BEFORE THE PUBLIC UTILITIES COMMISSION OF THE

STATE OF CALIFORNIA

Application of the California Energy Commission for Approval of Electric Program Investment Charge Proposed 2015 through 2017 Triennial Investment Plan.	Application 14-04-034 (Filed April 29, 20014)
And Related Matters.	Application 14-05-003 Application 14-05-004 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 29, 2016**

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I.

INTRODUCTION AND SUMMARY

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 will also be served on all parties in the most recent EPIC proceedings; the most recent general rate cases of PG&E, SCE and SDG&E; and 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.

Furthermore, in D.15-04-020, Ordering Paragraph 6, the Commission required the EPIC Administrators to identify specific Commission proceedings addressing issues related to each EPIC project in their annual EPIC reports. In Ordering Paragraph 24 of the same Decision, the Commission required the EPIC Administrators to 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 files its annual report on the status of its EPIC activities for 2016. This is SCE's third annual report pertaining to its 2012-2014 EPIC Triennial Investment Plan (Application (A.) 12-11-004) after receiving CPUC approval on November 14, 2013. This is SCE's first annual report pertaining to its 2015-2017 EPIC Triennial Investment Plan (Application (A.) 14-05-005) after receiving CPUC approval on April 9, 2015.

Respectfully submitted,

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February 29, 2016

EPIC ADMINISTRATOR ANNUAL REPORT

EPIC Administrator Annual Report

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1. Executive Summary

a) Overview of Programs/ Plan Highlights

2015 represented SCE's second full year of implementing program operations of its 2012 – 2014 Investment Plan Application[1] after receiving Commission approval on November 19, 2013[2], and first partial year of implementing program operations of its 2015 – 2017 Investment Plan Application[3] after receiving Commission approval on April 9th, 2015.[4] SCE presents the highlights from its 2012 – 2014 Investment Plan and 2015 – 2017 Investment Plan separately below.

(1) 2012-2014 Investment Plan

For the period between January 1 and December 31, 2015, SCE expended a total of $10,745,311 toward project costs and $400,017 toward administrative costs for a grand total of $11,145,328. SCE's cumulative expenses over the lifespan of its 2012 – 2014 EPIC program amount to $15,731,475. SCE committed $38,444,258 toward projects and encumbered $19,543,006 through executed purchase orders during this period; SCE has $0 in uncommitted EPIC funding.

SCE continued project execution activities towards the approved portfolio of 15 projects; 3 of these projects were completed during the calendar year 2015. The list of completed 2012-2014 Investment Plan projects include: 1) Cyber-Intrusion Auto-Response and Policy Management System; 2) Outage Management and Customer Voltage Data Analytics; and, 3) Portable End-to-End Test System. In accordance with the Commission's directives,[5] SCE has completed final project reports for these three projects and included them in the Appendices of this annual report, along with supporting spreadsheets.

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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, 2015, SCE expended a total of $243,306 toward project costs and $320,074 toward administrative costs for a grand total of $563,380. Since 2015 represents SCE first partial year of implementing program operations of its 2015-2017 Investment Plan, cumulative expenses over the lifespan of its 2015 – 2017 EPIC program amount to $563,380. SCE committed $22,752,151 toward projects and encumbered $0 through executed purchase orders during this period; SCE has $16,563,975 in uncommitted EPIC funding.

SCE launched 12 projects during the calendar year 2015. All 12 projects received funding commitments through SCE's Advanced Technology portfolio management process.

b) Status of Programs

(1) 2012-2014 Investment Plan

As of December 31, 2015, SCE has expended $14,638,757 [6] on project costs. Table 1 below summarizes the current funding status of SCE's EPIC projects:

Table 1: 2012-2014 Triennial Investment Plan: 2015 Projects

1. Energy Resources Integration
• 4 Projects Funded • Total Funding Committed: $10,400,240
2. Grid Modernization and Optimization

• 5 Projects Funded
  o 1 Project Cancelled in Q2 2014[7]
  o 1 Project Completed in 2015[8]
• Total Funding Committed: $8,903,994

3. Customer Focused Products and Services
• 3 Projects Funded   o 1 Project Completed in 2015[9] • Total Funding Committed: $6,508,803

6 SCE's cumulative project expenses amounted to $14,266,085 based on the project spreadsheet in Appendix A. SCE's accounting system calculates in-house labor overheads separately which amounted to $372,672. As a result, SCE expended a total of $14,638,757 on project 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.

9 Outage Management & Customer Voltage Data Analytics.

4. Cross-Cutting/Foundational Strategies and Technologies
• 3 Projects Funded   o 1 Project Completed in 2015[10] • Total Funding Committed: $12,631,221
Total Projects Funded: 15 Total Funding Committed: $38,444,258[11] *Note: Due to intrinsic variability in TD&D /R&D projects, amounts shown are subject to change*

Table 2 below summarizes SCE's 2015 administrative expenses:

Table 2: 2012-2014 Triennial Investment Plan: 2015 Administration

• Program Administration	Total Funding Committed: $1,092,718 Total 2015 Cost: $400,017 Total Cumulative Cost: $1,092,718

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

As of December 31, 2015, SCE has expended $243,306 [12] on project costs. Table 3 below summarizes the current funding status of SCE's EPIC projects:

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

1. Energy Resources Integration
• 3 Projects Funded • Total Funding Committed: $5,328,580
2. Grid Modernization and Optimization
• 6 Projects Funded • Total Funding Committed: $14,328,442
3. Customer Focused Products and Services
• 3 Projects Funded • Total Funding Committed: $3,095,129
4. Cross-Cutting/Foundational Strategies and Technologies
• 0 Projects Funded • Total Funding Committed: $0
Total Projects Funded: 12 Total Funding Committed: $22,752,151[13] *Note: Due to intrinsic variability in TD&D /R&D projects, amounts shown are subject to change*

[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 $217,870 based on the project spreadsheet in Appendix A. SCE's accounting system calculates in-house labor overheads separately which amounted to $25,436. As a result, SCE expended a total of $243,306 on project costs.

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

Table 4 below summarizes SCE's 2015 administrative expenses:

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

• Program Administration	Total Funding Committed: $2,084,230 Total 2015 Cost: $320,074 Total Cumulative Cost: $320,074

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 serve the interests of ratepayer benefits. Please refer to Decision (D.)12-05-037. This Decision further stipulates that the EPIC will continue through 2020[14] with an annual budget of $162 million.[15] Approximately 80% of the EPIC is administered by the CEC, and 20% is administered by the investor-owned utilities (IOUs). Additionally, about 0.5% of the 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]

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 both of its 2012-2014 and its 2015-2017 EPIC Investment Plans.

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14 D.12-05-037, OP1.
15 D.12-05-037, OP7.
16 Id, OP5.
17 Id.
18 D.12-05-037, OP 7.
19 A.12-11-004.
20 A.14-05-005.

b) EPIC Program Components

The Commission limited SCE's involvement in the first two EPIC cycles (2012-2014 and 2015-2017) to technology demonstration and deployment projects, per D.12-05-037. The Commission defines technology demonstration and deployment projects as installing and operating pre-commercial technologies or strategies at a scale sufficiently large in conditions sufficiently reflective of anticipated actual operating environments to enable appraisal of the operational and performance characteristics and the financial risks.[21]

In accordance with the Commission's requirement for technology demonstration and deployment 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) EPIC Program Regulatory Process

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 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

[21] D.12-05-037, OP3.B.
[22] A.12-11-004.
[23] A.14-05-005.
[24] D.15-09-005.

justify why the project should be given 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 2015 Annual Report to provide a status update to the Commission and stakeholders on its program implementation.

d) <u>Coordination</u>

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

- Joint Administrators Workshop on August 18, 2015; and
- Joint Administrators Symposium on December 3, 2015.

SCE also supported the CEC's execution of its 2012-2014 Investment Plan. On February 24, 2014, SCE attended the CEC's workshop that examined the implementation of the first-triennial Investment Plan. Moreover, the EPIC Administrators met on a near-weekly basis to discuss implementing the 2012-2014 and 2015-2017 Investment Plans and to plan and coordinate the joint stakeholder workshop and joint public symposium. SCE is currently planning a collaborative meeting with the CEC to help further coordinate the respective investments plans.

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

In 2015, SCE participated in a stakeholder workshop and public symposium on the execution of its 2012-2014 and 2015-2017 Investment Plans. At the stakeholder workshop held at SDG&E's Energy Innovation Center in San Diego on August 18, 2015 the focus was on distributed energy resources (DERs). The workshop highlighted a few EPIC projects that involve DERs from each IOU and the CEC. Public stakeholders had the opportunity to ask questions specific to the DER, EPIC projects and the EPIC program in general.

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[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.

In addition, the IOUs and the CEC held the first annual EPIC symposium. This public symposium brought together an array of interested stakeholders to learn about the status of the respective EPIC portfolios. The EPIC symposium was held at the Folsom Inn in Folsom on December 3, 2015.

The Commission also held a public workshop on Phase II of its Decision[26], approving the 2015-2017 Investment Plans. The workshop brought together the IOUs and the ORA to discuss the most appropriate regulatory mechanism for notifying the Commission and the public of new projects, subsequent to Commission approval of an Investment Plan. While consensus could not be reached at the workshop, there was ample public discussion among parties.

SCE supported numerous parties applying for CEC, EPIC funding in both 2015 and 2016. Letters of Support (LOS) and Commitment (LOC) were given to parties showing our support for their bids on CEC projects. In SCE nomenclature, 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 actually be required.

A LOC shows early financial and/or technical support should the project be 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. Through the SCE EPIC website the public can access SCE's Investment Plan Applications, request a LOS or LOC and directly contact SCE with questions pertaining to EPIC.

3. Budget

a) Authorized Budget

(1) 2012 – 2014 Investment Plan

[26] D.15-04-020.

Table 5: 2015 Authorized EPIC Budget

2015 (Jan 1 - Dec 31)	Administrative	Project Funding	Commission Regulatory Oversight Budget
SCE Program	$1.3M	$11.9M	$0.33M[27]
CEC Program	$5.3M	$47.7M	

(2) 2015 – 2017 Investment Plan

Table 6: 2015 Authorized EPIC Budget

2015 (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) Commitments/ Encumbrances

(1) 2012 – 2014 Investment Plan

As of December 31, 2015, SCE has committed $39,536,976 and encumbered $19,543,006 of its authorized 2012-2014 program budget.

(2) 2015 – 2017 Investment Plan

As of December 31, 2015, SCE has committed $24,836,381 and encumbered $0 of its authorized 2015-2017 program budget.

For CEC remittances, SCE remitted $5.6M for program administration, and $75.6M for encumbered projects during calendar year 2015.

For CPUC remittances, SCE remitted $349k in calendar year 2015.

c) Dollars Spent on In-House Activities

(1) 2012 – 2014 Investment Plan

As of December 31, 2015, SCE has spent $3,584,421[28] on in-house activities.

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

[28] SCE expended a total of $3,211,749 on in-house activities through 2015 based on the project spreadsheet in Appendix A. SCE's accounting systems calculates in-house labor overheads separately which amounted to $372,672. As a result, SCE expended a total of $3,584,421 on in-house costs.

(2) **2015 – 2017 Investment Plan**

As of December 31, 2015, SCE has spent $218,263[29] on in-house activities.

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

(1) **2012 – 2014 Investment Plan**

As of December 31, 2015, SCE does not have any pending fund shifting requests and/or approvals.

(2) **2015 – 2017 Investment Plan**

As of December 31, 2015, 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, 2015, SCE has $0 in uncommitted/unencumbered funds.

(2) **2015 – 2017 Investment Plan**

As of December 31, 2015, SCE has $16,563,975 in uncommitted/unencumbered funds.

f) **Joint CEC/SCE Projects**

As of December 31, 2015, SCE does not have any joint projects with the CEC.

4. **Projects**

a) **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.

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[29] SCE expended a total of $192,827 on in-house activities through 2015 based on the project spreadsheet in Appendix A. SCE's accounting systems calculates in-house labor overheads separately which amounted to $25,436. As a result, SCE expended a total of $218,263 on in-house costs.

b) **Project Status Report**

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

c) **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)**

(xv) **Status Update**

The following project descriptions reflect the projects' status information as of December 31, 2015.

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

1. Integrated Grid Project – Phase 1

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

The project will 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 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. This value-oriented demonstration would inform many key questions that have been asked: • What is the value of distributed generation and where is it most valuable? • What is the cost of intermittent resources? • What is the value of storage and where is it most valuable? • How effectively can demand response manage intermittency and what is the value? • What is the value of flexible demand response (e.g. the flexibility to charge a vehicle over an extended range of time)? • What is the value of controlling a thermostat? • How are these resources/devices co-optimized? • What infrastructure is required to enable an optimized solution? • What incentives/rate structure will enable an optimized solution?
Deliverables: • An IGP cost/benefit analysis and business case • A systems requirement specification • An IGP demonstration architecture • A distributed grid control architecture capable of supporting the use of market mechanism, price signals, direct control or

distributed control to optimize reliability and economic factors on the distribution grid • A data management and integration architecture supporting the overarching IGP architecture • A supporting network and cybersecurity architecture for the IGP architecture • Incentive structures that encourage technology adoption that provide benefits to overall system operations • A Volt/Var optimization strategy • RFPs to secure vendor solutions for the field demonstration phase of the IGP project • Post analyses - review, findings and recommendations on GridLAB-D models used in the IGP architecture and design • IGP lab demonstration using a simulated environment • Final project report (Phase 1)
Metrics: 1a. Number and total nameplate capacity of distributed generation facilities 1b. Total electricity deliveries from grid-connected distributed generation facilities 1c. Avoided procurement and generation costs 1d. Number and percentage of customers on time variant or dynamic pricing tariffs 1e. Peak load reduction (MW) from summer and winter programs 1f. Avoided customer energy use (kWh saved) 1g. Percentage of demand response enabled by automated demand response technology (e.g. Auto DR) 1h. Customer bill savings (dollars saved) 1i. Nameplate capacity (MW) of grid-connected energy storage 3a. Maintain / Reduce operations and maintenance costs 3b. Maintain / Reduce capital costs 3c. Reduction in electrical losses in the transmission and distribution system 3d. Number of operations of various existing equipment types (such as voltage regulation) before and after adoption of a new smart grid component, as an indicator of possible equipment life extensions from reduced wear and tear 3e. Non-energy economic benefits 3f. Improvements in system operation efficiencies stemming from increased utility dispatchability of customer demand side management 5a. Outage number, frequency and duration reductions 5b. Electric system power flow congestion reduction

5c. Forecast accuracy improvement 5f. Reduced flicker and other power quality differences 5i. Increase in the number of nodes in the power system at monitoring points 7b. Increased use of cost-effective digital information and control technology to improve reliability, security, and efficiency of the electric grid (PU Code § 8360); 7c. Dynamic optimization of grid operations and resources, including appropriate consideration for asset management and utilization of related grid operations and resources, with cost-effective full cyber security (PU Code § 8360); 7d. Deployment and integration of cost-effective distributed resources and generation, including renewable resources (PU Code § 8360); 7e. Development and incorporation of cost-effective demand response, demand-side resources, and energy-efficient resources (PU Code § 8360); 7f. Deployment of cost-effective smart technologies, including real time, automated, interactive technologies that optimize the physical operation of appliances and consumer devices for metering, communications concerning grid operations and status, and distribution automation (PU Code § 8360); 7h. Deployment and integration of cost-effective advanced electricity storage and peak-shaving technologies, including plug-in electric and hybrid electric vehicles, and thermal-storage air-conditioning (PU Code § 8360); 7j. Provide consumers with timely information and control options (PU Code § 8360); 7k. Develop standards for communication and interoperability of appliances and equipment connected to the electric grid, including the infrastructure serving the grid (PU Code § 8360); 7l. Identification and lowering of unreasonable or unnecessary barriers to adoption of smart grid technologies, practices, and services (PU Code § 8360) 8b. Number of reports and fact sheets published online 8d. Number of information sharing forums held. 8f. Technology transfer 9b. Number of technologies eligible to participate in utility energy efficiency, demand response or distributed energy resource rebate programs 9c. EPIC project results referenced in regulatory proceedings and policy reports. 9d. Successful project outcomes ready for use in California IOU grid (Path to market).

<table>
<tr><td colspan="3">Schedule:
IGP Phase 1: Q2 2014 – Q4 2017
IGP Phase 2: TBD</td></tr>
<tr><td>EPIC Funds Encumbered:
$8,859,484</td><td colspan="2">EPIC Funds Spent:
$4,308,412</td></tr>
<tr><td colspan="3">Partners:
TBD; SCE is currently exploring collaboration opportunities.</td></tr>
<tr><td>Match Funding:

TBD</td><td>Match Funding split:
TBD</td><td>Funding Mechanism:
Pay-for-Performance Contracts</td></tr>
<tr><td colspan="3">Treatment of Intellectual Property
SCE has no current patents or licensing agreements signed. Future Intellectual Property is to be determined.</td></tr>
<tr><td colspan="3">Status Update
In 2015, the IGP project team refined the project scope and demonstration design approach, and issued key Requests for Proposals (RFPs) for Control Systems and the Field Area Network. In addition, the project team took steps to align activities with the Distribution Resources Plan (DRP) requirements; going forward, the project will become the test bed for DRP Demonstration D. The site selection for IGP was reviewed in light of the DRP requirements and alternate demonstration locations are now being considered to ensure sufficient DER resources are available.

The following activities were completed by the project team in 2015:
• Completed IGP-Area circuit modeling
• Participated in the development of the Grid Modernization Business Requirements and Concept of Operations
• Aligned IGP’s scope to Grid Modernization efforts by defining 8 corresponding demonstration sub-projects
• Developed detailed IGP Use Cases (in accordance with the new Grid Modernization Architecture concepts)
• Developed detailed Technical Specifications for Control System functionality (Volt/VAR, Power Flow, and Microgrid controls)
• Issued RFP for IGP Control Systems
• Developed detailed Technical Specifications for the Field Area Network (communication systems)
• Issued RFP for the Field Area Network
• Installed key components of the controls lab to evaluate IGP assets prior to field deployment</td></tr>
</table>

• Tested control applications and systems from potential vendors (DVI, Spirae, Landis+Gyr) • Completed overall High Level IGP Conceptual Architecture • Completed Initial draft of the IGP System Requirements Document • Developed initial draft of the IGP System Design Document

2. Regulatory Mandates: Submetering Enablement Demonstration

Investment Plan Period: 1st Triennial Plan (2012-2014)	**Assignment to value Chain:** Demand-Side Management
Objective & Scope: On November 14, 2013, the Commission voted to approve the revised Proposed Decision (PD) Modifying the Requirements for the Development of a Plug-In Electric Vehicle Submetering Protocol set forth in D.11-07-029. The investor-owned utilities (IOUs) are to implement a two phased pilot beginning in May 2014, with funding for both phases provided by the EPIC. This project, Phase I of the pilot will (1) evaluate the demand for Single Customer of Record submetering, (2) estimate billing integration costs, (3) estimate communication costs, and (4) evaluate customer experience. 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.	
Deliverables: 1. Submetering Protocol Report 2. Manual Subtractive Billing Procedure 3. 3PE Final Report and Recommendation	
Metrics: 6a. TOTAL number of SCE customer participants (Phase 1 & 2 each have 500 submeter limit) 6b. Number of SCE NEM customer participants (Phase 1 & 2 each have 100 submeter limit of 500 total) 6c. Submeter MDMA on-time delivery of customer submeter interval usage data 6d. Submeter MDMA accuracy of customer submeter interval usage data	
Schedule: Q1 2014 – Q4 2016	

<table>
<tr><td colspan="2">EPIC Funds Encumbered:
$1,090,100</td><td colspan="2">EPIC Funds Spent:
$815,437</td></tr>
<tr><td colspan="4">Partners:
N/A</td></tr>
<tr><td>Match Funding:
N/A</td><td colspan="2">Match Funding split:
N/A</td><td>Funding Mechanism:
Pay-for-Performance Contracts</td></tr>
<tr><td colspan="4">Treatment of Intellectual Property
SCE has no current patents or licensing agreements signed. Future Intellectual Property is to be determined.</td></tr>
<tr><td colspan="4">Status Update
SCE worked closely with the CPUC/ED and Submetering MDMAs to extend the Phase 1 Pilot six months to enroll 92 customers. SCE will provide its customers with subtractive billing to separately bill household and EV charging on their respective rates. SCE will support its customers during their Pilot participation by answering their questions and resolving their issues. SCE will provide a similar service to the three Submetering MDMAs. The Phase 1 Submetering Pilot is on schedule and under budget.

The three Submeter MDMAs, (eMotorWerks, NRG and Ohmconnect) were issued purchase orders to enable SCE to pay the MDMAs for enrolling customers and providing SCE with monthly EV submeter usage data. Nexant was selected by the three IOUs to be the third party evaluator of the Submetering Pilots. PG&E contracted Nexant on behalf of the three IOUs who will share the costs equally as mandated by CPUC. SCE's share is $439,580 which is payable quarterly through 2018.

Milestones achieved
• Requested and received CPUC's approval to extend the Phase 1 Pilot enrollment period six months.
• Submitted Tier 1 Advice Letter to CPUC to update Phase 1 Pilot tariff due to Pilot extension.
• Enrolled 92 SCE customers in the Pilot by end of extended enrollment period August 31, 2015.
• Supporting 92 customers during their 12 month participation in the Phase 1 Pilot..</td></tr>
</table>

3. Distribution Planning Tool

Investment Plan Period: 1st Triennial Plan (2012-2014)	**Assignment to value Chain:** Distribution
Objective & Scope: This project involves the creation, validation, and functional demonstration of an SCE distribution system model that will address the future system architecture that accommodates distributed generation (primarily solar photovoltaic), plug-in electric vehicles, energy storage, customer programs (demand response, energy efficiency), etc. The modeling software to be used allows for implementation of advanced controls (smart charging, advanced inverters, etc.). These controls will enable interaction of a residential energy module and a power flow module. It also enables the evaluation of various technologies from an end-use customer perspective as well as a utility perspective, allowing full evaluation from substation bank to customer. This capability does not exist today. The completed model will help SCE demonstrate, communicate and better respond to technical, customer and market challenges as the distribution system architecture evolves.	
Deliverables: • Grid LAB-D user interface • SCE circuit model • Updated GridLAB-D to handle Cyme 7 database • Base cases & benchmark • Specifications for test cases from stakeholders • Created test cases • Periodic updates/meetings with stakeholders • Executed test cases • Final project report	
Metrics: 1d. Number and percentage of customers on time variant or dynamic pricing tariffs 1g. Percentage of demand response enabled by automated demand response technology (e.g. Auto DR) 5c. Forecast accuracy improvement 7b. Increased use of cost-effective digital information and control technology to improve reliability, security, and efficiency of the electric grid (PU Code § 8360) 7c. Dynamic optimization of grid operations and resources, including appropriate consideration for asset management and	

utilization of related grid operations and resources, with cost-effective full cyber security (PU Code § 8360) 7e. Development and incorporation of cost-effective demand response, demand-side resources, and energy-efficient resources (PU Code § 8360); 8c. Number of times reports are cited in scientific journals and trade publications for selected projects. 8d. Number of information sharing forums held. 8f. Technology transfer 9b. Number of technologies eligible to participate in utility energy efficiency, demand response or distributed energy resource rebate programs 9c. EPIC project results referenced in regulatory proceedings and policy reports. 9d. Successful project outcomes ready for use in California IOU grid (Path to market).		
Schedule: Q1 2014 – Q1 2017		
EPIC Funds Encumbered: $558,391	**EPIC Funds Spent:** $671,231	
Partners: N/A		
Match Funding: N/A	**Match Funding split:** N/A	**Funding Mechanism:** Pay-for-Performance Contracts
Treatment of Intellectual Property SCE has no current patents or licensing agreements signed. Future Intellectual Property is to be determined.		
Status Update In 2015, SCE and Battelle continued the work which commenced in 2014 with the creation of additional GridLAB-D modules and add-on tools for Grid Command Distribution. The key accomplishments in 2015 included: • The development of a GridLAB-D Valuation tool which serves to capture the locational value or true cost of technologies including: Energy Storage, Demand Response, PV, Conservation Voltage Reduction, and Electric Vehicles • Additional functionality was added to the Commercial module making demand response events possible • Validation of the Commercial module and Commercial DR module		

• Additional scripting tools and functionalities in Grid Command Distribution were developed to aid in SCE Circuit model development • Training workshops and knowledge transfer sessions were conducted SCE has successfully implemented the modeling of representative circuit feeders in GridLab-D using the commercial models and tools developed and validated in collaboration with Battelle. As part of a core research project involving internal and external stakeholders, these models are being used to study the impact of high PV penetration and implementation of cost effective mitigation technologies which include demand response. Additional phases of the modeling work will continue in 2016.

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

Investment Plan Period: 1st Triennial Plan (2012-2014)	**Assignment to value Chain:** Demand-Side Management
Objective & Scope: The Beyond the Meter (BTM) project will demonstrate the use of a DER management system to interface with and control DER based on customer and distribution grid use cases. It will also demonstrate the ability to communicate near-real time information on the customer's load management decisions and DER availability to SCE for grid management purposes. Three project objectives include: 1) 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.	
Deliverables: • "Enabling Communication Unification" status report • Written specifications for all three class of devices (EVSEs, solar inverters, and RESUs) • "Industry Harmonization and Closing Gaps" report	

• Receive devices for testing • Complete final report and recommendations
Metrics: 1a. Number and total nameplate capacity of distributed generation facilities 1b. Total electricity deliveries from grid-connected distributed generation facilities 1c. Avoided procurement and generation costs 1e. Peak load reduction (MW) from summer and winter programs 1f. Avoided customer energy use (kWh saved) 1g. Percentage of demand response enabled by automated demand response technology (e.g. Auto DR) 3f. Improvements in system operation efficiencies stemming from increased utility dispatchability of customer demand side management 5b. Electric system power flow congestion reduction 5f. Reduced flicker and other power quality differences 5i. Increase in the number of nodes in the power system at monitoring points 7b. Increased use of cost-effective digital information and control technology to improve reliability, security, and efficiency of the electric grid (PU Code § 8360); 7c. Dynamic optimization of grid operations and resources, including appropriate consideration for asset management and utilization of related grid operations and resources, with cost-effective full cyber security (PU Code § 8360); 7d. Deployment and integration of cost-effective distributed resources and generation, including renewable resources (PU Code § 8360); 7e. Development and incorporation of cost-effective demand response, demand-side resources, and energy-efficient resources (PU Code § 8360); 7f. Deployment of cost-effective smart technologies, including real time, automated, interactive technologies that optimize the physical operation of appliances and consumer devices for metering, communications concerning grid operations and status, and distribution automation (PU Code § 8360); 7g. Integration of cost-effective smart appliances and consumer devices (PU Code § 8360); 7h. Deployment and integration of cost-effective advanced electricity storage and peak-shaving technologies, including plug-in electric and hybrid electric vehicles, and thermal-storage air-conditioning (PU Code § 8360);

<table>
<tr><td colspan="4">7j. Provide consumers with timely information and control options (PU Code § 8360);
7k. Develop standards for communication and interoperability of appliances and equipment connected to the electric grid, including the infrastructure serving the grid (PU Code § 8360);
7l. Identification and lowering of unreasonable or unnecessary barriers to adoption of smart grid technologies, practices, and services (PU Code § 8360)
8b. Number of reports and fact sheets published online
8d. Number of information sharing forums held.
8f. Technology transfer
9a. Description/documentation of projects that progress deployment, such as Commission approval of utility proposals for wide spread deployment or technologies included in adopted building standards.
9b. Number of technologies eligible to participate in utility energy efficiency, demand response or distributed energy resource rebate programs
9c. EPIC project results referenced in regulatory proceedings and policy reports.
9d. Successful project outcomes ready for use in California IOU grid (Path to market).</td></tr>
<tr><td colspan="4">Schedule:
Q3 2014 – Q4 2016</td></tr>
<tr><td colspan="2">EPIC Funds Encumbered:
$1,781,200</td><td colspan="2">EPIC Funds Spent:
$1,057,691</td></tr>
<tr><td colspan="4">Partners:
N/A</td></tr>
<tr><td>Match Funding:
N/A</td><td colspan="2">Match Funding split:
N/A</td><td>Funding Mechanism:
Pay-for-Performance Contracts</td></tr>
<tr><td colspan="4">Treatment of Intellectual Property
SCE has no current patents or licensing agreements signed. Future Intellectual Property is to be determined.</td></tr>
<tr><td colspan="4">Status Update
During 2015, the project team engaged stakeholder groups throughout SCE including Transportation Electrification and Customer Service to understand and document high-level requirements and use cases critical to the business. The technical team also conducted market research to identify technology and vendor capabilities, architectures, and availability of DER</td></tr>
</table>

technologies. In addition, the team developed high level architectures. Finally, the team completed the scope, schedule, and budget; and updated the Project Management Plan to reflect new scope and budget modifications.

5. Portable End-to-End Test System

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

<table>
<tr><td colspan="3">9e. Technologies available for sale in the market place (when known).</td></tr>
<tr><td colspan="3">Schedule:
Q1 2014 – Q4 2015</td></tr>
<tr><td colspan="2">EPIC Funds Encumbered:
$212,837</td><td>EPIC Funds Spent:
$37,271</td></tr>
<tr><td colspan="3">Partners:
N/A</td></tr>
<tr><td>Match Funding:
N/A</td><td>Match Funding split:
N/A</td><td>Funding Mechanism:
Pay-for-Performance Contracts</td></tr>
<tr><td colspan="3">Treatment of Intellectual Property
SCE has no current patents or licensing agreements signed. Future Intellectual Property is to be determined.</td></tr>
<tr><td colspan="3">Status Update
In the process of developing the methodology to utilize the Portable End-to-End Test System (PETS) in the field, and through feedback from the end-users it was discovered that there were a limited number of test scenarios where the tool would be a great improvement over existing test procedures. As a result, the project team concluded that there was no substantial value in further pursuing the development of the PETS tool. Although the tool would be an improved method of testing system performance when conducting end-to-end relay tests, the implementation of a companywide PETS (utilizing a Real Time Digital Simulator system) proved to not be cost effective when compared to traditional test methods at this time. The major aspects that would drive the cost of implementing the PETS projects are:

• Development of specialized training programs for field crews

• Availability of the tool; it would be extremely costly to purchase several PETS test units to accommodate the different regions within SCE’s territory when compared to purchasing existing standard tools

• Dedicated engineering staff to support issues related to maintenance and training

After careful deliberation of the benefits associated with proceeding with the PETS project, SCE has decided to halt further development of the technology and to close out the project.</td></tr>
</table>

Furthermore, the early close-out of this project does not impact how protection schemes are tested today as it was intended to be a proof-of-concept demonstration project. More information will be provided in the final report.

6. Voltage and VAR Control of SCE Transmission System

Investment Plan Period: 1st Triennial Plan (2012-2014)	**Assignment to value Chain:** Transmission
Objective & Scope: This project involves 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.	
Deliverables: • Demonstration design specification • Construction documents: drawings, cable schedule, and bill of material • Monitoring console software and hardware • Advanced Volt/VAR Control (AVVC) testing • Field deployment • Controller operation monitoring and adjustment • AVVC final report and closeout	
Metrics: 3a. Maintain / Reduce operations and maintenance costs 3c. Reduction in electrical losses in the transmission and distribution system 3d. Number of operations of various existing equipment types (such as voltage regulation) before and after adoption of a new smart grid component, as an indicator of possible equipment life extensions from reduced wear and tear 7b. Increased use of cost-effective digital information and control technology to improve reliability, security, and efficiency of the electric grid (PU Code § 8360) 7c. Dynamic optimization of grid operations and resources, including appropriate consideration for asset management and utilization of related grid operations and resources, with cost-effective full cyber security (PU Code § 8360)	

<table>
<tr><td colspan="3">8b. Number of reports and fact sheets published online
8d. Number of information sharing forums held.
8f. Technology transfer
9c. EPIC project results referenced in regulatory proceedings and policy reports.
9d. Successful project outcomes ready for use in California IOU grid (Path to market).</td></tr>
<tr><td colspan="3">Schedule:
Q1 2014 – Q4 2018</td></tr>
<tr><td colspan="2">EPIC Funds Encumbered:
$37,875</td><td>EPIC Funds Spent:
$227,053</td></tr>
<tr><td colspan="3">Partners:
N/A</td></tr>
<tr><td>Match Funding:
N/A</td><td>Match Funding split:
N/A</td><td>Funding Mechanism:
Pay-for-Performance Contracts</td></tr>
<tr><td colspan="3">Treatment of Intellectual Property
SCE has no current patents or licensing agreements signed. Future Intellectual Property is to be determined.</td></tr>
<tr><td colspan="3">Status Update
In 2015, the project team continued working in collaboration with the Portfolio Management Office (PMO) to gather all the information needed to complete the Emergent Project Evaluation Form (EPEF) process. Note: This process is needed to determine the substation installation schedule and associated cost estimate. During this period, all deployment requirements are gathered and all changes affecting existing substation equipment are studied. The project team worked with Grid Control Center (GCC) engineers, protection engineers and Substation Construction and Maintenance (SC&M) personnel to evaluate the work needed. On August 20, 2015, EPEF requirements were fulfilled and the process was approved for installation to start in January 2017. In addition, stakeholders were regularly engaged and updated of project progress and deployment schedule and updates.

In an effort to publicize the novel work developed, the project team presented the work in two consecutive NASPI (North American Synchrophasor Initiative) meetings, worked on a NASPI focus paper, published an IEEE transactions paper, and published testing and simulation findings in the 49th HICSS (Hawaiian International Conference on Systems Sciences) conference.</td></tr>
</table>

In addition, the team continued to finalize testing of the controller system and drafted a demonstration specification document to be utilized during the software implementation phase.

