize injury risk to the public and utility workers.

This work provided significant value by validating HiZ concepts (demonstrable on a laboratory bench) and demonstrating them in a simulated field environment. This allowed SCE to expose the SSTDR HiZ system to a more complex demonstration utilizing actual field equipment, in turn helping project engineers understand real-world operational issues. This work sets the stage for electric utility vendors to create commercial-grade equipment to realize the full value of this technology.

## 3.3 Metrics

The following metrics for safety, power quality, and reliability apply to the High-Impedance Fault Detector Project:

- **Outage number, frequency, and duration reduction:** The Spread Spectrum Time Domain Reflectometry (SSTDR) high-impedance (HiZ) system can reduce outages associated with HiZ faults. The system has demonstrated the ability to identify an HiZ fault within one pole span, which can reduce outage duration by eliminating a utility worker's need to perform a driven inspection of the circuit to identify the fault location.

- **Public and utility worker safety improvement and hazard exposure reduction:** The project has demonstrated that this system conceptually can identify and notify Grid Operations quickly of a wire anomaly, de-energizing the wire manually or automatically. In a real-world operating scenario, this would reduce the exposure of a fallen energized line from days to minutes, and improve public and utility worker safety.

- **Increase in the number of nodes in the power system at monitoring points:** The system has demonstrated the ability to monitor multiple circuit nodes and branches for electrical conductivity for a large percentage of a circuit. While it is too early to specify the coverage limitations, this system shows the potential to provide a new level of power system monitoring capability.

## 3.4 Technical Lessons Learned and Recommendations

### 3.4.1 Chirps

New chirps have been investigated and integrated into the system. (A chirp is a set of signals that change in frequency as time increases.) These use a shorter-length signal to minimize the overlapping of inbound and outbound signals. The shorter signal length also provides higher temporal resolution by minimizing the overlap between adjacent peaks. The chirps were shortened by including a smaller number of cycles in the outbound signal while maintaining the same frequency content. The total number of different types of chirps also was reduced by removing chirps that did not have strong signal reflections. This reduced the signal acquisition and processing time.

### 3.4.2 Peripheral Box

The amplification and switching components involved in the system were integrated into a single coupler switch box (Figure 3). This minimizes the set-up time needed for testing by combining more than 20 discrete components into 1 easy-to-use box, plus ensures identical wiring between testing events.

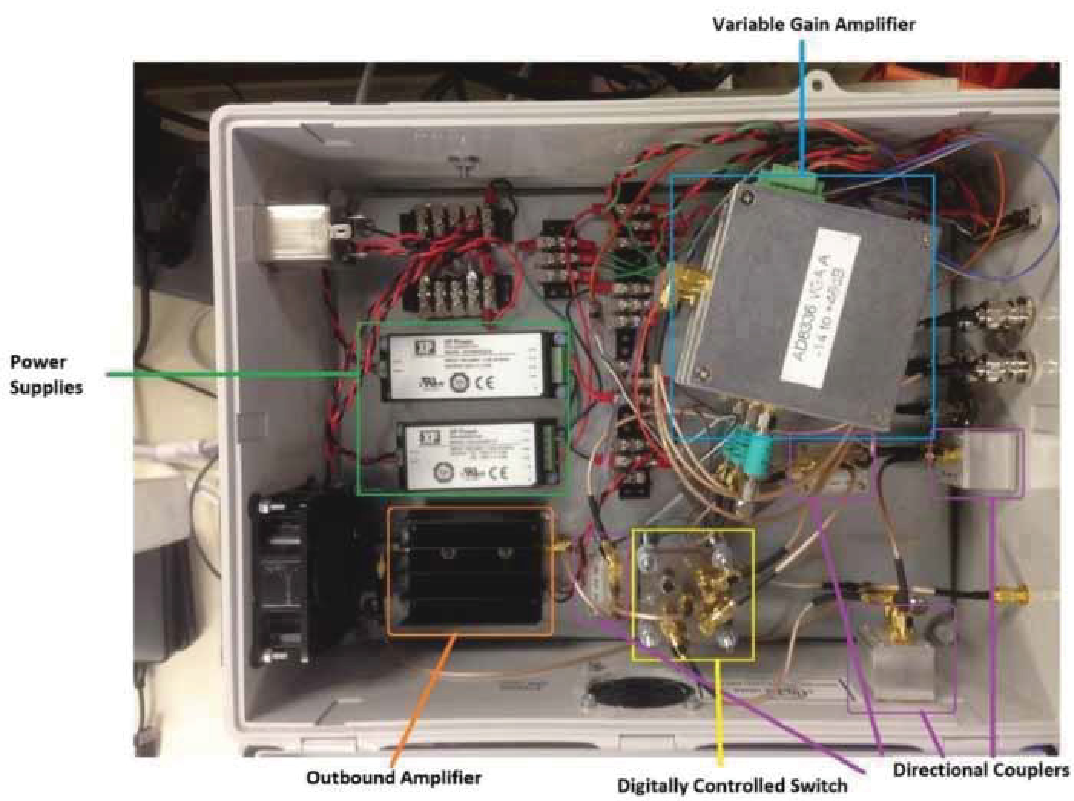


**Figure 3. Coupler Peripheral Box**

### 3.4.3 Anomaly Detection

The anomaly detection algorithm continues to be improved. Modifications in this phase included incorporating short-term and long-term averaging to better identify abnormal trends in the received signals. When anomalies occur, they will more strongly affect the short-term average due to the individual measurement having a higher weight. The anomalies can therefore be identified as extrema in the difference between the short- and long-term averages, which incorporate many measurements. Comparison of the short-term and long-term averages allows for a more robust detection of anomalies. Processing of the anomalies over time also has been added to allow better filtering of noise in the anomaly detection process, and to reduce the effect of impulsive noise on the detection algorithm.

### 3.4.4 Transformer Backfeed Detection

A project goal was to determine the ability of the high-impedance (HiZ) system to detect a broken line on a primary phase of a transformer.

A 4-kV to 240/120-VAC transformer (shown in Figure 4) was procured and brought into the laboratory. Capacitive couplers were attached to each of the primary side connections to allow a signal to be injected through one primary bushing and to be received through the other primary bushing. A signal was transmitted through the transformer's primary windings to measure its propagation. (This duplicates the scenario where the signal is sent on Phase A and is listened to on Phase B, assuming that A and B are the two phases connected to the transformer.) A resistor was placed on the secondary side to match the impedance of the capacity couplers, which allowed for maximum transmission of the signal through the transformer.

The testing demonstrated that any signal transmitted through the primary side of a transformer reflects from an impedance and travels back through the primary side of a transformer, resulting in an attenuation of at least 20 dB. This amount of attenuation caused by a transformer makes anomaly detection through a transformer difficult, if not impossible, with this technology.

**Figure 4. Transformer Testing**

### 3.4.5 Laboratory Demonstration~~Research~~ Environment

Commercial off-the-shelf equipment was utilized in order to perform the project experiments. The system is a PXI Express controller from National Instruments that includes two digitizers, a signal generator, an analog/digital input/output device, and a computer. This hardware was programmed using LabVIEW software, which allowed the establishment of custom programs, algorithms, and data manipulation routines. Dual directional couplers were selected to isolate the transmit signals and the reflected signals going into the digitizers. A broadband amplifier was placed before the directional couplers and after the arbitrary waveform generator to amplify the signal to 1 watt. A low-noise amplifier was utilized after the reflected signal portion of the directional coupler and before the digitizer to amplify the reflected signal and match the digitizer voltage range. The antennas were used to capture noise from the atmosphere and radiated emissions from the capacitive coupler. Figure 5 shows a block diagram representative of the research environment for a system that monitors three-conductor phases. Figure 6 shows a picture of the system as it was configured for single-phase testing. Note that the components shown outside of the PXI have now been relocated to the switch box.

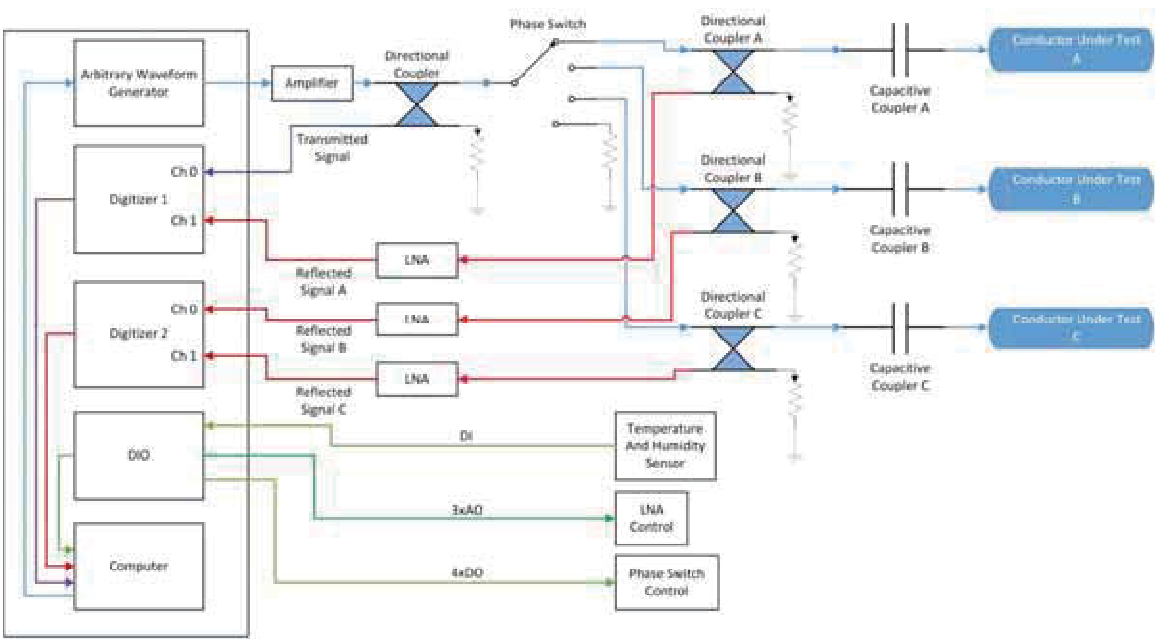


**Figure 5. The HiZ Research Environment for Three-Phase Monitoring**

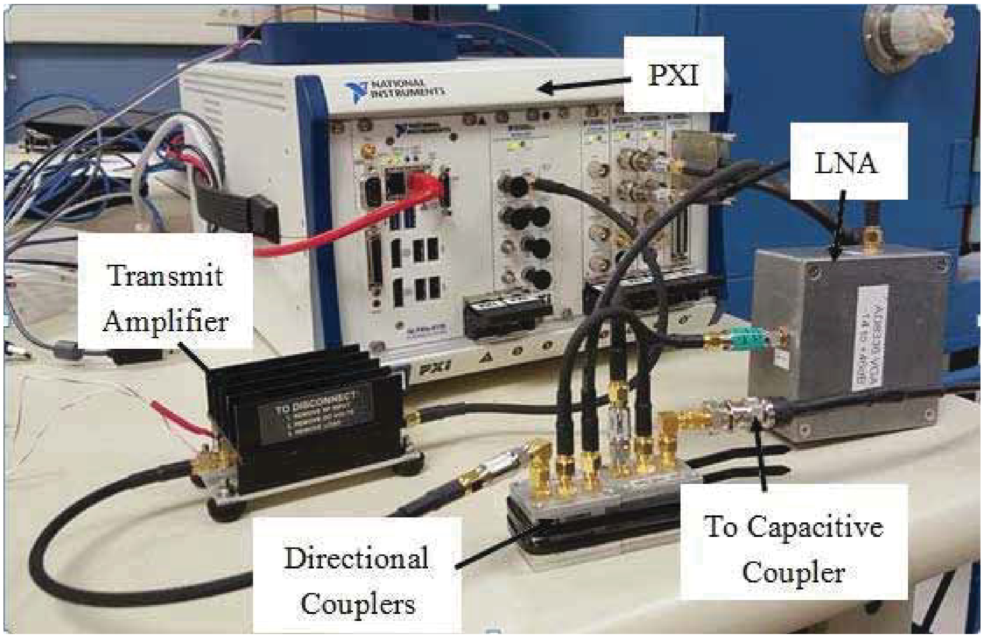


Figure 6. PXI, Coupler and Amplifier Setup

### 3.4.6 Field Test Environments

Several field test environments were utilized to support advancement of the high-impedance (HiZ) system. These environments served two primary purposes: 1) to gather information on HiZ performance on power lines outside of the laboratory environment, and 2) to iteratively test the HiZ system as it progressed.

#### *3.4.6.1 Short-Line Field Testing*

The short-line field test site, shown in Figure 7, is located on the grounds of the Southwest Research Institute (SwRI) in Texas.

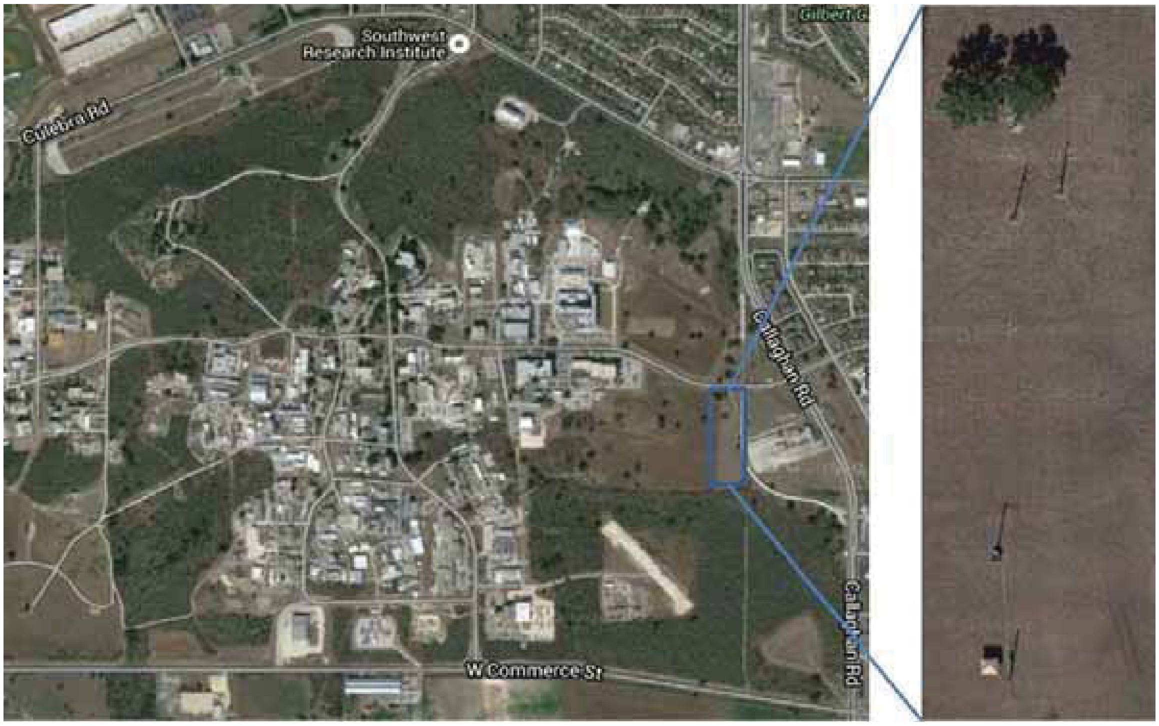


Figure 7. SwRI Short-Line Field Test Site

For the extension project, an approximately 100-meter section of 336 aluminum conductor steel-reinforced cable (ACSR) was strung along 19 tripod structures. The line, elevated approximately 1.5 to 2 meters above ground, was insulated from contact with the tripods using electrical PVC conduit. Utilizing this setup, SwRI was able to conduct both de-energized testing of a longer section of line than it previously could, as well as testing at 120 VAC as an initial energized test.

Figure 8. Energized Short-Line Test Setup at SwRI Field Site

#### 3.4.6.2 Long-Line Field Testing

The long-line Southwest Research Institute (SwRI) field test site (shown in Figure 9), located approximately 60 miles west of San Antonio in Sabinal, Texas, consists of a 3-phase energizable conductor. The site has a 1-mile straight-line conductor configuration, as shown in Figure 10, with an additional 1/3-mile feeder line to the utility connection. The line is 4/0 aluminum conductor steel reinforced cable (ACSR) in a 3-phase plus neutral configuration that can be energized to 14 kV. In a de-energized configuration, the phases can be crossed to create a 3-mile single phase. The site provides a distribution-grade conductor for testing where anomaly impedance discontinuities can be introduced and analyzed, but it does not include any equipment installed on the lines.

For the project, the line was energized at 480 VAC and then at 4 kV. A phase-to-phase distribution transformer was installed just before the line midpoint.

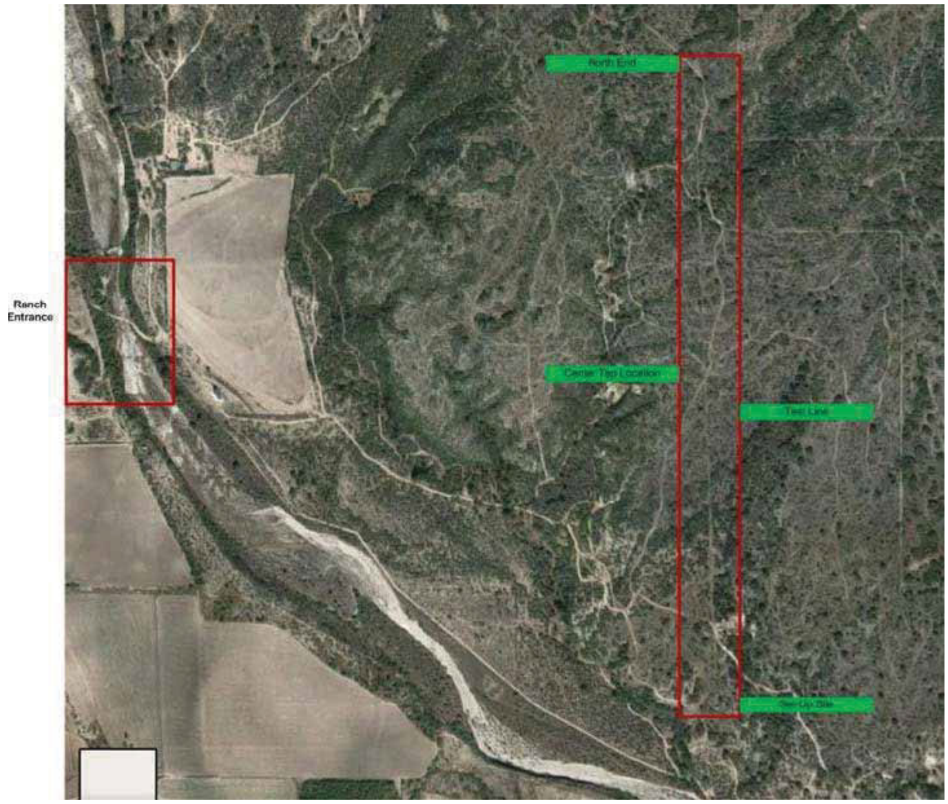


Figure 9. Aerial View of Sabinal Long-Line Test Facility

While the short-line test site focused on understanding the behavior of the high-impedance signals on power conductors, the long-line test site provided a clean-line environment for focusing on detecting anomaly impedance discontinuities. Results from testing at the site were used to further refine the signal processing and anomaly detection algorithms.