7. Superconducting Transformer (SCX) Demonstration

<table>
<tr><td colspan="2">Investment Plan Period:
1st Triennial Plan (2012-2014)</td><td>Assignment to value Chain:
Distribution</td></tr>
<tr><td colspan="3">Objective & Scope:

<u>This project was cancelled in 2014. No further work is planned.</u>

Original Project Objective and Scope:
SCE will support this $21M American Reinvestment and Recovery Act (ARRA) Superconducting Transformer (SCX) project by providing technical expertise and installing and operating the transformer at SCE’s MacArthur substation. The SCX prime contractor is SuperPower Inc. (SPI), teamed with SPX Transformer Solutions (SPX) {formerly Waukesha Electric Systems}. SCE has provided two letters of commitment for SCX. The SCX project will develop a 28 MVA High Temperature Superconducting, Fault Current Limiting (HTS-FCL) transformer. The transformer is expected to be installed in 2015. SCE is supporting this project and is not an ARRA grant sub-recipient. SCE is being reimbursed for its effort by EPIC. SCE’s participation in this project was previously approved under the now-defunct California Energy Commission’s PIER program.</td></tr>
<tr><td colspan="3">Deliverables:
• N/A</td></tr>
<tr><td colspan="3">Metrics:
N/A</td></tr>
<tr><td colspan="3">Schedule:
Project was cancelled in Q2 2014.</td></tr>
<tr><td colspan="2">EPIC Funds Encumbered:
$0</td><td>EPIC Funds Spent:
$10,241</td></tr>
<tr><td colspan="3">Partners:
N/A</td></tr>
<tr><td>Match Funding:
N/A</td><td>Match Funding split:
N/A</td><td>Funding Mechanism:
Pay-for-Performance Contracts</td></tr>
</table>

Treatment of Intellectual Property SCE has no current patents or licensing agreements signed.
Status Update SPX Transformer Solutions officially withdrew support from the project in Q2, 2014. As a result, SuperPower could no longer complete the delivery of the HTS-FCL transformer to SCE. SuperPower communicated the desire to identify a new transformer manufacturer as a partner, but was unable to secure one within a reasonable timeframe. At the time of SPX's withdrawal, SCE did not have an executed agreement with SuperPower. SCE formally cancelled this project in Q3 2014.

8. State Estimation Using Phasor Measurement Technologies

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

9e. Technologies available for sale in the market place (when known)		
Schedule: Q2 2014 – Q4 2017		
EPIC Funds Encumbered: $7,500	**EPIC Funds Spent:** $39,456	
Partners: N/A		
Match Funding: N/A	**Match Funding split:** N/A	**Funding Mechanism:** Pay-for-Performance Contracts
Treatment of Intellectual Property SCE has no current patents or licensing agreements signed. Future Intellectual Property is to be determined.		
Status Update SCE has worked with the selected vendor to specify, test, and validate state estimation techniques using PMU data. This data was used to validate the operation of the Linear State Estimator and data conditioning functions. For next steps, the project team will begin to implement applications and tools to demonstrate their use in real-time operations.		

9. Wide-Area Reliability Management & Control

Investment Plan Period: 1st Triennial Plan (2012-2014)	**Assignment to value Chain:** Grid Operation/Market Design
Objective & Scope: With the planned wind and solar portfolio of 33% penetration, a review of the integration strategy implemented in the SCE bulk system is needed. The basic premise for the integration strategy is that a failure in one area of the grid should not result in failures elsewhere. The approach is to minimize failures with well designed, maintained, operated and coordinated power grids. New technologies can provide coordinated wide-area monitoring, protection, and control systems with pattern recognition and advance warning capabilities. This project will demonstrate new technologies to manage transmission system control devices to prevent cascading outages and maintain system integrity.	
Deliverables: • Lab demonstration of control algorithms using real time simulations with Hardware in the loop (RTWHIL)	

- Develop recommendations based on the control system testing - Final project report		
Metrics: 6a. Enhanced contingency planning for minimizing cascading outages 8b. Number of reports and fact sheets published online 8d. Number of information sharing forums held. 8f. Technology transfer		
Schedule: Q2 2014 – Q2 2017		
EPIC Funds Encumbered: $618,450	**EPIC Funds Spent:** $292,816	
Partners: N/A		
Match Funding: N/A	**Match Funding split:** N/A	**Funding Mechanism:** Pay-for-Performance Contracts
Treatment of Intellectual Property SCE has no current patents or licensing agreements signed. Future Intellectual Property is to be determined.		
Status Update In 2015, SCE and V&R Energy utilized the Potential Cascading Modes (PCM) tool to identify a list of initiating events for cascading outage analysis. In addition, the project team has demonstrated a cascading outage analysis framework to identify how cascading events performed under various levels of stress. For next steps, the project team will validate the demonstration environment, complete demonstrations, and develop the final project report.		

10. Distributed Optimized Storage (DOS)

Investment Plan Period: 1st Triennial Plan (2012-2014)	**Assignment to value Chain:** Distribution
Objective & Scope: This field pilot will demonstrate 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.
Deliverables: • Target feeder models • Selected feeders for the project • Requirement development for solution • RFP for all devices • Procurement of all devices • Evaluation of centralized controller and representative energy storage devices • Test platform readiness for protection evaluation • Testing of various energy storage footprints for protection • Engagement of all expected SCE departments for deployment • Procurement of M&V equipment • Deployment of M&V Equipment and energy storage devices 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: $0	**EPIC Funds Spent:** $45,853	
Partners: TBD		
Match Funding: N/A	**Match Funding split:** N/A	**Funding Mechanism:** Pay-for-Performance Contracts
Treatment of Intellectual Property SCE has no current patents or licensing agreements signed. Future Intellectual Property is to be determined.		
Status Update During 2015, the DOS project aligned itself with the Integrated Grid Project (IGP) and the SCE's Energy Storage Ownership Initiative (ESOI). Technical specifications required to procure energy storage devices are being developed based on current ESOI energy storage specifications in partnership with IGP and ESOI. These specifications will be used to procure the DOS storage devices in the 2016/2017 time frame. In addition, the project team has been working with landowners at potential installation sites within the Integrated Grid Project demonstration location in the Orange County area.		

11. Outage Management and Customer Voltage Data Analytics Demonstration

Investment Plan Period: 1st Triennial Plan (2012-2014)	**Assignment to value Chain:** Grid Operation/Market Design
Objective & Scope: Voltage data and customer energy usage data from the Smart Meter network can be collected and leveraged for a range of initiatives focused on achieving operational benefits for	

Transmission & Distribution. Before a full implementation of this new approach can be considered, a Pilot 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 Pilot project will be conducted to understand the feasibility and value of providing smart meter data inputs and enhanced methodology for calculating the Indexes. The Pilot will focus on a limited geography (SCE District or Region) to obtain the Smart Meter inputs to calculate the Indexes and compare that number with the current methodologies to identify any anomalies. A hybrid approach using the Smart Meter-based input data combined with a better comprehensive electric connectivity model obtained from GIS may provide a more efficient and effective way of calculating the Indexes. Additionally, an effort to evaluate the accuracy of the Transformer Load Mapping data will be carried out.
Deliverables: • Voltage Analytics for Power Quality Model • Simulated Circuit Condition Model • Customer and Transformer Load Analysis Model • Enhanced Inputs and SAIDI/SAIFI Analysis • Final Project Report
Metrics: 3a. Maintain / Reduce operations and maintenance costs 5c. Forecast accuracy improvement 5f. Reduced flicker and other power quality differences 6a. Enhance Outage Reporting Accuracy and SAIDI/SAIFI Calculation 8b. Number of reports and fact sheets published online 8f. Technology transfer 9c. EPIC project results referenced in regulatory proceedings and policy reports.
Schedule: Q1 2014 – Q4 2015

<table>
<tr><td colspan="2">EPIC Funds Encumbered:
$702,436</td><td colspan="2">EPIC Funds Spent:
$978,803</td></tr>
<tr><td colspan="4">Partners:
N/A</td></tr>
<tr><td>Match Funding:
N/A</td><td colspan="2">Match Funding split:
N/A</td><td>Funding Mechanism:
Pay-for-Performance Contracts</td></tr>
<tr><td colspan="4">Treatment of Intellectual Property
SCE has no current patents or licensing agreements signed. Future Intellectual Property is to be determined.</td></tr>
<tr><td colspan="4">Status Update
The project demonstrated an analytics and visualization application that used smart meter data for distribution grid operational benefits. The project also conducted a feasibility study to determine if the use of smart meter data could improve the Outage Management SAIDI/SAIFI/MAIFI (reliability) metric calculation process.

The following project milestones were achieved:
i. The application was demonstrated in a lab environment using smart meter data of approximately 20,000 customers on 14 distribution circuits.
ii. The application demonstrated 14 use cases developed by SCE using customer meter voltage, consumption and event data.
iii. The application successfully overlaid the meter data on SCE’s distribution system GIS to provide a visualization of the condition of the network.
iv. The application was successfully tested by electric distribution planners and engineers.
v. The feasibility study for using smart meter data in the calculation of system reliability indices was completed and several manually-intensive steps were identified for elimination.

The project was successfully completed in 2015 and the final report will be submitted in 2016.</td></tr>
</table>

12. SA-3 Phase III Demonstration

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

Objective & Scope: This project is intended to apply the findings from the Substation Automation Three (SA-3) Phase II (Irvine Smart Grid Demonstration) project to demonstrate real solutions to automation problems faced by SCE today. The project will demonstrate two standards-based automation solutions (sub-projects) as follows: Subproject 1 (Bulk Electric System) will address issues unique to transmission substations including the integration of centrally managed critical cyber security (CCS) systems and NERC CIP compliance; 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.
Deliverables: • Bulk & Hybrid System Design Drawings & Diagrams • Hybrid System Deployment and Demonstration • BES System Deployment and Demonstration • Final Project Report
Metrics: 3a. Maintain / Reduce operations and maintenance costs 3b. Maintain / Reduce capital costs 5a. Outage number, frequency and duration reductions 5i. Increase in the number of nodes in the power system at monitoring points 6a. Increased cybersecurity 7b. Increased use of cost-effective digital information and control technology to improve reliability, security, and efficiency of the electric grid (PU Code § 8360) 7c. Dynamic optimization of grid operations and resources, including appropriate consideration for asset management and utilization of related grid operations and resources, with cost-effective full cyber security (PU Code § 8360)

7k. Develop standards for communication and interoperability of appliances and equipment connected to the electric grid, including the infrastructure serving the grid (PU Code § 8360) 8b. Number of reports and fact sheets published online 8d. Number of information sharing forums held. 8f. Technology transfer 9c. EPIC project results referenced in regulatory proceedings and policy reports 9d. Successful project outcomes ready for use in California IOU grid (Path to market) 9e. Technologies available for sale in the market place (when known)		
Schedule: Q1 2014 – Q1 2017		
EPIC Funds Encumbered: $909,701.86	**EPIC Funds Spent:** $868,271	
Partners: N/A		
Match Funding: N/A	**Match Funding split:** N/A	**Funding Mechanism:** Pay-for-Performance Contracts
Treatment of Intellectual Property: SCE has no current patents or licensing agreements signed. Future Intellectual Property is to be determined.		
Status Update: Major activities for the Substation Automation Demonstration 3, Phase III (SA-3) project in 2015 involved: 1) identifying qualified vendors and conducting procurement activities for IEC 61850 compliant devices and systems; 2) working to identify and confirm the substation site to be used for the demonstration; and 3) working to finalize stakeholder agreement on demonstration objectives. Milestones achieved • Defined Business Requirements and Use Cases • Completed Functional Design and Technical Specifications • Completed the Substation Standard Review Team (SSRT) Pilot request for Olinda A-Substation • Completed SSRT Pilot approval for Olinda • Completed Preliminary Scope of Work and Design for Olinda • Completed the Stakeholder Job-walk for Olinda • Completed Re-evaluation of Olinda A-station		

• Resulted in relocation of the pilot to Viejo A-substation because of construction and civil work schedule impact • Completed SSRT Pilot approval for Viejo • Completed Preliminary Scope of Work for Viejo • Completed the Stakeholder Job-walk for Viejo • Completed Engineering contractor Job Walk • Started Preliminary Demonstration Design for Engineering contract award • Started lab Demonstration of new annunciator (Programmable Automation Controller (PAC)) system

13. Next-Generation Distribution Automation

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

• Secondary Network Monitoring demonstration and report • Final Project Report
Metrics: 3a. Maintain / Reduce operations and maintenance costs 3d. Number of operations of various existing equipment types (such as voltage regulation) before and after adoption of a new smart grid component, as an indicator of possible equipment life extensions from reduced wear and tear 5a. Outage number, frequency and duration reductions 5c. Forecast accuracy improvement 5d. Public safety improvement and hazard exposure reduction 5e. Utility worker safety improvement and hazard exposure reduction 5i. Increase in the number of nodes in the power system at monitoring points 6a. Improve data accuracy for distribution substation planning process 7b. Increased use of cost-effective digital information and control technology to improve reliability, security, and efficiency of the electric grid (PU Code § 8360) 7c. Dynamic optimization of grid operations and resources, including appropriate consideration for asset management and utilization of related grid operations and resources, with cost-effective full cyber security (PU Code § 8360) 7d. Deployment and integration of cost-effective distributed resources and generation, including renewable resources (PU Code § 8360) 7k. Develop standards for communication and interoperability of appliances and equipment connected to the electric grid, including the infrastructure serving the grid (PU Code § 8360) 8b. Number of reports and fact sheets published online 8d. Number of information sharing forums held. 8f. Technology transfer 9c. EPIC project results referenced in regulatory proceedings and policy reports 9d. Successful project outcomes ready for use in California IOU grid (Path to market) 9e. Technologies available for sale in the market place (when known)
Schedule: Q1 2014 – Q4 2016

EPIC Funds Encumbered:	**EPIC Funds Spent:**
$2,722,696.60	$2,576,547

Partners: N/A		
Match Funding: N/A	**Match Funding split:** N/A	**Funding Mechanism:** Pay-for-Performance Contracts
Treatment of Intellectual Property: SCE has no current patents or licensing agreements signed. Future Intellectual Property is to be determined.		

Status Update:

Remote Intelligent Switch (RIS)

For 2015, SCE continued development of the RIS project and demonstration. Project specification and deliverables were finalized, and the RFP process was completed. After reviewing all RFP respondents, the team awarded the project to the highest scoring vendor, Siemens. Development of the RIS solution started, resulting in the initial algorithm programming, several demonstration of the RIS system's capabilities at Siemens's facility, and an initial delivery of pre-production evaluation cabinets.

High Impedance Fault Detection

Existing high impedance fault detection solutions available in the market focus on current and voltage monitoring; however, evaluation results demonstrate none of these technologies have been able to securely detect high impedance faults reliably (too many false alarms). As a result, a new approach is necessary and SCE's Advanced Technology considers the reflectometry-based solution as an innovative and promising approach. Advanced Technology and Apparatus Engineering are working with Southwest Research Institute (SWRI) to demonstrate the feasibility of implementing a reflectometry-based solution for detection of high impedance faults.

Overhead Remote Fault Indicator (RFI)

In 2015 SCE successfully evaluated and standardized the Overhead Remote Fault Indicator (RFI). The RFI is a device which provides local visualization and remote indication of a fault on distribution circuits. The RFI is used by our System Operators as a means of automatically and remotely detecting and identifying faults to reduce outage time.

Long Beach Network Situation Awareness

In the year 2015, the Long Beach situational Awareness Project had the following activities and accomplishments: • Finalized the scope of the project, identifying 12 sites impacted by the installation of Voltage/Current monitoring devices. • Out of the 12 sites, 9 sites will be installed with SCE's current Field Area Network Communication devices, Netcomm, while 3 remaining sites will be installed with IP Point to Multipoint radios. • Established two underground radio network access points at the Long Beach area and performed radio study of the signal coverage in Long Beach to determine the amount of Access Points (APs) required to fully cover the entire Long Beach electrical network. • Established communication with Consolidated Edison to benchmark SCE system with Con. Edison network monitoring and alarming system. Intelligent Fuse • Technical Specification were finalized for the Intelligent and went through the Request For Proposal (RFP) process • Two vendors(G&W and Siemens) responded and both solutions were evaluated and scored • G&W was awarded the winning bid

14. Enhanced Infrastructure Technology Evaluation

Investment Plan Period: 1st Triennial Plan (2012-2014)	**Assignment to value Chain:** Distribution
Objective & Scope: At the request of Distribution Apparatus Engineering (DAE) group's lead Civil Engineer, Advanced Technology (AT) will investigate, pilot, 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, pilot 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 SCE to install repeaters on streetlights due to aesthetics). DAE also sees the need for technologies that may minimize premature vault change-outs (avg. replacement cost	

is ~$250K). At present, DAE does not have the necessary real-time vault data to sufficiently address the increasing vault deterioration issue nor do we utilize a hardened ventilation system that would help this issue by removing the excess heat out of the vaults (blowers last ~ 2 years, need better bearings for blower motors, etc.).
Deliverables: • Vault Monitoring Technologies Demonstration Report • Vault Ventilation Field Demonstration Report • Hybrid Pole Demonstration Report • Concealed Communication Assets Demonstration Report • Final Project Report
Metrics: 3a. Maintain / Reduce operations and maintenance costs 3b. Maintain / Reduce capital costs 4g. Wildlife fatality reductions (electrocutions, collisions) 5a. Outage number, frequency and duration reductions 6a. Operating performance of underground vault monitoring equipment 8b. Number of reports and fact sheets published online 8d. Number of information sharing forums held 8f. Technology transfer 9c. EPIC project results referenced in regulatory proceedings and policy reports
Schedule: Q2 2014 – Q4 2017

EPIC Funds Encumbered: $24,606	**EPIC Funds Spent:** $68,740

Partners: N/A

Match Funding: N/A	**Match Funding split:** N/A	**Funding Mechanism:** Pay-for-Performance Contracts

Treatment of Intellectual Property: SCE has no current patents or licensing agreements signed. Future Intellectual Property is to be determined.
Status Update: In 2015, the project team accomplished the following: • Enhanced vault ventilation blower was specified, delivered, and is currently being field tested • Developed draft specification for Hybrid Distribution Pole

• Created conceptual insulator-antenna for initial communication testing • Installed vault temperature equipment for testing and monitoring

15. Dynamic Line Rating Demonstration

Investment Plan Period: 1st Triennial Plan (2012-2014)	**Assignment to value Chain:** Transmission
Objective & Scope: Transmission line owners apply fixed thermal rating limits for power transmission lines. These limits are based on conservative assumptions of wind speed, ambient temperature and solar radiation. They are established to 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.	
Deliverables: • Installed Dynamic Line Rating System Prototypes • Final Project Report	
Metrics: 3b. Maintain / Reduce capital costs 5b. Electric system power flow congestion reduction 6a. Increased power flow throughput 7b. Increased use of cost-effective digital information and control technology to improve reliability, security, and efficiency of the electric grid (PU Code § 8360) 7c. Dynamic optimization of grid operations and resources, including appropriate consideration for asset management and utilization of related grid operations and resources, with cost-effective full cyber security (PU Code § 8360) 8b. Number of reports and fact sheets published online 8d. Number of information sharing forums held 8f. Technology transfer 9c. EPIC project results referenced in regulatory proceedings and policy reports	

9d. Successful project outcomes ready for use in California IOU grid (Path to market) 9e. Technologies available for sale in the market place (when known)		
Schedule: Q2 2014 – Q1 2016		
EPIC Funds Encumbered: $249,970	**EPIC Funds Spent:** $463,613	
Partners: N/A		
Match Funding: N/A	**Match Funding split:** N/A	**Funding Mechanism:** Pay-for-Performance Contracts
Treatment of Intellectual Property: SCE has no current patents or licensing agreements signed. Future Intellectual Property is to be determined.		
Status Update: The project team worked with the vendor to identify system requirements and the devices needed for the demonstration project. The project team worked with transmission engineering, system planning, and the Grid Control Center to identify the system stress points and congested transmission lines that are most suitable for the demonstration. The team worked with the vendor to pinpoint the locations of communication routing devices needed. The procurement process was completed and two instances of the CAT-1 monitoring system in addition to a communication repeater system were delivered. SCE requires adherence to the T&D pilot standards process when a project involves installation of non-standard equipment on a transmission line or a substation. The project team presented the project in both Substation Standards Review Team (SSRT) and the Transmission Standards Review Team (TSRT), worked with the vendor to develop training material, and drafted detailed deployment and maintenance procedures. In May 2015, Transmission and substation standards were approved to proceed, and standards were issued and published. In February 2015, the team initiated the deployment design process and both transmission and substation drawing packages were issued and published. Also, a CEII / NERC CIP Evaluation Processes is required when the project involves installations at the		

bulk power transmission system or at medium (or higher) level substations. The process was completed by altering the boxes to be in compliance with NERC-CIP requirements. After initiating installation of the system, it was discovered that there are some obstacles in the communication line-of-sight would require further testing. A decision was made not to continue the work after the vendor decided not to support Dynamic Line Rating after the end of the demonstration phase. SCE will work to close this project out in 2016, and write a final report in 2017.

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

Investment Plan Period: 1st Triennial Plan (2012-2014)	**Assignment to value Chain:** Grid Operation/Market Design
Objective & Scope: Viasat in partnership with SCE and Duke Energy has been awarded a DOE contract (DE-0E0000675) to deploy a Cyber-intrusion Auto-response and Policy Management System (CAPMS) to provide real-time analysis of root cause, extent and consequence of an ongoing cyber intrusion using proactive security measures. CAPMS will be demonstrated in the SCE Advanced Technology labs at Westminster, CA. The DOE contract value is $6M with SCE & Duke Energy offering a cost share of $1.6M and $1.2M respectively.	
Deliverables: • System Requirements Artifact • Measurement and Validation Data • System Test Results • Final Project Report	
Metrics: 5a. Outage number, frequency and duration reductions 7b. Increased use of cost-effective digital information and control technology to improve reliability, security, and efficiency of the electric grid (PU Code § 8360) 7l. Identification and lowering of unreasonable or unnecessary barriers to adoption of smart grid technologies, practices, and services (PU Code § 8360) 8b. Number of reports and fact sheets published online 8d. Number of information sharing forums held. 8f. Technology transfer 10a. Description or documentation of funding or contributions committed by others 10c. Dollar value of funding or contributions committed by others.	

Schedule: Q3 2014 – Q3 2015		
EPIC Funds Encumbered: $1,767,758	**EPIC Funds Spent:** $1,804,650	
Partners: Viasat; Duke Energy		
Match Funding: N/A	**Match Funding split:** N/A	**Funding Mechanism:** Pay-for-Performance Contracts
Treatment of Intellectual Property: SCE has no current patents or licensing agreements signed. Future Intellectual Property is to be determined.		
Status Update: CAPMS completed the following activities in 2015, in no specific order: • Equipment was installed and configured in the SCE Advanced Technology laboratory to support test and demonstration activities. • Test system requirements were developed by SCE. • Threat scenarios were developed for use in system demonstration and test. • ViaSat completed CAPMS software development. • System and software integration and testing was accomplished in the SCE Advanced Technology laboratory and test reports were developed. • System test and demonstration was conducted using threat scenarios and CAPMS responses were observed and recorded by ViaSat. • A demonstration was held for the Department of Energy in September. • The final project report was developed and will be submitted with the EPIC annual report in February 2016.		

(1) <u>2015 – 2017 Triennial Investment Plan Projects</u>

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

Investment Plan Period: 2nd Triennial Plan (2015-2017)	**Assignment to value Chain:** Demand-Side Management
Objective & Scope: This proposed project builds upon the "Beyond the Meter Advanced Device Communications" project from the first EPIC	

triennial investment plan, and 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.
Deliverables: • TBD
Metrics: TBD
Schedule: TBD

EPIC Funds Encumbered: TBD	**EPIC Funds Spent:** $14,693

Partners: TBD

Match Funding: TBD	**Match Funding split:** TBD	**Funding Mechanism:** Pay-for-Performance Contracts

Treatment of Intellectual Property: SCE has no current patents or licensing agreements signed. Future Intellectual Property is to be determined.
Status Update: The project will demonstrate the use of an IEEE 2030.5 Distributed Energy Resource Management System. This project will launch in 2016. The project team plans to start the system requirements specification in early 2016; the demonstration will be performed in the 2016/2017 time frame.

2. Advanced Grid Capabilities Using Smart Meter Data

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

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

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

EPIC Funds Encumbered: TBD	**EPIC Funds Spent:** $88,253

Partners: TBD

Match Funding: TBD	**Match Funding split:** TBD	**Funding Mechanism:** Pay-for-Performance Contracts

Treatment of Intellectual Property: SCE has no current patents or licensing agreements signed. Future Intellectual Property is to be determined.
Status Update: Improving accuracy of Transformer/Meter correlation model: The project demonstrated a statistical model that correlates the voltage signature of a meter with that of other meters connected to the transformer to identify mismatches and provide a "better match" alternative. It also demonstrated an algorithm that improved accuracy by comparing the time period of single transformer outages to smart meter outage events to identify incorrectly mapped meters. The following activities were completed in 2015: i. Demonstration of Voltage signature and single transformer Outage events algorithms in a lab environment using smart meter data of 3 distribution circuits. ii. Identified data challenges and limitations on the use of the algorithms.

iii. Completed validation of algorithms' results through comparisons with field verified data. Phase identification of customers: It will demonstrate the algorithm developed in collaborative research by EPRI and SCE to identify the phase of a customer using SCADA, electrical network information and smart meter data. Additionally, the collaborative research by UC Riverside and SCE will be demonstrated in the later part of the project. i. Work on this subpart has been scheduled to start in 2016.

3. Proactive Storm Impact Analysis Demonstration

Investment Plan Period: 2nd Triennial Plan (2015-2017)	**Assignment to value Chain:** Distribution
Objective & Scope: This project will demonstrate proactive storm analysis techniques prior to 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 for storm management and field crew deployment.	
Deliverables: • RFP Package • Requirements / Use Cases • Measurement and Validation Plan • Supplier's Pilot Report • Technology Transfer Plan • Final project report	
Metrics: 2a. Hours worked in California and money spent in California for each project 3a. Maintain / Reduce operations and maintenance costs 3b. Maintain / Reduce capital costs 5a. Outage number, frequency and duration reductions	

5c. Forecast accuracy improvement 5d. Public safety improvement and hazard exposure reduction 8f. Technology transfer 9d. Successful project outcomes ready for use in California IOU grid (Path to market) 9e. Technologies available for sale in the market place (when known)
Schedule: Q3 2015 – Q2 2017

EPIC Funds Encumbered:	**EPIC Funds Spent:**
TBD	$77,582

Partners:
TBD

Match Funding:	**Match Funding split:**	**Funding Mechanism:**
TBD	TBD	Pay-for-Performance Contracts

Treatment of Intellectual Property:
SCE has no current patents or licensing agreements signed. Future Intellectual Property is to be determined.
Status Update: During 2015, the project team engaged in Project Initiation and Project Planning activities, including execution of stakeholder engagement, requirements analysis, vendor and market research, and development of procurement documentation. The project successfully completed contract negotiations with two contractors and also obtained approval for the Project Management Plan. The project is on track to achieve key milestones outlined for Q1 of 2016.

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

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

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

automation and advanced distribution equipment.

Deliverables: • TBD		
Metrics: TBD		
Schedule: TBD		
EPIC Funds Encumbered: TBD	**EPIC Funds Spent:** $0	
Partners: TBD		
Match Funding: TBD	**Match Funding split:** TBD	**Funding Mechanism:** Pay-for-Performance Contracts
Treatment of Intellectual Property: SCE has no current patents or licensing agreements signed. Future Intellectual Property is to be determined.		
Status Update: The project will initiate the project planning phase in 2016.		

5. System Intelligence and Situational Awareness Capabilities

Investment Plan Period: 2nd Triennial Plan (2015-2017)	**Assignment to value Chain:** Distribution
Objective & Scope: This project will demonstrate system intelligence and situation awareness capabilities such as high impedance fault detection, intelligent alarming, predictive maintenance, and automated testing. This will be accomplished by integrating intelligent algorithms and advanced applications with the latest substation automation technologies, next generation control systems, latest breakthrough in substation equipment, sensing technology, and communications assisted protection schemes, This system will leverage the IEC 61850 Automation Standard and will include cost saving technology such as process bus, peer to peer communications, and automated engineering and testing technology. This project will also inform complementary efforts at SCE aimed at meeting security and NERC CIP compliance requirements	
Deliverables: • TBD	

Metrics: TBD	
Schedule: TBD	
EPIC Funds Encumbered: TBD	**EPIC Funds Spent:** $0
Partners: TBD	

Match Funding: TBD	**Match Funding split:** TBD	**Funding Mechanism:** Pay-for-Performance Contracts
Treatment of Intellectual Property: SCE has no current patents or licensing agreements signed. Future Intellectual Property is to be determined.		
Status Update: The project will initiate the project planning phase in 2016.		

6. Regulatory Mandates: Submetering Enablement Demonstration - Phase 2

Investment Plan Period: 2nd Triennial Plan (2015-2017)	**Assignment to value Chain:** Demand-Side Management
Objective & Scope: This project expands on the submetering project from the first EPIC triennial investment plan cycle to demonstrate plug-in electric vehicle (PEV) submetering at multi-dwelling and commercial facilities. Specifically, the project will leverage 3rd 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)	

<table>
<tr><td colspan="3">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)</td></tr>
<tr><td colspan="3">Schedule:
Q4 2015 – Q3 2018</td></tr>
<tr><td colspan="2">EPIC Funds Encumbered:
TBD</td><td>EPIC Funds Spent:
$25,301</td></tr>
<tr><td colspan="3">Partners:
TBD</td></tr>
<tr><td>Match Funding:
TBD</td><td>Match Funding split:
TBD</td><td>Funding Mechanism:
Pay-for-Performance Contracts</td></tr>
<tr><td colspan="3">Treatment of Intellectual Property:
SCE has no current patents or licensing agreements signed. Future Intellectual Property is to be determined.</td></tr>
<tr><td colspan="3">Status Update:
SCE recently initiated the preparations for the Phase 2 Submetering Pilot by participating in stakeholder kick off meetings hosted by CSOD. In addition, the CPUC hosted meetings that included the other IOUs and external stakeholders. The Phase 1</td></tr>
</table>

Pilot will start on November 1, 2016 and end in 18 months on April 30, 2018. Milestones achieved Held kickoff meeting with SCE stakeholders and with the CPUC including the other IOUs and external stakeholders. Established Work Group structure and schedule to address Phase 2 issues and requirements in preparation for finalizing the Phase 2 Tier 2 Advice Letter due June 30, 2016.

7. Bulk System Restoration Under High Renewables Penetration

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

for their inputs for further developing this approach into an actual operational tool.		
Deliverables: • TBD		
Metrics: TBD		
Schedule: TBD		
EPIC Funds Encumbered: TBD	**EPIC Funds Spent:** $2,726	
Partners: TBD		
Match Funding: TBD	**Match Funding split:** TBD	**Funding Mechanism:** Pay-for-Performance Contracts
Treatment of Intellectual Property: SCE has no current patents or licensing agreements signed. Future Intellectual Property is to be determined.		
Status Update: In 2015, this project was authorized to proceed with the planning phase of the project lifecycle. The team had numerous meetings both within the project team as well as with project stakeholders, sponsors, and advisors from SCE's Engineering, Planning, and Grid Operations groups to develop the detailed scope of work which culminated in the development of the Project Management Plan (PMP), which addresses the following. • A detailed Scope of Work statement • The project's work breakdown structure (WBS) and associated organization structure • The labor resource plan • A procurement plan that describes the materials and services that the project anticipates needing. • The project's milestone and deliverable schedule • The detailed project cost estimate The PMP is currently in the stages of being finalized and reviewed for approval, which is expected to happen early in 2016. Once the PMP is approved, the project will then receive authorization to proceed to the execution phase of the project lifecycle.		

8. Series Compensation for Load Flow Control

<table>
<tr><td colspan="2">Investment Plan Period:
2nd Triennial Plan (2015-2017)</td><td colspan="2">Assignment to value Chain:
Transmission</td></tr>
<tr><td colspan="4">Objective & Scope:
The intent of this project is to demonstrate and deploy the use of Thyristor Controlled Series Capacitors (TCSC) for load flow control on series compensated transmission lines. On SCE’s 500 kV system in particular, several long transmission lines are series compensated using fixed capacitor segments that do not support active control of power flow. The existing fixed series capacitors use solid state devices as a protection method and are called Thyristor Protected Series Capacitors (TPSC)</td></tr>
<tr><td colspan="4">Deliverables:
• TBD</td></tr>
<tr><td colspan="4">Metrics:
TBD</td></tr>
<tr><td colspan="4">Schedule:
TBD</td></tr>
<tr><td colspan="2">EPIC Funds Encumbered:
TBD</td><td colspan="2">EPIC Funds Spent:
$0</td></tr>
<tr><td colspan="4">Partners:
TBD</td></tr>
<tr><td>Match Funding:
TBD</td><td colspan="2">Match Funding split:
TBD</td><td>Funding Mechanism:
Pay-for-Performance Contracts</td></tr>
<tr><td colspan="4">Treatment of Intellectual Property:
SCE has no current patents or licensing agreements signed. Future Intellectual Property is to be determined.</td></tr>
<tr><td colspan="4">Status Update:
In 2015 “Series Compensation for Load Flow Control” project was authorized to proceed according to SCE’s Portfolio Management Office (PMO) processes. This project is currently in the planning stage to address the deliverables and milestones for the project activities.</td></tr>
</table>

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

<table>
<tr><td>Investment Plan Period:
2nd Triennial Plan (2015-2017)</td><td>Assignment to value Chain:
Distribution</td></tr>
<tr><td colspan="2">Objective & Scope:</td></tr>
</table>

<table>
<tr><td colspan="3">This project demonstrates the electrification of transportation and vocational loads that previously used internal combustion engines powered by petroleum fuels in the SCE fleet. The VAPS system uses automotive grade lithium ion battery technology (Chevrolet Volt and Ford Focus EV) which is also used in notable stationary energy storage projects (Tehachapi 32 MWh Storage)</td></tr>
<tr><td colspan="3">Deliverables:
• TBD</td></tr>
<tr><td colspan="3">Metrics:
TBD</td></tr>
<tr><td colspan="3">Schedule:
TBD</td></tr>
<tr><td>EPIC Funds Encumbered:
TBD</td><td colspan="2">EPIC Funds Spent:
$8,385</td></tr>
<tr><td colspan="3">Partners:
TBD</td></tr>
<tr><td>Match Funding:
TBD</td><td>Match Funding split:
TBD</td><td>Funding Mechanism:
Pay-for-Performance Contracts</td></tr>
<tr><td colspan="3">Treatment of Intellectual Property:
SCE has no current patents or licensing agreements signed. Future Intellectual Property is to be determined.</td></tr>
<tr><td colspan="3">Status Update:
In 2015 a Request for Information (RFI) was sent to 12 qualified potential suppliers of Versatile Plug-in Auxiliary Power Systems (VAPS) with the primary function of electrically powering vehicle air conditioning systems. Applicability of such a system is very broad and includes all of SCE’s light duty pickup trucks (typically Ford F150). Five responses to the RFI were received. Meetings were held with SCE’s Transportation Services Department (TSD) in which both RFI responses and TSD fleet electrification priorities were reviewed and discussed in detail. In parallel with the RFI activity projects based on evaluating hybridized drivetrains of Class 2, 5 and 8 trucks were formally approved to proceed through SCE Advanced Technology’s (AT) Project Selection Process. As of the end of the year a comprehensive project plan to procure and evaluate systems addressing each of these areas in the 2016-2017 timeframe was under development.</td></tr>
</table>

10. Dynamic Power Conditioner

<table>
<tr><td colspan="3">Investment Plan Period:
2nd Triennial Plan (2015-2017)</td><td colspan="2">Assignment to value Chain:
Distribution</td></tr>
<tr><td colspan="5">Objective & Scope:
This project 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</td></tr>
<tr><td colspan="5">Deliverables:
TBD</td></tr>
<tr><td colspan="5">Metrics:
TBD</td></tr>
<tr><td colspan="5">Schedule:
TBD</td></tr>
<tr><td colspan="2">EPIC Funds Encumbered:
TBD</td><td colspan="3">EPIC Funds Spent:
$930</td></tr>
<tr><td colspan="5">Partners:
TBD</td></tr>
<tr><td>Match Funding:
TBD</td><td colspan="3">Match Funding split:
TBD</td><td>Funding Mechanism:
Pay-for-Performance Contracts</td></tr>
<tr><td colspan="5">Treatment of Intellectual Property:
SCE has no current patents or licensing agreements signed. Future Intellectual Property is to be determined.</td></tr>
<tr><td colspan="5">Status Update:
In 2015, the project team focused on gathering all of the requirements that will be needed for the demonstration phase of the project. The project team has been reaching out to vendors and several federal national labs to complete specification documents for hardware and software platforms.</td></tr>
</table>

11. Optimized Control of Multiple Storage Systems

<table>
<tr><td>Investment Plan Period:
2nd Triennial Plan (2015-2017)</td><td colspan="2">Assignment to value Chain:
Distribution</td></tr>
<tr><td colspan="3">Objective & Scope:
This project aims to demonstrate the ability of multiple energy storage controllers to integrate with SCE's Distribution Management System (DMS) and other decision making engines to realize optimum dispatch of real and reactive power based on grid needs</td></tr>
<tr><td colspan="3">Deliverables:
• TBD</td></tr>
<tr><td colspan="3">Metrics:
TBD</td></tr>
<tr><td colspan="3">Schedule:
TBD</td></tr>
<tr><td>EPIC Funds Encumbered:
TBD</td><td colspan="2">EPIC Funds Spent:
$0</td></tr>
<tr><td colspan="3">Partners:
TBD</td></tr>
<tr><td>Match Funding:
TBD</td><td>Match Funding split:
TBD</td><td>Funding Mechanism:
Pay-for-Performance Contracts</td></tr>
<tr><td colspan="3">Treatment of Intellectual Property:
SCE has no current patents or licensing agreements signed. Future Intellectual Property is to be determined.</td></tr>
<tr><td colspan="3">Status Update:
In 2015, the Optimized Control of Multiple Storage Systems project began to evaluate the requirements to align with the Integrated Grid Project and the SCE's Energy Storage Ownership Initiative (ESOI). This project will also leverage real-time circuit information to autonomously curtail load on the system and will have the ability to disconnect the Energy Storage Systems based on abnormal circuit conditions.</td></tr>
</table>

12. DC Fast Charging Demonstration

<table>
<tr><td>Investment Plan Period:
2nd Triennial Plan (2015-2017)</td><td>Assignment to value Chain:
Demand-Side Management</td></tr>
<tr><td colspan="2">Objective & Scope:
The goal of this project is to demonstrate public DC fast charging stations at SCE facilities near freeways in optimal locations to</td></tr>
</table>

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: • TBD		
Metrics: TBD		
Schedule: TBD		
EPIC Funds Encumbered: TBD	**EPIC Funds Spent:** $0	
Partners: TBD		
Match Funding: TBD	**Match Funding split:** TBD	**Funding Mechanism:** Pay-for-Performance Contracts
Treatment of Intellectual Property: SCE has no current patents or licensing agreements signed. Future Intellectual Property is to be determined.		
Status Update: In 2015, the detailed project planning phase was initiated. In order to demonstrate the feasibility and effectiveness of installing fast charging stations, initial planning has been focused on assessing the impact of existing fast charging stations on the electric distribution system. A team of experts is being assembled, including Advanced Technology, Engineering, Electric System Planning, and Power Quality, and equipment is being specified to instrument approximately 25 stations. In addition, the project will include a plan to study the effects of associated storage to reduce system impact. Through the planning process, task definition and scheduling is being done in close collaboration with team experts. Project planning was on schedule as of the end of the year. Once SCE's plan is complete in early 2016, Tesla Motors, an automotive		

OEM responsible for much of the interest in DC fast charging, will be engaged as the project transitions into the execution phase.

5. 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, 2015, SCE expended a total of $10,745,311 toward project costs and $400,017 toward administrative costs for a grand total of $11,145,328. SCE's cumulative expenses over the lifespan of its 2012 – 2014 EPIC program amount to $15,731,475. SCE committed $38,444,258 toward projects and encumbered $19,543,006 through executed purchase orders during this period; SCE has $0 in uncommitted EPIC funding.

SCE continued project execution activities towards the approved portfolio of 15 projects; 3 of these projects were completed during the calendar year 2015. The list of completed 2012-2014 Investment Plan projects include: 1) Cyber-Intrusion Auto-Response and Policy Management System; 2) Outage Management and Customer Voltage Data Analytics; and, 3) Portable End-to-End Test System. In the case of the Outage Management and Customer Voltage Data Analytics project, SCE has decided to proceed with system-wide implementation of the tools and methods that were demonstrated as part of the project, representing a successful example of technology transfer for SCE's EPIC program. For the other two projects that successfully completed in 2015, SCE will perform knowledge transfer of the technical findings and lessons learned to business, which will serve to inform future investment decision. In accordance with the Commission's directives,[30] SCE has completed final project reports for these 3 projects and included them in the Appendix of this annual report.

[30] D.13-11-025, OP14.

(2) 2015-2017 Investment Plan

For the period between January 1 and December 31, 2015, SCE expended a total of $243,306 toward project costs and $320,074 toward administrative costs for a grand total of $563,380. Since 2015 represents SCE first partial year of implementing program operations of its 2015-2017 Investment Plan, cumulative expenses over the lifespan of its 2015 – 2017 EPIC program amount to $563,380. SCE committed $22,752,151 toward projects and encumbered $0 through executed purchase orders during this period; SCE has $16,563,975 in uncommitted EPIC funding.

SCE launched 12 projects during the calendar year 2015. All 12 projects received funding commitments through SCE's Advanced Technology portfolio management process.

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

During the calendar year 2016, SCE will continue to focus on successfully executing its remaining 12 approved projects as part of its 2012 – 2014 Investment Plan, and 12 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 two planned workshops in 2016. In these workshops, 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 will discuss the initiatives and proposed project activities that are planned for execution under its 2015 – 2017 Investment Plan. Lastly, SCE will inform stakeholders of its plans surrounding potential contracting opportunities and direct them to the EPIC webpage for the latest information on the EPIC program.

c) 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. 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, the launching of new corporate or regulatory initiatives[31] 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 guidance on specific technologies.

[31] The CPUC's Distribution Resources Plan is one example.

Appendix A

EPIC 1 Program Report 2013086

Outage Management and Customer Voltage Analytics

EPIC 1 Program Report 2013086

Outage Management and Customer Voltage Analytics

SOUTHERN CALIFORNIA EDISON®

An EDISON INTERNATIONAL® Company

Report Prepared by: Southern California Edison

Report Prepared for: The California Public Utilities Commission

February 18, 2016

Executive Summary

SCE successfully demonstrated the use of meter data for Distribution grid benefits in this EPIC I[1] project. The project consisted of a scaled pilot demonstration and a feasibility study.

The scaled pilot consisted of approximately 20,000 customers' historic meter data (meter events and hourly voltage and consumption) on 14 distribution circuits of 12 substations. Fourteen use case were developed and successfully demonstrated. These use cases addressed voltage deterioration along a circuit, voltage of a strategic node (fuse, switch, etc.), identification of Distribution system assets outside of user defined voltage threshold limits, transformer load evaluation and overloading conditions with loss of life estimation using the IEEE standard C57.91-195, load aggregation to a strategic node upstream of several transformers, outage reconstruction and reporting models utilizing voltage data and meter exceptions/event data, etc.

The demonstration occurred in an isolated lab environment and included installation of a vendor's analytics platform. The platform consumed the historic meter data to provide metrics, graphics and circuit visualization overlaid on SCE's comprehensive geographic information system (cGIS). An easy-to-understand user interface provided the necessary information for Distribution planners, engineers, outage reporting analysts and customer service representatives to make quick and informed decisions. It enabled planners and engineers to perform quick assessments for Transformer Load Management and engineering analysis in finer detail than was previously possible. The project provided valuable insight into the technical requirements for an enterprise-wide implementation of a similar analytics and visualization tool.

The demonstration concluded with user testing/evaluation by Distribution system engineers and planners and outage reporting analysts to educate them of the value, test the functionality of this tool and to receive feedback on opportunities for improvement. The demonstration of the use cases with the analytics platform was so successful that SCE is proceeding with an enterprise-wide deployment of a platform with similar functionality that uses smart meter data.

The feasibility study was on the potential use of meter outage events in SAIDI/SAIFI metric calculation. It included an evaluation of the existing outage analysis process and the changes and benefits of using meter outage events with time stamps. The study concluded with comparison/validation testing between using the existing method versus meter events time stamps in calculating Customer Minutes of Interruption (basis for System Average Interruption Duration Index/System Average Interruption Frequency Index) values on a single area outage as well as for an entire District. The general conclusion from the comparison testing was that

[1] EPIC I: Electric Program Investment Charge established by the California Public Utilities Commission in Decision 12-05-037 for Rulemaking 11-10-003 on May 24, 2012. EPIC I represents SCE's first Triennial Investment Plan application A12-11-004filed for approval November 1, 2012, pp. 37-39.

using meter event data can be an efficient and accurate method for calculating CMI values. The study also made recommendations. These included (i) automation of some steps of the outage analysis process, (ii) implementation of interfaces between databases including Outage Management System (OMS), Outage Database and Reliability Metrics (ODRM) and Edison Smart Connect Data Warehouse (ESCDW) to enable sharing of data and (iii) conduct a study to capture outages of meters that do not generate (i.e. non-smart meters) or communicate meter events.

The demonstrated capability to leverage smart meter data with SCE existing tools and data systems opens the way to fundamentally change how distribution engineers and planners approach Distribution system asset and system management. These disciplines would literally have a broad view of the Distribution network or circuit by circuit, enabling them to pinpoint problem Distribution system assets in a minimum amount of time, readily perform comparative analysis, and to efficiently prioritize Distribution system asset maintenance and replacement. It also has the potential to improve the outage analysis process in reliability indices reporting.

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1 Project Background

Smart meter data presents a valuable opportunity to provide analytics tools that benefit the T&D system. However, it was first necessary to demonstrate that data collected from smart meters could be integrated into an outage management and analytics solution. This project was a first step towards that massive undertaking. It was a crucial step, based on the sheer magnitude of the data available, the complexity of the system being managed and the process transformation expected. A sweeping paradigm shift of T&D analytics and OMS fully integrated to the smart meter level, without certainty as to the viability of the application, would be impractical and potentially flawed.

The SCE system includes five million customer smart meters generating voltage and usage data at 60 minute intervals around the clock, seven days a week. The SmartConnect™ platform polls the meters once per day, then transmits that data to the Edison SmartConnect™ Data Warehouse (ESCDW) for storage. The sheer magnitude of the data necessitated the project confine itself to a sample of customers and electric infrastructure.

With the deployment of smart meters throughout its service territory, a significant amount of data was being collected and stored. The concept of using the meters as sensors on the distribution network had been envisioned and specified years ago in Edison SmartConnect™ design specification. It is only in the last few years that analytics applications using smart meter data were starting to be marketed by software development vendors.

The availability of energy consumption, service interruption, and voltage data presented the opportunity for a distribution system analytics application, furthering SCE's drive toward customer service excellence. This project demonstrated that capability through installation of an Integrated Analysis Platform (IAP) data model. The IAP Data Model was implemented through a partnership between SCE and its third-party vendors using historical meter data.

14 use cases on voltage analytics, customer and transformer load analysis, outage reconstruction and a simulated circuit model were demonstrated in a scaled pilot. The scaled pilot demonstration with approximately 20,000 smart meters was integrated with SCE's GIS electrical network model. These meters were distributed across SCE's service territory and associated with 14 distribution circuits. The analytics and visualization solution utilized 90 days of historic customer meter hourly consumption and voltage data and meter events and exceptions. The demonstration was performed in an isolated environment using a database and server in SCE's Advanced Technology laboratories. The meter data was extracted from the ESCDW and stored on the lab database along with the related GIS, infrastructure and Distribution system asset data for the 14 circuits.

Separately, the idea of using smart meter data in service reliability indices reporting was also identified. The existing indices calculation process is time and labor intensive in researching and validating reportable outages from one or more databases, field maintenance records, etc. It was speculated that meter outage events could be used in the indices calculation process to eliminate /reduce some time consuming steps. A feasibility study would be needed before any changes to the existing process could be implemented. The feasibility study would include an analysis of all the existing process steps, identification of areas where meter event data could be beneficial and the potential for automation of some of the process steps.

This project was funded by the Electric Program Investment Charge (EPIC). The California Public Utilities Commission (CPUC) established the EPIC program May 31, 2012 in Decision 12-05-037.[2] SCE, as one of the four program administrators, submitted its first three-year investment plan November 1, 2012[3] pursuant to the requirements set out in the Commission's EPIC Program Decision. This project, Outage Management and Customer Voltage Data Analytics, was specified in the filing within Section 6.3 Customer-Focused Products and Services Enablement and Integration.[4]

2 Project Objective

The key objective of this project was to demonstrate how SCE's smart meter data could benefit the distribution grid. To achieve that objective, a technology demonstration and a feasibility study were conducted. The technology demonstration included using smart meter data in an analytics and visualization solution at scale. This project achieved the objective by demonstrating 14 Distribution system use cases in an analytics and visualization application using approximately 20,000 meter data associated with 14 circuits.

The feasibility study was on using smart meter outage data to improve or enhance the reliability indices calculation process. More specifically, the study was conducted to determine the benefits that the meter outage events and/or exceptions data could provide to the reliability indices (SAIDI/SAIFI) calculation process.

3 Issues Addressed

CPUC mandated that the California investor owned utilities (IOUs) report on service reliability, i.e., the frequency and duration of both sustained and momentary outages. This decision directed the IOUs to compute service interruption statistics: 1) including transmission, substation and distribution outages, and 2) excluding planned outages. These statistics are reported annually as three indices:

1. System Average Interruption Frequency Index (SAIFI): this index indicates the average number of sustained outages per customer per year, where a sustained outage is defined as an outage lasting five minutes or more.
2. System Average Interruption Duration Index (SAIDI): this index reflects minutes of sustained outages per customer (on average) per year.

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[2] State of California, California Public Utilities Commission, *Phase 2 Decision Establishing Purposes and Governance for Electric Program Investment Charge and Establishing Funding Collections for 2013-2012* (Decision 12-05-037, May 31, 2012).
[3] State of California, California Public Utilities Commission, *Application of Southern California Edison Company (U 338-E) for Approval of Its Triennial Investment Plan for the Electric Program Investment Charge Program,* Application 12-11-004, Sacramento, CA, November 1, 2012, 1-180.
[4] *Application of Southern California Edison Company (U 338-E) for Approval of Its Triennial Investment Plan for the Electric Program Investment Charge Program,* 37-39.

3. Momentary Average Interruption Frequency Index (MAIFI): this index reflects the average number of outages lasting less than 5 minutes per customer per year.

The current process used to calculate the indices requires significant human intervention, decision making and calculation. Currently, outages must be manually researched and validated against standard criteria to be counted. Intuitively, the SmartConnect™ platform has the potential to perform these calculations with greater accuracy and in a more efficient manner than the existing manual process. A feasibility study was conducted to evaluate whether smart meter data could provide the benefits of improved accuracy and efficiency.

Lastly, SCE, as with other electric utilities, is required to deliver, on demand, 100% of consumer electrical watt (load) requirements within a predefined voltage range. The utilities must, at the same time, deliver that power at an optimum power factor[5] to conserve energy and control costs. The inherent complexity of the electrical network combined with the dynamics of consumer demand make meeting these tasks highly challenging. The means to manage these tasks in the electric distribution system is Voltage/VAR[6] control. Due to the cost, traditional technology limited Voltage/VAR monitoring to substations and feeder lines where high-level adjustments could be made. SCE did not have the ability to track voltages at the end of every distribution circuit—much less at each customer meter—without deploying a field technician. The smart meters virtually upended data and visualization capability, by allowing visualization of voltage deterioration along a circuit based on smart meter voltage data. With this type of application, SCE would have the capability to diagnose problems, develop strategies to conserve energy and review Voltage/VAR with system visualization.

Meeting each of these challenges would result in enhanced customer service excellence; but the approach had to be demonstrated as viable, effective and efficient before systemic changes could be implemented.

4 Project Scope

The scope of this project was to demonstrate that smart meter data could provide T&D operational and reliability indices reporting benefits. The project consisted of (a) a scaled pilot demonstration of an analytics and visualization solution and (b) a feasibility study on using smart meter outage events for calculating reliability indices (SAIDI/SAIFI).

a. The scope of the analytics and visualization solution project was to demonstrate 14 electric distributions system use cases by using historic smart meter data from approximately 20,000 customer meters on 14 circuits. Ninety days of historic meter (meter events, and hourly voltage and consumption) data was converted and merged into a standard database format for consumption by the analytics solution to demonstrate the use cases.

[5] The power factor is the ratio of true power to apparent power.
[6] Volt-Ampere Reactive or VAR is a unit used to measure reactive power in alternating current.

The analytics and visualization application was required to demonstrate the following functionality:

1. Device and transformer monitoring, replacement and identification of overloaded transformers.
2. An interactive simple circuit visualization model with key devices and nodes.
3. Historical outage visualization.
4. Ability of a user to receive intelligent feedback from voltage data on a circuit to make dispatch decisions about an outage.

The following were deliverables of the analytics and visualization part of the project:

i. Solution Architecture and Design document.
ii. Step-by-step instruction manual/user guide with detailed product descriptions of all features.
iii. Showcase of application functionality that met the 14 use cases.
iv. Written assessment of the ability to receive intelligent feedback from voltage data on a circuit and input from collected voltage data at specific points to make dispatch decisions on an outage.
v. Feasibility assessment on using near real-time data (including outage and voltage-based meter exceptions), identifying network traffic impact, latency of data, etc., for determining near real-time state/status of key devices on a circuit.
vi. Onsite product demonstration and walk-through of the use cases.
vii. User training/testing sessions (UATs), materials and documentation.
viii. Technical assessment of alternate options for reliability indices reporting.
ix. White paper on the ability to export data into a format for a software program, such as Microsoft Excel and power flow modeling such as CYME.

b. The feasibility of using smart meter events data in the calculation of CMI for SAIDI/SAIFI was explored by SCE engineers and staff. The scope included an analysis of:

1. Eight types of outage scenarios.
2. Data flow of meter events to ESCDW.
3. Current outage analysis process.
4. Accuracy of the meter events.
5. Completeness of the data sets.
6. Integration of current and proposed SAIDI/SAIFI/MAIFI calculation criteria.
7. Layout of outage CMI calculation methodology.
8. Potential increase in efficiency and accuracy of the SAIDI/SAIFI/MAIFI calculation.

The deliverable of this feasibility study was a report documenting the findings of the scope elements above, and bringing forward challenges and recommendations.

5 Major Tasks

The major tasks for this project were approached in two separate efforts: (1) demonstration of smart meter data for T&D analytics and circuit visualization, and (2) a feasibility study of using smart meter data in calculating the service reliability indices.

5.1 Demonstrate application of smart meter data for T&D analytics and circuit visualization

5.1.1 Define Demonstration Parameters

Distribution system assets selected: SCE determined this demonstration project would include a cross section of substations and range of circuits to help ensure a solid cross section of both Distribution system assets and customer meters would be included. SCE's comprehensive Geographic Information System (cGIS) project is where all Distribution system assets is available to engineers and planners on a geospatial map of the distribution network. Since the cGIS data base was one of the crucial data bases for this demonstration, we decided to follow that implementation pattern and select substations and Distribution system assets from areas where cGIS was operational. Circuits from those substations were then selected for inclusion in this demonstration to provide a geographical representation of SCE's customers and Distribution system assets. The result was a selection of twelve distribution substations and fourteen circuits as shown in Table 1.

Table 1, Substations and Circuits in Demonstration

Substation Name	Circuit Names
Duarte	Spinks
Goleta	Ace
Harvard	Bragdon
Haveda	Sump
Hesperia	Mesquite
Lancaster	Crowder and Oban
Little Rock	Calli Valli and Sun Village
Lucerna	Sky Hi
Modoc	Lauro
Monrovia	Alta
Palmdale	Caliber
Tortilla	Huevos

The approximately 20,000 customer SmartConnect™ meters included in this demonstration were served by the fourteen listed circuits. A subset of these customer meters on each side (i.e. line and load) of strategic Distribution system nodes (junction box, switch, fuse, etc.) were identified and designated to be "bellwether meters." Bellwether meters specifically identified the location of outages and provided other operational data such as voltage deterioration along a circuit.

Analytics selected: Only analytics currently used by SCE distribution engineers, planners and outage reporting analyst were considered for inclusion in this demonstration. The demonstration offered, for the first time, data at the customer meter level at a level of accuracy not previously available. The T&D analytics selected for this scaled pilot demonstration project were:

1) Evaluate load on an existing transformer.
2) Detect transformer overload conditions.
3) Detect and analyze voltage anomalies and complaints.
4) Perform load switching calculations.
5) Recreate and visualize circuit voltage profiles.
6) Graphically view each circuit to determine the states of Distribution system assets.
7) Visually reconstruct an outage and its restoration.
8) Assess the state of key circuit devices on geospatial maps.
9) Data export to report applications and for other analysis not included in this project.

5.1.2 The IAP Data Model and Preexisting SCE Databases

IAP Data Model Demonstration

This demonstration required a front-end software platform to integrate SmartMeter™ data with SCE operating data bases (e.g. the electric distribution network GIS). This software, called an integrated analysis platform (IAP), was intended to enable engineers and planners to aggregate smart meter data to the circuit or feeder level, or to "drill down" to individual meter locations, depending upon the analytics being performed. The IAP achieved the goal and provided engineers and planners with visualization and dashboard data presentations.

In this scaled pilot, the IAP demonstration was performed using historical meter data from approximately 20,000 customer meters connected to fourteen circuits in SCE's service territory. The data was loaded onto SCE's Advanced Technology lab servers along with the circuit layouts from cGIS. Three months of customers' historic hourly consumption, voltage and meter events data was used. The IAP was preconfigured to accept and utilize this data.

The IAP was also configured to recognize two types of events: meter events and analytic events. Meter events are created by the meter such as an outage or a high or low voltage threshold is exceeded. Analytic events are generated by the IAP as the result of analyzing incoming readings plus meter events and recognizing patterns in the data. Analytic events were defined by the engineers and planners over operating ranges with upper and lower limits. Much of the reporting in the IAP dashboards was based on analytic events.

Simulated Circuit Model (SCM):

The visualization capability of the IAP was used to overlay smart meter data on the electric network cGIS, giving distribution engineers and planners a geospatial tool to rapidly:

1) Visualize the state of key devices on a distribution circuit segment using historic voltage data and meter events/exceptions from bellwether SmartConnect™ meters;
2) Assess the status of key devices using voltage data from bellwether meters and generate an area-wide heat map and view of key device states; and
3) Reconstruct outages and restoration timing, and then generate outage reports utilizing voltage and meter events/exceptions data.

5.1.3 Conduct User Acceptance Tests (UATs) on the Analytics and the SCM

The analytics included in this project were grouped into three categories: voltage analytics for power quality, customer and transformer load analysis and the SCM. UATs were developed as test controls, reflecting the typical analysis performed by distribution system engineers, planners and grid operations analysts ranging from adding new load to a transformer, voltage degradation along a circuit to reconstructing outage timelines for reporting purposes. The IAP data model was tested for performance against this set of use cases that reflected T&D analytic tools, circuit visualization and outage management needs. The UATs were the actual step-by-step tests to determine capability of the model to use smart meter data for T&D analytics. Distribution engineers and planners in these tests:

- Evaluated the voltage data at the end of a circuit and at several strategic node locations along a circuit. The data was then analyzed to demonstrate the types of proactive decisions planners and engineers will make on power flow and quality analytics, including potential capacitor bank location(s) at strategic points along a circuit.

- Evaluated the energy consumption data starting with the end-point customers and aggregating it to the transformer and circuit level. The data was then analyzed to:
    1) Assess the Distribution system asset loading conditions of the electrical network,
    2) Provide comparisons to nameplate ratings, and
    3) Present loading status in the form of heat map visualization.

- Visually reviewed the status indication of distribution circuits based on strategically selected bellwether meter data being collected, analyzed and integrated with the electric network GIS.

Some UAT examples included:

Use Case Category: Voltage analytics for power quality

Use Case 2, Analytic: Identify overloaded transformers to determine if a service transformer is causing high or low voltage at the customer level.
Expected Result 2a: The user (distribution engineer or planner) viewed historical voltage data generated by smart meters connected to a transformer. This

enabled the user to identify any pattern of high or low voltage readings which could point to an overloaded transformer.

Use Case Category: Customer and transformer load analysis

Use Case 6, Analytic: Evaluate unplanned additional load at the transformer level (e.g. new electric vehicle load).

Expected Result 6c: The user viewed customer connected load profiles for a selected transformer to determine aggregated kWh load on that transformer.

Use Case Category: Simulated Circuit Model (SCM)

Use Case 11, Visualization: Review the operating status of key devices on the distribution network using bellwether meter voltage data, displayed as an overlay to SCE's electrical network GIS.

Expected Result 11a: The SCM, for a selected circuit, displayed a single-line diagram with key device locations and previous day voltage profiles for each device.

The UATs, in total, included 12 analytics and visualizations with 30 expected results**.**

This demonstration was conducted using SmartConnect™ customer meter data and SCE operating Distribution system circuit information. Since publication of the full documents in this project would potentially compromise the privacy of SCE customers and security of SCE Distribution system assets they are not included in full. All graphics included in this report have been altered to obscure customer specific and Distribution system asset specific location information.

5.2 Reliability Indices: Conduct a Feasibility Study Using SmartConnect™ Meter Event Data

Whenever a smart meter experiences an outage, a primary power down event is created and stored in the meter. Likewise, when power is restored, a primary power up event is created and stored in the meter. Each meter event is date and time stamped along with its unique meter identifier. Meter events are retrieved once a day (when power is restored) and stored in ESCDW. Given the availability of meter event data from each meter it would be possible to calculate customer minutes of interruption (CMI) of an outage. Using smart meter data to calculate CMI could potentially improve accuracy and efficiency in the current methodology. A feasibility study was needed to evaluate the validity of these potential benefits.

The feasibility study included five steps:

1) Post-outage analysis process improvement study

   Document the current post outage analysis process to identify potential efficiency and/or accuracy improvements.

2) Meter outage events data flow improvement study and meter time stamp accuracy

   Verify the accuracy of both meter events data and the meter time stamp (as to the timing of the service interruption event)

3) Layout the CMI calculation methodology using smart meter data

Provide the CMI calculation process using smart meter data.

4) Test Case 1:

Compare previously verified single incident CMI values to CMI values calculated by meter time stamps and identify the back-end changes needed with different types of outages.

5) Test Case 2:

Demonstrate scalability of the methodology changes in Test Case 1 using the district of Santa Barbara.

6 Results

The T&D analytics and SCM demonstration project and the reliability indices feasibility study proved smart meter data can be used to increase data management efficiency, increase reliability and improve report accuracy. The integration of smart meter data and ability to visualize the distribution network will fundamentally transform voltage analytics, customer and transformer load analysis, outage management and reliability reporting.

6.1 UAT Results: T&D Analytics and the SCM

The UAT stepped demonstrations were conducted in the SCE Advanced Technology laboratory. This provided a controlled environment to help ensure each step was consistently followed.

6.1.1 Voltage Analytics for Power Quality

There were four voltage analytics selected for the demonstration. Each of the four was identified as a sequentially numbered Use Case.

Use Case 1: Review the voltage profile of strategic nodes[7] along a distribution circuit to evaluate capacitor bank placement requirements based on voltage deterioration. As proof that smart meter data can be used to demonstrate voltage deterioration along a circuit two specific Expected Results were specified that, in combination, allowed the user to a) review the voltage of selected bellwether meters on either side of a key device on a circuit, and thus b) determine the voltage profile and any deterioration from the substation to the end point. The expected results were successful in every instance of the test. Fig. 1 shows the screen available to the user for determining the Expected Results. All the graphics are interactive and so clicking on an icon, a bar on a graph, etc. will take you to another screen with more details. Starting from the top, the blue lightning bolt icon indicates a transformer with low voltage located on the cGIS map. The second graph shows the secondary voltage profile over time where maximum (red), minimum (blue) and average (green) voltage of the transformer. The second graph from the bottom shows maximum (red), average (green) and minimum voltage operating bounds. The bottom bar graph is the number of service points (meters) with low

[7] A strategic node is defined as selected electrical connections on a circuit, typically a fuse, switch, junction box etc.

voltage alarms. The same exercise can be performed for high secondary voltage (red icons) alarming transformers.

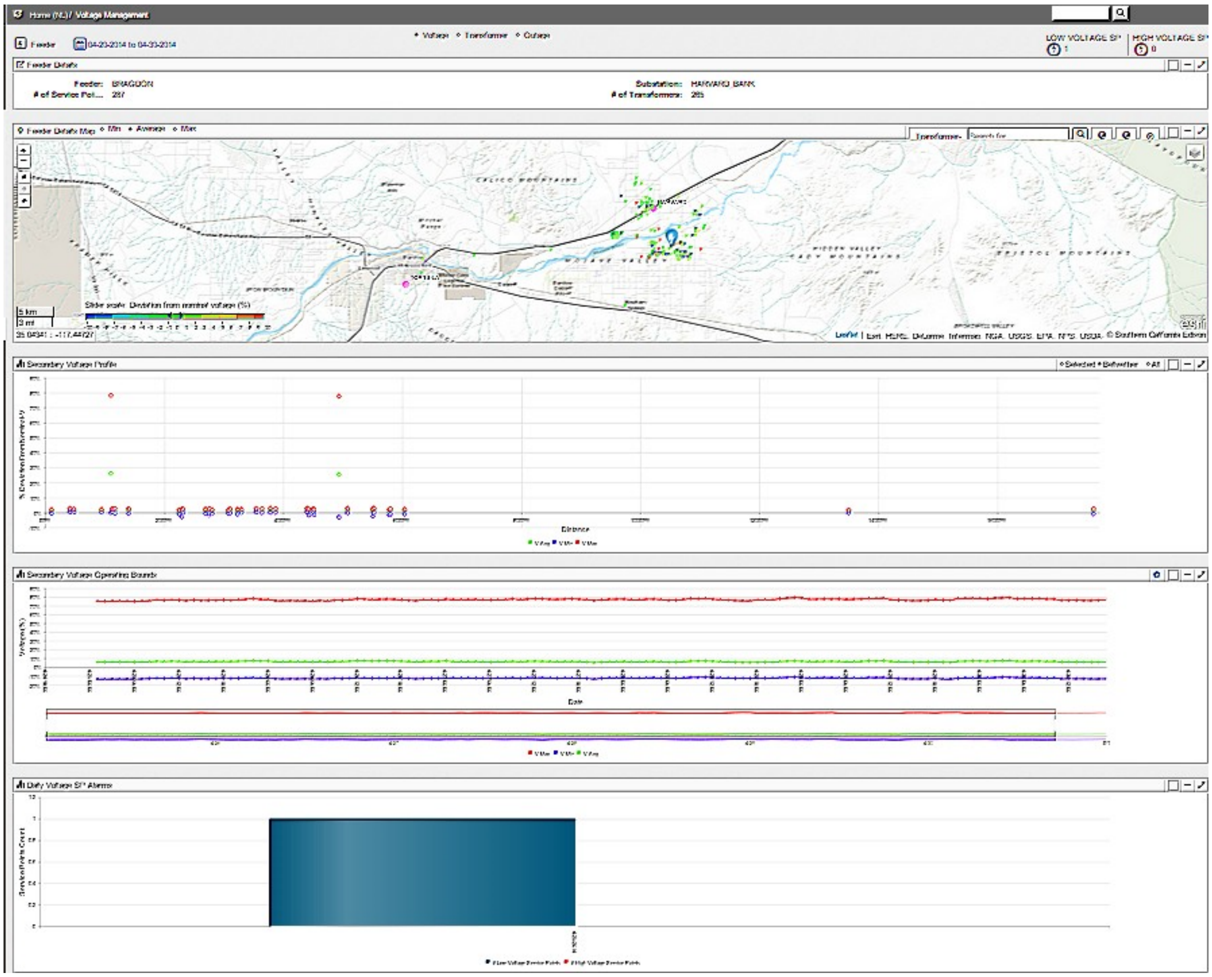

Figure 1, Feeder Detail Screen (Voltage Context)

Use Case 2: Determine if a service transformer load is contributing to high or low voltage at the customer level: identify transformers that are overloaded in the system and compare the voltage of customers connected to a selected transformer for potential power quality issues. There were three Expected Results that allowed the user to: a) view, on a system wide basis, historical data from smart meters connected to a transformer to identify any pattern of high/low voltage readings to locate overloaded transformers, b) identify overloaded transformers within a region by entering high and low voltage thresholds, and c) select individual transformers and review voltage profiles of all customers attached to the selected transformer to identify high or low voltage abnormalities at the customer level. The Transformer Management Dashboard (Fig. 2) provided data that allowed users to complete their analysis for all three Expected Results in Use Case 2. Starting from the top, the numbers in the red and amber icons on the map represent the number of transformers experiencing peak utilization of over

150% (red) to within 80% - 120% (amber) of name plate rating. The color bar in the bottom of the window indicates the percent peak utilization. The bar graph in the middle indicates percent peak utilization of each transformer. Each bar represents a transformer. The third graph is a histogram of percent utilization versus the number of transformers. From left to right, the range is from 5% peak utilization to more than 200% peak utilization.