Figure 10. Line View of Sabinal Test Facility

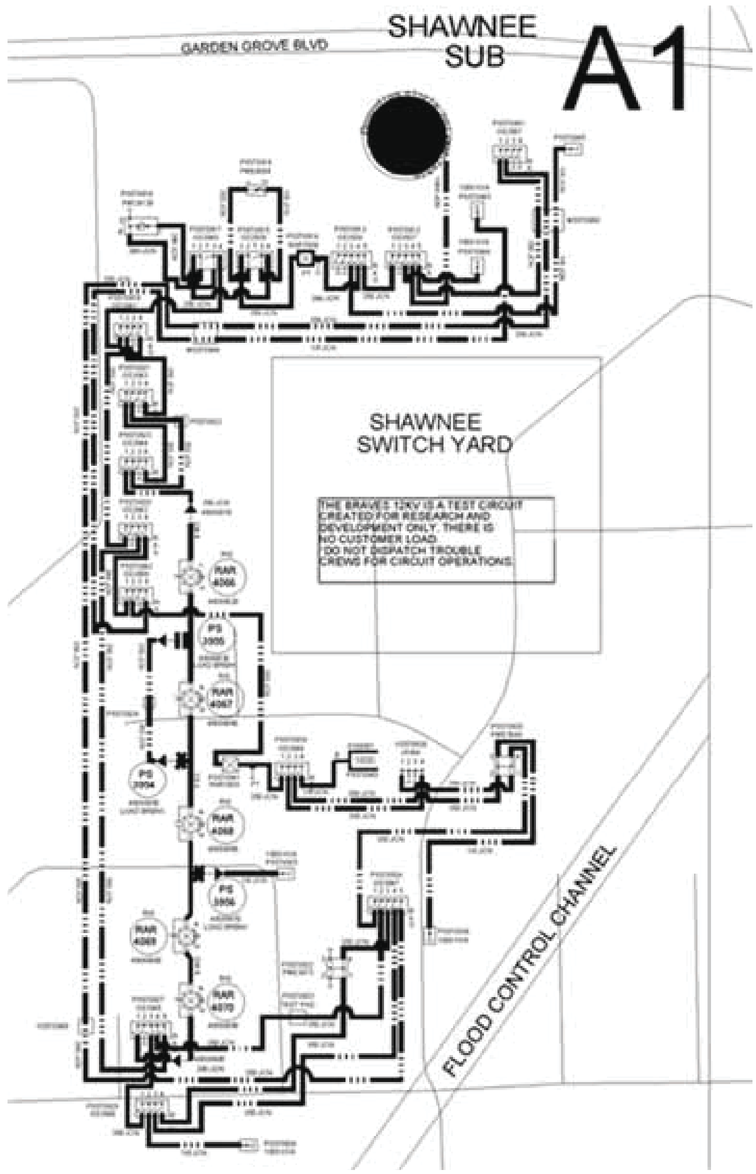


**Figure 11. EDEF Test Site One Line**

### 3.4.6.3 *EDEF Field Testing*

The SCE-owned Equipment Demonstration Evaluation Facility (EDEF) test site is located at the Shawnee Substation in Westminster, CA. This facility features an energizable test environment, shown in Figure 11, consisting of three-phase distribution lines above and underground. There are multiple switches and reclosers installed, as well as other types of representative equipment for a distribution environment. This site represents a more realistic view of a distribution system.

Use of the EDEF site allowed for full testing of the high-impedance (HiZ) system, including monitoring on three phases, and the detection of different HiZ fault conditions.

Figure 12. EDEF Site

## 3.5 Technology/Knowledge Transfer Plan

While additional work is required to continue system performance refinement, the lessons learned from this project can be transferred to actual prototyping and field testing, as well as bringing a Spread Spectrum Time Domain Reflectometry high-impedance system to a pre-production stage.

## 3.6 Stakeholder Engagement

Stakeholder engagement consisted of various meetings throughout the project, and during these meetings the project team shared updates, achievements, and challenges. In addition, the project team held two demonstrations specifically for stakeholders and SCE executives, providing them with the opportunity to see the system working in real time. Lastly, the project team prepared a final presentation, summarizing the results of all activities, and shared it with all stakeholders.

Considering that many of the stakeholders were not involved during the previous proof-of-concept laboratory work, this project provided them with an introduction to the team's vision for Spread Spectrum Time Domain Reflectometry technology. The stakeholders were impressed with the speed and accuracy with which the system was able to identify a change in a circuit's impedance discontinuity.

# List of Acronyms

| | |
|---|---|
| ACSR | Aluminum Conductor Steel-Reinforced Cable |
| dB | Decibel |
| CPUC | California Public Utilities Commission |
| EPIC | Electric Program Investment Charge |
| EDEF | Equipment Demonstration Evaluation Facility |
| GIS | Geographic Information Systems |
| HiZ | High Impedance |
| kV | Kilovolt |
| SCE | Southern California Edison |
| SSTDR | Spread Spectrum Time Domain Reflectometry |
| SwRI | Southwest Research Institute |
| VAC | Volts Alternating Current |

| Investment Program Period | Program Administrator | Project Name | Project Type | A brief description of the project | Date of the award | Was this project awarded in the immediately prior calendar year? | Assignment to Value Chain | Encumbered Funding Amount ($) | Committed Funding Amount ($) | Funds Expended to date: Contract/Grant Amount ($) | Funds Expended to date: In house expenditures ($) | Funds Expended to date: Total Spent to date ($) | Administrative and overhead costs incurred for each project |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Select from: 1st triennial (2012-2014); 2nd triennial (2015- | Select from: CEC, PG&E, SCE, SDG&E | Enter project title. | Describe the type of project th. | General description (objective, scope, deliverables, schedule) | The date the award/grant was made | Yes/No | Select from: Generation, Transmission | ($) | ($) | ($) | ($) | ($) | ($)Does not include EPIC administration costs. Includes only project specific |
| 1st triennial (2012-2014) | SCE | **Integrated Grid Project**<br>*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 | $ 11,234,429 | $ 17,431,024 | $ 15,567,745 | $ 1,829,394 | $ 17,397,139 | N/A |
| 1st triennial (2012-2014) | SCE | **Regulatory Mandates: Submetering Enablement Demonstration** | Customer Focused Products and Services | On 11/14/13, the California Public Utilities Commission (CPUC) voted to approve the revised Proposed Decision (PD) Modifying the Requirements for the Development of a Plug-In Electric Vehicle Submetering Protocol set forth in D.11-07-029. The investor-owned utilities (IOUs) are to implement a two phased pilot beginning in May 2014, with funding for both phases provided by the Electric Program Investment Charge (EPIC). This project, Phase I of the pilot will (1) evaluate the demand for Single Customer of Record submetering, (2) estimate billing integration costs, (3) estimate communication costs, and (4) evaluate customer experience. IOU's and external stakeholders will finalize the temporary metering requirements, develop a template format used to report submetered, time-variant energy data, register Submeter Meter Data Management Agents and develop a Customer Enrollment Form, and finalize MDMA Performance Requirements. The IOUs will also solicit a 3rd party evaluator to evaluate customer experience. | 8/15/2012 | No | Demand-Side Management | $ - | $ 1,138,359 | $ 980,035 | $ 158,324 | $ 1,138,359 | N/A |
| 1st triennial (2012-2014) | SCE | **Distribution Planning Tool** | Energy Resources Integration | This project involves the creation, validation, and functional demonstration of an SCE distribution system model that will address the future system architecture that accommodates distributed generation (primarily solar photovoltaic), plug-in electric vehicles, energy storage, customer programs (demand response, energy efficiency), etc. The modeling software to be used allows for implementation of advanced controls (smart charging, advanced inverters, etc.). These controls will enable interaction of a residential energy module and a power flow module. It also enables the evaluation of various technologies from an end-use customer perspective as well as a utility perspective, allowing full evaluation from substation bank to customer. This capability does not exist today. The completed model will help SCE demonstrate, communicate and better respond to technical, customer and market challenges as the distribution system architecture evolves. | 8/15/2012 | No | Distribution | $ - | $ 1,071,128 | $ 847,320 | $ 223,808 | $ 1,071,128 | N/A |

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

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

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

| Investment Program Period | Program Administrator | Project Name | Project Type | A brief description of the project | Date of the award | Was this project awarded in the immediately prior calendar year? | Assignment to Value Chain | Encumbered Funding Amount ($) | Committed Funding Amount ($) | Funds Expended to date: Contract/Grant Amount ($) | Funds Expended to date: In house expenditures ($) | Funds Expended to date: Total Spent to date ($) | Administrative and overhead costs incurred for each project |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1st triennial (2012-2014) | SCE | **Beyond the Meter: Customer Device Communications, Unification and Demonstration (Phase II)** | Customer Focused Products and Services | The Beyond the Meter (BTM) project will demonstrate the use of a DER management system to interface with and control DER based on customer and distribution grid use cases. It will also demonstrate the ability to communicate near-real time information on the customer's load management decisions and DER availability to SCE for grid management purposes.<br><br>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 | $ 2,079,825 | $ 1,472,050 | $ 1,282,316 | $ 179,734 | $ 1,462,050 | 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 | $ - | $ 39,564 | $ 24,120 | $ 15,444 | $ 39,564 | N/A |
| 1st triennial (2012-2014) | SCE | **Voltage and VAR Control of SCE Transmission System** | Energy Resources Integration | This project involves the demonstration of software and hardware products that will enable automated substation volt/var control. Southern California Edison (SCE) will demonstrate a Substation Level Voltage Control (SLVC) unit working with a transmission control center Supervisory Central Voltage Coordinator (SCVC) unit to monitor and control substation voltage. The scope of this project includes systems engineering, testing, and demonstration of the hardware and software that could be operationally employed to manage substation voltage. | 8/15/2012 | No | Transmission | $ 563,428 | $ 865,049 | $ 253,733 | $ 269,986 | $ 523,719 | N/A |

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

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

| Investment Program Period | Program Administrator | Project Name | Project Type | 2017 Update | Coordination with CPUC Proceedings or Legislation |
|---|---|---|---|---|---|
| 1st triennial (2012-2014) | SCE | **Beyond the Meter: Customer Device Communications, Unification and Demonstration (Phase II)** | Customer Focused Products and Services | The EPIC 1 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. | |
| 1st triennial (2012-2014) | SCE | **Portable End-to-End Test System** | Grid Modernization and Optimization | The final project report is complete, was submitted with the 2015 Annual Report, and is available on SCE's public EPIC web site. | |
| 1st triennial (2012-2014) | SCE | **Voltage and VAR Control of SCE Transmission System** | Energy Resources Integration | In 2017, the project accomplished the following:<br>1) Developed a Business Requirement Document and an Implementation Plan detailing how the Volt and Var Optimization demonstration will be formulated, implemented, and integrated with existing SCE systems.<br>2) Implemented User Interfaces for the Voltage and Var Optimization tool.<br>3) Implemented the Security Constrained Optimal Power Flow Formulation and Solution.<br>4) Implemented a data conversion module to allow reading data from the Energy Management System into the Voltage and Var Optimization tool.<br><br>This project is scheduled for completion in 2018 | |