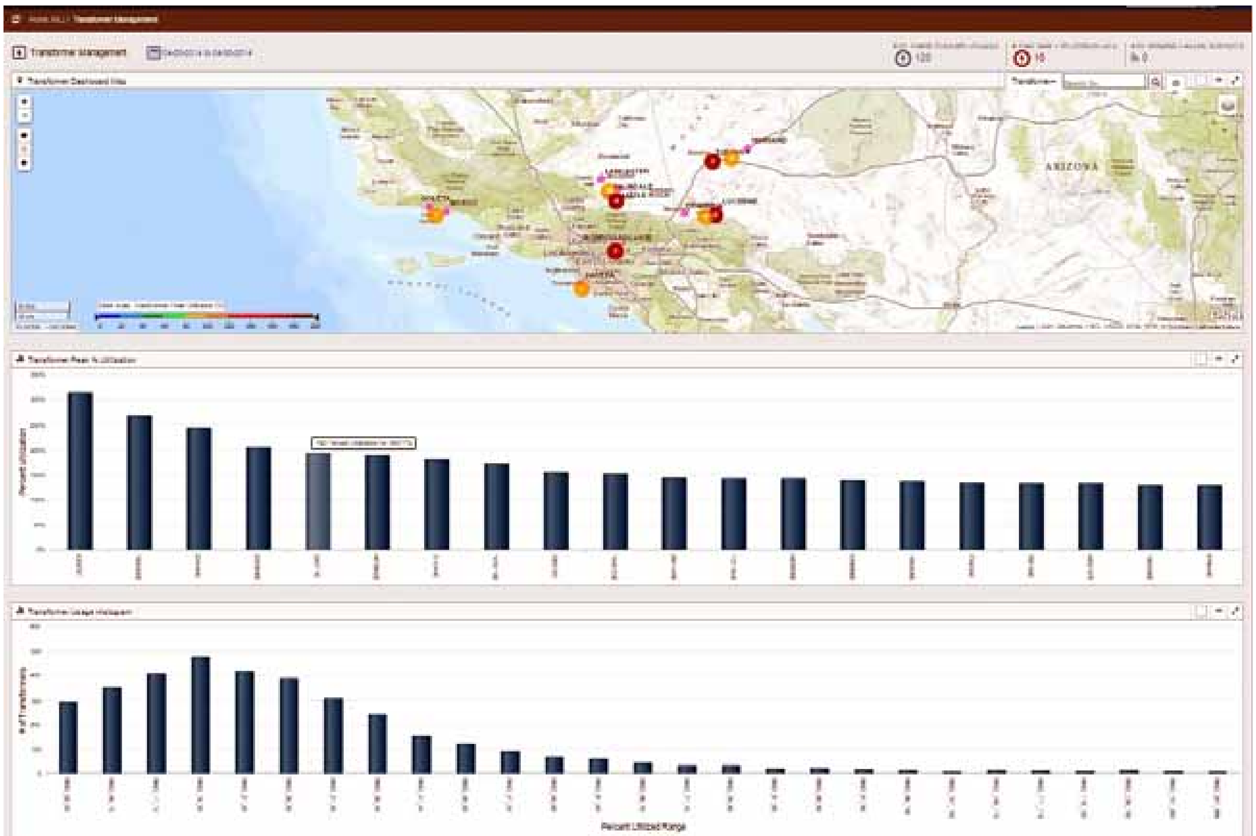

Figure 2, Transformer Management Dashboard

Use Case 3: Identify Distribution system assets operating outside of user-defined voltage limits through the GIS data visualization tool (i.e. the SCM). Two specific Expected Results were selected to demonstrate proof smart meter data would provide the user with visualized voltage data: a) on a historical basis for comparative time periods for any customer, and other customers in the vicinity on the same circuit, and b) as a color heat map (green, orange, or red) based on voltage thresholds entered by the user. Users affirmed both these Expected Results were met using Feeder Details Screen, Fig. 1.

Use Case 4: Demonstrate the ability to export data in the proper format for data manipulation in other power and non-power analysis tools. There were two Expected Results for this straightforward test: a) user can export data into a format that can be manipulated in a software program, such as Microsoft Excel, to generate additional reports and analysis for purposes other than power analysis, and b) user can export data into a format that can be manipulated in a power flow modeling software such as CYME. This functionality was displayed on the Service Point List (Fig. 3) where the user entered a query; the results were displayed on a map with a list/data table and the ability to export the data in various format.

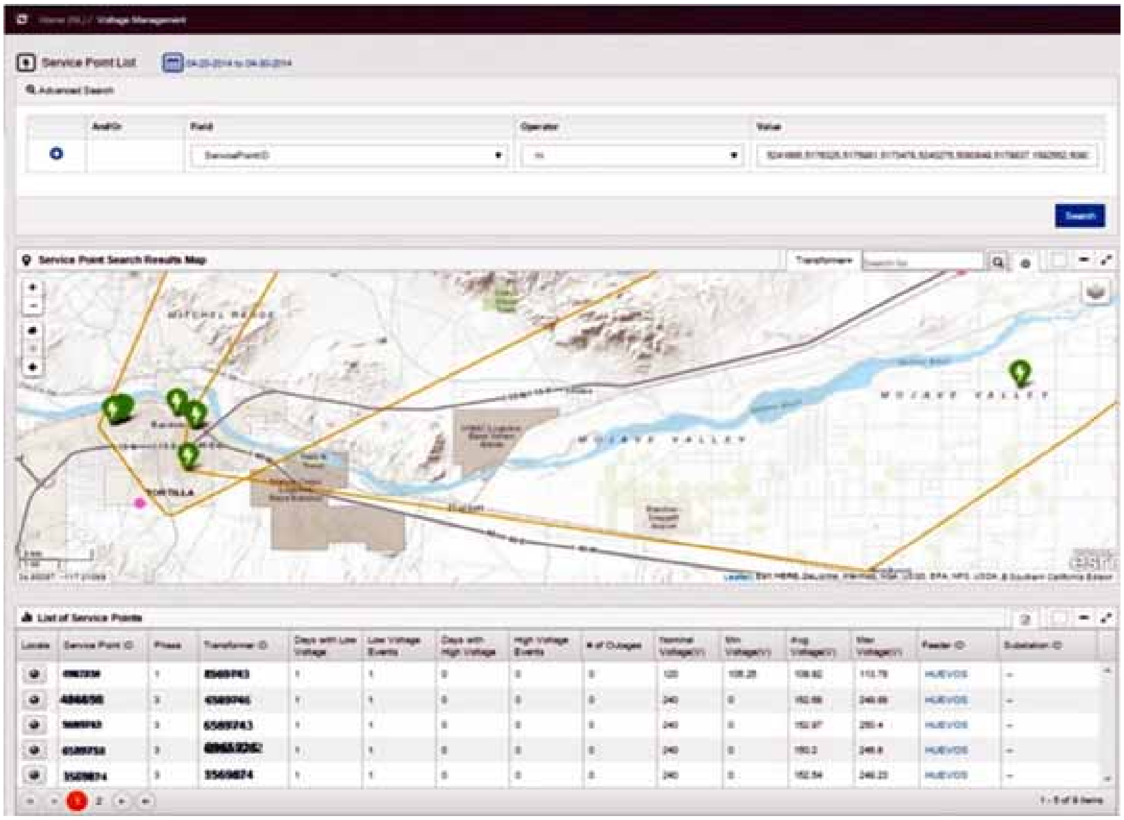

Figure 3, Service Point List

Note: This figure has been altered from the original to obscure specific customer and Distribution system asset information

6.1.2 Customer and Transformer Load Analysis

The second Use Case Category, Customer and Transformer Load Analysis, included four analytics for demonstration. As with the Voltage Analytics Use Cases, each was a sequentially numbered (continued from the Voltage Analytics Use Case numbers) Use Case.

Use Case 6:[8] Provided the ability to evaluate load addition at the transformer level. This analytic had six Expected Results: a) user was able to identify a specific transformer on SCE's GIS electrical network, b) user was then able to query the transformer to verify all the customers connected to the transformer, c) then viewed the cumulative load (aggregated customer load profiles from smart meter data) on the transformer in kWh, d) and then viewed the transformer load profiles for a 24-hour period, as well for a given historical duration up to a year, and e) viewed the same data converted to a kVA load profile, also for a 24 hour period and a given historical duration up to a year; lastly, f) the user hypothetically added kVA (i.e. for new service) to evaluate impact of additional load on the transformer.

The Transformer Details displayed in Fig. 4 enabled users to complete their analysis. Starting from the top left is the transformer (green icon) location on circuit map with its associated meters (green squares). On the top right is transformer rating (horizontal line) with customer (amber lines) and aggregated load (green line) profiles over time. Similarly, below is the customer and aggregated voltages with user defined limits (horizontal lines). The pie chart indicates percentage of individual customer loads contributing to the total load on the transformer.

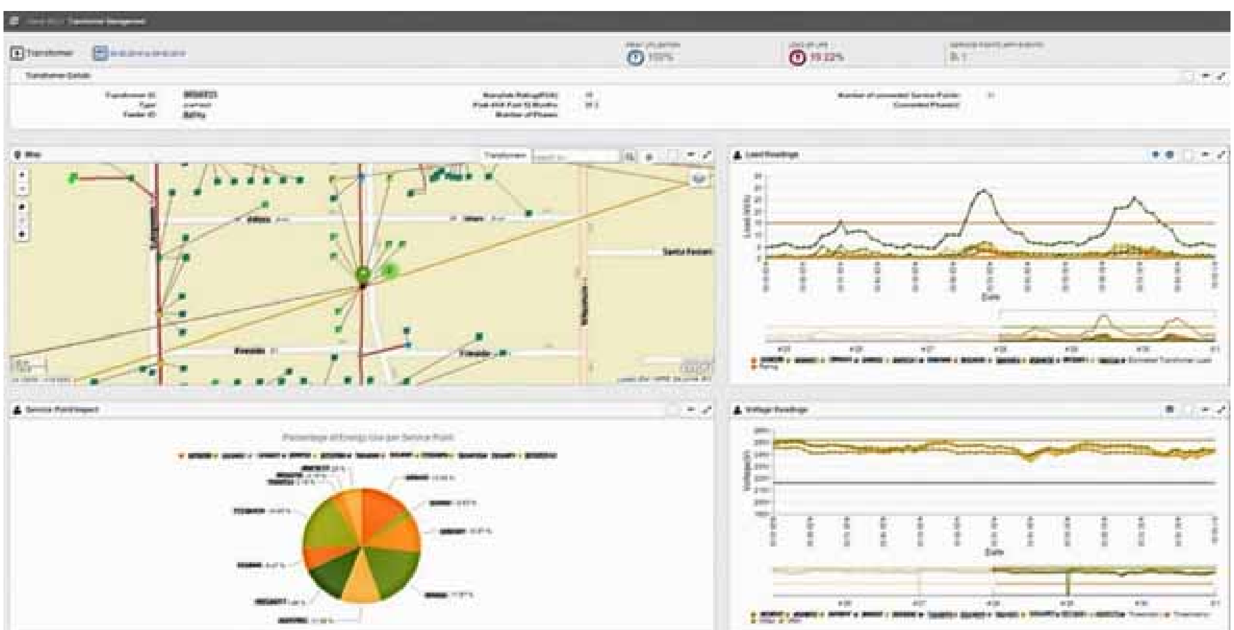

Figure 4, Transformer loading details.

Note: Figure has been altered from the original: street names were redacted to preserve customer privacy

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[8] Use Case 5 was deleted and the Expected Results were incorporated into other Use Cases.

Use Case 7: Provided the ability to view aggregate load and generate load profiles of strategic nodes upstream of multiple transformers by aggregating load from the customer meter to the transformer to the strategic node along the same feeder. This Use Case included four Expected Results to demonstrate this use case. The user, in each expected result, was able to: a) identify strategic nodes (red arrow) along any given distribution circuit on SCE's cGIS electrical network, b) aggregate the customer loads and generate load profiles for the transformers connected to the strategic node along a selected circuit, c) view the load profiles for a 24-hour period as well for a given historical duration, but no more than a year, and then d) view the same data converted into a kVA load profile, again for either a 24-hour period or a historical duration exceeding a year. The Feeder Details Screen (Distribution system asset Context version) page, Fig. 5, depicts the view used to demonstrate this Use Case.

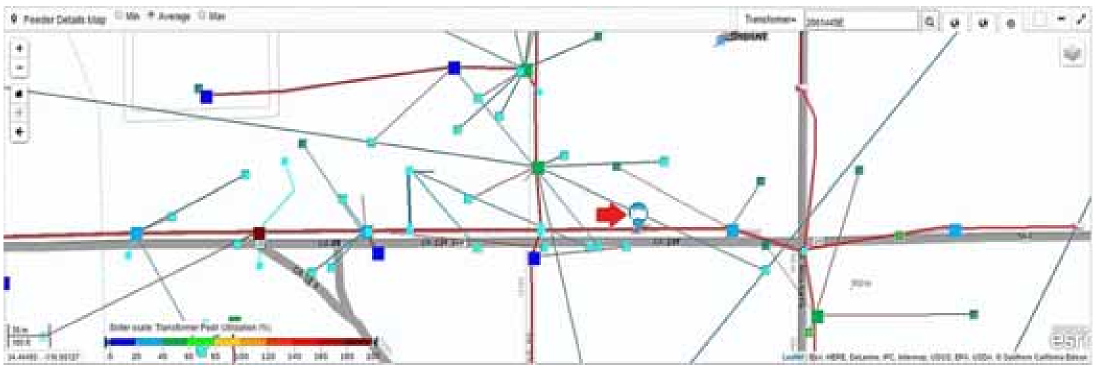

Figure 5, Feeder Details with transformers (big squares) and meters (small squares) identified. Transformers are color coded to indicate percent utilization.

Note: Figure has been altered from the original: street names and transformer ID were redacted to preserve customer privacy.

Use Case 8: Identify transformers at risk of overload based on a comparison of aggregated peak kVA load and transformer nameplate rating. There were three Expected Results to prove this Use Case. The user, in the three tests: a) reviewed transformer load profiles at a given point in time to determine if the rating (15kVA – horizontal green line) of the transformer is adequate to handle the current load profile, b) compared the load profile to an acceptable load threshold based on SCE distribution loading standards, and c) compared the load profile to an acceptable load threshold based on the transformer nameplate rating. The Transformer Details Screen Load Readings Chart, Fig. 6, shows the graphical presentation for the load readings and the data details.

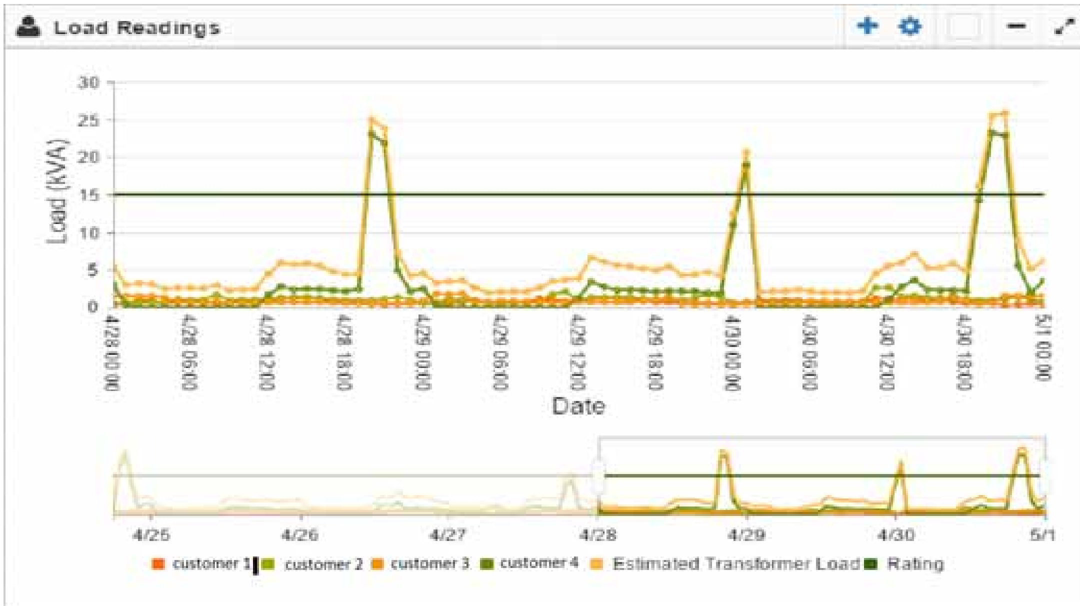

Figure 6, Transformer Loading details at an individual customer and aggregated level

Use Case 9: Generate an area wide heat map visualization to identify potential Distribution system assets at risk based on the load profiles at the transformer and circuit level. Expected Results for this demonstration test stated the User would be able to: a) enter user defined criteria similar to that used for Use Cases 1-3 to identify potential transformers at risk, and b) generate a transformer heat map layered on SCE's GIS electrical distribution network to visually identify all transformers in normal, at risk, or abnormal load conditions (green, yellow or red status indicators). The visual display was shown as the Distribution system asset Management Dashboard, Fig.7.

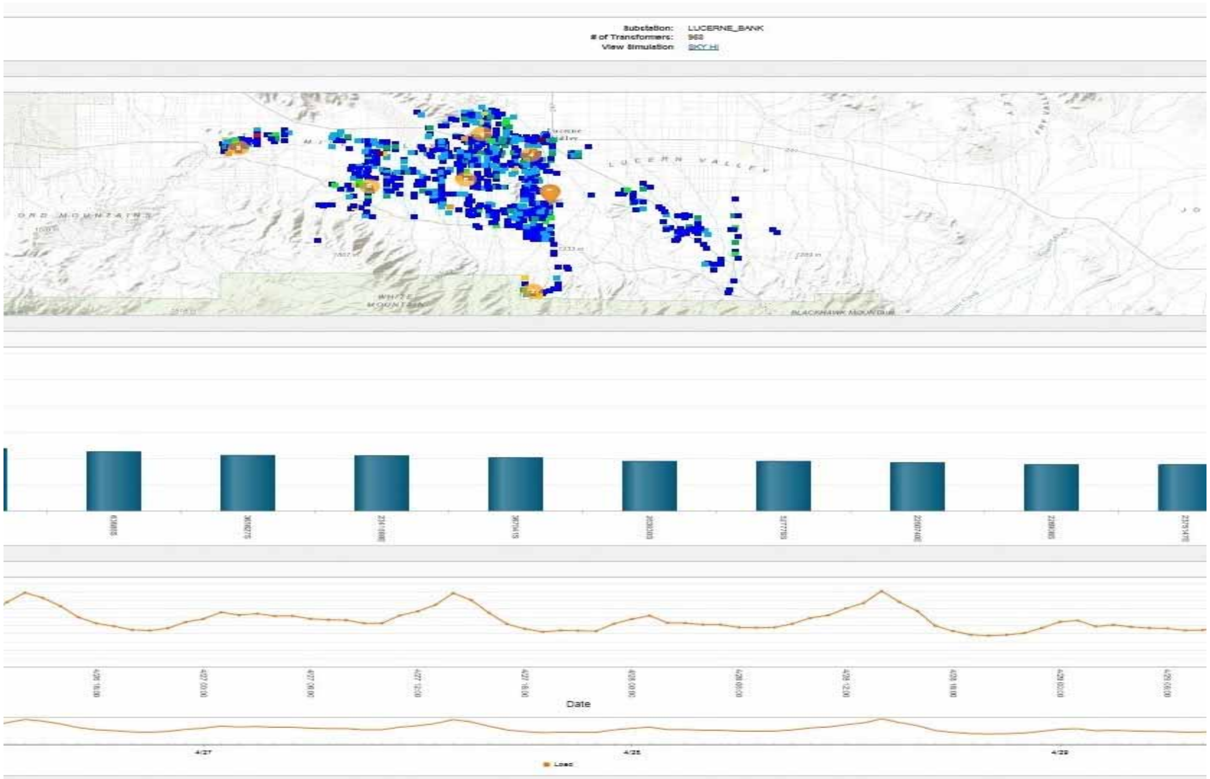

Figure 7, Transformer Dashboard Map overlaid on electrical distribution network GIS to visually identify all transformers

Use Case 10: Demonstrate the ability to export data in the formats for data manipulation in other power and non-power analysis tools. There were two Expected Results for this straightforward test, parallel to the Expected Results in Use Case 4: a) user can export data into a format that can be manipulated in a software program, such as Microsoft Excel, to generate additional reports and analysis for purposes other than power analysis, and b) user can export data into a format that can be manipulated in a power flow modeling software such as CYME. The Transformer List View provided an export option, including nameplate kVA, peak kVA, percent loss of life over the date range number of service points and number of phases observed, among other fields, as shown in Fig. 8, List of Transformers. This View also allowed selection of formats.

Figure 8, List of Transformers View

6.1.3 The Simulated Circuit Model

The SCM's strength was in the visualization of electrical network through smart meter data at a high level view with the ability to drill down to the smart meter level. This Use Case Category included three visualizations to test the application of smart meter data to T&D operations, including outage management. The Use Cases here are sequentially numbered, continuing from the previous Use Case Category.

> Use Case 11: Visually display the state of key devices on a distribution circuit segment using historic voltage data and meter events or exceptions from bellwether SmartConnect™ meters. There were five Expected Results for this visualization: a) the SCM overlaid a single-line diagram of a circuit with key devices and their respective voltage profiles for the previous day over the GIS electrical network, b) user selected a date range for voltage profiles, c) system analyzed and processed the voltage data from the bellwether meters (previously identified for each circuit) along with the geographical boundaries the meters were in, and determined the status of the geographical area for the time period selected, then d) the user was able to play back the last 30 days to visually notice the change of the status of the geographical areas during the time period, and e) the user was able to then play back the last 30 days to visually notice the change of the state of the devices during the time period. These tests were performed using the Feeder Details (SCM Context) screen, Fig. 9.

> Use Case 12: Graphically represent the status of key devices on the GIS electrical network using voltage data from bellwether meters. Based on the voltage profiles at the transformer and circuit, generate an area wide heat map visualization to identify state of key devices. There were four Expected Results to demonstrate this capability: a) the application interacts with the GIS electrical network and loads a single-line diagram of the circuit with key devices and their respective voltage profiles for the previous day, b) user selected a time period for the modeling (e.g., last 30 days), c) the system analyzed and processed the voltage data for the bellwether meters (previously identified for each circuit) along with the geographical boundaries the meters were in and determined the status of the geography for the time period selected, and then d) the user was able to play back the last 30 days to visually notice the change of the status of the geographical areas during the time period. These four Expected Results also were proven using the screen shown in Fig. 9, Feeder Details (SCM Context)

Figure 9, Feeder Details (SCM Context)

Use Case 13: Provide outage reconstruction and reporting models utilizing voltage data and meter exceptions/event data. The IAP was able to recreate outages, restoration timing, and customer counts then associate that data on a visual display. There were four Expected Results associated with this function: a) The IAP was able to retrieve meter outage and restoration events from the database (Teradata or others); provided a visualized replay of the outage sequence using outage start and restoration time stamps; displayed that data on the GIS map with heat map functionality, which allowed b) the user to view the outage on a single-line circuit map, along with the energized status of all distribution system assets by virtue of their associated bellwether meters, enabling c) the user to scroll through the outage event to see timeline of the start of the outage to the time individual devices were re-energized, and finally allowed the d) user to export restoration timing and customer counts for a selected outage, which can be used for outage reporting metrics, including the reliability indices. These tests also were performed using the screen shown above in Fig. 9, Feeder Details (SCM Context).

6.2 Feasibility Study: Use SmartConnect™ Meter Events in Reliability Indices Calculation

The feasibility study was laid out as a five step process as described under Major Tasks in section 5.2. The study focused on a single index (SAIDI) to perform the analysis and conduct the two test cases.

1) Post outage analysis process improvement study:
   Analysis of the current Post-Outage CMI Validation process (Fig. 10) showed the process to be highly labor intensive; using analyst time. The Simulate, Update and Confirm steps

below are the most labor intensive steps. It was believed these laborious steps could be replaced and made more efficient by using smart meter data, but it was necessary to first confirm the accuracy of the meter data and identify any conflicts between data systems before recommending process changes.

CURRENT CMI VALIDATION PROCESS

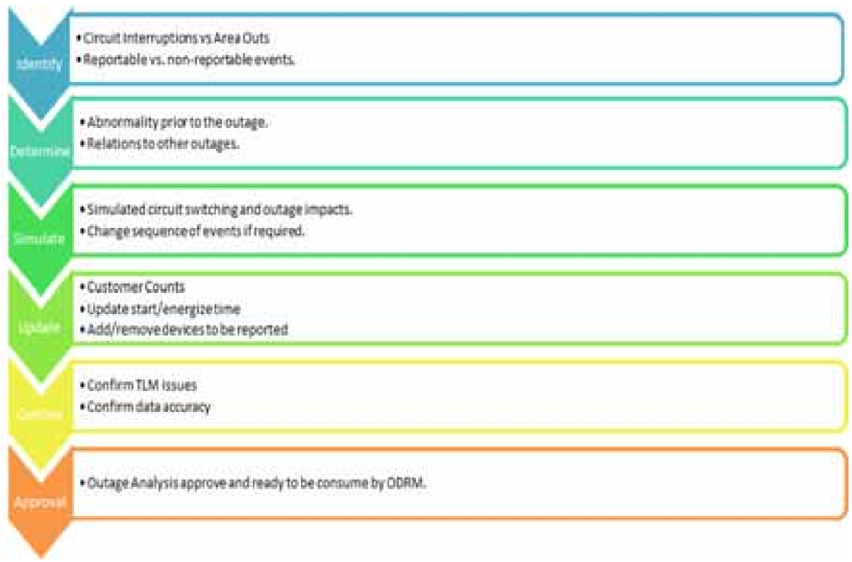

Figure 10, Existing CMI Post-Outage Validation Process

2) Meter outage events data flow improvement study and meter time stamp accuracy:
The smart meter event time stamps and records proved to be accurate, dependable and consistent. The integrated systems, however, presented challenges that required engineering intervention to resolve.

3) Develop CMI calculation methodology using smart meter event data:
Initially, it was anticipated smart meter data would readily enable CMI calculation automation. Systematic analysis of the CMI calculation process and the various data systems accessed for input made it clear that full automation would require a more extensive investment than anticipated for work on major systems (i.e. OMS, ESCDW and ODRM).

A hybrid alternative to full automation was identified. It would use smart meter event data and would not require full integration of the databases. While it would remove the most labor intensive (simulate & update) steps, this alternative would require reconstruction of the current meter outage events reporting tool. After analysis of the two Test Cases was completed, this became the recommended CMI Validation Process change.

Recommended Solution: The hybrid solution would generate an outage report based on meter events with manual input of reportable events information. As shown in Fig. 11 below, this solution has the potential to reduce engineering intervention.

RECOMMENDED CMI VALIDATION PROCESS

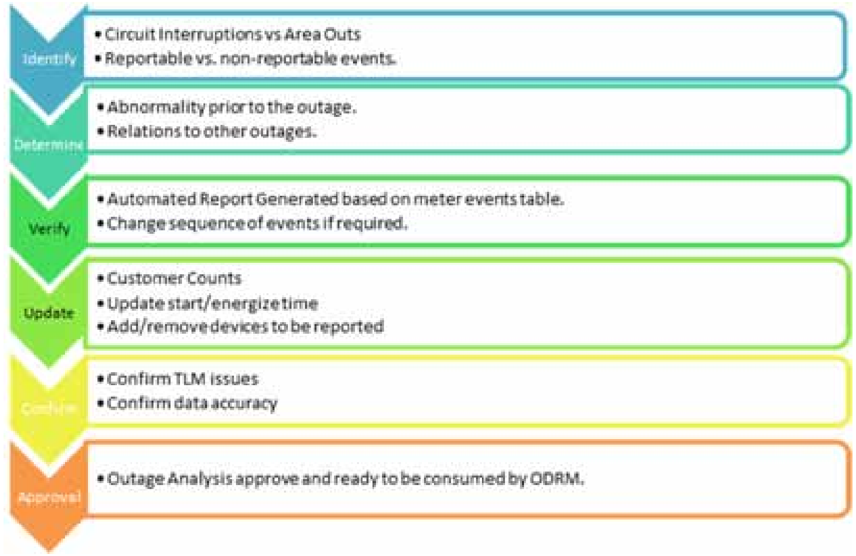

Figure 11, Recommended CMI Post-Outage Validation Process
Includes the verify and update steps automated; manual input of outage information

4) Test Case 1: comparison of verified single incident CMI values to CMI values using meter event time stamp
This step of the Feasibility Study compared the CMI calculations made through the ODRM versus the SmartConnect™ meter events. The results of this analysis are shown in Table 2 below. Eight single outages and the calculated SAIDI index were included in the analysis. In six of the outages the calculated CMI differences were within 0.1% concluding that individual meter outage events calculated SAIDI values very close to the ODRM SAIDI values. Note that columns 1 – 3 are based on non-use of smart meter data (1) to complete use of smart meter data (3). Also note that “3-Normalized” are meter counts adjusted to account for discrepancies between databases.

Table 2, Single Line Outage Analysis and Results

	Customer Minutes of Interruption (CMI)							
Outage - Incident #	1	2	3	Delta (2:3)	3 - Normalized	Delta(2:3-n)	SAIDI(ODRM)	SAIDI (3-N)
1. SEWELL (#113092530)	167749.50	167403.50	162380.78	5022.72	167479.82	-76.32	0.03331	0.03220
2. WARRIOR (#113092417)*	148774.00	155740.50	131960.52	23779.98	156760.45	-1019.95	0.03082	0.03055
3. MENIFEE (#112874277)~	13368.05	21057.78	8982.65	12075.13	10956.09	10101.69	0.00422	0.00219
4. IBEX (#1130947393)	119580.53	121679.37	95765.25	25914.12	97106.26	24573.11	0.02436	0.01944
5. CANAL (#113000883)	210626.10	210626.10	187102.18	23523.92	211160.64	-534.54	0.04210	0.04214
6. DOGWOOD (#111878051)^	94955.10	97330.60	68470.20	28860.40	98928.81	-1598.21	0.01910	0.01903
7. BREN (#113091134)	94257.68	93690.22	81337.40	12352.82	93875.18	-184.97	0.01876	0.01879
8. ALLEGRA	52442.33	52296.13	42074.40	10221.73	52311.08	-14.95	0.01047	0.01047
Santa Barbara District - (April to July) New Datalab	NA	3997933.82	2745940.58	1251993.23	2998697.21	999236.61	0.80041	0.58665

*Missing half of events, used OMS start/end time instead.

~ Menifee experience a shorter than expected outage for half of the circuit.

^ Dogwood experience a longer than expected outage for half the circuit.

Use Case 4 difference could be attributed to the lack of gap fil in the months of April and May

A negative delta signifies a Use Case 3 has a higher CMI.

5) Test Case 2: demonstrate scalability of the methodology performed in Test Case 1 with the district of Santa Barbara.
   The individual outage meter events were deemed very close to the ODRM SAIDI values on a network wide basis. When expanded to the district level, however, the impact of legacy meters is much larger due to the effect of commercial and industrial customers on a smaller customer base. Outage analysis using smart meter data can be scalable and able to cover a majority of all outages at the district level. Even considering the impact of commercial and industrial customers on the district level analysis, there was still a 17% improvement in the SAIDI metric using smart meter data compared to ODRM calculations as shown in Fig. 12.

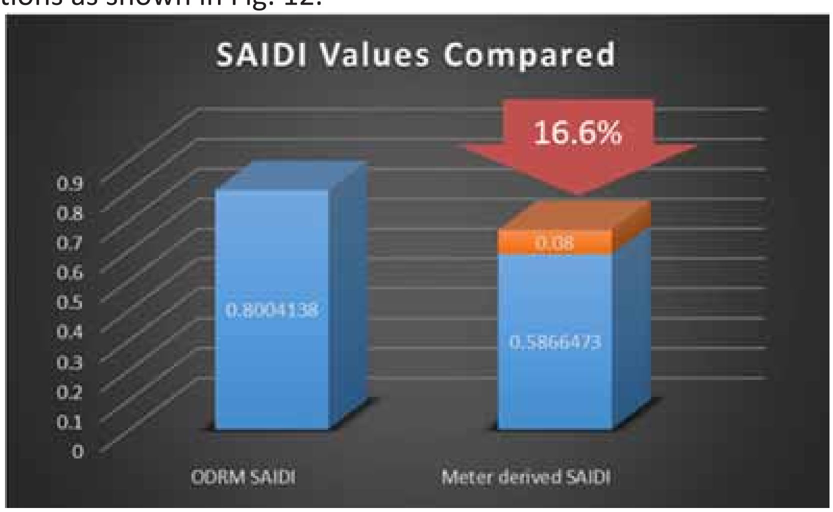

Figure 12, SAIDI Values Compared

Note: A total of 1,634 Unique Customers were missing due to non-ITRON and non-communicating meters, accounting for 10.1% of the total 26.7% difference between Meter Events CMI and ODRM CMI.

The feasibility study demonstrated that expanding use of smart meter data to other applications will require additional effort. While immediate labor efficiencies can be captured and reporting accuracy potentially increased, other systemic changes will typically be necessary to achieve full integration of smart meter data into reliability reporting. Communications timing between data bases, dissimilar smart meter configurations, and divergent uses of shared data are examples of challenges that must be overcome to fully obtain the benefits of automated reliability reporting.

6.3 Special Implementation Issues (particular to the technology)

This demonstration project brought into clarity two challenges that will need to be addressed by SCE, and any electric utility, and intends to integrate smart meter data with T&D operations and management.

First, T&D systems and processes have typically been developed over the years for different purposes. Smart meter data has a lot of potential but would require a reassessment of these processes and systems to absorb and correctly utilize the data. Additionally, any differences in the systems being integrated or the data being used must be equalized to avoid conflicts.

Second, the challenge to integrate a working electric distribution GIS system with smart meter data cannot be understated. It required a significant time investment by SCE third party vendors to make this aspect of the demonstration workable.