| Investment Program Period | Program Administrator | Project Name | Project Type | A brief description of the project | Date of the award | Was this project awarded in the immediately prior calendar year? | Assignment to Value Chain | Encumbered Funding Amount ($) | Committed Funding Amount ($) | Funds Expended to date: Contract/Grant Amount ($) | Funds Expended to date: In house expenditures ($) | Funds Expended to date: Total Spent to date ($) | Administrative and overhead costs incurred for each project |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1st triennial (2012-2014) | SCE | **Superconducting Transformer (SCX) Demo** | Grid Modernization and Optimization | SCE will support this $21M American Reinvestment and Recovery Act (ARRA) Superconducting Transformer (SCX) project by providing technical expertise and installing and operating the transformer at SCE's MacArthur substation. The SCX prime contractor is SuperPower Inc. (SPI), teamed with SPX Transformer Solutions (SPX) {formerly Waukesha Electric Systems}. SCE has provided two letters of commitment for SCX. The SCX project will develop a 28 MVA High Temperature Superconducting, Fault Current Limiting (HTS-FCL) transformer. The transformer is expected to be installed in 2015. SCE is supporting this project and is not an ARRA grant sub-recipient. SCE is being reimbursed for its effort by EPIC. SCE's participation in this project was previously approved under the now defunct California Energy Commission's PIER program. | 8/15/2012 | No | Distribution | $ - | $ 10,241 | $ - | $ 10,241 | $ 10,241 | N/A |
| 1st triennial (2012-2014) | SCE | **State Estimation Using Phasor Measurement Technologies** | Cross-Cutting/Foundational Strategies & Technologies | Accurate and timely power system state estimation data is essential for understanding system health and provides the basis for corrective action that could avoid failures and outages. This project will demonstrate the utility of improved static system state estimation using Phasor Measurement Unit (PMU) data in concert with existing systems. Enhancements to static state estimation will be investigated using two approaches: 1) by using GPS time to synchronize PMU data with Supervisory Control and Data Acquisition (SCADA) system data; 2) by augmenting SCE's existing conventional state estimator with a PMU based Linear State Estimator (LSE). | 8/15/2012 | No | Grid Operation/Market Design | $ - | $ 822,182 | $ 300,046 | $ 522,136 | $ 822,182 | N/A |
| 1st triennial (2012-2014) | SCE | **Wide-Area Reliability Management & Control** | Energy Resources Integration | With the planned wind and solar portfolio of 33% penetration, a review of the integration strategy implemented in the SCE bulk system is needed. The basic premise for the integration strategy is that a failure in one area of the grid should not result in failures elsewhere. The approach is to minimize failures with well designed, maintained, operated, and coordinated power grids. New technologies can provide coordinated wide-area monitoring, protection, and control systems with pattern recognition and advance warning capabilities. This project will demonstrate new technologies to manage transmission system control devices to prevent cascading outages and maintain system integrity. | 8/15/2012 | No | Grid Operation/Market Design | $ 949,510 | $ 871,128 | $ 321,486 | $ 119,571 | $ 441,057 | N/A |

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

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

| Investment Program Period | Program Administrator | Project Name | Project Type | 2017 Update | Coordination with CPUC Proceedings or Legislation |
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| 1st triennial (2012-2014) | SCE | **Superconducting Transformer (SCX) Demo** | Grid Modernization and Optimization | SCE formally cancelled this project in Q3 2014. | N/A - Cancelled. |
| 1st triennial (2012-2014) | SCE | **State Estimation Using Phasor Measurement Technologies** | Cross-Cutting/Foundational Strategies & Technologies | The EPIC 1 Final Report for the State Estimation Using Phasor Measurement Technologies Project is complete, is being submitted with the 2017 Annual Report, and will be posted on SCE's public EPIC web site. | |
| 1st triennial (2012-2014) | SCE | **Wide-Area Reliability Management & Control** | Energy Resources Integration | In 2017, SCE is currently working with Siemens on utilizing Devers SVC for power oscillation damping (POD) to accommodate for the increase penetration of renewable resources. To demonstrate the effectiveness and benefits of the proposed POD a series of test cases were created for the assessment of the performance of the SVC POD functionality under different operating conditions and to ensure that the functionality will not negatively impact SCE Bulk system operation and control. SCE is also working with Manitoba HVDC to provide the technical services support to SCE to assist the ongoing Devers SVC POD tuning and testing demonstrations. Also, to expand the POD functionality to damp forced oscillations created by Solar PV generating stations due to improper tuning of the inverter control system.<br>Siemens has completed the implementation of updating the SVC dynamic models to include the POD Controller and added the POD functionality to Devers SVC transient model (i.e. PSCAD Model). The models are currently used to tune and select the best gains for the POD controller.<br>Manitoba has provided Training to the SCE Engineers on SVC POD tuning studies.<br><br>The project will be completed in 2018. | |

| Investment Program Period | Program Administrator | Project Name | Project Type | A brief description of the project | Date of the award | Was this project awarded in the immediately prior calendar year? | Assignment to Value Chain | Encumbered Funding Amount ($) | Committed Funding Amount ($) | Funds Expended to date: Contract/Grant Amount ($) | Funds Expended to date: In house expenditures ($) | Funds Expended to date: Total Spent to date ($) | Administrative and overhead costs incurred for each project |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1st triennial (2012-2014) | SCE | **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 | $ - | $ 68,175 | $ 540 | $ 67,635 | $ 68,175 | 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 | $ - | $ 1,018,405 | $ 702,359 | $ 316,046 | $ 1,018,405 | 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 | $ 2,785,584 | $ 6,429,471 | $ 2,207,852 | $ 728,923 | $ 2,936,775 | N/A |

| Investment Program Period | Program Administrator | Project Name | Project Type | Leveraged Funds | Partners | Match Funding | Match Funding Split | Funding Mechanism | Intellectual Property | Identification of the method used to grant awards. | If competitively selected, provide the number of bidders passing the initial pass/fail screening for project | If competitively selected, provide the name of selected bidder. | If competitively selected, provide the rank of the selected bidder in the selection process. | If competitively selected, explain why the bidder was not the highest scoring bidder, explain why a lower scoring bidder was selected. |
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| 1st triennial (2012-2014) | SCE | **Distributed Optimized Storage (DOS) Protection & Control Demonstration** | Energy Resources Integration | TBD | TBD | TBD | TBD | Pay-for-Performance Contracts | SCE has no current patents or licensing agreements signed. Future Intellectual Property is to be determined. | TBD | TBD | TBD | TBD | TBD |
| 1st triennial (2012-2014) | SCE | **Outage Management and Customer Voltage Data Analytics Demonstration** | Customer Focused Products and Services | N/A | N/A | N/A | N/A | Pay-for-Performance Contracts | SCE has no current patents or licensing agreements signed. Future Intellectual Property is to be determined. | Directed Awards Issued to the Following Vendor(s):<br><br>Cyient, Inc.;<br>Nexant Inc | N/A | N/A | N/A | N/A |
| 1st triennial (2012-2014) | SCE | **SA-3 Phase III Demonstration** | Grid Modernization and Optimization | N/A | N/A | N/A | N/A | Pay-for-Performance Contracts | SCE has no current patents or licensing agreements signed. Future Intellectual Property is to be determined. | Competitive Bid ((Request for Proposal) to the Following Vendor(s):<br>1- ....<br><br>(Direct award) to the Following Vendor(s):<br>2- .... | | | | N/A |

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

| Investment Program Period | Program Administrator | Project Name | Project Type | 2017 Update | Coordination with CPUC Proceedings or Legislation |
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| 1st triennial (2012-2014) | SCE | **Distributed Optimized Storage (DOS) Protection & Control Demonstration** | Energy Resources Integration | The DOS Protection & Control Demonstration project was approved in the SCE EPIC 1 Triennial plan. Command and control of distributed energy resources (DER) is a common goal of the DOS Protection and Control Demonstration and the Integrated Grid Project (IGP). To optimally manage the DOS Protection & Control Demonstration and maximize cost efficiency, the design, procurement, and testing of the control systems have been combined. In addition, since field demonstrations are difficult to schedule and costly to conduct, the DOS Protection & Control field demonstration has been combined with the IGP field demo. Following successful testing of the DOS Protection & Control Demonstration/IGP control systems in the laboratory environment, the controls will be deployed in SCE's production environment as part of the IGP field demonstration.<br><br>Milestones achieved in 2017<br><br>- Completed Pre-FAT<br>- Completed FAT 1 Sandbox Testing<br>- Completed FAT 1<br>- Refined Battery "Dual Use" Use Cases | Energy Storage R,.15-03-011; D.14-10-040 & D.14-10-045<br>Resource Adequacy OIR, R.14-10-010 |
| 1st triennial (2012-2014) | SCE | **Outage Management and Customer Voltage Data Analytics Demonstration** | Customer Focused Products and Services | The final project report is complete, was submitted with the 2015 Annual Report, and is available on SCE's public EPIC web site. | |
| 1st triennial (2012-2014) | SCE | **SA-3 Phase III Demonstration** | Grid Modernization and Optimization | 2017 accomplishments:<br>The original project scope addressing field demonstration has been restored to the project. With this change, the SA-3 Phase III project will be deployed at Viejo A-station for field demonstration and an in-service date of Jun 28, 2019.<br><br>High level 2017 accomplishments:<br>• Viejo relay rack wiring has been completed in the Grid Technology & Demonstration (GT&M) lab.<br>• The SA-3 component configuration files were developed to enable vendor Factory Acceptance Testing.<br>• Relay racks have been delivered and installed in SCE's GT&M lab.<br>• An SCE Cybersecurity assessment for the Substation Management System (SMS) was performed.<br>• The HMI Service (software) has been received, tested, and minor issue have been reported.<br>• The new A-Station Annunciator has been received and is set up for testing. | |

| Investment Program Period | Program Administrator | Project Name | Project Type | A brief description of the project | Date of the award | Was this project awarded in the immediately prior calendar year? | Assignment to Value Chain | Encumbered Funding Amount ($) | Committed Funding Amount ($) | Funds Expended to date: Contract/Grant Amount ($) | Funds Expended to date: In house expenditures ($) | Funds Expended to date: Total Spent to date ($) | Administrative and overhead costs incurred for each project |
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| 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 | $ - | $ 4,129,805 | $ 3,113,822 | $ 1,015,983 | $ 4,129,805 | 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 | $ - | $ 79,119 | $ 31,700 | $ 47,419 | $ 79,119 | N/A |
| 1st triennial (2012-2014) | SCE | **Dynamic Line Rating Demonstration** | 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 ensure compliance with safety codes, maintain the integrity of line materials, and ensure 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. | 12/17/2013 | No | Transmission | $ - | $ 468,601 | $ 380,051 | $ 88,550 | $ 468,601 | N/A |
| 1st triennial (2012-2014) | SCE | **Cyber-Intrusion Auto-Response and Policy Management System (CAPMS)** | Cross-Cutting/Foundational Strategies & Technologies | Viasat in partnership with SCE and Duke Energy has been awarded a DOE contract (DE-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 | $ - | $ 1,809,323 | $ 1,703,701 | $ 105,622 | $ 1,809,323 | N/A |
| 2nd triennial (2015-2017) | SCE | **Integration of Big Data for Advanced Automated Customer Load Management** | Customer Focused Products and Services | This proposed project builds upon the "Beyond the Meter Advanced Device Communications" project from the first EPIC triennial investment plan, and purposes to demonstrate how the concept of "big data" 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) to determine the optimal load management scheme and execute by communicating to centralized energy hubs at the customer level. | 11/17/2014 | Yes | Demand-Side Management | $ 842,560 | $ 1,169,185 | $ 784,360 | $ 20,460 | $ 804,821 | $ 5,113 |
| 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 | $ - | $ 235,595 | $ 8,801 | $ 197,316 | $ 206,117 | $ 6,871 |

| Investment Program Period | Program Administrator | Project Name | Project Type | Leveraged Funds | Partners | Match Funding | Match Funding Split | Funding Mechanism | Intellectual Property | Identification of the method used to grant awards. | If competitively selected, provide the number of bidders passing the initial pass/fail screening for project | If competitively selected, provide the name of selected bidder. | If competitively selected, provide the rank of the selected bidder in the selection process. | If competitively selected, explain why the bidder was not the highest scoring bidder, explain why a lower scoring bidder was selected. |
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| 1st triennial (2012-2014) | SCE | **Next-Generation Distribution Automation** | Grid Modernization and Optimization | N/A | N/A | N/A | N/A | Pay-for-Performance Contracts | SCE has no current patents or licensing agreements signed. Future Intellectual Property is to be determined. | Competitive Bid<br><br>Directed Awards Issued to the Following Vendor(s):<br><br>Cleaveland Price Inc.; Doble Engineering Company; GE MDS LLC.; One Source Supply Solutions LLC. | 2 | G&W Electric Company; Par Electrical Contractors Inc. | G&W Electric Company; Par Electrical Contractors Inc. | |
| 1st triennial (2012-2014) | SCE | **Enhanced Infrastructure Technology Evaluation** | Grid Modernization and Optimization | N/A | N/A | N/A | TBD | Pay-for-Performance Contracts | SCE has no current patents or licensing agreements signed. Future Intellectual Property is to be determined. | Directed Awards Issued to the Following Vendor(s):<br><br>American Restore, Inc.; Rivcomm, Inc.; California Turbo Inc | N/A | N/A | N/A | N/A |
| 1st triennial (2012-2014) | SCE | **Dynamic Line Rating Demonstration** | Grid Modernization and Optimization | N/A | N/A | N/A | N/A | Pay-for-Performance Contracts | SCE has no current patents or licensing agreements signed. Future Intellectual Property is to be determined. | Directed Awards Issued to the Following Vendor(s):<br><br>Wesco Distribution Inc<br><br>Black & Veatch Corporation<br><br>The Valley Group | N/A | N/A | N/A | N/A |
| 1st triennial (2012-2014) | SCE | **Cyber-Intrusion Auto-Response and Policy Management System (CAPMS)** | Cross-Cutting/Foundational Strategies & Technologies | DOE & Duke Energy Contributions: $4,486,430 | Viasat; Duke Energy | N/A | N/A | Pay-for-Performance Contracts | SCE has no current patents or licensing agreements signed. Future Intellectual Property is to be determined. | Directed Awards Issued to the Following Vendor(s):<br><br>@ Business Inc; Magnetic Instrumentation Inc; Saker Systems, LLC; World Wide Technology Inc; Zones, Inc.; Accuvant Inc; Electric Power Group, LLC; Schweitzer Engineering Labs Inc | N/A | N/A | N/A | N/A |
| 2nd triennial (2015-2017) | SCE | **Integration of Big Data for Advanced Automated Customer Load Management** | Customer Focused Products and Services | TBD | TBD | TBD | TBD | Pay-for-Performance Contracts | SCE has no current patents or licensing agreements signed. Future Intellectual Property is to be determined. | Competitive | 1 | Kitu, Inc | TBD | TBD |
| 2nd triennial (2015-2017) | SCE | **Advanced Grid Capabilities Using Smart Meter Data** | Grid Modernization and Optimization | TBD | TBD | TBD | TBD | Pay-for-Performance Contracts | SCE has no current patents or licensing agreements signed. Future Intellectual Property is to be determined. | TBD | TBD | TBD | N/A - This technology is very new | There are almost no vendors offering technologies in this area |

| Investment Program Period | Program Administrator | Project Name | Project Type | If interagency or sole source agreement, specify date of notification to the Joint Legislative Budget Committee (JLBC) was notified and date of JLBC authorization. | Does the recipient for this award identify as a California-based entity, small business, or businesses owned by women, minorities, or disabled veterans? | How the project leads to technological advancement or breakthroughs to overcome barriers to achieving the state's statutory energy goals | Applicable metrics |
|---|---|---|---|---|---|---|---|
| 1st triennial (2012-2014) | SCE | **Next-Generation Distribution Automation** | Grid Modernization and Optimization | N/A; Applicable to CEC only. | G&W Electric Company: California-based entity; Small Business<br><br>Par Electrical Contractors Inc.: California-based entity | N/A; Applicable to CEC only. | 3a. Maintain / Reduce operations and maintenance costs<br>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<br>5a. Outage number, frequency and duration reductions<br>5c. Forecast accuracy improvement<br>5d. Public safety improvement and hazard exposure reduction<br>5e. Utility worker safety improvement and hazard exposure reduction<br>5i. Increase in the number of nodes in the power system at monitoring points<br>6a. Improve data accuracy for distribution substation planning process<br>7b. Increased use of cost-effective digital information and control technology to improve reliability, security, and efficiency of the electric grid (PU Code § 8360);<br>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);<br>7d. Deployment and integration of cost-effective distributed resources and generation, including renewable resources (PU Code § 8360);<br>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);<br>8b. Number of reports and fact sheets published online<br>8d. Number of information sharing forums held.<br>8f. Technology transfer |
| 1st triennial (2012-2014) | SCE | **Enhanced Infrastructure Technology Evaluation** | Grid Modernization and Optimization | N/A; Applicable to CEC only. | American Restore, Inc.: California-based entity<br><br>Rivcomm, Inc.: California-based entity; Small Business<br><br>California Turbo Inc: California-based entity | N/A; Applicable to CEC only. | 3a. Maintain / Reduce operations and maintenance costs<br>3b. Maintain / Reduce capital costs<br>4g. Wildlife fatality reductions (electrocutions, collisions)<br>5a. Outage number, frequency and duration reductions<br>6a. Operating performance of underground vault monitoring equipment<br>8b. Number of reports and fact sheets published online<br>8d. Number of information sharing forums held.<br>8f. Technology transfer<br>9c. EPIC project results referenced in regulatory proceedings and policy reports. |
| 1st triennial (2012-2014) | SCE | **Dynamic Line Rating Demonstration** | Grid Modernization and Optimization | N/A; Applicable to CEC only. | Wesco Distribution Inc: California-based entity; DBE<br><br>Black & Veatch Corporation: California-based entity<br><br>The Valley Group - N/A | N/A; Applicable to CEC only. | 3b. Maintain / Reduce capital costs<br>5b. Electric system power flow congestion reduction<br>6a. Increased power flow throughput<br>7b. Increased use of cost-effective digital information and control technology to improve reliability, security, and efficiency of the electric grid (PU Code § 8360);<br>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);<br>8b. Number of reports and fact sheets published online<br>8d. Number of information sharing forums held.<br>8f. Technology transfer<br>9c. EPIC project results referenced in regulatory proceedings and policy reports.<br>9d. Successful project outcomes ready for use in California IOU grid (Path to market).<br>9e. Technologies available for sale in the market place (when known). |
| 1st triennial (2012-2014) | SCE | **Cyber-Intrusion Auto-Response and Policy Management System (CAPMS)** | Cross-Cutting/Foundational Strategies & Technologies | N/A; Applicable to CEC only. | @ Business Inc: DBE<br><br>Magnetic Instrumentation Inc: N/A<br><br>Saker Systems, LLC: California-base entity; Small Business; DBE<br><br>World Wide Technology Inc: DBE<br><br>Zones, Inc.: DBE<br><br>Accuvant Inc: California-based entity<br><br>Electric Power Group, LLC: California-based entity<br><br>Schweitzer Engineering Labs Inc: California-based entity | N/A; Applicable to CEC only. | 5a. Outage number, frequency and duration reductions<br>7b. Increased use of cost-effective digital information and control technology to improve reliability, security, and efficiency of the electric grid (PU Code § 8360);<br>7l. Identification and lowering of unreasonable or unnecessary barriers to adoption of smart grid technologies, practices, and services (PU Code § 8360)<br>8b. Number of reports and fact sheets published online<br>8d. Number of information sharing forums held.<br>8f. Technology transfer<br>10a. Description or documentation of funding or contributions committed by others<br>10c. Dollar value of funding or contributions committed by others. |
| 2nd triennial (2015-2017) | SCE | **Integration of Big Data for Advanced Automated Customer Load Management** | Customer Focused Products and Services | N/A; Applicable to CEC only. | Small Business | N/A; Applicable to CEC only. | Metrics plan TBD |
| 2nd triennial (2015-2017) | SCE | **Advanced Grid Capabilities Using Smart Meter Data** | Grid Modernization and Optimization | N/A; Applicable to CEC only. | TBD | N/A; Applicable to CEC only. | 3a. Maintain / Reduce operations and maintenance costs<br>7b. Increased use of cost-effective digital information and control technology to improve reliability, security, and efficiency of the electric grid (PU Code § 8360)<br>8d. Number of information sharing forums held<br>8f. Technology transfer |

| Investment Program Period | Program Administrator | Project Name | Project Type | 2017 Update | Coordination with CPUC Proceedings or Legislation |
|---|---|---|---|---|---|
| 1st triennial (2012-2014) | SCE | **Next-Generation Distribution Automation** | Grid Modernization and Optimization | EPIC1 final reports have been completed for the projects listed below. These are included with the 2017 EPIC annual report and will be posted on SCE's public EPIC site. PLease refer to the final reports for details.<br><br>- Remote Intelligent Switch<br>- Remote Fault Indicator<br>- Remote Intelligent Fuse<br>- High Impedance Fault Detector<br>- Long Beach Secondary Network | |
| 1st triennial (2012-2014) | SCE | **Enhanced Infrastructure Technology Evaluation** | Grid Modernization and Optimization | The final project report is complete, was submitted with the 2016 Annual Report, and is available on SCE's public EPIC web site. | |
| 1st triennial (2012-2014) | SCE | **Dynamic Line Rating Demonstration** | Grid Modernization and Optimization | The final project report is complete, was submitted with the 2016 Annual Report, and is available on SCE's public EPIC web site. | |
| 1st triennial (2012-2014) | SCE | **Cyber-Intrusion Auto-Response and Policy Management System (CAPMS)** | Cross-Cutting/Foundational Strategies & Technologies | The final project report is complete, was submitted with the 2015 Annual Report, and is available on SCE's public EPIC web site. | California Energy Solutions for the 21st Century (CES-21), D.14-03-029 |
| 2nd triennial (2015-2017) | SCE | **Integration of Big Data for Advanced Automated Customer Load Management** | Customer Focused Products and Services | In 2017 the Big Data project accomplished many of its objectives. These included:<br>• Procurement of the IEEE 2030.5 Application server,<br>• Collaboration with key internal and external stakeholders to develop lab and production network architectures, and<br>• Deployment of the servers in the lab and<br>• Completion of most of the lab integration, cybersecurity, acceptance and functional testing.<br><br>There were some important benefits resulting from the testing. They included:<br>• Revisions to the IEEE 2030.5 standard, Rule 21 regulatory documents including the tariff and the California Smart Inverter Implementation Profile (CSIP) of IEEE 2030.5,<br>• Support for the production Distributed Energy Management System (DERMS) procurement specifications, and<br>• Revisions to the production network architectures due to cyber security deficiencies (e.g., cypher suites and support by other cyber security technologies).<br><br>The project is currently planned for completion in 2018. | |
| 2nd triennial (2015-2017) | SCE | **Advanced Grid Capabilities Using Smart Meter Data** | Grid Modernization and Optimization | The EPIC II Final Report for the Advanced Grid Capabilities Project is complete, is being submitted with the 2017 Annual Report, and will be posted on SCE's public EPIC web site. | |