6.4 Value Proposition

This project demonstrated that smart meter data can be used to provide T&D operational and reliability benefits. It may also have the potential to increase the efficiency and accuracy in reliability report calculations. Electric service reliability has the potential to dramatically increase as applications using smart meter data are made available. Approaches to address voltage fluctuations, transformer loss of life, outages, and unplanned load increases or decreases will change from reactive to proactive. The project demonstrated tools that engineers and planners can utilize to visualize and analyze electric demand and take action to protect the Distribution system assets from unplanned failure and outages. As an example, the IAP demonstrated the transformer load analysis tool. This tool has the potential to improve reliability by identifying all severely overloaded transformers. A proactive planned approach can then be taken to replace these transformers before failure. This planned approach also has the potential to also reduce cost, incurred from failures during non-business hours or environmental and safety benefits derived from preventing catastrophic failure. Additionally, it will also enable engineers and planners to optimize transformer operation to achieve the return on investment that was initially planned when the transformer was placed in service.

There are also societal economic benefits anticipated as this new generation of tools is incorporated into Distribution operations. The economic impact of service interruptions on customers is generally not measured unless the outage is pervasive. That is not to say the societal costs of service interruptions are not incurred, only that they are difficult to measure. Unplanned outages disrupt commerce at all levels, interrupt the continuous flow of society and create unsafe public conditions. Reducing service interruptions and improving voltage stability will have a direct, positive impact on society.

7 EPIC Program Metrics

The EPIC Metrics for this project were selected as shown in Table 3.

Table 3, EPIC Metrics

D.13-11-025, Attachment 4. List of Proposed Metrics and Potential Areas of Measurement (as applicable to a specific project or investment area in applied research, technology demonstration, and market facilitation)	
3. Economic benefits	
a. Maintain / Reduce operations and maintenance costs	See 7.1
5. Safety, Power Quality, and Reliability (Equipment, Electricity System)	
c. Forecast accuracy improvement	See 7.2
f. Reduced flicker and other power quality differences	See 7.3
6. Other Metrics	
a. Enhance Outage Reporting Accuracy and SAIDI/SAIFI Calculation	See 7.4
8. Effectiveness of information dissemination	
b. Number of reports and fact sheets published online	See 7.5
f. Technology transfer	See 7.6
9. Adoption of EPIC technology, strategy, and research data/results by others.	
c. EPIC project results referenced in regulatory proceedings and policy reports.	See 7.7

7.1 Reduce operations and maintenance costs

The utility will have much to gain as Distribution system asset life will be extended through voltage and transformer load management. Unplanned outages which are currently highly labor intensive processes may be avoided. Operating and maintenance costs will be lower as Distribution system asset lives are optimized and extended through improved planning. As demonstrated in the Use Case Category - customer and transformer load analysis, engineers and planners would be able to use these tools to identify and visualize overloaded transformers and take targeted corrective action.

7.2 Forecast Accuracy Improvement

The voltage analytics demonstrated use of smart meter data to enhance T&D engineers and planners tool set. Using the voltage profiles and system visualization tools in this demonstration, engineers could identify overloaded transformers enabling them to direct corrective actions before equipment failure would have occurred.

7.3 Reduced flicker and other power quality differences

This project targeted voltage analytics for power quality. It successfully demonstrated the ability to evaluate capacitor bank placement based on voltage deterioration along a circuit. Engineers were able to demonstrate the IAP's capability to review and visualize voltage profiles, and deterioration from a smart meter at the end of the circuit to the substation. Engineers were also able to visualize the locations of overloaded transformers on a GIS map; enabling them to target voltage problems and take action before a failure occurred.

7.4 Enhance Outage Reporting Accuracy and SAIDI/SAIFI/MAIFI Calculation

Application of smart meter data to the reliability indices calculations can improve CMI metrics. The level of accuracy and efficiency may improve from the existing methodology.

7.5 Number of reports and fact sheets published online

This report is the first publication of the demonstration results.

7.6 Technology transfer

The results of this IAP demonstration have applicability to any electric utility interested in integrating smart meter data with T&D analytics and outage management. The demonstration successfully displayed the utilization of smart meter data to enhance T&D operations and maintenance toolset. SCE is in the initial stages of procuring and implementing a similar tool enterprise-wide for its T&D engineers and planners.

During 2015 SCE presented an overview of the project at two industry meetings:

- 4th Annual Utility Analytics conference, Phoenix, March 5th 2015, session 201 – presentation entitled "Advanced Analytics for Voltage Management"
- EPIC Innovation Symposium, December 3, 2015, presentation on "Outage Management and Customer Voltage Analytics"

7.7 EPIC project results referenced in regulatory proceedings and policy reports.

This report represents the first release of project results.

7.8 Project Objectives: Met

The objectives of this project were met. Users demonstrated the benefits of using smart meter data for enhanced analytics and the capability to visualize circuit state clearly will someday streamline the outage recovery process. The feasibility study identified the potential for smart meter data to improve the process of calculating CMI for reliability reporting. The study also pointed out the need to align data bases when implementing these new tools.

7.9 Measurement and verification results

The results of this demonstration were measured by the stepped control process implemented during the User Test. The users were T&D engineers, planners, outage reporting analysts and IT engineers. The Tests were conducted under laboratory conditions and users were provided a manual to follow each of the steps that demonstrated the use case. The user then was required to report on the success or failure of the technical requirements of the use case. The users found the results successful and proposed implementation of the analytics and visualization tools to their respective management.

Appendix B

Advanced Technology 2013038

Portable End-to-End Test System (PETS) Final Project Report

Advanced Technology
2013038
Portable End-to-End Test System (PETS)
Final Project Report

Developed by

SCE Transmission & Distribution, Advanced Technology Organization

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Disclaimer

Acknowledgments

Prepared for: Southern California Edison, Advanced Technology, Public Utilities Commission of the State of California

Prepared by: Aleida Gonzalez

Principle Investigators (s): Christopher Clarke, Aleida Gonzalez

Change Log

Version	Date	Description of Change	Project Report No.
0.01	20160121	First revision	PS-13-038
0.02	20160218	Final version	PS-13-038

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1 Executive Summary

The intention of this demonstration project is to develop a Portable-End-to-End Test System (PETS) tool to conduct end-to-end testing of relay protection equipment using a portable Real Time Digital Simulator (RTDS) at each substation connected to the line under test. The test is designed to provide realistic fault simulations in order to prove that the entire relay protection schemes are properly configured including physical wirings. Aside from being able to conduct existing End-to-End test procedures which focus on the relay, the tool would be able to test the system as well. More specifically the tool would be able to test all communications pertaining to the line being tested and run a large number of disturbances using an automated script to identify a pass or fail based on predetermined SCE test criteria. Test reporting procedures would be similar to what is performed in the RTDS lab today to help ensure that all performed tests are properly evaluated. This project does not support any existing regulatory proceedings. However, relay testing falls under NERC/WECC bulk power reliability criteria. Therefore, this project, as a proof of concept has the potential to increase the reliability of our protective schemes via rigorous testing and thus demonstrate SCE's proactive approach towards reliability.

The first step was to overcome the difficulty of being able to sync the simulation of the system under test using the portable RTDS units located at different substations. Close collaboration with the software developer resulted in an addition of a case start timer to the simulation software, which allowed the start time be synchronized. After a few delays in ordering the necessary equipment, test cases, scripts and draft test plans were created to test a two and three point line end-to-end relay test utilizing the prototype PETS tool. Preparations were made to conduct a preliminary test under a control environment in order to test the prototype prior to field testing.

In the process of developing the methodology to perform the test in the field, and through feedback from the end-users it was discovered that there were a limited number of test scenarios where the tool would be a great improvement over existing test procedures. As a result the project team concluded that there was no substantial value in further pursuing the development of the PETS tool. Although the tool would be an improved method of testing system performance when conducting end-to-end relay tests, the implementation of a companywide Portable End-to-End Test system (utilizing a Real Time Digital Simulator system) would not be cost effective when compared to traditional test methods. The major aspects that would drive the cost of implementing the PETS projects are:

- Development of specialized training would be required for field crews to be able to use the tool
- Availability of the tool; it would be extremely costly to purchase several PETS test sets to accommodate the different regions within SCE's territory when compared to purchasing existing tool in use
- Dedicated engineering staff to support issues related to maintenance and training

After careful deliberation of the benefits associated with proceeding with the PETS project, the team concluded that the tool did not provide value to the rate payers, except for demonstration purposes. Notwithstanding the innovation of the tool, it is not currently a viable option. Furthermore, the early close-out of this project does not impact how protection schemes are tested today as it was intended to be a proof of concept demonstration project.

2 Project Summary

The intention of this demonstration project is to develop a Portable-End-to-End Test System (PETS) tool to conduct end-to-end testing of relay protection equipment using a portable Real Time Digital Simulator (RTDS) at each substation connecting the line under test. The RTDS is a computer that is capable of simulating electric power system transients in real time. It has hardware in the loop (HIL) capability and can simulate system conditions and implement the closed-loop response of the device under test. The PETS tool test is designed to provide realistic fault simulations in order to prove that the entire relay protection schemes are properly configured including physical wirings.

2.1 Project Objective

PETS will provide more thorough testing in fewer hours than required by traditional tests during commissioning and routing of transmission lines. Test technicians would be provided with more accurate and extensive test results which means higher assurance that critical transmission and distribution lines and components are operationally adequate and exceed NERC/WECC bulk power reliability criteria.

2.2 Problem Statement

The existing end-to-end protective relaying scheme provides for a limited testing of relay schemes. The PETS tool would provide an opportunity for more comprehensive testing of protective relay schemes at high voltage transmission lines. The PETS tool would:

- Be able to test system performance (currently there does not seem to be a method to test the entire protection scheme at the same time; for example, provide the same currents and voltages to all the relays at the same time).
- Provide greater flexibility to test crews when performing 3 terminal end to end relay tests. Existing test set-up is limiting given that test personnel only have access to very few pre-determined fault scenarios. Typically the scenarios are created using past DFR recorded events, or created using comtrade files from previous tests. The PETS tool would provide flexibility in creating different fault scenarios where fault type, inception angle, location and resistance could easily be changed.
- Have the ability to test relays in adjacent positions at the same time by injecting the same faults. The adjacent relays would then experience a reverse fault and their behavior could be observed.

2.3 Scope

This demonstration project will explore the feasibility of developing and implementing an end-to-end relaying scheme test tool using portable RTDS, amplifiers and satellite clocks. The tool set would address 1) relay protection equipment, 2) communications, and 3) provide a pass/fail grade based on the results of automated testing using numerous simulated disturbances. When compared to existing tools, which provide a limited number of scenarios (disturbances) and focus on testing protection elements, the PETS project will additionally provide testing of system protection. It will also develop a process and methodology to perform such testing in the field. Tests will be documented using a reporting procedure used in the RTDS lab today, ensuring all test data is properly evaluated.

Initially the scope aimed to achieve three main tasks:

- Develop and validate RTDS power system model for end-to-end testing.
- Demonstrate in-lab test of 2 and 3 terminal lines using RTDS hardware-in-the-loop. Test plan document developed in-lab to be used during end-to-end field testing
- Demonstrate field test of a 3 terminal line using the RTDS in the field. Final report with results of end-to-end field testing and test procedure based on NERC requirements.

During the process of developing the methodology to demonstrate the in-lab test and development of documentation to perform end-to-end field testing, and through feedback from the end-users it was discovered that there is a limited number of test scenarios where the tool would be a great improvement over how the tests are conducted today. Although the PETS system would be an improved method of testing system performance when conducting end-to-end relay tests, the implementation of a companywide Portable End-to-End Test system (utilizing a Real Time Digital Simulator system) would not be cost effective when compared to traditional methods of conducting these tests. Also while in the process of preparing for the first demonstration, it became apparent that using the PETS tools would require specialized training that would not be readily available to field crews.

After reviewing the feasibility of company wide deployment of the PETS tools it was deemed prudent to discontinue the project in its early stages. The completed tasks include development of test cases, scripts and draft test plans to test a two and three point line end-to-end relay test.

Other factors that affected the development of this project were delays in ordering and delivery of equipment as well as group-reorganization.

2.4 Schedule

A high level schedule overview is presented in the following table:

Task Name	Duration
Authority to proceed	0 days
Spec & Procure Portable RTDS	4 Months
Create RTDS end-to end test tool	9 Months
Create test cases and Scripts	3 Months
Create and test reporting tool	3 Months
Test tool in field	2 Months
Train SCE stakeholders	2 Months
Create final report	3 Months
End project	0 days

Table 1 Project Schedule

2.5 Milestones and Deliverables

Table 2 shows a list of milestones and deliverables. Due to early close-out of project, a status of "cancelled" is shown in status column.

Milestone/Deliverable	Status
Specs & Procure Portable RTDS	Completed
Develop PETS tool	Completed
Create RTDS end-to-end test tool (Dec. 2014)	Cancelled
Create test cases & scripts (Dec. 2014)	Completed
Create and test reporting tool	Cancelled
Test tool in the field	Cancelled
Training SCE Stakeholders	Cancelled
Create final report	Completed
Final Report Out to Stakeholders	Completed

Table 2 Milestones and Deliverables

3 Test Set-Up/Procedure

PETS will employ portable Real-Time Digital Simulators (RTDS's) in substations at each end of the transmission line being tested (see figure 1).

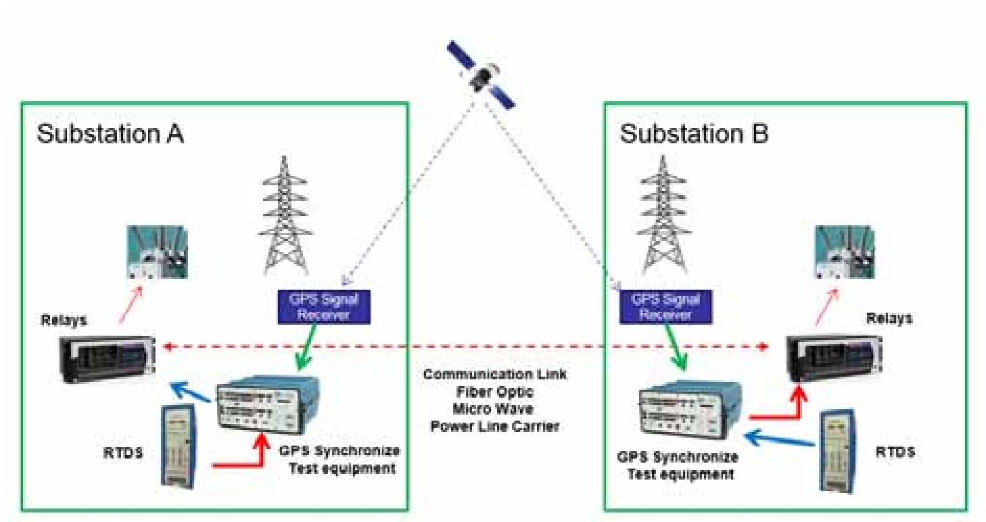

Figure 1 Test set-up

3.1 Software/Hardware

Different software interfaces were utilized in the development this project. RTDS modeling and validation was performed using RSCAD version 4.005. Load flow data was viewed and extracted using PSLF 18, and short circuit data was viewed and extracted using CAPE 2012. All scripting was done in Notepad++ and Microsoft Excel. ProtTest software was used to interact between relays and Doble test sets and GE Enervista was used to communicate with protective relays.

The hardware components of the PETS tool consist of Portable RTDS units, Doble test sets (voltage and current amplifiers), GPS clock and antenna for synchronization.

3.2 Test Methodology

There are two main stages to the development of the PETS tool. The first stage comprised of creating test cases, scripts and draft test plans in order to complete dry run in a control lab environment. In the second stage the tool would involve prototype lab testing and field tests. A multi-terminal (3-point) test would be conducted with a field crew at each location to test the full capabilities of the tool. 90 percent of the first stage was completed, the second stage was not achieved.

3.3 Test Case development

The initial test case development took place in the Advanced Technologies Power System Lab. A less complex 2 terminal end-to-end case was created in RTDS to test the start timer in order to perform synchronization tests.

Figure 2 Start Timer

The RTDS simulates a model of the system under test and surrounding nearby area in real time. Every substation modeled contains a bus label and infinite source model. The label defines the bus name, voltage base, and type. The label information used show in table 3. After the model is built it can be manipulated through RSCAD Runtime. RSCAD Runtime provides two critical functions, 1) it allows the user to interact with and manipulate the simulation and 2) it enables the simulation results to be monitored and recorded. Figure 3 below shows the controls for the fault conditions. The slider, pushbutton, dial, and switch components are all model inputs that assign the value they are given in the Runtime to the associated variable in the draft model. Figure 4 shows a one line diagram of the two terminal test case with internal and external fault locations.

Bus Name	Short Name	Source P	Source Q	Load P	Load Q
Pardee	PAR	-	-	466.8	(117.5)
Sylmar	SY	1,134.0	(479.0)	-	-
Gould	GO	-	-	79.4	(74.0)
Eagle Rock	ER	-	-	132.9	5.0
Santa Clara	SC	-	-	223.7	(2.4)
Vincent	VIN	549.9	76.1	-	-
Goodrich	GR	(140.0)	(29.0)	-	-
Mesa	ME	-	-	412.0	15.7
Center	CE	-	-	110.6	23.6
Walnut	WL	419.1	1.6	-	-
Litehipe	LI	54.2	(3.2)	-	-
Redondo	RE	300.0	-	526.0	-
Rio Hondo	RH	-	-	464.4	(137.0)
Laguna Bell	LB	-	-	-	-
Del Amo	DELA	97.2	(19.8)	-	-

Table 3 Source Model Data

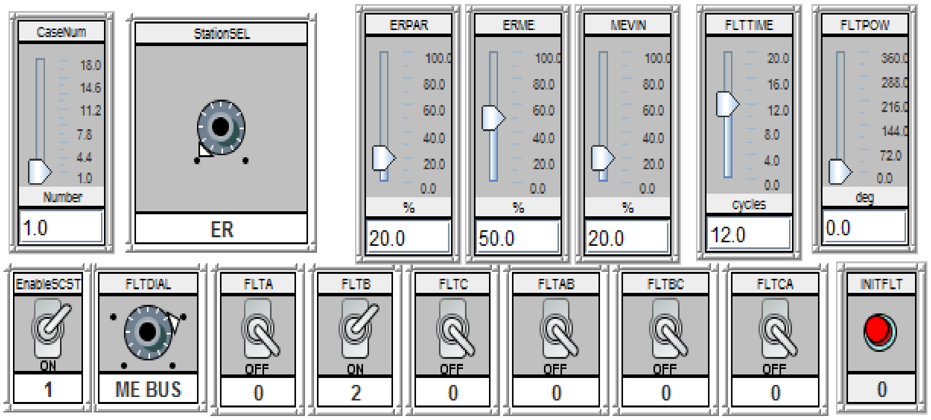

Figure 3 Runtime Controls

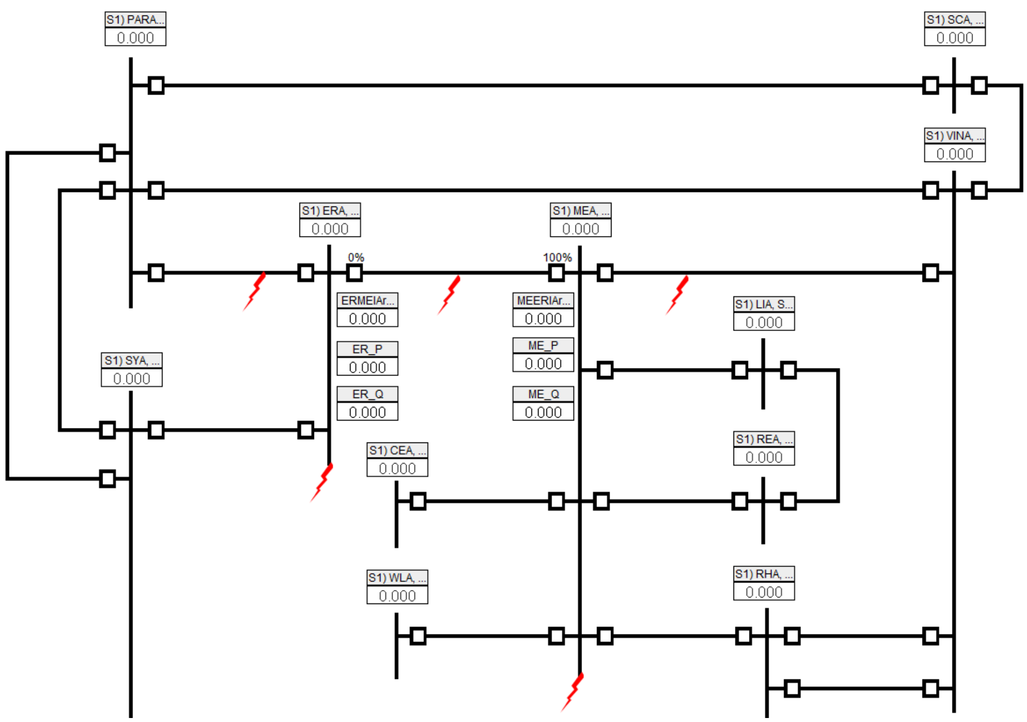

Figure 4 Two Terminal Oneline Diagram

Scripts were utilized in order to control the operation of the simulation and to collect and analyze the results. Figure 5 shows a snapshot of one of the scripts used to control and set-up the fault conditions and table 4 shows case scenarios that are used as inputs to the script.

```
MasterPlotLockState = 1;


dialoginput ( "Enter a scemario between 1 and 18: ",number);
sscanf (number, "%d" , num);

SetSlider "Subsystem #1 : CTLs : Inputs : CaseNum" = num;

if(num == 1)
{
     //Red Bluff Bus - BG
     SetDial "Subsystem #1 : CTLs : Inputs : FLTDIAL" = 5;
     SetSlider "Subsystem #1 : CTLs : Inputs : FLTTIME" = 12;
     SetSlider "Subsystem #1 : CTLs : Inputs : FLTPOW" = 0.0;
     setFltType(0,1,0,0,0,0);
     setDraftVar(20,50,50,20);
}
if(num == 2)
{
     //Red Bluff Bus - AB
     SetDial "Subsystem #1 : CTLs : Inputs : FLTDIAL" = 5;
     SetSlider "Subsystem #1 : CTLs : Inputs : FLTTIME" = 12;
     SetSlider "Subsystem #1 : CTLs : Inputs : FLTPOW" = 45.0;
     setFltType(0,0,0,1,0,0);
     setDraftVar(20,50,50,20);
}
if(num == 3)
{
     //20% Beyond //Red Bluff Bus - CG
     SetDial "Subsystem #1 : CTLs : Inputs : FLTDIAL" = 6;
     SetSlider "Subsystem #1 : CTLs : Inputs : FLTTIME" = 12;
     SetSlider "Subsystem #1 : CTLs : Inputs : FLTPOW" = 90.0;
     setFltType(0,0,1,0,0,0);
     setDraftVar(20,50,50,20);
}
```

Figure 5 Example of Script

Test No.	Description	Location (FLTDIAL)	Fault Time (FLTTIME)	Fault POW (FLTPOW)	FLTA	FLTB	FLTC	FLTAB	FLTBC	FLTCA
1	Right Bus - BG	2	0.20	0	-	1	-	-	-	-
2	Right Bus - AB	2	0.20	45	-	-	-	1	-	-
3	20% Beyond Right Bus - CG	1	0.20	90	-	-	1	-	-	-
4	20% Beyond Right Bus - ABC	1	0.20	0	-	-	-	1	1	1
5	Left Bus - AG	4	0.20	45	1	-	-	-	-	-
6	Left Bus - CA	4	0.20	90	-	-	-	-	-	1
7	20% Beyond Left Bus - AG	5	0.20	0	1	-	-	-	-	-
8	20% Beyond Left Bus - BCG	5	0.20	45	-	1	1	-	-	-
9	80% From Left Bus - AB	3	0.20	45	-	-	-	1	-	-
10	80% From Left Bus - CG	3	0.20	0	-	-	1	-	-	-
11	80% From Left Bus - BCG	3	0.20	90	-	1	1	-	-	-
12	80% From Left Bus - ABCG	3	0.20	45	1	1	1	-	-	-
13	60% From Left Bus - BG	3	0.20	90	-	1	-	-	-	-
14	40% From Left Bus - CA	3	0.20	0	-	-	-	-	-	1
15	20% From Left Bus - BC	3	0.20	45	-	-	-	-	1	-
16	20% From Left Bus - AG	3	0.20	0	1	-	-	-	-	-
17	20% From Left Bus - ACG	3	0.20	45	1	-	1	-	-	-
18	20% From Left Bus - ABCG	3	0.20	90	1	1	1	-	-	-

Table 4 Script Input Parameters

After successfully running the 2 terminal end-to-end simulation, a 3 terminal end-to-end test case was created, a one line diagram in shown in figure 6. Ultimately the 3 terminal test did make it to the actual field test.

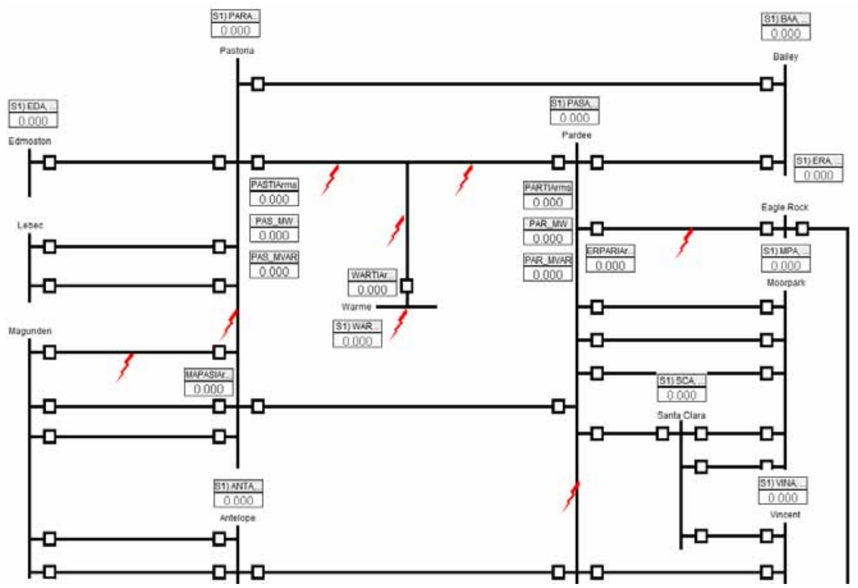

Figure 6 Three Terminal Oneline Diagram

3.3.1 Test Set-Up

The test set-up for the PETS prototype tool included the following equipment:

- 3 Portable RTDS units
- 3 Doble test sets (voltage and current amplifiers)
- 3 GPS Clocks
- 3 Antennas
- Protection relays

Each end of the line would be equipped with a portable RTDS unit, doble test set, GPS clock and antenna. Voltage and current signals from the portable RTDS are sent via a GTAO interface card to the Doble test set which are subsequently transferred to the protection relays. The output scaling for the GTAO cards is adjusted so that the primary voltage and current measurements read by the relay matches that of the RTDS RunTime. Selected relay signals are mapped to outputs on the relay and then physically connected to the Portable RTDS front panel interface. In RSCAD, the GTFPI component outputs all the digital signals as a 16-bit word. The individual signals are extracted using word-to-bit conversion components. GTAO and GTFPI setup configuration are presented in figure 7 and 8 respectively.

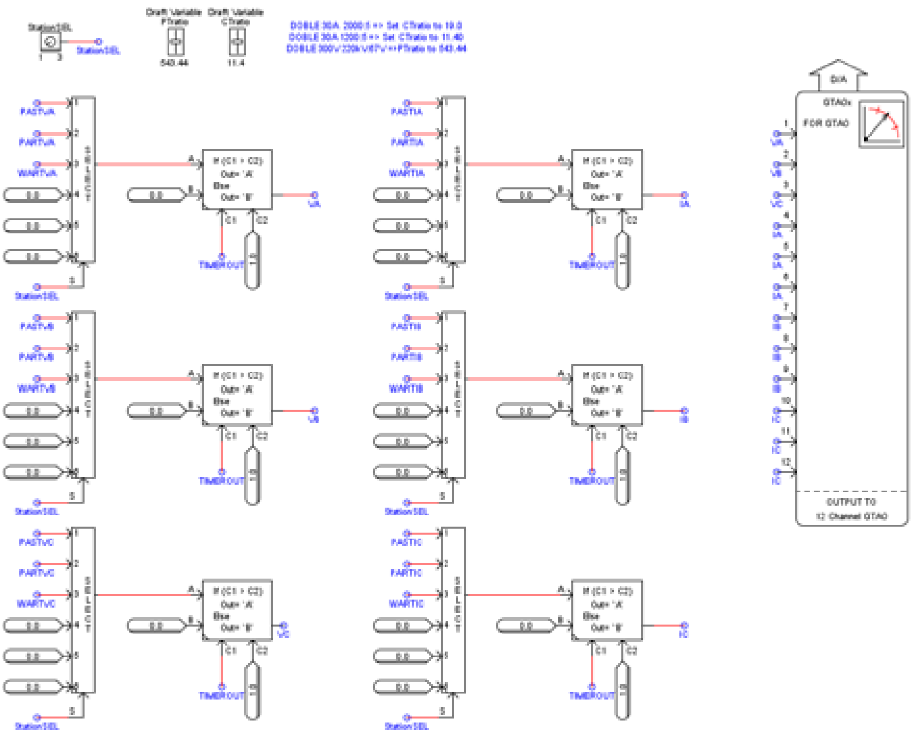

Figure 7 GTAO Setup Configuration

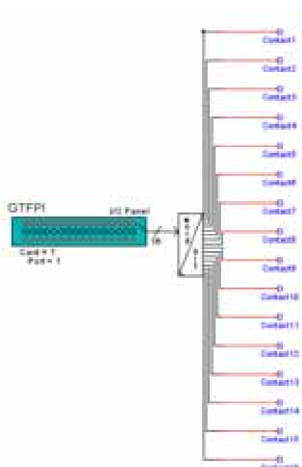

Figure 8 GTFPI Setup Configuration

4 Project Results

No results were recorded.

4.1 Technical Results, Findings, and Recommendations

Project may be revisited at a later time if it deemed that it would provide greater reliability at lower costs.

4.2 Technical Lessons Learned

The test setup yielded lessons learned that pointed the team to determining that this technology was not a viable option at this time.

For example, the test set up required significant power to drive 5 Doble test sets, as well as an outdoor area to set up a GPS antenna. Additionally the test setup needed to mirror field conditions (i.e., no external monitors, all test equipment needed to be transportable, etc.), so that we would be able to perform the test in a remote location without any unexpected events.

Furthermore, the setup required a mobile RTDS unit and Doble test set per terminal, meaning that 3 of each (RTDS unit and Doble test set) would be needed for lines that contained 3 terminals.

The team's analysis discovered however, that in our system very few 220 lines in fact have more than 2 terminals, and that the existing test systems were adequate options for testing 2 terminal lines.

4.3 Value Proposition

The objective of the PETS project was to meet EPIC's primary principle criteria of providing greater reliability to the customers. However, it was determined that the benefits associated with this demonstration project did not outweigh the costs and ultimately it would not provide added value.

4.4 Technology/Knowledge Transfer Plan

A technology transfer plan was not developed.

5 Metrics

The project was successful in proving that the tools exist to conduct advanced end-to-end relay testing, albeit not cost effective.

6 Appendix

List of Acronyms

AT	Advanced Technology (the organization)
EPIC	Electric Program Investment Charge
GPS	Global Positioning System
GTAO	Gigabit Transceiver Analogue Card
GTFPI	Gigabit Transceiver Front Panel Interface
PETS	Portable-End-to-End Test System
RTDS	Real Time Digital Simulator
SCE	Southern California Edison

Appendix C

Cyber-Intrusion Auto-Response and Policy Management System

(CAPMS)

Electric Program Investment Charge (EPIC)

Project Final Report

CYBER-INTRUSION AUTO-RESPONSE AND POLICY MANAGEMENT SYSTEM (CAPMS)

Prepared for: California Public Utilities Commission

Prepared by: Southern California Edison

October 2015

EPIC-1 Program

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1 Executive Summary

The resiliency of the electric grid of the future will depend on improvements in monitoring, forecasting, coordination, and automation of existing and new equipment. Many of these additions require communications between devices within a geographic area, and to back-office control centers. The Cyber-intrusion Auto-response Policy Management System (CAPMS) project investigated the use of Bayesian decision tree logic to implement configurable security policies into an existing cybersecurity system. The project successfully built and demonstrated a system that can correlate events from secure sensor input points, determine the likelihood of various types of attacks, and respond accordingly.

A cyber-attack might target multiple devices simultaneously across various locations, so it is necessary to build a defense that allows for pre-programmed responses to such attacks. Attacks might come in the form of unauthorized access and changes to equipment, disruption of communications channels, changes to measurements, or even unauthorized control commands. Responses can be notifications to operators, quarantine of certain devices, changes to firewall rules to block traffic, or integrations that send information to existing or new systems and displays.

At the center of the new functionality is a Bayesian decision engine that is continually receiving information from infrastructure components, connected devices, and other systems. For example, given inputs from a physical security system, a work management system, and a network monitoring system, CAPMS can alert operators when there is unexpected access within a secure area such as a substation. This can increase the frequency of security checks and protective scanning functions, or even revoke credentials until operators can confirm the authorization of the access. Such checks could benefit normal operations as well, to help ensure coordination and awareness of unplanned changes.

Our finding from this project is that such a system can be useful in providing cybersecurity-related information to operators so they can be aware of potential threats and attacks, as well as to invoke automatic or operator-confirmed responses such as blocking and isolating attacks. The system might also improve adherence to safety and other maintenance procedures by enforcing checks. Another important finding from the project is that for it to be most useful, the cybersecurity system has to be able to take action. In some cases, this will mean blocking communication to some devices. This doesn’t mean that grid equipment can stop functioning safely and reliably, so communicating grid equipment vendors must include a non-communicating mode that requires only local measurements.

2 Project Background

The CAPMS project was a technology demonstration effort investigating the ability of a cybersecurity system to identify and respond automatically to attacks in a predefined way. The project is an addition to SCE's successful Common Cybersecurity System (CCS), now being actively deployed and tested in substations. CAPMS uses the CCS product for its base functionality, and SCE worked with the CCS vendor ViaSat to develop and test new functional capabilities that SCE believes will be required to secure the future electric grid. As the vendor, ViaSat was responsible for the design and development of CAPMS. SCE provided practical utility experience to guide ViaSat's understanding of the system's desired functionality and provided the test environment.