| Investment Program Period | Program Administrator | Project Name | Project Type | A brief description of the project | Date of the award | Was this project awarded in the immediately prior calendar year? | Assignment to Value Chain | Encumbered Funding Amount ($) | Committed Funding Amount ($) | Funds Expended to date: Contract/Grant Amount ($) | Funds Expended to date: In house expenditures ($) | Funds Expended to date: Total Spent to date ($) | Administrative and overhead costs incurred for each project |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 2nd triennial (2015-2017) | SCE | **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 | $ 845,257 | $ 1,023,822 | $ 759,047 | $ 127,861 | $ 886,908 | $ 12,464 |
| 2nd triennial (2015-2017) | SCE | **Next-Generation Distribution Equipment & Automation - Phase 2** | Grid Modernization and Optimization | This project will leverage lessons learned from the Next Generation Distribution Automation – Phase 1 project performed in the first EPIC triennial investment plan period. This project will focus on integrating advanced control systems, modern wireless communication systems, and the latest breakthroughs in distribution equipment and sensing technology to develop a complete system design that would be a standard for distribution automation and advanced distribution equipment | 11/16/2015 | No | Distribution | $ 3,255,942 | $ 11,002,138 | $ 1,894,639 | $ 570,678 | $ 2,465,317 | $ 30,067 |
| 2nd triennial (2015-2017) | SCE | **System Intelligence and Situational Awareness Capabilities** | Grid Modernization and Optimization | This project will demonstrate system intelligence and situation awareness capabilities such as high impedance fault detection, intelligent alarming, predictive maintenance, and automated testing. This will be accomplished by integrating intelligent algorithms and advanced applications with the latest substation automation technologies, next generation control systems, latest breakthrough in substation equipment, sensing technology, and communications assisted protection schemes, This system will leverage the IEC 61850 Automation Standard and will include cost saving technology such as process bus, peer to peer communications, and automated engineering and testing technology. This project will also inform complementary efforts at SCE aimed at meeting security and NERC CIP compliance requirements | 11/16/2015 | No | Distribution | $ 2,047,294 | $ 3,140,256 | $ 1,181,756 | $ 65,290 | $ 1,247,046 | $ 17,269 |
| 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 | $ - | $ 2,342,268 | $ 716,475 | $ 89,721 | $ 806,196 | $ 8,122 |

| Investment Program Period | Program Administrator | Project Name | Project Type | Leveraged Funds | Partners | Match Funding | Match Funding Split | Funding Mechanism | Intellectual Property | Identification of the method used to grant awards. | If competitively selected, provide the number of bidders passing the initial pass/fail screening for project | If competitively selected, provide the name of selected bidder. | If competitively selected, provide the rank of the selected bidder in the selection process. | If competitively selected, explain why the bidder was not the highest scoring bidder, explain why a lower scoring bidder was selected. |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 2nd triennial (2015-2017) | SCE | **Proactive Storm Impact Analysis Demonstration** | Grid Modernization and Optimization | TBD | TBD | TBD | TBD | Pay-for-Performance Contracts | SCE has no current patents or licensing agreements signed. Future Intellectual Property is to be determined. | Competitive | 9 | IBM, First Quartile Consulting | TBD | TBD |
| 2nd triennial (2015-2017) | SCE | **Next-Generation Distribution Equipment & Automation - Phase 2** | Grid Modernization and Optimization | TBD | TBD | TBD | TBD | Pay-for-Performance Contracts | SCE has no current patents or licensing agreements signed. Future Intellectual Property is to be determined. | Competitive Bid<br><br>Directed Awards Issued to the Following Vendor(s):<br><br>Athena Power, Inc.; G&W Electric Company; Southwest Research Institute | 4 | Cleaveland Price Inc.; Schneider Electric; Sentient Energy, Inc.; Wesco Distribution Inc. | Cleaveland Price Inc.; Schneider Electric; Sentient Energy, Inc.; Wesco Distribution Inc. | Multiple prototypes were required for testing purposes |
| 2nd triennial (2015-2017) | SCE | **System Intelligence and Situational Awareness Capabilities** | Grid Modernization and Optimization | TBD | TBD | TBD | TBD | Pay-for-Performance Contracts | SCE has no current patents or licensing agreements signed. Future Intellectual Property is to be determined. | Competitive Bid<br><br>Directed Awards Issued to the Following Vendor(s): GENERAL NETWORKS, TESCO AUTOMATION LTD, MORRIS & WILLNER PARTNERS, | N/A | N/A | N/A | N/A |
| 2nd triennial (2015-2017) | SCE | **Regulatory Mandates: Submetering Enablement Demonstration - Phase 2** | Customer Focused Products and Services | TBD | TBD | TBD | TBD | Pay-for-Performance Contracts | SCE has no current patents or licensing agreements signed. Future Intellectual Property is to be determined. | TBD | TBD | TBD | TBD | TBD |

| Investment Program Period | Program Administrator | Project Name | Project Type | If interagency or sole source agreement, specify date of notification to the Joint Legislative Budget Committee (JLBC) was notified and date of JLBC authorization. | Does the recipient for this award identify as a California-based entity, small business, or businesses owned by women, minorities, or disabled veterans? | How the project leads to technological advancement or breakthroughs to overcome barriers to achieving the state's statutory energy goals | Applicable metrics |
|---|---|---|---|---|---|---|---|
| 2nd triennial (2015-2017) | SCE | **Proactive Storm Impact Analysis Demonstration** | Grid Modernization and Optimization | N/A; Applicable to CEC only. | First Quartile: Small Business | N/A; Applicable to CEC only. | 2a. Hours worked in California and money spent in California for each project<br>3a. Maintain / Reduce operations and maintenance costs<br>3b. Maintain / Reduce capital costs<br>5a. Outage number, frequency and duration reductions<br>5c. Forecast accuracy improvement<br>5d. Public safety improvement and hazard exposure reduction<br>8f. Technology transfer<br>9d. Successful project outcomes ready for use in California IOU grid (Path to market)<br>9e. Technologies available for sale in the market place (when known) |
| 2nd triennial (2015-2017) | SCE | **Next-Generation Distribution Equipment & Automation - Phase 2** | Grid Modernization and Optimization | N/A; Applicable to CEC only. | Sentient Energy, Inc.: California-based entity<br><br>Wesco Distribution Inc.: California-based entity; Business owned by women, minorities, or disabled veterans | N/A; Applicable to CEC only. | Metrics plan TBD |
| 2nd triennial (2015-2017) | SCE | **System Intelligence and Situational Awareness Capabilities** | Grid Modernization and Optimization | N/A; Applicable to CEC only. | GENERAL NETWORKS: California-based entity<br>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<br>3a. Maintain / Reduce operations and maintenance costs<br>3b. Maintain / Reduce capital costs<br>3c. Reduction in electrical losses in the transmission and distribution system<br>3f. Improvements in system operation efficiencies stemming from increased utility dispatchability of customer demand side management<br>5a. Outage number, frequency and duration reductions<br>5e. Utility worker safety improvement and hazard exposure reduction<br>7b. Increased use of cost-effective digital information and control technology to improve reliability, security, and efficiency of the electric grid (PU Code § 8360);<br>8e. Stakeholders attendance at workshops<br>8f. Technology transfer |
| 2nd triennial (2015-2017) | SCE | **Regulatory Mandates: Submetering Enablement Demonstration - Phase 2** | Customer Focused Products and Services | N/A; Applicable to CEC only. | TBD | N/A; Applicable to CEC only. | 1d. Number and percentage of customers on time variant or dynamic pricing tariffs<br>1h. Customer bill savings (dollars saved)<br>3e. Non-energy economic benefits<br>4a. GHG emissions reductions (MMTCO2e)<br>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.<br>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)<br>7j. Provide consumers with timely information and control options (PU Code § 8360):<br>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)<br>7l. Identification and lowering of unreasonable or unnecessary barriers to adoption of smart grid technologies, practices, and services (PU Code § 8360)<br>8e. Stakeholders attendance at workshops<br>8f. Technology transfer<br>9c. EPIC project results referenced in regulatory proceedings and policy reports<br>9d. Successful project outcomes ready for use in California IOU grid (Path to market)<br>9e. Technologies available for sale in the market place (when known) |

| Investment Program Period | Program Administrator | Project Name | Project Type | 2017 Update | Coordination with CPUC Proceedings or Legislation |
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| 2nd triennial (2015-2017) | SCE | **Proactive Storm Impact Analysis Demonstration** | Grid Modernization and Optimization | In 2017 the project team completed a proof of concept (PoC) storm damage model and visualization tools which forecast asset damage and the number field staff required for storm restoration for the entire SCE territory. SCE has started to demonstrate the solution with Grid Operations during storm events, optimizing field deployment decisions. Completion of final POC storms model is targeted for May 2018. Full production implementation of the solution in the SCE IT environment is anticipated to occur after the project ends (post May 2018). | Distribution Resources Plan, R.14-08-013; A.15-07-003<br>Integrated Demand-side Resource Program, R.14-10-003 |
| 2nd triennial (2015-2017) | SCE | **Next-Generation Distribution Equipment & Automation - Phase 2** | Grid Modernization and Optimization | In 2017, the project team accomplished the following:<br>**Underground Remote Fault Indicator** – successfully demonstrated the first UG RFI model. SCE is the first utility able to develop this product for underground application. SCE will be installed UG RFIs at 50 locations in December 2017 for field demonstration in 2018. This is a significant breakthrough for the electric utility industry.<br>**Long Beach Secondary Network Situation Awareness**- successfully developed the first Current & Voltage Sensors model for the secondary network. Four units were installed at four locations and good data telemetry was demonstrated. This enables 2018 demonstration of the use of real-time data together with load flow simulation to provide system operators with real-time situational awareness and contingency planning capability.<br>**High Impedance Fault Detection** - completed proof of concept testing for High Impedance Fault Detection using Spread Spectrum Time Domain Reflectometry Technology in SCE's energized lab. Energized demonstration is scheduled at SCE's Equipment Demonstration & Evaluation (12kV) Facility (EDEF) for Q2 2018 prior to seeking approval for field demonstration on several distribution circuits.<br>**Remote Integrated Switch** – completed the planning for field demonstration of 26 RIS at Johanna Substation. On track to implement new RIS automation schemes at Johanna Substation in Q1 2018.<br>**Real-time Equipment Health Diagnostic** – Successfully completed technology evaluations for the Predictive Equipment Failure Project to evaluate and demonstrate technologies that can monitor and assess energized equipment (cable, splices, transformers, switches etc.) and indicate remaining life or existing condition. The goal is to enable testing on energized distribution systems to avoid scheduling planned outages. Evaluated 5 technologies and vendors and identified two for additional testing in 2018-2019. This project has significant potential impact to reliability, safety and affordability.<br>**Hybrid Pole** – Received prototype poles for demonstration and completed strength testing. Hybrid poles weigh 1/3 of wood poles with similar pole ratings. The goal is to evaluate poles designed to withstand wild fires, thereby improving system. If successfully demonstrated, hybrid poles could be standard equipment in high fire hazard areas. | Distribution Resources Plan, R.14-08-013; A.15-07-003<br>Integrated Demand-side Resource Program, R.14-10-003 |
| 2nd triennial (2015-2017) | SCE | **System Intelligence and Situational Awareness Capabilities** | Grid Modernization and Optimization | This project demonstrates three technologies for improving grid reliability:<br>1-Process Bus demonstration<br>2-Intelligent Alarm processing<br>3-Substation Testing Tools<br><br>2017 Achievements<br><br>Process Bus lab demonstration:<br>-Preliminary lab test results were documented and shared at Distributech in January 2018. This information will be included in the final report.<br>-Process bus units were procured from Siemens, SEL, GE, and ABB, installed in the lab, and testing was primarily complete in 2017 per SCE's test plan. Bank differential testing has been delayed while we await vendor product updates.<br>-SCE leveraged available funding (added scope) and was able to perform and complete optical CT testing in the lab.<br>-The Functional Design Specification was completed<br>-Factory Accepting Testing (FAT) has been completed<br>-Preliminary integration system testing started with SEL and ABB devices.<br>-Mayberry Substation has been selected for demonstration on a 115KV line.<br><br>Intelligent Alarms:<br>Demonstration of Intelligent Alarms Processing was cancelled following a stakeholder meeting in March 2017 where SCE energy management system architecture changes were discussed.<br><br>Substation Testing Tools:<br>-An RFI was issued and Triangle Microworks was identified as a vendor that could meet SCE requirements to provide an automated test tool for Substation HMIs. A PO was been awarded to Triangle-Microworks for configuration of their Digital Test Manager software to support SCE's end-to-end testing demonstration (PLC, relay, HMI, and EMS simulation and testing). | |
| 2nd triennial (2015-2017) | SCE | **Regulatory Mandates: Submetering Enablement Demonstration - Phase 2** | Customer Focused Products and Services | 2017 Update<br><br>This Submetering Phase 2 Pilot project started January 16, 2017 and will end April 30, 2018. One-Hundred-Fifty-One submeters are enrolled with three Meter Data Management Agents:<br>1. ChargePoint, 130 submeters enrolled, three submeters terminated early<br>2. eMotorWerks, 20 submeters enrolled, one submeter terminated early<br>3. Kitu Systems, one submeter enrolled<br><br>- Nexant, the third party Pilot evaluator, will submit their final report to the CPUC on September 1, 2018.<br>- Subsequently, the CPUC must decide if the Submetering Protocol will be approved. CPUC decision date is unknown at this time. | |

| Investment Program Period | Program Administrator | Project Name | Project Type | A brief description of the project | Date of the award | Was this project awarded in the immediately prior calendar year? | Assignment to Value Chain | Encumbered Funding Amount ($) | Committed Funding Amount ($) | Funds Expended to date: Contract/Grant Amount ($) | Funds Expended to date: In house expenditures ($) | Funds Expended to date: Total Spent to date ($) | Administrative and overhead costs incurred for each project |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 2nd triennial (2015-2017) | SCE | **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:<br><br>* 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.<br><br>* 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.<br><br>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 | $ - | $ 42,193 | $ 7,500 | $ 34,693 | $ 42,193 | $ 4,355 |
| 2nd triennial (2015-2017) | SCE | **Series Compensation for Load Flow Control** | Renewables/DER Resource Integration | The intent of this project is to demonstrate and deploy the use of Thyristor Controlled Series Capacitors (TCSC) for load flow control on series compensated transmission lines. On SCE's 500 kV system in particular, several long transmission lines are series compensated using fixed capacitor segments that do not support active control of power flow. The existing fixed series capacitors use solid state devices as a protection method and are called Thyristor Protected Series Capacitors (TPSC) | 11/16/2015 | No | Transmission | $ - | $ 5,920 | $ - | $ 5,920 | $ 5,920 | $ 2,548 |
| 2nd triennial (2015-2017) | SCE | **Versatile Plug-in Auxiliary Power System (VAPS)** | Grid Modernization and Optimization | This project demonstrates the electrification of transportation and vocational loads that previously used internal combustion engines powered by petroleum fuels in the SCE fleet. The VAPS system uses automotive grade lithium ion battery technology (Chevrolet Volt and Ford Focus EV) which is also used in notable stationary energy storage projects (Tehachapi 32 MWh Storage) | 11/17/2014 | Yes | Distribution | $ 760,503 | $ 1,194,992 | $ 394,670 | $ 77,396 | $ 472,066 | $ 5,638 |
| 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 | $ 782,000 | $ 1,166,372 | $ 278,875 | $ 28,063 | $ 306,938 | $ 1,197 |
| 2nd triennial (2015-2017) | SCE | **Optimized Control of Multiple Storage Systems** | Renewables/DER Resource Integration | This project aims to demonstrate the ability of multiple energy storage controllers to integrate with SCE's Distribution Management System (DMS) and other decision making engines to realize optimum dispatch of real and reactive power based on grid needs | 11/17/2014 | Yes | Distribution | $ - | $ 520,761 | $ - | $ 3,761 | $ 3,761 | $ - |

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

| Investment Program Period | Program Administrator | Project Name | Project Type | If interagency or sole source agreement, specify date of notification to the Joint Legislative Budget Committee (JLBC) was notified and date of JLBC authorization. | Does the recipient for this award identify as a California-based entity, small business, or businesses owned by women, minorities, or disabled veterans? | How the project leads to technological advancement or breakthroughs to overcome barriers to achieving the state's statutory energy goals | Applicable metrics |
|---|---|---|---|---|---|---|---|
| 2nd triennial (2015-2017) | SCE | **Bulk System Restoration Under High Renewables Penetration** | Renewables/DER Resource Integration | N/A; Applicable to CEC only. | Nayak Corporation - NA | N/A; Applicable to CEC only. | Metrics plan TBD |
| 2nd triennial (2015-2017) | SCE | **Series Compensation for Load Flow Control** | Renewables/DER Resource Integration | N/A; Applicable to CEC only. | TBD | N/A; Applicable to CEC only. | Metrics plan TBD |
| 2nd triennial (2015-2017) | SCE | **Versatile Plug-in Auxiliary Power System (VAPS)** | Grid Modernization and Optimization | N/A; Applicable to CEC only. | No | N/A; Applicable to CEC only. | Metrics plan TBD |
| 2nd triennial (2015-2017) | SCE | **Dynamic Power Conditioner** | Grid Modernization and Optimization | N/A; Applicable to CEC only. | TBD | N/A; Applicable to CEC only. | Metrics plan TBD |
| 2nd triennial (2015-2017) | SCE | **Optimized Control of Multiple Storage Systems** | Renewables/DER Resource Integration | N/A; Applicable to CEC only. | TBD | N/A; Applicable to CEC only. | Metrics plan TBD |