ViaSat designed the CAPMS system to be flexible, incorporating a broad set of data points to help provide a comprehensive view of the cyber-physical security status to a utility. This project limited the scope of CAPMS demonstration by focusing on the synchrophasor system and the development that had already occurred to support SCE's deployed CCS devices. SCE conducted the following activities in this project:

- A comprehensive analysis of the threats to a synchrophasor system
- Analysis of methods with which CAPMS could be used to detect and react to threats
- Development of attack use cases which could be tested in SCE's laboratory environment
- Development of high level requirements to communicate SCE's desired functionality to ViaSat
- Reviews with ViaSat to provide feedback on interim CAPMS functionality
- CAPMS system testing

2.1 Threat Identification

The three underlying properties of electronic communication that security measures attempt to guarantee are privacy, integrity, and availability. Physical security is required in all locations where attackers could get access to unencrypted data. Cybersecurity systems use cryptographic methods to hide protected information in encrypted communication tunnels, as well as to authenticate the identity of devices and users to prevent unauthorized access. They can also monitor processes, files, and communications to detect and prevent suspicious activity. Ensuring the availability of communications can be difficult, since redundant backup capability requires multiple physical communications paths in case one path is unavailable. Organizations must balance the cost of these protections with the risk of breaches and the damage that an attacker could cause. It can be very expensive to guarantee these properties to a high degree of probability. Utilities can also require that devices have built-in safeguards that protect equipment against unsafe operation, focus on early detection and response, isolation and containment, and ability to continue functioning safely while recovering from attacks, even when communications are not available.

2.1.1 Availability

Denial-of-service attacks can cause problems by flooding a network with disruptive traffic, but many other types of attacks can also block or prevent communications. As mentioned, redundancy is the only way to defend against these types of attacks, but it may be possible also to build tolerance into the system against this type of attack. Network outages occur frequently, and not always because of attacks. Applications and automation functionality must be able to withstand extended periods of isolation if at all possible. They must be able to operate safely in an isolated state, using only local measurements to perform their function. They must be able to store critical information during outages, and send it later.

2.1.2 Privacy

Ensuring privacy prevents spying on private communications. Attackers can gain financially or strategically by using private information to their advantage. Customers rely on service providers to safeguard their information, including energy usage data, equipment, rate plans, and so on. If an attacker gains access to private communications, it may be necessary to prevent communications until someone removes the threat and the system regains security of the channel.

2.1.3 Integrity

Given access to a network, it can be possible for a device to trick other devices into trusting it, allowing for man-in-the-middle attacks, where a rogue agent could modify or initiate trusted communications. Integrity assurance measures must be able to verify the identity of devices, so that it is difficult for an attacker to gain trusted status. Security systems must also be able to prevent rogue devices or software agents from gaining access to trusted networks.

2.2 Detection

Access to a wide array of information sources is a key element in the CAPMS system's ability to detect anomalous activity (e.g. events) and correlate that activity to determine the appropriate response. In order to establish the required confidence level, implementations must augment existing cyber security monitoring information with numerous sources of data beyond that which is typically the focus of cyber security monitoring with the current philosophy employed by utilities. The complexity of system vulnerabilities and the evolving nature of threats require these additional sources of information, including the systems listed below.

- Operational Applications
- Physical Security Systems
- Workforce Management

Figure 1 provides an overview component diagram of CAPMS system. It includes the central security services provided by the Trusted Network Platform, or TNP, and adds the ability to manage policies that administrators can install on servers in the grid control center as well as on remote hosts. Additionally, adapters to 3rd party security systems and operational systems provide additional sensor inputs and actuator outputs.

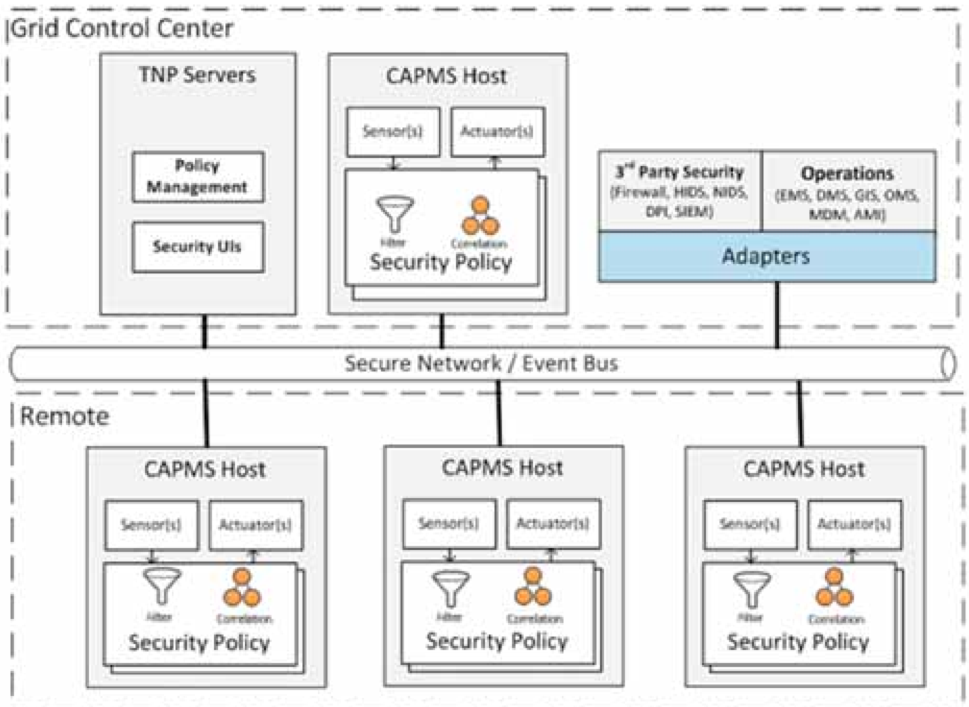

Figure 1: CAPMS Overview Diagram

This section describes several of the sensor input sources of information that may be required. However, the system is highly configurable, so these sources and policies can change at each installation site.

2.2.1 Cyber Security Event Information

Event information typically available within the cybersecurity system continues to play a key role in detecting anomalous system activities.

Monitoring

The cybersecurity system monitors devices using an agent installed on those it is protecting. It can monitor files, running processes, events, and network communications. It can take action locally, such as restarting a stopped process, or preventing unknown processes from starting.

Bill of Health

The system can centrally store a fingerprint (cryptographic signature) of monitored items to identify unauthorized changes. This is included in an overall “Bill of Health” measure of the expected configuration of each device. This adds some overhead in making approved changes, since the operator must compute and store the new approved signature. However, correlation of changed configuration without approval is a reasonable trigger to take action.

Network Alarms

The central security services can receive network alarms through SNMP or other means. The auto-response policies can use this information to correlate events and determine likelihood of attacks or suspicious activity.

Authentication Alarms

The system manages public key infrastructure for device certificates used in authentication and encryption. The system can revoke and manage these credentials through separately protected channels. It can also receive attempted logins, failed logins, and other events from active directory or other LDAP services for use in policies.

Firewall Activity

Firewalls often block everything except approved connections, possibly by address, port, and protocol. The system can log and collect attempts to initiate unapproved communications for use in correlating events to drive policies and responses. In addition, firewalls can provide the capability to create traffic baselines and then compare the real-time traffic patterns against these baselines. If the difference from a baseline exceeds an operator set threshold, a firewall can send an alert to the CAPMS detection process.

2.2.2 Operational Applications

Operational applications can provide a wealth of information, both at a grid level and an application level, that can be further utilized by the CAPMS system to determine that a cyber-attack is, or is not, occurring. There are numerous systems employed by utilities in this area providing functionality such as Supervisory Control and Data Acquisition (SCADA), State Estimation, Wide Area Monitoring Protection and Control (WAMPAC), Energy Management Systems (EMS), Distribution Management Systems (DMS), Outage Management Systems (OMS), and Advanced Metering Infrastructure (AMI).

Data Validity

Some attacks might attempt to change readings and measurements from grid components to make it look as if something is happening that really isn't, possibly prompting an operator to operate equipment when it isn't necessary. Existing systems may be able to validate readings and determine that someone has altered certain readings or that a device is malfunctioning in some way. Data validity involves assessing the current state or value of a directly observed data point (analog or digital) against the estimated/calculated/expected value. This is typically a dynamic determination driven by a State Estimator or other advanced application that utilizes a power system model to make the determination in the context of current grid conditions. Sending this information to the cybersecurity system can allow it to distinguish between actual grid events and cyber-attacks.

Alarm/Abnormal Condition

Alarm/Abnormal conditions occur when the current state or value of a directly observed data point (analog or digital) is not within a pre-determined range or state. These limits or normal state designations are typically static and done on a point-by-point basis within the operational application and don't vary based on the dynamics of the power grid.

Data Quality

Data quality is an indication to determine/detect if a data point (or points) is not updating or functioning as normal. While the state of the communicating device is the primary driver of data quality, there are some cases where the device communications are normal but the data quality flags may indicate "bad" data. An example of this might be something such as an RTU reporting that a point is "locally forced" to a value.

Loss of Device Communications Events

Loss of communications events occur when a device that directly supplies data to the operational application (such as a Remote Terminal Unit (RTU) in the case of a SCADA system) loses communications connectivity with the operational application. The system may detect the failure because of failure to receive a reply to a poll (request) from a SCADA master from the device in simple serial system architectures or by a loss of a TCP connection in more advanced systems. This would probably be associated with loss of data but there may or may not be any correlation to the impacted data (if multiple devices are affected, it may be difficult to determine which device corresponds to what data).

Switching Orders/Tags

These include items such as "Hold Orders", "Caution Orders", or other tags, which may communicate ongoing and approved activities or operational constraints on power system devices. These have both operational and safety aspects.

2.2.3 Physical Security Systems

Physical Alarms

If an attacker has physical access to protected assets, those assets are in severe danger of compromise. There may be existing physical security systems in place, but coordinating those alarms with the cybersecurity system can increase the protection of those assets by locking them down against network or local access while investigating and clearing the physical alarm.

Tamper Alarms

Some devices have the ability to send an event when someone attempts to open a protective physical enclosure. The system can use these events in auto-response logic.

2.2.4 Workforce Management

Work Plan / Approvals

One possible strategy for the cybersecurity system is to prevent access and changes to physical or cyber assets unless a scheduled, approved work plan exists. The combination of activity when nothing was scheduled will trigger an alert state, in which the system adopts a heightened security posture, while determining whether or not the activity is an attack.

2.3 Evaluation

Given the ability to detect and collect the required events and conditions, the policy engine provides the ability to correlate information and trigger alarms or to take action. For example, one policy created within the SCE CAPMS system demonstration establishes that when the system detects access to a substation, but no work is scheduled, the system notifies the operator and elevates the alert state, potentially blocking some changes or scanning for changes more often. Eventually, as the system gathers more information about other related activities, it identifies the most likely targets and can take proactive action if desired. Proactive actions can include investigative actions and other types of responses described in Section 2.4.

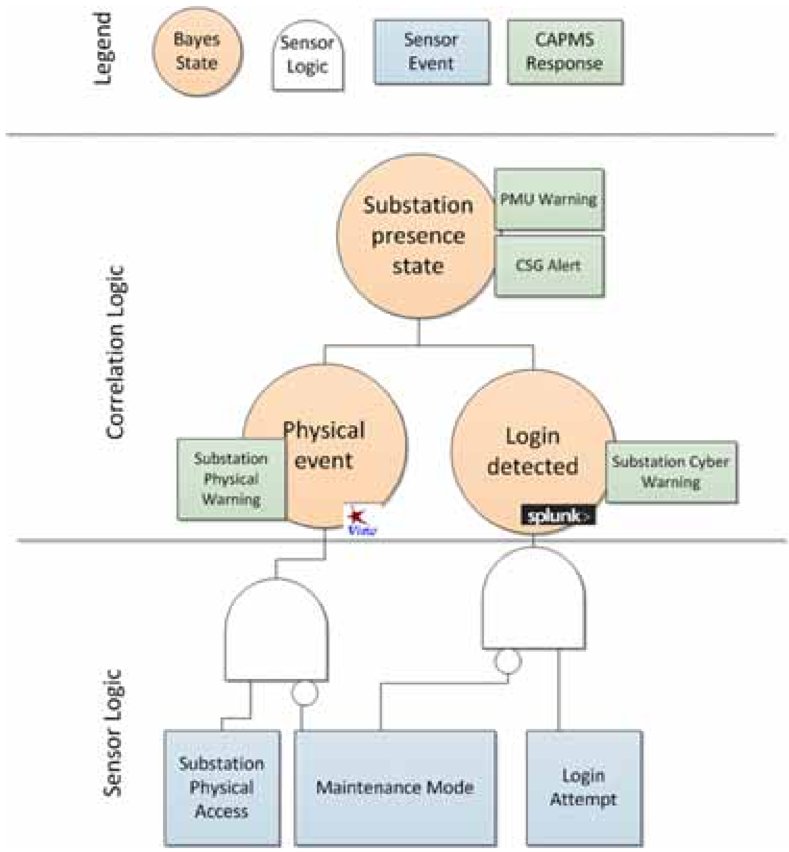

Figure 2: Simple Correlation Logic Definition

2.3.1 Root Cause Analysis

Sometimes it may be difficult to determine the source of an attack. One goal of the system is to gather enough information to identify the cause of alerts and events. With an accurate identified cause, it might be possible to isolate the problem and contain it.

Confidence

The system uses a Bayesian network to model the different attacks and the conditions under which they can be determined. The model can use Boolean logic, with states being either “true” or “false”. It can also compute the probability or confidence of each determination, which allows for tuning of the determinations, filtering alerts by criticality, and other sorts of fine-grained output. The model may limit responses to thresholds in confidence, enabling a tailored response based on how confident the model is that an attacker has achieved their goal.

Extent

One goal of the CAPMS project was to implement the grouping of cybersecurity alert states by location and device. Given this feature, an operator can quickly see the extent of an attack by how many devices and locations are reporting certain conditions.

Consequence

Additionally, operators would like to know what might happen as a result of an attack. System designers could pre-program certain policy result states with this type of information, to alert and notify the operator that a certain condition has been met that will lead to a known consequence.

2.4 Response

The purpose of the CAPMS project is to add functionality to not only gather information and compute the likelihood that observed system activity is the result of a cyber-attack, but also to respond when it has been determined that a cyber-attack has, or is occurring. Responses can take many forms, including simple logged alert events, notifications, or even wipe or quarantine. Obviously, most operators will want the ability to review and confirm automated actions until they feel comfortable with the logic and determinations.

2.4.1 Notification

Logs

Writing a cyber-alert state to a log file is probably the simplest, most basic action. Another system could collect and combine these events with other information in a management console or as input into other processes.

Alerts

The next level of notification is to show the alert state on some sort of display, which could be the security system application.

Programmatic

If desired, the policy engine can send alert state determinations, and potentially the underlying contributing information, to external applications.

2.4.2 Forensic

The system can initiate a forensic response in cases where it suspects an attack but has not identified the specific target. For example, the system could increase the frequency or amount of monitoring and scanning in a suspected attack area to find affected components more quickly.

2.4.3 Isolation / Containment

Once the system gathers enough information to identify the affected components, it is possible to block them from communicating or otherwise contain them to prevent further damage. Or, in cases where someone is using a certain credential inappropriately, the system can revoke it.

Security Association Management

Once the policy engine determines that an attacker has control of a device, it may be desirable to block it from communicating. If the cybersecurity system is managing the security associations used for secure communications, breaking them is very easy. If a different system were managing the security associations, a secure programmatic method of transferring the control message would be required.

Credential Revocation

In the scenario where an attacker is using a valid (but probably compromised) account to make unauthorized changes, the system could revoke the credentials for that account to prevent further changes.

Graceful Degradation

Reliability and safety are very important to energy utilities. If the security system initiates any automatic responses, operators want to ensure that it will not affect the safe, reliable delivery of power. On the other hand, if an attacker gains control of a device, it may be possible to affect the delivery of power and the safe operation of the system. Devices responsible for the operation of the grid must be able to operate safely and effectively with or without communications. Without communications, a device can rely only on local measurements.

Security-Related Operational Modes

Critical components could have redundancies or multiple levels of degradation based on input from CAPMS and other sources to keep them operating safely. Equipment could implement various modes of operation (heightened security states) with local policies as needed.

2.4.4 Contingency Planning

Utilities always strive to be able to handle events where a single piece of equipment fails, so called “N-1” contingencies. It could be possible for CAPMS to predict failures larger than “N-1” and to send those scenarios to a contingency planning system in order to determine the best course of action. For example, if a certain type of equipment has been compromised in a certain area, that list of equipment could be sent to a grid management system for planning, potentially before it is actually taken out of service. The utility could then potentially avoid cascading outages by balancing resources prior to equipment operation.

2.4.5 Cyber-Threat Information Sharing

Another possible response is to notify interested parties about detected cyber-threats and provide them enough information to detect or prevent further attacks.

3 Project Tasks

3.1 Threat Analysis

As Information and Communications Technology (ICT) has become a key enabler utilized by utilities for more efficient and effective grid operations, it has also led to more complex and interconnected monitoring and control systems. Utilities now rely on increased connectivity, within the system and external to the system, to adapt to changing business and operational environments. Advances in connectivity, however, also provide new potential paths for undesirable activity, intentional or unintentional, which may affect the resilience of critical operational systems. The main objective of the threat analysis effort within the SCE CAPMS project was to gain a better understanding of the sensor points and their correlations needed to detect a potential cyber event, malicious or otherwise, within a Wide Area Monitoring Protection and Control (WAMPAC) system that utilizes synchrophasor-based technology. To accomplish this, SCE analyzed threats to these systems with a focus on how they could potentially influence a utility’s operational decision-making. The main components of this approach were examining system characteristics that an attacker could be exploit and the informational impacts from the identified attacks.

3.1.1 Informational Impacts

Systems such as WAMPAC, which utilities utilize for real-time grid operations, are only as effective as the information provided to them. One method employed in the SCE threat analysis was to categorize attacks by the potential impact that they might have on the information within the system. When control system information is affected, the overall impacts to the utility can be severe as these systems are integral to the utility's ability to make critical operational decisions or take appropriate actions with their command and control capabilities. If an attacker's activities go unnoticed and affect the availability or integrity operational data or command and control capabilities, they could potentially affect the safety and reliability of the power grid itself. Improving the ability of a utility to detect and react to unauthorized cyber activity can directly affect its ability to operate the power grid in a resilient manner. The project utilized five basic information impact categories in this analysis as follows:

- **Distort** - A distortion or manipulation of information
- **Disruption** - A disruption in the flow of information
- **Destruction** - A destruction of information
- **Disclosure** - A disclosure of information which may provide an attacker with access to information they would normally not have access to and possibly leading to other compromises
- **Discovery** - A discovery of information not previously known that can be used to launch an attack on a particular target

Of the five categories, three (distort, disrupt, and destroy) were of particular interest as they have the most ability to likely impact the utility operational decision-making.

Architecture

Figure 3 illustrates a high-level view of a WAMPAC system architecture. The three key system components worth noting are:

- **Phasor Measurement Unit (PMU)** – measures electrical inputs, calculates and time stamps phasor(s)
- **Phasor Data Concentrator (PDC)** – time aligns data from multiple PMUs and also does basic data quality checks
- **Phasor Gateway** – utilized to securely exchange synchrophasor data between entities

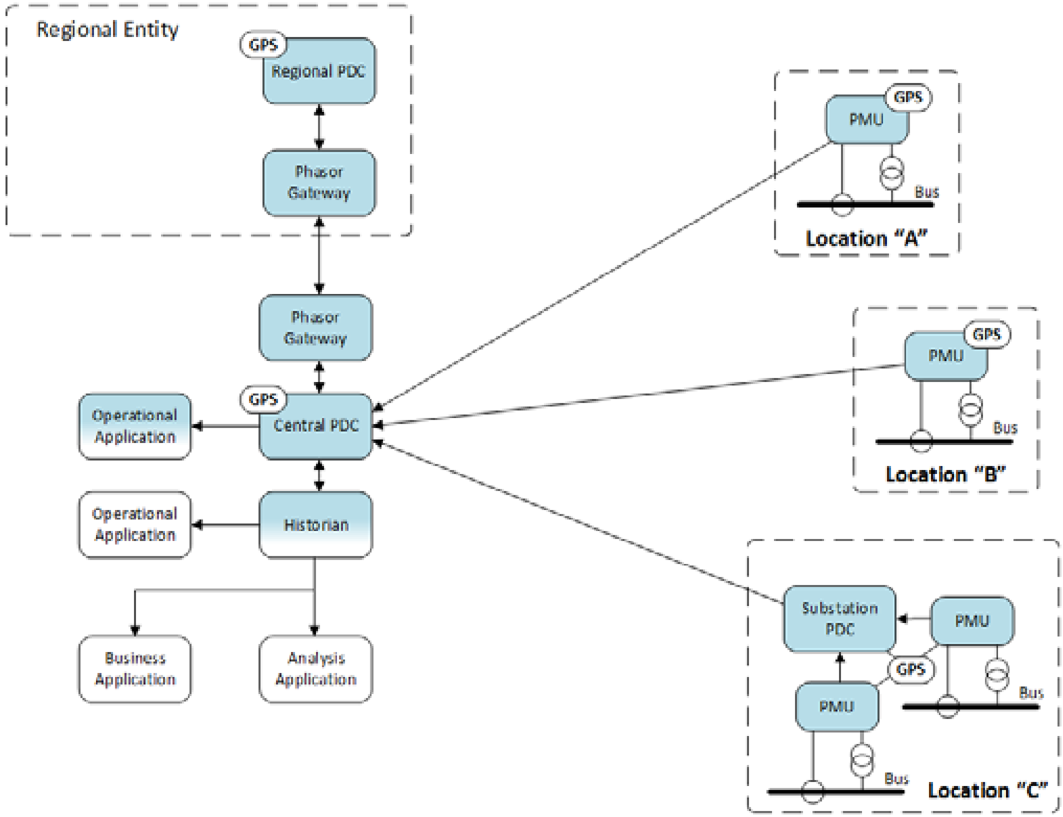

Figure 3: Example WAMPAC System Architecture

As part of the threat analysis, SCE cataloged attacks against these components aimed at disrupting their primary system functionality. Critical to the overall performance of the WAMPAC system is the reliance on a high precision time source at the various locations where these components are located.

Protocols and Standards

The project team also examined key protocols and standards utilized within WAMPAC systems for possible attack vectors as part of the threat analysis including:

- C37.118.2-2011, IEEE Standard for Synchrophasor Data Transfer for Power Systems
- IP based communications (both UDP and TCP)
- IRIG and NTP timing references

3.1.2 Process

The process utilized by SCE for the WAMPAC threat analysis consisted of three major steps as shown in Figure 4.

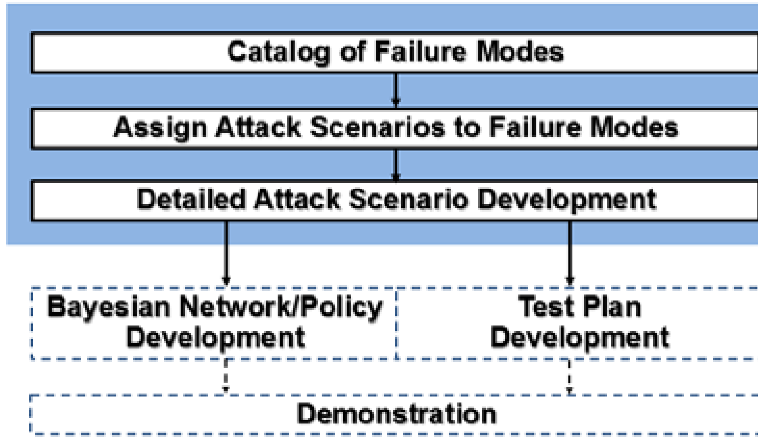

Figure 4: CAPMS Threat Analysis Process

Catalog Failure Modes

The first step of the SCE CAPMS threat analysis was to brainstorm possible failure modes within the WAMPAC system from the perspective of the system components performing their assigned functions and then correlate these failure modes against possible attack targets and attack types. This first step also identified the potential informational impact for each failure mode. This step of the analysis yielded 32 significant and distinct failure modes as shown in Appendix A. The goal of this step was to identify a good representative set of failure modes, not an exhaustive list of all possible failure modes.

Assign Attack Scenarios to Failure Modes

From the master list of failure modes, the team developed a second matrix that identified at least one plausible attack scenario for each failure mode. In some cases, the team mapped multiple attack scenarios to a single failure mode, mainly due to multiple attack targets within the system. Part of this step was the categorization of these attacks based on the system component or function that they targeted. The SCE analysis of potential threats to a synchrophasor-based system identified four basic areas that an attacker could potentially target in order to interfere with proper system operation:

- **Timing attacks** - Attacks targeting the distribution of timing signals utilized by the individual components of the system
- **Application layer attacks** - Attacks targeting the application layer protocol (IEEE C37.118)
- **Network attacks** - Attacks targeting the network infrastructure utilized within the system with the intent of disputing information flows
- **Host attacks** - Attacks targeting hosts of the individual components of the control system (e.g. hardware/OS)

This step of the analysis yielded 53 plausible attack scenarios as shown in Appendix B and represented in Figure 5. The goal of this step was to identify a good representative set of attack scenarios, not an exhaustive list of all possible attacks on a WAMPAC system.

Legend

May not be relevent to SCE specific architecture

Currently not planned as part of SCE demo or not significantly interesting

X with no color may lead to multiple rows on second tab

					Informational impact of attack					Components potentially vulnerable to this type of attack (Candidate Components)							
Failure ID	Attack Category	Attack Target (Funtional)	Attack Type	Possible Result/Failure Mode	Distort	Disrupt	Destruct	Disclosure	Discovery	DFR/PMU	GPS (Substation)	USI Master	PDC	GPS (Control Center)	Historian	Phasor Gateway	Network
T1	Timing	Network Time Distribution	Spoofing NTP/SNTP server	Clock error within C37.118 server	X					X	X		X	X			X
T2	Timing	Network Time Distribution	DoS attack on NTP/SNTP server	C37.118 server reverts to alternate time source		X				X	X		X	X			X
T3	Timing	Network Time Distribution	DoS attack on NTP/SNTP server	C37.118 server reverts to internal clock		X				X	X		X	X			X
T4	Timing	IRIG-B Time Distribution	Substituting/Spoofing IRIG-B input	PMU clock error	X					X	X						
T5	Timing	IRIG-B Time Distribution	Disrupting IRIG-B input	PMU reverts to internal clock		X				X	X						
T6	Timing	GPS Signal Reception	GPS jamming	PMU or PDC reverts to internal clock		X					X			X			
T7	Timing	GPS Signal Reception	GPS spoofing	Clock error within C37.118 server	X						X			X			
T8	Timing	GPS Receiver	Unauthorized configuration change	Clock error within C37.118 server	X					X	X		X	X			
AL1	Application Layer	C37.118	Spoofing C37.118 server	False data stream transmitted to upstream C37.118 client	X					X			X		X	X	
AL2	Application Layer	C37.118	Spoofing C37.118 server	False configuration or header message transmitted to upstream C37.118 client	X					X			X		X	X	
AL3	Application Layer	C37.118	Spoofing C37.118 client	C37.118 server data stream redirected to imposter		X				X			X		X	X	
AL4	Application Layer	C37.118	Spoofing C37.118 client	Spoofed C37.118 client starts/stops PMU data		X				X			X		X	X	
AL5	Application Layer	C37.118	Man-In-The-Middle	Monitoring/eavesdropping of messages (header/configuration/data stream) from C37.118 server to C37.118 client				X		X			X		X	X	
AL6	Application Layer	C37.118	Man-In-The-Middle	altered configuration or header message sent to upstream C37.118 client	X					X			X		X	X	
AL7	Application Layer	C37.118	Man-In-The-Middle	altered data stream sent to upstream C37.118	X					X			X		X	X	
AL8	Application Layer	C37.118	Fuzzing C37.118 protocol	Abnormal behavior or termination of the application on target device		X				X			X		X	X	
AL9	Application Layer	C37.118	Unauthorized/rouge C37.118 client	Command message from unauthorized C37.118 client starts/stops PMU data stream		X				X			X		X	X	
AL10	Application Layer	IEC 61850-90-5															
N1	Network	Network Infrastructure	Flooding (DoS)	Delayed receipt of data stream by upstream C37.118 client		X											X
N2	Network	Network Infrastructure	Flooding (DoS)	Message exchange interupted between C37.118 client and server		X											X
N3	Network	Network Infrastructure	ARP spoofing	Message exchange interupted between C37.118 client and server		X				X			X		X	X	X
H1	Host	Network Interface (NIC)	DoS	Device unable to access network		X				X	X	X	X	X	X	X	
H2	Host	Network Interface (NIC)	DoS	Abnormal behavior or termination of the		X				X	X	X	X	X	X	X	
H3	Host	Network Interface (NIC)	Port scanning	Open logical network interface to device discovered (e.g. ftp, telnet, http, etc.)					X	X	X	X	X	X	X	X	
H4	Host	Firmware/OS	Malware	Device utilized to gain access to other protected network resources					X	X	X	X	X	X	X	X	
H5	Host	Firmware/OS	Malware	Unexpected behavior of device		X				X	X	X		X	X	X	
H6	Host	Configuration	configuration	Phasor data within data stream incorrect	X					X			X			X	
H7	Host	Configuration	configuration	Mismatch between header/configuration messages and phasor data within data stream	X					X			X			X	
H8	Host	Database	uauthorized database access	Archieved/historical data modified	X										X		
H9	Host	Database	uauthorized database access	Archieved/historical data deleted			X								X		

Figure 5: Threat Matrix Table

3.1.3 Threat Analysis Results

The project team then utilized the key results from the threat analysis as inputs into the CAPMS Bayesian Network and Policy development as well as the detailed test plan development and fall into two primary areas:

- Understanding of the potential sensor points and data sources required to detect activities and their impacts
- Basic understanding of the sensor logic and correlation logic to correctly detect these attacks

SCE selected a testing scenario associated with a device level attack. Out of the four categories of attacks, this was deemed the most likely to potentially occur as a result of physical security challenges associated with these devices. These challenges stem from the likelihood that a field deployed cyber asset, such as a PMU, will be installed in remote, unmanned facility where advanced physical security measures, such as those which may be found at a utility control center my not be practical or effective. These physical security challenges make it likely that an adversary may choose this route over an attack launched remotely due to the fewer number of cyber defenses that an attacker would need to circumvent or avoid.

Although there are numerous attacks that could be launched by an adversary when locally present within a remote facility such as a substation, the unauthorized change to a devices configuration is perhaps one of the most difficult to detect before an improper system operation occurs. A secondary benefit of focusing on this type of attack is that it may also be effective in detecting approved utility activity that may not have been properly coordinated.

The potential impact of this type of attack would alter data that operational applications consume. This altered data could potentially make it appear that a grid event is occurring when in fact one is not, or to mask or camouflage a grid event from detection in a timely manner. In either case, the result of such altered data could lead to a scenario where a Grid Operator, or operational application through automation, takes inappropriate action in response to what appeared to be correct power system readings.

3.2 Use Cases

The final step of the threat analysis selected one attack scenario from each category and developed a more detailed version identifying not only the steps that an attacker might perform, but also impacts that these activities might induce. These impacts can range from grid level events such as an outage or equipment operation to secondary system events such as loss of communications or specific message exchanges. These four selected attack scenarios also become the primary candidates for testing and demonstration later in the project.

3.2.1 Attack Scenario 47: Unauthorized party/system changes DFR/PMU configuration

Narrative

A Threat Agent gains physical access to a remote substation that includes one or more DFR/PMU units. While physically present, the Threat Agent gains logical access to a DFR/PMU unit and modifies the configuration of the unit with the intent of impacting the utility's operational decision making capabilities. Once the Threat Agent has made the intended configuration changes, they reboot the DFR/PMU unit (to help ensure that configuration changes take effect). The Threat Agent then physically exits the facility.

Assumptions

- Configuration changes to the DFR/PMU unit will take effect immediately (or shortly thereafter the changes are made via reboot of the unit)
- The Threat Agent is knowledgeable of the system, corresponding technology, and has a basic understanding of the operation of the power gird
- Command Frames and Config Frames are exchanged between the PDC and DFR/PMU over TCP
- The DFR/PMU employs the spontaneous data transmission method as described in Annex F of IEEE Std C37.118.2

Pre-conditions

- All communications to the remote substation are functioning normally
- The DFR/PMU has been fully commissioned including functional testing to validate the configuration and communications connectivity
- The PDC at the control center has been configured, functionally tested, and is receiving data (via C37.118 format) from the DFR/PMU

- The CCS client of DFR/PMU has been configured and is monitoring the file associated with the DFR/PMU configuration for changes

Scenario Steps

Step	Description	Possible Sensors
1	The DFR/PMU unit is commissioned	N/A
2	The CCS Client on the DFR/PMU unit begins monitoring target files	N/A
3	A Threat Agent gains physical access to the remote substation where the target DFR/PMU has been installed	Physical security system
4	The Threat Agent gains logical access to DFR/PMU	
	a) Via local console interface of the DFR/PMU interface using compromised credentials or default account	DFR/PMU-Windows log
	b) Via network using RDP and compromised credentials or back door, etc.	DFR/PMU-Windows log
	c) Via network using spoofed USI master software running locally	
5	The Threat Agent modifies the configuration of the target DFR/PMU	1) DFR/PMU-Application log 2) CCS Client (BoH or QoT)
6	The Threat Agent applies the change so that the modified configuration takes effect	DFR/PMU-Application log
7	The Threat Agent terminates logical access	
	a) logs out of DFR/PMU	DFR/PMU-Windows log
	b) Leaves DFR/PMU console open (if that's how he gained access)	
	c) Drops RDP connection	DFR/PMU-Windows log
8	Communications (streaming of the Data Frames) between the affected DFR/PMU unit and PDC are interrupted	PDC-Application log
9	The Threat Agent exits the remote substation	
10	The PDC listens on UDP Port 4713 (default port per IEEE C37.118.2 standard) for Data Frames from the DFR/PMU	
11	The DFR/PMU resumes sending Data Frames to the PDC (via UDP). The DFR/PMU will indicate that a configuration change has been made by asserting Bit 10 of the STAT field within the Data Frame.	C37.118 deep packet inspection (detection of assertion of Bit 10 of the STAT field within the Data Frame)
12	Upon receipt of the Data Frame noting the configuration change (Bit 10 of the STAT field asserted), the PDC sends the Command Frame (Send CFG-1,2, or 3) to the DFR/PMU.	1) PDC-Application log 2) C37.118 deep packet inspection (detection of commands sent from PDC to DFR/PMU)

Step	Description	Possible Sensors
13	The DFR/PMU processes the Command Frame (Send CFG-1,2, or 3) and sends the response (Configuration Frame) to the Threat Agent	1) PDC-Application log 2) C37.118 deep packet inspection (detection of Configuration Frame)
14	Synchrophasor data being received by the PDC is not accurate of current grid conditions	Upstream operational application or system operator
15	The PDC time correlates the incorrect data from the affected DFR/PMU unit along with data from other (normal) DFR/PMU units and forwards the aggregated data to upstream operational application (such as EMS), Phasor Gateway and/or Historian	
16	The operational application detect data anomaly	Upstream operational application log or system operator
17	The Historian stores the received (incorrect) data	
18	The Phasor Gateway forwards the aggregated data to and external entity and/or the Historian forwards the aggregated data to other internal (non-operational) application	1) External Entity (None) 2) Non-operational application log or application owner

3.2.2 Attack Scenario 13: Erroneous IRIG-B output of GPS receiver creates clock error in DFR/PMU

Narrative

A Threat Agent gains physical access to a remote substation that includes one or more DFR/PMU units. While physically present, the Threat Agent gains logical access to the GPS receiver that provides time synchronization to the DFR/PMU via an IRIG-B interface. The Threat Agent modifies the configuration of the GPS receiver with the intent of causing the DFR/PMU to affix incorrect time stamps to the C37.118 data frames and affect the utility's operational decision making capabilities. Once the Threat Agent has made the intended configuration changes, they reboot the GPS receiver unit (to help ensure configuration changes take effect). The Threat Agent then physically exits the facility. The incorrect time stamps affixed to the C37.118 Data Frames from the target DFR/PMU to the PDC are perceived as late data by the PDC, and they are flagged as a waiting period violation.

Assumptions

- Configuration changes to the GPS receiver unit will take effect immediately (or shortly thereafter the changes are made via reboot of the unit)
- Communications networks between the remote substation and the utility backbone/core are not interrupted during this scenario
- The Threat Agent is knowledgeable of the system, corresponding technology, and has a basic understanding of the operation of the power gird
- Data Frames from the DFR/PMU are sent to the PDC over UDP
- Command Frames and Config Frames are exchanged between the PDC and DFR/PMU over TCP
- The DFR/PMU employs the spontaneous data transmission method as described in Annex F of IEEE Std C37.118.2

Pre-conditions

- All communications to the remote substation are functioning normally
- The DFR/PMU has been fully commissioned including functional testing to validate the configuration and communications connectivity
- The PDC at the control center has been configured, functionally tested, and is receiving data (via C37.118 format) from the DFR/PMU

Scenario Steps

Step	Description	Possible Sensors
1	The DFR/PMU unit is commissioned	N/A
2	A Threat Agent gains physical access to the remote substation where the target DFR/PMU and GPS receiver has been installed	Physical security system
3	The Threat Agent gains logical access to GPS receiver	Device log
	a) Via web console	
	b) Via serial console port	
4	The Threat Agent modifies the configuration of the target GPS receiver	Device log
5	The Threat Agent restarts the affected GPS receiver unit so that the modified configuration takes effect	
6	The Threat Agent terminates logical access	
7	The IRIG-B output of the GPS receiver is altered as a result of the configuration change and not accurate	
8	The Threat Agent exits the remote substation	Physical security system
9	The DFR/PMU updates its internal clock based on the IRIG-B input from the GPS receiver	Device application log
10	The DFR/PMU utilizes the misaligned internal clock to affix time stamps on C37.118 Data Frames sent to the PDC (via UDP).	
11	The PDC reaches its maximum wait time for collecting data from downstream PMU devices. The PDC aggregates the data from other PMUs, inserts filler values for the missing PMU data, and transmits the aggregated data within the Data Frames being sent to upstream C37.118 clients (phasor gateway, operational applications, historian, etc.). Within the aggregated Data Frame, bits 15 & 14 of the STAT field corresponding to the data block containing the missing PMU data are set to “10” to note that this data is invalid.	1) PDC application log 2) C37.118 Deep Packet Inspection (detection of Bits 15 & 14 in STAT field for corresponding PMU data block of Data Frame set to “10”)
12	C37.118 clients upstream from the PDC receive data frames that contain no data from the target DFR/PMU.	Application log
13	The operational application detect data anomaly	Application logs/alarms
14	The Historian stores the received data	

Step	Description	Possible Sensors
15	The Phasor Gateway forwards the aggregated data to and external entity and/or Historian forwards the aggregated data to other internal (non-operational) application	
16	Non-operational/analysis application detects data anomaly	Application logs/alarms

3.2.3 Attack Scenario 32: Unauthorized device degrades network performance by flooding the network with excessive traffic

Narrative

A Threat Agent gains logical access to a host on the utility substation network infrastructure where the target DFR/PMU is connected. The Threat Agent then utilizes the compromised host to execute a flooding type Denial-of-Service (DoS) attack. The attack results in the available network bandwidth being inadequate for the DFR/PMU to meet the performance requirements for the data frames between the DFR/PMU and PDC. This in turn results in a waiting period violation within the PDC for the specific DFR/PMU.

Assumptions

- The DFR/PMU is currently sending data frames to the PDC.
- The Threat Agent is knowledgeable of the system, corresponding technology, and has a basic understanding of the operation of the power grid.

Pre-conditions

- All communications to the remote substation are functioning normally
- The DFR/PMU has been fully commissioned including functional testing to validate the configuration and communications connectivity
- The PDC at the control center has been configured, functionally tested, and is receiving data (via C37.118 format) from the DFR/PMU

Scenario Steps

Step	Description	Possible Sensors
1	A Threat Agent gains logical access to the substation network where the target DFR/PMU has been installed	Network infrastructure
2	The Threat Agent gains logical access to a host device within the substation network where the target DFR/PMU has been installed	Host logs
	a) Via console interface using compromised credentials or default account	

Step	Description	Possible Sensors
	b) Via network using RDP and compromised credentials, back door, or by brute force	
3	The Threat Agent begins a flooding DoS attack from the compromised host	
	a) PING flood attack against the router's local LAN interface	Router log
	b) Smurf attack sent to LAN broadcast address with router's local LAN interface as source address	Router log
	c) UDP flooding attack against the router's local LAN interface	Router log
4	The available network bandwidth decreases to the point that the DFR/PMU cannot meet its minimum performance requirements for transmitting data frames to the PDC.	1. Network infrastructure 2. Deep Packet Inspection
5	The PDC reaches its maximum wait time for collecting data from downstream PMU devices. The PDC aggregates the data from other PMUs, inserts filler values for the missing PMU data, and transmits the aggregated data within the Data Frames being sent to upstream C37.118 clients (phasor gateway, operational applications, historian, etc.). Within the aggregated Data Frame, bits 15 & 14 of the STAT field corresponding to the data block containing the missing PMU data are set to "10" to note that this data is invalid.	1. PDC application log 2. C37.118 Deep Packet Inspection (detection of Bits 15 & 14 in STAT field for corresponding PMU data block of Data Frame set to "10")
6	The Threat Agent exits/terminates logical access to the compromised host. The DoS attack remains active	Network infrastructure
7	C37.118 clients upstream from the PDC receive data frames that contain no data from the target DFR/PMU.	Application log
8	The operational application detect data anomaly	Application logs/alarms
9	The Historian stores the received data	
10	The Phasor Gateway forwards the aggregated data to and external entity and/or Historian forwards the aggregated data to other internal (non-operational) application	
11	Non-operational/analysis application detects data anomaly	Application logs/alarms

3.2.4 Attack Scenario 26: Unauthorized device intercepts and alters the configuration frame from PMU to PDC

Narrative

A Threat Agent executes a man-in-the-middle (MITM) attack on the data exchange between a DFR/PMU and the PDC located at the utility's control center. After monitoring this data exchange, the Threat Agent then intercepts a Configuration Frame sent from the DFR/PMU to the PDC and alters the time base (TIME_BASE) field within the Configuration Frame. The time base is utilized by a C37.118 client to determine the actual fractional second of the time stamp of the phasor data within the Data Frame. This altered Configuration Frame is then processed by the PDC and used to parse subsequent Data Frames from the DFR/PMU.

Assumptions

- Communications networks between the remote substation and the utility backbone/core are not interrupted during this scenario. The Threat Agent is knowledgeable of the system, corresponding technology, and has a basic understanding of the operation of the power grid.
- Data Frames from the DFR/PMU are sent to the PDC over UDP
- Command Frames and Config Frames are exchanged between the PDC and DFR/PMU over TCP
- The DFR/PMU employs the spontaneous data transmission method as described in Annex F of IEEE Std C37.118.2

Pre-conditions

- All communications to the remote substation are functioning normally
- The DFR/PMU is streaming Data Frames to the PDC.
- The DFR/PMU has been fully commissioned including functional testing to validate the configuration and communications connectivity
- The PDC at the control center has been configured, functionally tested, and is receiving data (via C37.118 format) from the DFR/PMU

Scenario Steps

Step	Description	Possible Sensors
1	A Threat Agent executes an ARP poising attack to intercept traffic between the DFR/PMU and the PDC	
2	The Threat Agent alters the Data Frames from the DFR/PMU to indicate falsely that a configuration change has been made by asserting Bit 10 of the STAT field within the Data Frame.	C37.118 deep packet inspection (detection of assertion of Bit 10 of the STAT field within the Data Frame)
3	The Threat Agent forwards the altered Data Frames to the PDC	
4	Upon receipt of the Data Frame noting the configuration change (Bit 10 of the STAT field asserted), the PDC sends the Command Frame (Send CFG-1,2, or 3) to the DFR/PMU.	C37.118 deep packet inspection (detection of Command Frame being sent to DFR/PMU)
5	The Threat Agent passes the Command Frame (Send CFG-1,2, or 3) through to the DFR/PMU unaltered	

Step	Description	Possible Sensors
6	The DFR/PMU processes the Command Frame (Send CFG-1,2, or 3) and sends the response (Configuration Frame) to the Threat Agent (thinking that the Threat Agent is the PDC)	
7	The Threat Agent then alters the time base (TIME_BASE) within the Configuration Frame received from the DFR/PMU and transmits the altered Configuration Frame to the PDC	C37.118 deep packet inspection (detection of Configuration Frame being sent to PDC)
8	The PDC receives and processes the altered Configuration Frame	
9	The Threat Agent ends the attack	
10	The DFR/PMU begins transmitting Data Frames directly to the PDC (no longer redirected to the Threat Agent)	
11	The PDC parses the Data Frames from the DFR/PMU according to the last received Configuration Frame.	
12	The PDC time correlates the data from the affected DFR/PMU unit along with data from other (normal) DFR/PMU units and forwards the aggregated data to upstream Operational Applications (such as EMS), Phasor Gateway and/or Historian	
13	The Operational Application detect data anomaly	
14	The Historian stores the received data	
15	The Phasor Gateway forwards the aggregated data to and external entity and/or the Historian forwards the aggregated data to other internal (non-operational) application	

3.3 Requirements

The requirements developed for this project are generally at a high level, which is appropriate for a system that is in a research and development phase. These requirements provide an outline of the basic desired functionality and can be further refined to support an actual field deployment.

3.3.1 Functional Requirements

The project used two approaches to develop requirements. The first considered the set of threats and attack use cases developed in sections 3.1 & 3.2. The second approach considered a generalized operational view based on the installation and use of the notional CAPMS system.

1. Installation
2. CAPMS Operational Cycle
    a. Sensing
    b. Policy Application
    c. Response
3. Security

Installation Requirements

A goal for CAPMS is to minimize additional utility resources required to install and configure CAPMS functionality. A future deployed CAPMS system would be installed on many field devices and ease of installation and configuration would be a high priority.

REQ ID	Requirement
1.1	CAPMS shall be installed on target client devices.
	Requirement met.
1.2	CAPMS installation shall be implemented as a CCS upgrade.
	Requirement met. Future system may be integrated into CCS.
1.3	Centralized CAPMS functions shall be installed within the existing CCS system.
	Requirement met.
1.4	CAPMS shall minimize configuration of point-to-point interconnection interfaces with external sensor and actuator actors.
	Requirement met. The project demonstrated a simplified standard interface.
1.5	CAPMS shall support a flexible set of interfaces to support vendor development of CCS/CAPMS clients.
	Requirement met. The JSON interface provides an open standard interface. Additional interfaces are possible.

Sensing Requirements

A goal for CAPMS is to demonstrate an increased level of awareness and policy responses when using data from systems that have traditionally been unavailable to a security system. The CAPMS is designed to use a variety of external data sources that provide additional context to the detection of cyber-physical security events.

REQ ID	Requirement
2.1	CAPMS shall receive and process syslog event messages from client devices and external interfaces.
	Requirement met. CAPMS has an internal log aggregator.
2.2	CAPMS shall receive and process TCP messages from client devices and external interfaces.
	Requirement met. CAPMS receives TCP messages through Splunk.
2.3	CAPMS shall use the Phasor Data Concentrator as a sensor
	Requirement met. CAPMS receives log messages from the Phasor Data Concentrator.
2.4	CAPMS shall use Splunk as a sensor
	Requirement met. Splunk was configured to receive syslog messages from several systems and provide that data to CAPMS.
2.5	CAPMS shall support deep packet inspection of C37.118 messages
	Requirement met. CAPMS monitors C37 messages and is aware of device configuration change messages.
2.6	CAPMS shall detect failed logins to monitored devices
	Requirement met. CAPMS receives failed login notices through the Splunk interface.
2.7	CAPMS shall provide the capability for the CAPMS operator to manually place the CAPMS agent “offline” or in an “online” mode.

REQ ID	Requirement
	Requirement met. Devices with the CAPMS agent can be enabled or disabled.

Policy Application Requirements

CAPMS policies should provide a flexible framework for the utility to configure the monitored data streams, and the responses that it should take upon detection of potential intrusion attempts.

REQ ID	Requirement
3.1	CAPMS shall perform an automated analysis to detect a cyber-intrusion.
	Requirement met. CAPMS uses a probabilistic Bayesian tree to determine the likelihood of intrusion.
3.2	CAPMS shall report the detection of a cyber-intrusion to CAPMS operator.
	Requirement met. The CAPMS GUI reports detected events and the CAPMS system is able to send notifications to other systems.
3.3	CAPMS shall use CCS functionality to assess the health and status of CCS enabled client devices.
	Requirement met.
3.4	CAPMS shall apply policies to detected cyber-intrusions and determine the most appropriate course of action.
	Requirement met. Policy responses provide both user notifications and automatic responses to be made.
3.5	CAPMS shall report the activation/deactivation of a policy and indicate the device(s) impacted to the CAPMS operator.
	Requirement met. Policy deployment and management is managed through a CAPMS GUI. Threat detections and responses are reported through the CAPMS GUI and optionally to other users and systems.
3.6	CAPMS shall provide a summary of all currently policy activations.
	Under development. The CAPMS GUI will provide a summary of detections and responses.
3.7	CAPMS shall provide policy options that require CAPMS operator approval before activation.
	Requirement met. CAPMS responses can be actions that require an operator's approval before being activated.
3.8	CAPMS shall provide the CAPMS operator with the ability to revert (i.e. Cancel) an activated policy.
	Requirement not tested but possible. Actions taken by the CAPMS system can be reviewed by the operator. Additionally, commanded actions taken by CAPMS can include restoration to previous functionality.
3.9	CAPMS shall provide a policy response that is informational only (i.e., Alert Notification).
	Requirement met. Multiple notification options are available.
3.10	CAPMS shall be able to change monitoring levels based on suspicious activity.
	Requirement met. The Bayesian tree allows for levels of certainty and the possibility to take actions as detections are made.
3.11	CAPMS shall be able to initiate new PKI exchange for monitored devices
	Requirement met through CCS functionality.

Response Requirements

The CAPMS response requirements were tailored to the testing environment, but were chosen to test and demonstrate the ability of CAPMS to interact with systems with defined interfaces and use them as part of a security policy's response.

REQ ID	Requirement
4.1	CAPMS shall use eDNA as an actuator.
	Requirement met. The eDNA system was used as a proxy for a Control Center application; CAPMS sends notifications informing an operator that a perceived electric system event are is actually a cyber-attack.
4.2	CAPMS shall support informational messages to external systems and their users as a policy response.
	Requirement met. CAPMS is able to send email and send notifications to systems.
4.3	CAPMS shall support defined interfaces on actuator systems to perform permitted actions as a policy response.
	Requirement met. The eDNA system provided an interface to receive messages from CAPMS.

Security Requirements

CAPMS should support and enhance SCE's ability to implement security policy and assist in meeting federal and state requirements for reporting and auditing.

REQ ID	Requirement
5.1	CAPMS policy engine shall support the implementation of SCE cyber-security policies for substation devices.
	Requirement met. CAPMS policies can support SCE policy guidelines.
5.2	CAPMS shall store logs of all event detections and actions taken to support SCE cyber-security polices for substation devices.
	Requirement met. CAPMS maintains an event log of detections and actions.
5.3	CAPMS shall provide authorized local users the ability to deactivate auto-response functionality.
	Requirement not tested.
5.4	CAPMS shall be able to send its application logs to SCE selected data repository or historian.
	Requirement not tested.

4 Project Results

4.1 Project Data Summary

Unlike many projects, CAPMS was not evaluating the performance, effectiveness, or efficiency of a new type of grid equipment or demand response program. CAPMS developed and demonstrated a new type of security system, one that operators can configure with policies to respond automatically when it detects cyber-intrusions. As such, there are no measurements to report and summarize that one might normally consider "data". However, the project did record several simulated data points. The data historian recorded the measurements from our two PMUs, attached to the grid model simulated by RTDS. SCE recorded the AC frequency at each PMU, and for each A, B, and C phase at each PMU, SCE recorded the voltage magnitude and phase angle as shown in Figure 6: PMU Data Points.

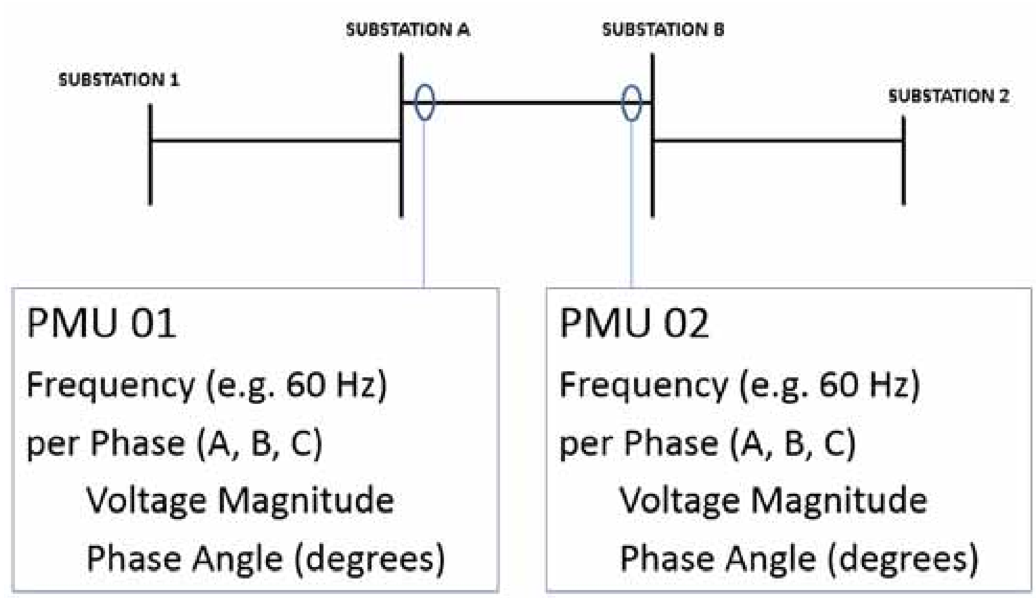

Figure 6: PMU Data Points

In addition to the data points measured directly by the PMUs, the project created several additional data points used to demonstrate inputs and outputs to and from CAPMS, as listed in the table below. The project created similar points for substation B and PMU 2.

POINTID	Type	LOCATION	I/O	Values
CAPMS.CALCSERV.PFL	Power Flow (from Phasors)	LINE		Analog (Current)
CAPMS.UNIVSERV.PFLABNML	Power Flow Abnormal	LINE	Input	0 = No, 1 = Yes
CAPMS.UNIVSERV.SUBAWORK	Scheduled Work	SUB A	Input	0 = No, 1 = Yes
CAPMS.UNIVSERV.SUBAPACC	Physical Access Alarm	SUB A	Input	0 = No, 1 = Yes
CAPMS.UNIVSERV.SUBANACC	Network Access Alarm	SUB A	Input	0 = No, 1 = Yes
CAPMS.UNIVSERV.SUBAPHYS	Physical Alert State	SUB A	Output	0 = Normal, 1 = Warning, 2 = Alarm
CAPMS.UNIVSERV.SUBACYBR	Cyber Alert State	SUB A	Output	0 = Normal, 1 = Warning, 2 = Alarm
CAPMS.UNIVSERV.PMU1CMBD	Combined Alert State	PMU 1	Output	0 = Normal, 1 = Warning, 2 = Alarm

Figure 8 shows a graph of a typical attack flow. There is no work scheduled, and the simulated attacker triggers the physical access alarm at substation A. This raises the substation alert state to “warning”. The attacker then modifies the configuration of the PMU to map one of the phases to a null input, effectively reducing the calculated power flow by one third (from 521 kW to around 350). This triggers the “power flow abnormal" point, meant to simulate a validation that a state estimator could produce, flagging measurements that don't seem to fit with the other observed points. Figure 7 shows a graph of the calculated power flow on the line during a simulated attack, including the "PFLABML" calculated point. Note that the blue "Power Flow" line uses the axis on the left (kW) whereas the red "Suspect Readings" line uses the axis on the right. (0 = No, 1 = Yes)

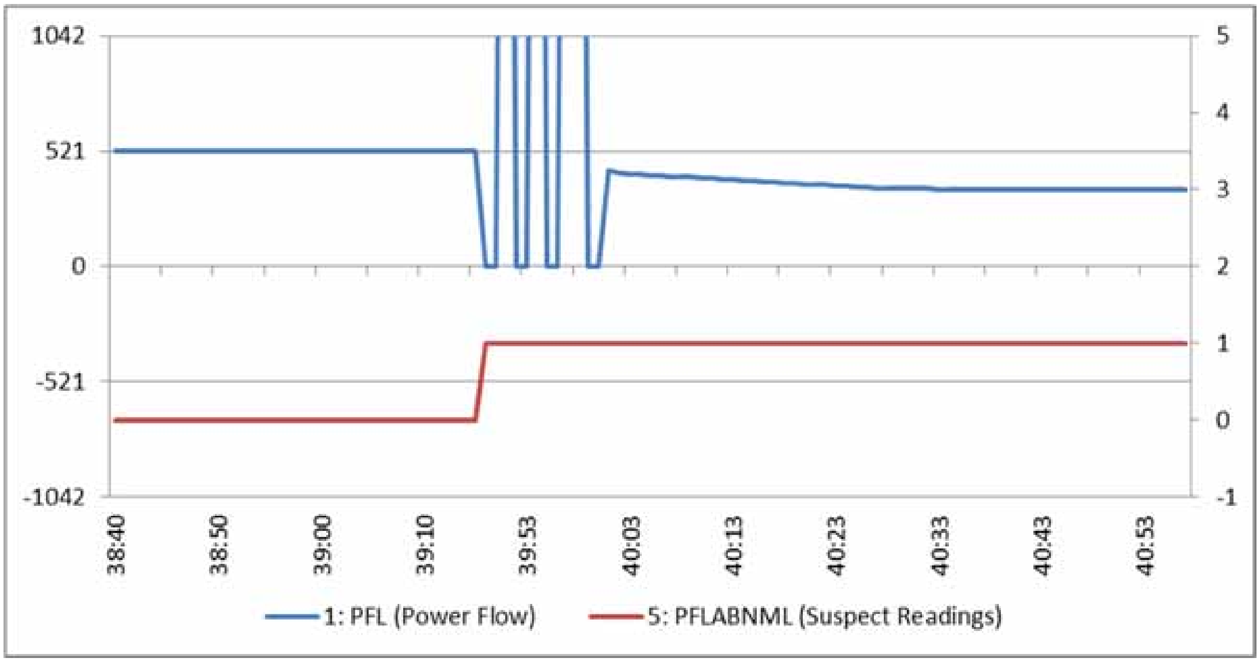

Figure 7: Simulated Power Flow during Configuration Attack

When CAPMS receives the "PFLABNML = 1" event, it raises the substation alert state (SUBAPHYS) to "alarm".

	38:36	38:37	38:42	38:43	38:44	39:18	39:19	39:40	39:41	40:26
8: PMU1CMBD (Device Alert State)	0							0	1	1
7: SUBAPHYS (Physical Alert State)	0			0	1			1	2	2
5: PFLABNML (Suspect Readings)	0					0	1			1
4: SUBAPACC (Physical Access)	0		0	1						1
2: SUBAWORK (Work Scheduled)	1	0								0

Figure 8: Demo Data Points Graph

The CAPMS output alert state points escalate from normal (0) to warning (1) and finally alarm (2) as the attack progresses, resulting in visible indicators on a simulated grid operator screen as shown in Figure 9.

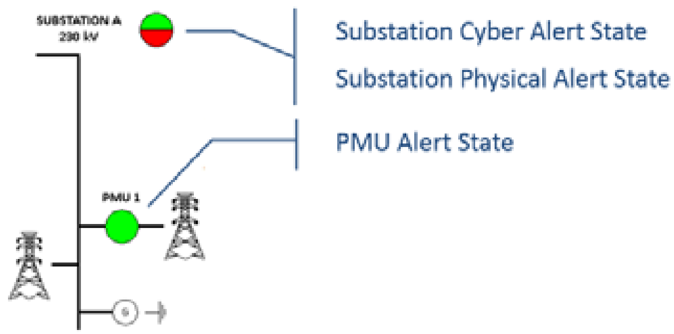

Figure 9: Simulated Grid Operator View with CAPMS Indicators

4.2 Findings

It seems likely that an auto-response policy management system could be effective in preventing and containing attacks. However, there are some potential hurdles that implementers must clear in order to deliver a cost-effective system to the industry.

4.2.1 Value

The value provided to a utility by CAPMS is more than just directly detecting and reacting to a cyber-attack. While this is the primary purpose of CAPMS, there are other potential benefits.

Preventing Operator Error

A cybersecurity system aware of system states could prevent operating errors by alerting Grid Operators that observed power system data within or utilized by an operational application may not be reflective of actual grid conditions. This is especially valuable given that in many cases, operators use power system data to make grid level decisions.

Human Performance Events

The system could detect human performance events, such as a failure to follow an approved process or procedure. Over time, this will improve consistency and adherence to procedures.

System Health Awareness

Such a system can increase awareness of the overall health of the applications, devices, and communications infrastructure utilized for grid operations. Knowing this will allow operators to avoid making changes that could weaken the system when it is in a weakened state.

4.2.2 Challenges

Deployment of CAPMS in an operational environment is not without its challenges.

Policy Definition

Automated responses require definition and integration at each deployment site, potentially requiring significant configuration and custom development effort. It is possible to develop policies that could be re-used, but it will be difficult to balance flexibility, stability, and cost-effectiveness.

Integration

Each deployment of the system must configure not only the policies, but also the inputs and outputs to those policies, with a potentially different set of systems. At this point, these interfaces are not well defined enough to be reusable, which could cause difficulties with maintaining them.

Operator Trust

The operators of the system will not immediately trust the system to make the right response decisions. They will want to understand and be involved in the definition of the policies, and they will want the ability to see the contributing inputs and be able to approve recommended actions before allowing automatic action. The system does include the ability to configure actions to require operator approval, as shown in Figure 10 below. Still, this could slow down response times until the system is tuned and trusted to react automatically.

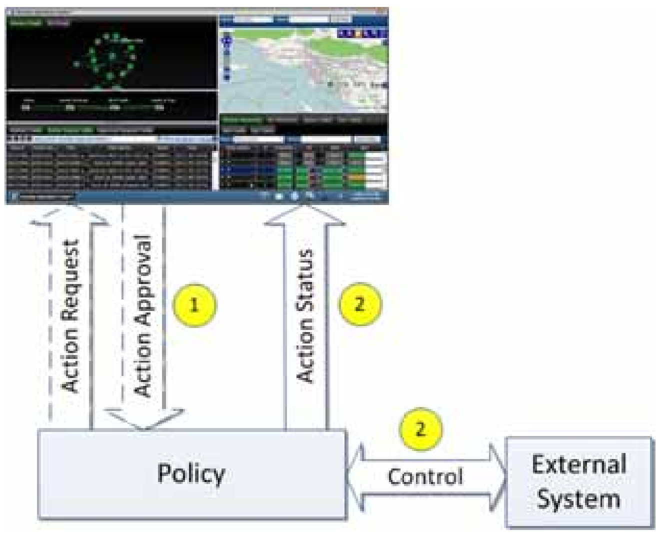

Figure 10: Operator Response Approval Flow

Scalability

The demonstration project implemented a simple policy at a single location. It is likely that management of large numbers of policies at thousands of locations will be difficult. Also, with a large deployment, the policy engine processing would probably need changes to be massively scalable.

Applicability

The system uses openly specified cybersecurity protocols, however most components do not implement them directly. CCS has agents that allow for the protection of Unix/Linux, Windows, and embedded systems, as well as hardware options for terminating protected channels. The protected endpoints do require IP communications.

4.3 Special Implementation Issues

4.3.1 System Integration Challenges

Adapters

Described in the communications architecture of CAPMS, third party adapters can greatly increase the capabilities of a CAPMS policy, benefitting both sensor and response functions. These third party services may provide both sensing and actuation functions. However, in order to use these third party services, projects must first create adapters.

These adapters can be a barrier of entry for integration with these third party services. It is most feasible for CAPMS policies to integrate with third party services that have a high level of configurability or plugin support.

An example of a sensor service that provides a high level of configurability is Splunk. The CAPMS project leveraged Splunk's support for real-time alert response, which allows for the execution of a script that enables the communication of Splunk-detected events to a CAPMS policy.

An example of an actuation service that provides a high level of configurability is the data historian, eDNA. This product allowed custom interfaces to be constructed that responded to CAPMS policy inputs.

Such configurability features are very important for enabling the use of a CAPMS policy. Services that do not have such integration capabilities can be a barrier from a CAPMS, requiring vendors or project teams to develop integrations with CAPMS policies.

The flexibility of the CAPMS policies in allowing for multiple interfaces does help to mitigate this as a potential issue.

4.3.2 Bayesian Modeling

Selecting Accurate Bayesian Probabilities in Correlative Models

The CAPMS approach describes a Bayesian model for interrelating conditions (both detectable and undetectable). These models accept input events from CAPMS sensors. These models treat these input events as evidence, which allows arrival at conditions that may require multiple inputs to determine whether they have occurred.

The diagram below shows an example of a correlated model in which the system uses the evidence to determine higher-order states.

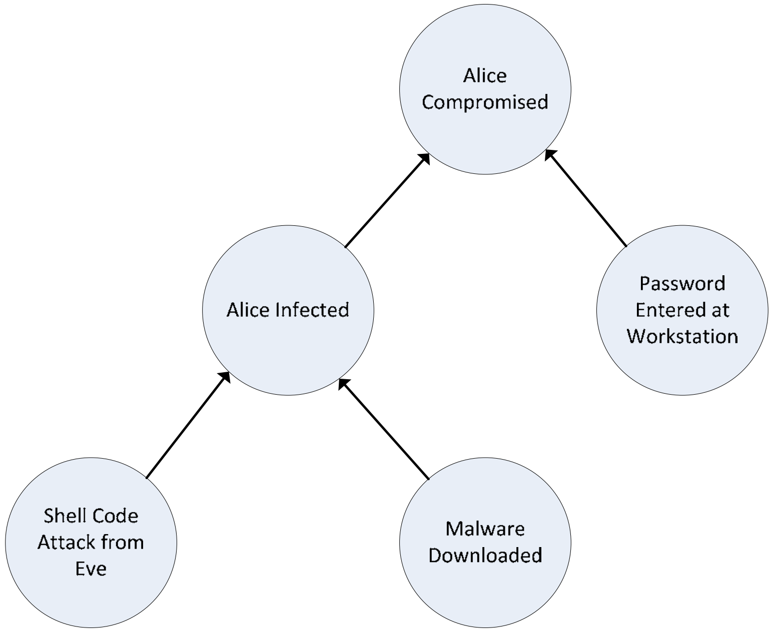

Figure 11 Bayesian Network of Attack Tree

As an example, consider the attack tree converted into the Bayesian network in Figure 11.

- S = "Shell Code Attack from Eve"
- M = "Malware Downloaded"
- W = "Password Entered at Workstation"
- I = "Alice Infected"
- C = "Alice Compromised"

Then SCE needs to define conditional probability tables for the non-leaf nodes, "I" and "C", based on their children. SCE might have the probability tables in Table 1.

Table 1 Conditional Probability Tables for I (above) and C (below)

S	M	P(I = true |S, M)	P(I = false |S, M)
true	true	0.97	0.03
true	false	0.66	0.34
false	true	0.57	0.43
false	false	0.11	0.89

I	W	P(C = true |I, W)	P(C = false |I, W)
true	true	0.82	0.18
true	false	0.60	0.40
false	true	0.48	0.52
false	false	0.14	0.86

Someone with knowledge of the relationship between goals should initialize these probability tables. In the event that this is impossible or impractical, SCE can try training our model with data that is representative of the state of the system. In the worst case, SCE can initialize our conditional probability tables as truth tables for the gates they may represent and use the Bayesian learning to get estimates that are more accurate.

This can prove to be a challenging element of the use of CAPMS policies. There are a few mitigations for this issue, described in the sections below.

Selection of Simple Probability Tables

The probabilities that the CAPMS project demonstrated upon completion are an example of this approach. CAPMS policies allow for the use of AND and OR logical behaviors so that complex conditional probability tables do not need to be crafted for simple conditions. This simple logic covers more conditions than one may expect.

For example, if CAPMS should enact a response in a condition where there is both a motion sensor detected and a login event, this does not need more complex probability tables for correlating these two conditions.

The use of a hybrid model that combines both simple Boolean logic with more complex probability calculations (when needed) helps to reduce the amount of work needed when assigning probabilities to a CAPMS policy. The approaches described in the sections that follow can aid the determination of these probability tables.