| Investment Program Period | Program Administrator | Project Name | Project Type | 2017 Update | Coordination with CPUC Proceedings or Legislation |
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| 2nd triennial (2015-2017) | SCE | **Bulk System Restoration Under High Renewables Penetration** | Renewables/DER Resource Integration | In Dec. 2016, this project was cancelled by SCE Senior Leadership as a result of internal organizational change that focused the organization on Distribution System strategic objectives. This was reported in the 2016 EPIC Annual Report. | Process Bus lab demonstration: |
| 2nd triennial (2015-2017) | SCE | **Series Compensation for Load Flow Control** | Renewables/DER Resource Integration | In 2016, it was determined that the deliverables for this project could easily be done via another project that was already in flight. So a determination was made to cancel this project. This was reported in the 2016 Annual Report. | Intelligent Alarms processing |
| 2nd triennial (2015-2017) | SCE | **Versatile Plug-in Auxiliary Power System (VAPS)** | Grid Modernization and Optimization | 2017 Accomplishments<br>**1. Class 8 EV Project (Heavy Duty Truck):** The International base vehicle was ordered and received in July. US Hybrid used the vehicle to validate the CAD model and begin the vehicle build design. The vehicle was sent to Phoenix and the flatbed was installed on the chassis in December 2017. However, due to schedule delays compounded by resource constraints, it was necessary to cancel this subproject before the drivetrain was converted.<br>**2. Class 5 PHEV Project (Medium Duty Truck):** The base vehicle was purchased in July and a potential crew was identified to use the vehicle. The crew provided input on the system features and Odyne completed the vehicle design layout. The vehicle was sent to Valley Power for the system installation in November and it should be complete and ready for testing in January 2018.<br>**3. Light Duty PHEV Truck Project:** The stock GMC Sierra was baseline tested and shipped to Efficient Drivetrain Inc. (EDI) for the hybrid upfit in April. EDI provided a detailed system design for review in July. The vehicle conversion was complete in November and EDI performed functionality testing in December. The vehicle will arrive at SCE in January 2018, undergo performance testing and be placed into the field March 2018.<br>**4. Large VAPS Project:** Freewire received a PO to build a trailer mounted portable energy system (MobiGen) August 2017. The system was complete in December. It will arrive at SCE in January 2018 and undergo performance and safety testing in Q1 2018.<br>**5. Medium VAPS Project:** SCE purchased an electric cable pullers from Envoltz. The system was delivered in September 2017 and underwent full performance and functionality testing which it passed without issues. The system is being prepared to be evaluated by field crews in Q1 2018.<br>**6. Small VAPS Project:** The Altec Jobsite Energy Management System (JEMS) 4E4 Troubleman truck was extensively tested for performance, functionality and safety over seven months. Various system deficiencies were discovered. SCE worked with Altec to rectify them, and a report was written documenting the test results "TR15 – JEMS Evaluation". Data tracking units were installed in 22 of the Altec JEMS trucks and the system performance was tracked for six months. The results of the system utilization was documented in a report written in December "TR17 – Field Data Analysis". The vehicle was returned to Transportation Service Dept. in November to be placed into the field. Additionally, a JEMS 4A base system underwent endurance testing for 600 discharges and charges in an environmental chamber for six months and the battery capacity was documented. The system showed a slight but noticeable decrease in the dedicated 12V battery capacity that will have a long term impact on idle mitigation run times over the life of the vehicle and a report was written documenting the results "TR16 – Endurance Test Summary". | Substation Testing Tools |
| 2nd triennial (2015-2017) | SCE | **Dynamic Power Conditioner** | Grid Modernization and Optimization | In 2017, The Advanced Energy Storage Organization partnered with SCE's Supply Management organization to solicit suppliers to support the Dynamic Power Conditioner (DPC) project. The original strategy for the solicitation involved a Request for Information (RFI), which would then lead to a list qualified Bidders for the final Request for Proposal (RFP). The RFI was released to 45 potential suppliers to determine their technical capabilities to support project requirements. The RFI resulted in five responses, where Siemens Industry was deemed as the only supplier technically qualified by the project management team to support project requirements.<br>The first milestone was achieved when the Vendor accepted the Purchase Order and received the authority to proceed. The second milestone was achieved in late December when the vendor provided the SCE with the design of the system.<br><br>The project will be completed in 2018. | |
| 2nd triennial (2015-2017) | SCE | **Optimized Control of Multiple Storage Systems** | Renewables/DER Resource Integration | In 2017, the goals of this project were found to overlap significantly with those of the EPIC II Regional Grid Optimization Demo Phase 2 project (otherwise known as Integrated Grid Project phase 2). This project was then cancelled and the proposed benefits will be realized through the Regional Grid Optimization Demo Phase 2 project. | |

| Investment Program Period | Program Administrator | Project Name | Project Type | A brief description of the project | Date of the award | Was this project awarded in the immediately prior calendar year? | Assignment to Value Chain | Encumbered Funding Amount ($) | Committed Funding Amount ($) | Funds Expended to date: Contract/Grant Amount ($) | Funds Expended to date: In house expenditures ($) | Funds Expended to date: Total Spent to date ($) | Administrative and overhead costs incurred for each project |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 2nd triennial (2015-2017) | SCE | **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 | $ - | $ 22,522 | $ 5,868 | $ 10,979 | $ 16,847 | $ 1,172 |
| 2nd triennial (2015-2017) | SCE | **Integrated Grid Project II (filed as Regional Grid Optimization Demo)** | Cross-Cutting/Foundational Strategies & Technologies | The project will deploy, field test and measure innovative technologies that emerge from the design phase of the Integrated Grid Project (IGP) that address the impacts of DER (Distributed Energy Resources) owned by both 3rd parties and the utility. The objectives are to demonstrate the next generation grid infrastructure that manages, operates, and optimizes the distributed energy resources on SCE's system. The results will help determine the controls and protocols needed to manage DER, how to optimally manage an integrated distribution system to provide safe, reliable, affordable service and also how to validate locational value of DERs and understand impacts to future utility investments. | 4/21/2016 | No | Grid Operation/Market Design | $ 15,851,750 | $ 16,346,835 | $ 8,032,428 | $ 643,853 | $ 8,676,280 | $ - |

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|---|---|---|---|---|---|---|
| Projects | 1st triennial (2012-20 | 17,612,776 | 37,723,624 | 27,716,826 | 5,698,816 | 33,415,642 |
| Projects | 2nd triennial (2015-2( | 24,385,306 | 38,212,859 | 14,064,419 | 1,875,991 | 15,940,410 |
| EPIC I Admin | 1st triennial (2012-20 | 342,846 | 1,200,105 | | | 1,093,108 |
| EPIC II Admin | 2nd triennial (2015-2( | 2,281,777 | 2,760,371 | | | 1,817,503 |
| Total | 1st triennial (2012-20 | 17,955,622 | 38,923,729 | | | 34,508,750 |
| Total | 2nd triennial (2015-2( | 26,667,083 | 40,973,230 | | | 17,757,913 |

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

| Investment Program Period | Program Administrator | Project Name | Project Type | If interagency or sole source agreement, specify date of notification to the Joint Legislative Budget Committee (JLBC) was notified and date of JLBC authorization. | Does the recipient for this award identify as a California-based entity, small business, or businesses owned by women, minorities, or disabled veterans? | How the project leads to technological advancement or breakthroughs to overcome barriers to achieving the state's statutory energy goals | Applicable metrics |
|---|---|---|---|---|---|---|---|
| 2nd triennial (2015-2017) | SCE | **DC Fast Charging Demonstration** | Customer Focused Products and Services | 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)** | Cross-Cutting/Foundational Strategies & Technologies | N/A; Applicable to CEC only. | Morris & Willner Partners: Business owned my women, minorities or disabled veterans.<br><br>World Wide Technology, Inc: Business owned my women, minorities or disabled veterans.<br><br>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<br>1b. Total electricity deliveries from grid-connected distributed generation facilities<br>1c. Avoided procurement and generation costs<br>1d. Number and percentage of customers on time variant or dynamic pricing tariffs<br>1e. Peak load reduction (MW) from summer and winter programs<br>1f. Avoided customer energy use (kWh saved)<br>1g. Percentage of demand response enabled by automated demand response technology (e.g. Auto DR)<br>1h. Customer bill savings (dollars saved)<br>1i. Nameplate capacity (MW) of grid-connected energy storage<br>3a. Maintain / Reduce operations and maintenance costs<br>3b. Maintain / Reduce capital costs<br>3c. Reduction in electrical losses in the transmission and distribution system<br>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<br>3e. Non-energy economic benefits<br>3f. Improvements in system operation efficiencies stemming from increased utility dispatchability of customer demand side management<br>5a. Outage number, frequency and duration reductions<br>5b. Electric system power flow congestion reduction<br>5c. Forecast accuracy improvement<br>5f. Reduced flicker and other power quality differences<br>5i. Increase in the number of nodes in the power system at monitoring points<br>7b. Increased use of cost-effective digital information and control technology to improve reliability, security, and efficiency of the electric grid (PU Code § 8360);<br>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);<br>7d. Deployment and integration of cost-effective distributed resources and generation, including renewable resources (PU Code § 8360);<br>7e. Development and incorporation of cost-effective demand response, demand-side resources, and energy-efficient resources (PU Code § 8360);<br>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); |

| Investment Program Period | Program Administrator | Project Name | Project Type | 2017 Update | Coordination with CPUC Proceedings or Legislation |
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| 2nd triennial (2015-2017) | SCE | **DC Fast Charging Demonstration** | Customer Focused Products and Services | In 2017, a grid impact assessment was performed on several DC Fast Charger locations. Our goal was to understand the fast charging operations from a grid perspective, and to understand the impact DC Fast chargers had on grid equipment - both now and in the future. Some metrics for assessing the impact DC fast chargers have on the grid were based on identifying whether sites were compliant with IEEE 519 Recommended Practice and Requirements for Harmonic Control in Electric Power Systems, and could operate safely within the limitations defined in ANSI C84.1 Electric Power Systems and Equipment — Voltage Ratings (60 Hertz). In addition to power quality, the average DC fast charger site demand was compared to its total circuit demand to quantify its percentage of the maximum demand the fast charging site occupied on its respective circuit.<br><br>In 2017, we collected some preliminary results. All Tesla sites evaluated in this study were compliant with IEEE 519, and operated safely within the limitations defined in ANSI C84.1. All Tesla sites evaluated made up 4% to 9% of their circuit's maximum load, and their demand in SCE's territory is expected to double by the end of 2017. Based on the strong correlation in power quality data between sites, and compliance with IEEE 519 and ANSI C84.1, we made the decision to reduce the number of sites we had initially planned to study from 15 sites to 7 sites. We may consider reducing the number of data loggers that we install for the EVgo DC Fast charging stations (within the first 5 to 7 installations) if we notice the same strong correlation in power quality data between sites, and compliance with IEEE 519 and ANSI C84.1. In total, the number of sites that are expected to be monitored will have gone from 25 sites, to potentially 13 to 15 sites depending on the results. The remaining data loggers are expected to be installed at EVgo stations by December 2017. The final analysis and report is now expected to be completed in January 2017, and the results will be reviewed among SCE's experts to assess the information contained in the study.<br><br>One mutually beneficial outcome of this study was changes made to voltage swell ride-through limits for Tesla's superchargers. This began when an unusual behavior was uncovered at some sites where the superchargers would stop discharging from 1, or sometimes 2, of the 3 phases when a voltage swell had occurred. After reviewing this behavior with Tesla, we discovered that this behavior was intentional, and occurred on each phase where a large enough voltage swell occurred. We informed Tesla that it was not uncommon to sometimes see brief voltage swells, and recommended that they re-program their de-rating limits for voltage swell ride-through limits according to SAE J2894. Tesla's engineers are now working to adopt these recommended changes, which will help improve their charge times in areas where voltage swells are more common. | |
| 2nd triennial (2015-2017) | SCE | **Integrated Grid Project II (filed as Regional Grid Optimization Demo)** | Cross-Cutting/Foundational Strategies & Technologies | Accomplishments in 2017 include:<br><br>Controllers – Predix UIB – 2030.5 (AT Lab)<br>- Completed Reconfiguration for Removal of Field Agent<br>- Completed DMS Adapter Reconfiguration<br>- Completed Install of Predix Version Update<br>- Completed FAT 2 Sandbox Testing<br>- Completed Cybersecurity Round 1 FAT testing<br>- Completed FAT 2 (First Round)<br>- Completed Predix Upgrade / Patch in FAT Environment<br>- Completed Integration Testing for 2030.5<br>- Completed FAT 2 Testing for 2030.5<br>- Completed Cybersecurity Round 2 (Final) FAT Testing<br><br>FAN (Field Area Network)<br>- Completed IGP Canopy Installation (Core Network + Radios)in Johanna / Camden / COCDO<br>- Completed Simulation Network Installation (50 Field Radios in Johanna | |