Collection of Data Which Influences Probabilities

The CAPMS platform has focused most of its efforts on the identification of key threats as well as the design of a system that allows for correlated modeling and responses. One of the potential areas for follow-on work would be the investigation of how to better model correlated events. Data that could influence the CAPMS work include:

- Forensics analysis of previous attacks
- Input from domain experts
- Simulation and modeling of attacks on a system reflective of the environment in which a CAPMS policy must reside

Incremental Refinement of Probabilities

CAPMS policies allow for configurable attributes. Conditional probability tables that inform the Bayesian networks may be included in these configurable attributes. This allows a policy to be reused and refined over time without going back to the original developer of the security policy for resubmission.

Operators of a security policy may need to modify these conditional probability tables after observation and testing of a policy. These operators may make an educated determination that a policy's decision is not arriving at the correct conclusions and may modify these conditional probability tables as a way to influence the decision-making. For example, if the "Shellcode Downloaded from Eve" condition described above is incorrectly causing the policy to conclude strongly that Alice is infected, when Alice is known to not be infected, then this is feedback into the behavior of the policy.

4.3.3 Issues with Representing Attack Trees as Bayesian Networks

There is also potential interest in using Bayesian networks for representation of attack trees described in NESCOR[1]. Consider how the With the OR gate, it is straightforward to have the two lower goals feed into the higher goal separately. However, with the AND gate this technique does not necessarily preserve the relationship between the two lower goals. For instance, in this case the AND is used because SCE expects that both “Shell Code Attack from Eve” and “Malware Downloaded” must happen in order for “Alice Infected” to happen. This is because there is some relationship between the two lower goals. It would violate the assumptions of the Bayesian network that “Shell Code Attack from Eve” and “Malware Downloaded” are independent events, when in reality, the fact that one has happened likely indicates that the other has happened or will happen since the attacker is likely trying to cause “Alice Infected.”

Depending on the specific events, it may make more sense to use the network on the left of Figure 12. In this way, SCE represents that “Shell Code Attack from Eve” could lead to “Malware Downloaded” which would then lead to “Alice Infected.” It also captures that “Shell Code Attack from Eve” by itself might be an indication of “Alice Infected” even without evidence of “Malware Downloaded.”

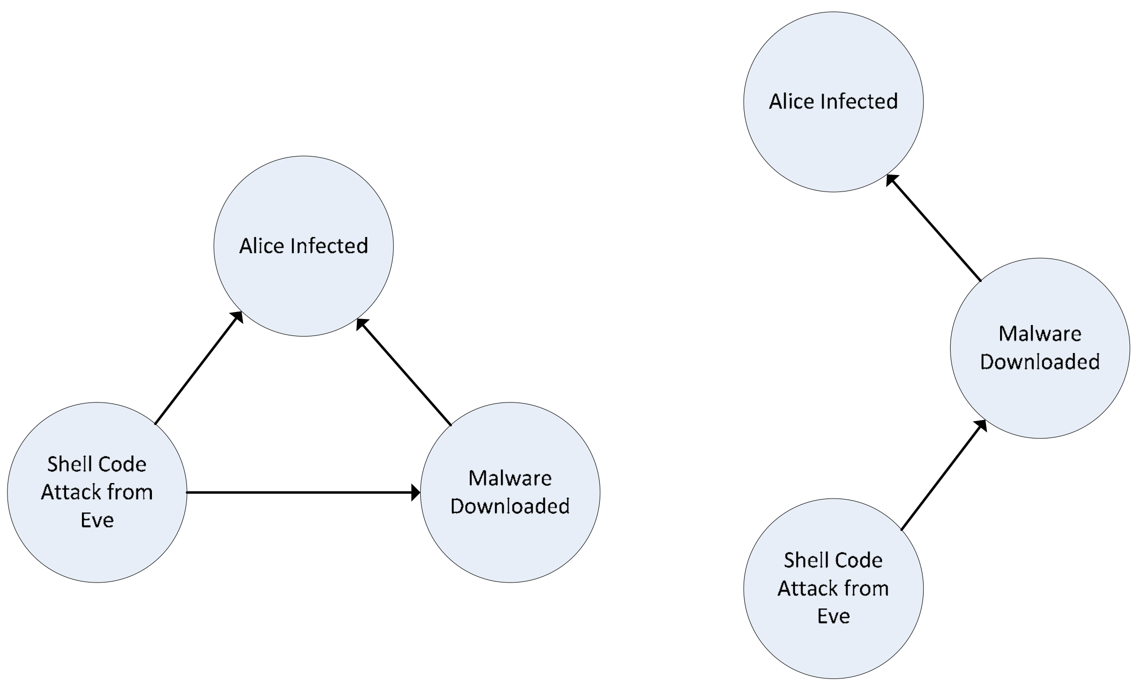

Figure 12 Two Options for Converting an AND Gate

If SCE wants to maintain a tree structure in our Bayesian network, SCE could use the network on the right of Figure 12. This method is proposed in (Qin & Lee, 2004). This preserves the assumption that “Shell Code Attack from Eve” would be a precursor to “Malware Downloaded.” It does not completely lose the benefit of having “Shell Code Attack from Eve” influence “Alice Infected” because if “Shell Code Attack from Eve” is

[1] http://smartgrid.epri.com/NESCOR.aspx

detected, this will increase the confidence that “Malware Downloaded” has happened, even if it is not detected, which will in turn raise the confidence that “Alice Infected” is true.

Preserving the tree structure keeps the representation simpler and allows for faster algorithm performance. Nevertheless, the more the Bayesian network reflects the causal relationships in reality, the more accurately it will predict the state of the system. The main issue with this method is that “Malware Downloaded” can block information passing from “Shell Code Attack from Eve” to “Alice Infected.” For example, if SCE knows that “Malware Downloaded” = true, then knowing anything about “Shell Code Attack from Eve” will not affect our belief about “Alice Infected.” This is because the probability table for “Alice Infected” only depends on “Malware Downloaded.” This does not respect the interpretation of an AND gate which should depend on both inputs.

4.4 Principles and Value Proposition

The security of communications is a fundamental underlying technology required for many advanced functions, so the CAPMS project contributes either directly or indirectly to all of the primary EPIC principles. It provides savings over typical solutions by placing cybersecurity primarily in the network infrastructure. This allows multiple grid devices and systems to reuse the network and security features, reducing the cost of communicating equipment and improving overall security and manageability. An effective cybersecurity solution will also provide greater reliability of the electric grid, since it will be able to proactively identify and neutralize threats before they can affect grid components.

Several of the secondary EPIC principles promote implementation of distributed resources programs such as solar, wind, energy storage, demand response, and electric vehicle charging. These programs require secure automated communication of regional forecasts and constraints, directly or indirectly specifying when to increase or decrease load and generation in order to balance supply with demand. Many of these programs will need to communicate with customer and third party energy services provider systems, and while they probably won’t use the same protections and defenses as internal systems, identification and correlation of threats may still be possible and beneficial.

4.5 Technology Transfer Plans

The results of this research show that there are a number of potential benefits to distributed security policies and auto-response to cyber-intrusions identified using correlation of sensor-based events. Future projects at SCE may use these results to inform requirements development for enhanced distributed resources management systems and other future projects. The technology meets several grid security objectives and design characteristics listed below.

- Support new and existing equipment
- Comply with standards and facilitate interoperability
- Implement common services architecture to support reuse
- Support multi-level security and dynamic trust boundary definition
- Provide ability to define automatic response to contain coordinated attacks

The project included a demonstration at SCE as well as one at Duke Energy. The Duke demonstration uses the same TNP foundation, and used much of the same CAPMS code. This helped project teams to identify and distinguish base functionality from configuration and custom code. Effective design and clear delineation of these boundaries should enable more widespread use and deployment of the technology, allowing for more potential savings due to economy of scale.

4.6 EPIC Metrics

D.13-11-025, Attachment 4. List of Proposed Metrics and Potential Areas of Measurement (as applicable to a specific project or investment area in applied research, technology demonstration, and market facilitation)	
5. Safety, Power Quality, and Reliability (Equipment, Electricity System)	
a. Outage number, frequency and duration reductions	See 4.6.1
7. Identification of barriers or issues resolved that prevented widespread deployment of technology or strategy	
b. Increased use of cost-effective digital information and control technology to improve reliability, security, and efficiency of the electric grid (PU Code § 8360)	See 4.6.2
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)	See 4.6.2
l. Identification and lowering of unreasonable or unnecessary barriers to adoption of smart grid technologies, practices, and services (PU Code § 8360)	See 4.6.2
8. Effectiveness of information dissemination	
b. Number of reports and fact sheets published online	See 4.6.3
d. Number of information sharing forums held.	See 4.6.3
f. Technology transfer	See 4.5
10. Reduced ratepayer project costs through external funding or contributions for EPIC-funded research on technologies or strategies	
a. Description or documentation of funding or contributions committed by others	See 4.6.4
c. Dollar value of funding or contributions committed by others.	See 4.6.4

4.6.1 Outage Reduction

A system such as CAPMS will help to prevent or reduce duration of outages caused by cyber and physical attacks, as well as other types of unplanned outages. It is difficult to estimate how large of an impact it might have, since it depends heavily on the depth of integration and configuration (how accurately and quickly it can identify attacks and other problems) and how many attacks or other problems occur, and how severe and extensive they are.

Risk evaluation methodologies can be applied to demonstrate the impact of CAPMS on reducing outages. Traditionally, risk is the product of an event's probability and the consequence of that event.

$$R = P * C$$

Previous academic work has developed methods to quantify expected losses in an attack to better evaluate various benefit options (Carlson, Rutnquist, & Nozick, 2004) and decompose the elements of probability in a manner that is appropriate to control systems (McQueen, Boyer, Flynn, & Beitel, 2006). This second paper characterizes the total probability as a product of conditional probabilities:

$P = P_1 * P_2 * P_3 * P_4 * P_5$ where

P_1 = the probability the system is on an attacker target list

P_2 = probability of being attacked given that the system is targeted

P_3 = probability of a perimeter breach given that the system is attacked

P_4 = probability of a successful attack given that there was a perimeter breach

P_5 = probability of damage given that the system was successfully attacked

Estimating the above probabilities is difficult and outside the scope of the project as is an impact analysis of the consequence of a successful attack. The above formulation does show where CAPMS can reduce the total risk by reducing the last three probabilities. Probabilities P_1 and P_2 are outside the scope of CAPMS and are generally addressed by maintaining a private network with a clear separation from the Internet.

4.6.2 Smart Devices

Utilities have traditionally preferred dedicated private connections for electronic communications with field equipment. Internet technologies offer an opportunity to reduce the cost of "smart" equipment by using routable protocols over virtual private network connections shared by multiple devices. However, cybersecurity systems must protect those communications from unauthorized access. Traditional public key infrastructure (PKI) technologies can manage this aspect, but if an attacker gains control of valid credentials, or finds an unprotected access point, operators need another layer of security to automatically detect and respond to these attacks in a timely manner. Operators must also be aware of cyber-threats that could alter their view of the grid, in order to prevent responses to false readings. CAPMS provides this higher-level of decision logic and automation, making smart grid and other communicating equipment safe and reliable.

4.6.3 Information Dissemination

Reports and Fact Sheets Published Online

1. **ViaSat Project Award Press Release**
   https://www.viasat.com/news/us-department-energy-award-funds-infrastructure-cybersecurity-development-viasat-and-two-major
2. **Interactive Energy Roadmap Project Effort Overview**
   https://www.controlsystemsroadmap.net/Efforts/Pages/CAPMS.aspx
3. **ieRoadmap Project Description Peer Review Slides**
   https://www.controlsystemsroadmap.net/ieRoadmap%20Documents/ViaSat-CAPMS-CEDS_Peer_Review_2014.pdf
4. **DoE CAPMS Flyer**
   https://www.controlsystemsroadmap.net/ieRoadmap%20Documents/CAPMS_flyer.pdf
5. **ICS SANS Institute Demonstration Slides**
   https://files.sans.org/summit/ics2015/PDFs/Live_ICS_Attack_Demo.pdf
6. **ICS Security Summit CAPMS Demo Video**
   https://www.youtube.com/watch?v=tZDDALpI_yo

Information Sharing Forums Held

1. **10th Annual ICS Security Summit CAPMS Demonstration**
   Orlando, FL | Sunday, Feb 22, 2015 - Mon, Mar 2, 2015
2. **CAPMS SCE Demonstration**
   Westminster, CA | Thursday, Sep 24, 2015
3. **CAPMS Duke Demonstration**
   Charlotte, NC | Tuesday, Sep 29, 2015

4.6.4 Reduced Ratepayer Project Costs

The CAPMS project received half of its funding from a DOE grant. Duke Energy committed approximately $1.2M, and the DOE committed approximately $3M to the overall CAPMS project.

5 Appendices

A. WAMPAC Failure Modes Matrix

				Informational impact of attack				
Failure ID	Attack Target (Funtional)	Attack Type	Possible Result/Failure Mode	Distort	Disrupt	Destruct	Disclosure	Discovery
T1	Network Time Distribution	Spoofing NTP/SNTP server	Clock error within C37.118 server	X				
T2	Network Time Distribution	Spoofing NTP/SNTP server	Clock error within PDC or Phasor Gateway	X	X			
T3	Network Time Distribution	DoS attack on NTP/SNTP server	C37.118 server reverts to alternate time source		X			
T4	Network Time Distribution	DoS attack on NTP/SNTP server	C37.118 server reverts to internal clock		X			
T5	IRIG-B Time Distribution	Substituting/Spoofing IRIG-B input	PMU clock error	X				
T6	IRIG-B Time Distribution	Disrupting IRIG-B input	PMU reverts to internal clock		X			
T7	GPS Signal Reception	GPS jamming	PMU or PDC reverts to internal clock		X			
T8	GPS Signal Reception	GPS spoofing	Clock error within C37.118 server	X				
T9	GPS Signal Reception	GPS spoofing	Clock error within PDC or Phasor Gateway	X	X			
T10	GPS Receiver	Unauthorized configuration change	Clock error within C37.118 server	X				
T11	GPS Receiver	Unauthorized configuration change	Clock error within PDC or Phasor Gateway	X	X			
AL1	C37.118	Spoofing C37.118 server	False data stream transmitted to upstream C37.118 client	X				
AL2	C37.118	Spoofing C37.118 server	False configuration or header message transmitted to upstream C37.118 client	X				
AL3	C37.118	Spoofing C37.118 client	C37.118 server data stream redirected to imposter		X			
AL4	C37.118	Spoofing C37.118 client	Spoofed C37.118 client starts/stops PMU data stream		X			
AL5	C37.118	Man-In-The-Middle	Monitoring/eavesdropping of messages (header/configuration/data stream) from C37.118 server to C37.118 client				X	
AL6	C37.118	Man-In-The-Middle	altered configuration or header message sent to upstream C37.118 client	X				
AL7	C37.118	Man-In-The-Middle	altered data stream sent to upstream C37.118 client	X				
AL8	C37.118	Fuzzing C37.118 protocol	Abnormal behavior or termination of the application on target device		X			
AL9	C37.118	Unauthorized/rouge C37.118 client	Command message from unauthorized C37.118 client starts/stops PMU data stream		X			
N1	Network Infrastructure	Flooding (DoS)	Delayed receipt of data stream by upstream C37.118 client		X			
N2	Network Infrastructure	Flooding (DoS)	Message exchange interupted between C37.118 client and server		X			
N3	Network Infrastructure	ARP spoofing	Message exchange interupted between C37.118 client and server		X			
H1	Network Interface (NIC)	DoS	Device unable to access network		X			
H2	Network Interface (NIC)	DoS	Abnormal behavior or termination of the application		X			
H3	Network Interface (NIC)	Port scanning	Open logical network interface to device discovered (e.g. ftp, telnet, http, etc.)					X
H4	Firmware/OS	Malware	Device utilized to gain access to other protected network resources					X
H5	Firmware/OS	Malware	Unexpected behavior of device		X			
H6	Configuration	configuration	Phasor data within data stream incorrect	X				
H7	Configuration	configuration	Mismatch between header/configuration messages and phasor data within data stream	X				
H8	Database	uauthorized database access	Archieved/historical data modified	X				
H9	Database	uauthorized database access	Archieved/historical data deleted			X		

B. WAMPAC Attack Scenario Matrix

Scenario ID	Associated Failure ID	Attack Category	Attack Target (Funtional)	Attack Type	Possible Result/Failure Mode	Possibe Attack Scenario	DFR/PMU	GPS (Substation)	USI Master	PDC	GPS (Control Center)	Historian	Phasor Gateway	Network
1	T1	Timing	Network Time Distribution	Spoofing NTP/SNTP server	Clock error within C37.118 server	Spoofed NTP/SNTP server creates clock error in PMU	x	x						
2	T2	Timing	Network Time Distribution	Spoofing NTP/SNTP server	Clock error within PDC or Phasor Gateway	Spoofed NTP/SNTP server creates clock error in PDC and causes waiting period violation for incoming data stream(s)				x	x			
3	T3	Timing	Network Time Distribution	DoS attack on NTP/SNTP server	C37.118 server reverts to alternate time source	Unavailable NTP/SNTP server causes PMU to revert to alternate time source	x	x						
4	T3	Timing	Network Time Distribution	DoS attack on NTP/SNTP server	C37.118 server reverts to alternate time source	Unavailable NTP/SNTP server causes PDC to revert to alternate time source				x	x			
5	T4	Timing	Network Time Distribution	DoS attack on NTP/SNTP server	C37.118 server reverts to internal clock	Unavailable NTP/SNTP server(s) cause PMU to revert to internal clock	x	x						
6	T4	Timing	Network Time Distribution	DoS attack on NTP/SNTP server	C37.118 server reverts to internal clock	Unavailable NTP/SNTP server(s) cause PDC to revert to internal clock				x	x			
7	T5	Timing	IRIG-B Time Distribution	Substituting/Spoofing IRIG-B input	PMU clock error	Rouge IRIG-B source connected to DFR/PMU creates clock error	x	x						
8	T6	Timing	IRIG-B Time Distribution	Disrupting IRIG-B input	PMU reverts to internal clock	Interuption of IRIG-B signal input causes DFR/PMU to revert to internal clock.	x	x						
9	T7	Timing	GPS Signal Reception	GPS jamming	C37.118 server reverts to internal clock	Error in the IRIG-B output of the GPS receiver causes PMU to revert to internal clock	x	x						
10	T7	Timing	GPS Signal Reception	GPS jamming	C37.118 server reverts to internal clock	Error in the NTP/SNTP output of the GPS receiver causes PDC to revert to internal clock				x	x			
11	T8	Timing	GPS Signal Reception	GPS spoofing	Clock error within C37.118 server	Spoofed GPS signal creates clock error GPS and PMU	x	x						
12	T9	Timing	GPS Signal Reception	GPS spoofing	Clock error within PDC or Phasor Gateway	Spoofed GPS signal creates clock error in PDC and causes waiting period violation for incoming data stream(s)				x	x			
13	T10	Timing	GPS Receiver	Unauthorized configuration change	Clock error within C37.118 server	Erroneous IRIG-B output of GPS receiver creates clock error in DFR/PMU	x	x						
14	T11	Timing	GPS Receiver	Unauthorized configuration change	Clock error within PDC or Phasor Gateway	Erroneous NTP/SNTP output of GPS receiver creates clock error in PDC and causes waiting period violation for incoming data stream(s)				x	x			
15	AL1	Application Layer	C37.118	Spoofing C37.118 server	False data stream transmitted to upstream C37.118 client	Spoofed PMU (C37.118 server) transmits incorrect data to PDC (C37.118 client)	x			x				
16	AL1	Application Layer	C37.119	Spoofing C37.118 server	False data stream transmitted to upstream C37.118 client	Spoofed PDC (C37.118 server) transmits incorrect data to Historian (C37.118 client)				x		x		
17	AL1	Application Layer	C37.120	Spoofing C37.118 server	False data stream transmitted to upstream C37.118 client	Spoofed PDC (C37.118 server) transmits incorrect data to Gateway (C37.118 client)				x			x	
18	AL1	Application Layer	C37.121	Spoofing C37.118 server	False data stream transmitted to upstream C37.118 client	Spoofed Phasor Gateway (C37.118 server) transmits incorrect data to external entity (C37.118 cleint)								
19	AL2	Application Layer	C37.118	Spoofing C37.118 server	False configuration or header message transmitted to upstream C37.118 client	Spoofed PMU (C37.118 server) transmits incorrect header or configuration to PDC (C37.118 client)	x			x				
20	AL2	Application Layer	C37.119	Spoofing C37.118 server	False configuration or header message transmitted to upstream C37.118 client	Spoofed PDC (C37.118 server) transmits incorrect header or configuration to Historian (C37.118 client)				x		x		
21	AL2	Application Layer	C37.120	Spoofing C37.118 server	False configuration or header message transmitted to upstream C37.118 client	Spoofed PDC (C37.118 server) transmits incorrect header or configuration to Phasor Gateway (C37.118 client)				x			x	
22	AL2	Application Layer	C37.121	Spoofing C37.118 server	False configuration or header message transmitted to upstream C37.118 client	Spoofed Phasor Gateway (C37.118 server) transmits incorrect header to external entity (C37.118 client)								
23	AL3	Application Layer	C37.118	Spoofing C37.118 client	C37.118 server data stream rediriected to imposter	Spoofed PDC (C37.118 client) intercepts data stream from PMU (C37.118 server)	x			x				
24	AL4	Application Layer	C37.118	Spoofing C37.118 client	Spoofed C37.118 client starts/stops PMU data stream	Spoofed PDC (C37.118 client) sends command message to stop data stream from PMU (C37.118 server) to authorized PDC	x			x				
25	AL5	Application Layer	C37.118	Man-In-The-Middle	Monitoring/eavesdropping of messages (header/configuration/data stream) from C37.118 server to C37.118 client	Unauthorized device monitors data stream between PMU and PDC and provides power system data to an unauthorized party.	x			x				
26	AL6	Application Layer	C37.118	Man-In-The-Middle	altered configuration or header message sent to upstream C37.118 client	Unauthorized device intercepts and alters the configuration frame from PMU to PDC.	x			x				
27	AL7	Application Layer	C37.118	Man-In-The-Middle	altered data stream sent to upstream C37.118 client	Unauthorized device intercepts and alters the data frame from PMU to PDC.	x			x				
28	AL8	Application Layer	C37.118	Fuzzing C37.118 protocol	Abnormal behavior or termination of the application on target device	Spoofed PMU (C37.118 server) sends malformed C37.118 data frames to PDC (C37.118 client)	x			x				
29	AL8	Application Layer	C37.119	Fuzzing C37.118 protocol	Abnormal behavior or termination of the application on target device	Spoofed PMU (C37.118 server) sends malformed C37.118 configuration frames to PDC (C37.118 client)	x			x				
30	AL9	Application Layer	C37.118	Unauthorized/rouge C37.118 client	Unauthorized C37.118 client starts/stops PMU data stream	Unauthorized C37.118 client sends command message to stop data stream from PMU to PDC	x			x				
31	N1	Network	Network Infrastructure	Flooding (DoS)	Delayed receipt of data stream by upstream C37.118 client	Unauthorized device degrades network performance by flooding the network with excessive data. Data frames sent from the PMU to the PDC are received late.	x			x				x
32	N2	Network	Network Infrastructure	Flooding (DoS)	Message exchange interupted between C37.118 client and server	Unauthorized device degrades network performance by flooding the network with excessive data. Data frames sent from the PMU to the PDC are interupted.	x			x				x
33	N3	Network	Network Infrastructure	ARP spoofing	Message exchange interupted between C37.118 client and server	Unauthorized device executes ARP spoofing attack causing data frames sent from the PMU to the PDC to be redirected to new target.	x			x				x
34	H1	Host	Network Interface (NIC)	DoS	Device unable to access network	Unauthorized device perfroms D0S attack on external interface of the Phasor Gateway.							x	
35	H1	Host	Network Interface (NIC)	DoS	Device unable to access network	Unauthorized device perfroms D0S attack on PDC.				x				
36	H1	Host	Network Interface (NIC)	DoS	Device unable to access network	Unauthorized device perfroms D0S attack onDFR/PMU.	x							
37	H2	Host	Network Interface (NIC)	DoS	Abnormal behavior or termination of the application	Unauthorized device performs D0S attack on PMU resulting in PMU malfunction	x							
38	H3	Host	Network Interface (NIC)	Port scanning	Open logical network interface to device discovered (e.g. ftp, telnet, http, etc.)	Unauthorized device perfroms port scan against DFR/PMU and gains access to DFR/PMU via open port.	x							
39	H3	Host	Network Interface (NIC)	Port scanning	Open logical network interface to device discovered (e.g. ftp, telnet, http, etc.)	Unauthorized device perfroms port scan on external interface of the Phasor Gateway and gains access to Phasor Gateway via open port.							x	
40	H3	Host	Network Interface (NIC)	Port scanning	Open logical network interface to device discovered (e.g. ftp, telnet, http, etc.)	Unauthorized device perfroms port scan against the PDC and gains access to PDC via open port.				x				
41	H4	Host	Firmware/OS	Malware	Device utilized to gain access to other protected network resources	Infected test device/laptop spreads malware to DFR/PMU. Malware then utilized to gain access to protected reources on the same network.	x							
42	H4	Host	Firmware/OS	Malware	Device utilized to gain access to other protected network resources	Malware passed to DFR/PMU via USI master	x		x					
43	H4	Host	Firmware/OS	Malware	Device utilized to gain access to other protected network resources	Infected portable USB storage device spreads malware to DFR/PMU. Malware then utilized to gain access to protected resources on the same network.	x							
44	H5	Host	Firmware/OS	Malware	Unexpected behavior of device	Rouge DFR/PMU application software inserted in supply chain to utility.	x							
45	H5	Host	Firmware/OS	Malware	Unexpected behavior of device	Rouge PDC application software inserted in supply chain to utility.					x			
46	H5	Host	Firmware/OS	Malware	Unexpected behavior of device	Rouge Phasor Gateway application software inserted in supply chain to utility.							x	
47	H6	Host	Configuration	configuration	Phasor data within data stream incorrect	Unauthorized party/system changes DFR/PMU configuration (e.g. CT and/or VT ratio's).	x							
48	H6	Host	Configuration	configuration	Phasor data within data stream incorrect	Unauthorized party/system changes DFR/PMU internal clock parameters	x							
49	H6	Host	Configuration	configuration	Phasor data within data stream incorrect	Unauthorized party/system disables DFR/PMU IRIG-B input.								
50	H6	Host	Configuration	configuration	Phasor data within data stream incorrect	Unauthorized party/system changes PDC internal clock parameters				x				
51	H7	Host	Configuration	configuration	Mismatch between header/configuration messages and phasor data within data stream	Unauthorized party/system changes DFR/PMU configuration (e.g. changing phasor identifiers).	x							
52	H8	Host	Database	uauthorized database access	Archieved/historical data modified	Unauthorized party/system gains access to Historian and modifies historical data						x		
53	H9	Host	Database	uauthorized database access	Archieved/historical data deleted	Unauthorized party/system gains access to Historian and deletes historical data						x		

C. Test Plan

Testing Goals

The overall goal of the testing outlined in this test plan is to validate the proof of concept for CAPMS functionality within the context of a utility operational environment. The team built the test plan around an attack scenario selected that represents an unauthorized change to a device configuration, a DFR/PMU unit in this specific case. Within this scenario, the project identified several variants to examine behavior under select conditions as follows:

- Variant 0 - This testing scenario executes the selected attack without CAPMS functionality enabled. This establishes a baseline for typical current monitoring and detection in a utility operational environment.
- Variant 1 - This variation of the testing installs a basic CAPMS policy and executes the selected attack. This demonstrates the basic behavior of the sensor logic and correlation logic within the CAPMS policies.
- Variant 2 - This variation of the test plan involves installing a more advanced CAPMS policy and executing the selected attack. This advanced policy supports complex decisions based on variations in the identified sensors (e.g. attacker physically present at the substation vs. remotely located).
- Variant 3 - This variation involves tuning exercises on the CAPMS policy utilized in variant 2 to optimize performance/effectiveness of the system. In this case, the tuning involved will account for authorized maintenance activities on the DFR/PMU unit. The tuning will take into consideration the subtle differences between an actual attack and authorized activities to accurately detect and react to the first while not inadvertently reacting to the latter.

Furthermore, specific goals during all of these testing variants are to:

- Demonstrate that the additional CAPMS functionality does not negatively impact the current or planned SCE CCS deployment
- Evaluate the CAPMS user interfaces
- Evaluate the dynamic behavior of CAPMS policies as sensor information and other inputs change
- Validate CAPMS ability to correlate inputs and make the proper decisions given the available sensors
- Identify and any unexpected behaviors of the CAPMS functionality that might inadvertently affect system functionality
- Understand how tuning can be utilized to minimize the risk of a false positive detection or reaction within the CAPMS functionality

Test Environment

The Southern California Edison facility consists of a setup depicted in Figure 13.

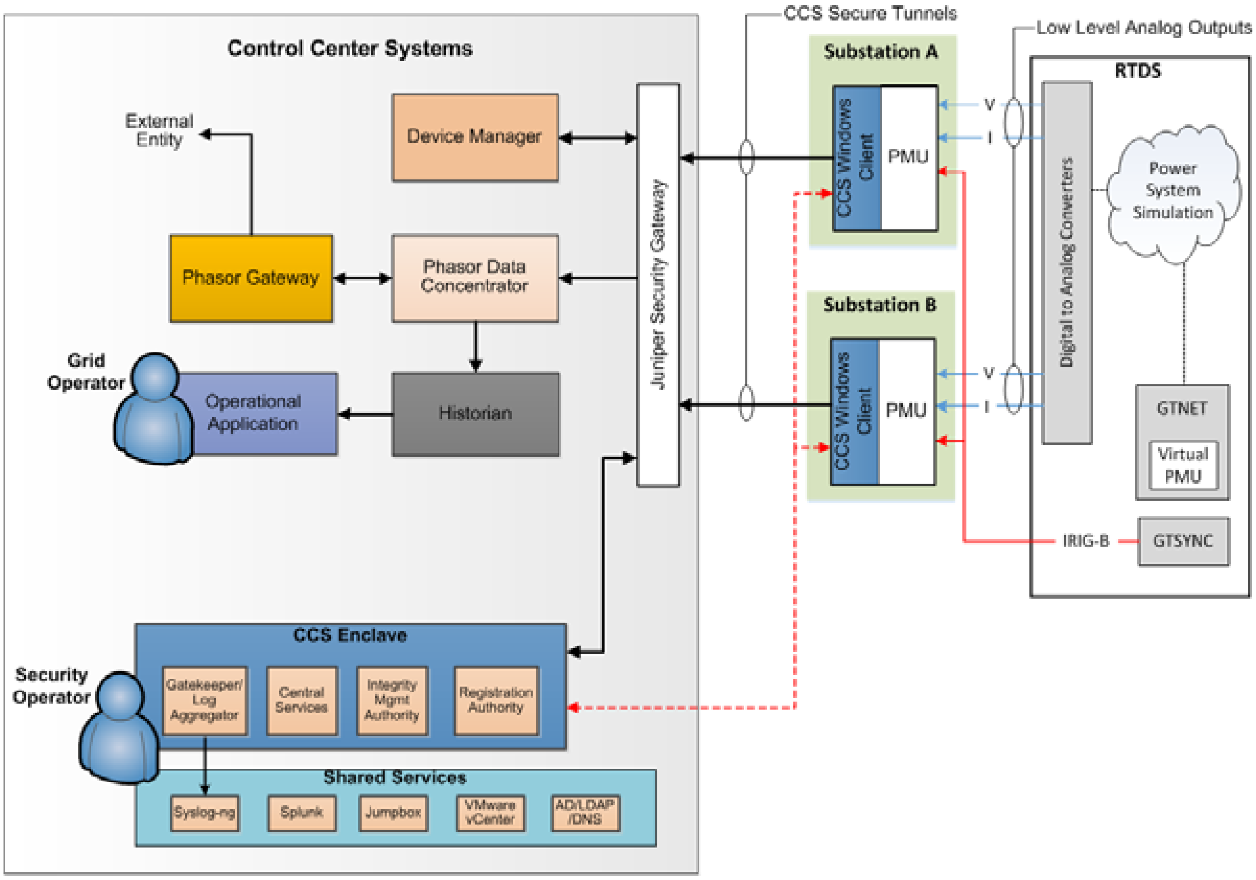

Figure 13: CAPMS ATO Network

This network contains three primary networks:

- Control Center Services – Contains the server-side components for PMU management and aggregation of data (eDNA, ePDC)
- CCS Enclave– Contains the CCS servers for security and policy management.
- Substation Network – This network contains two CCS-enabled Phasor Measurement Units (PMU) connected to the RTDS system.

Application-level communication occurs between each PMU and the Phasor Data Concentrator (ePDC) using the C37.118 protocol, a protocol for exchanging Phasor measurement values. The ePDC aggregates these measurements and sends them on to the eDNA Historian service using the C37.118 protocol. The eDNA Historian service provides the ability to graph and visualize the measurements which have been collected. For the purposes of the CAPMS grant, the eDNA Historian plays the role that an Energy Management System (EMS) or State Estimator (SA) would in a more complete system.

Communication between the PMUs and the ePDC is over a VPN connection provided by CCS, terminating at the edge of the CCS-BACKOFFICE network. Within the CCS-BACKOFFICE network, the CAPMS deep packet inspection (DPI) capabilities perform inspection on the C37.118 protocol traffic, inspecting for data anomalies or significant events.

Detailed attack steps and scenarios may be disclosed under NDA. Contact SCE for more information.

Appendix D

2015 EPIC Annual Report - Project Status Reports Spreadsheet

Investment Program Period	Program Administrator	Project Name	Project Type	A brief description of the project	Date of the award	Was this project awarded in the immediately prior calendar year?	Assignment to Value Chain	Encumbered Funding Amount ($)	Committed Funding Amount ($)	Funds Expended to date: Contract/Grant Amount ($)	Funds Expended to date: In house expenditures ($)	Funds Expended to date: Total Spent to date ($)	Administrative and overhead costs incurred for each project	Leveraged Funds	Partners	Match Funding	Match Funding Split	Funding Mechanism	Intellectual Property	Identification of the method used to grant awards.
1st triennial (2012-2014)	SCE	**Integrated Grid Project** *Note: Previously referred to as Regional Grid Optimization*	Cross-Cutting/Foundational Strategies & Technologies	The project will demonstrate, evaluate, analyze and propose options that address the impacts of DER (Distributed Energy Resources) penetration and increased adoption of DG (Distributed Generation) owned by consumers on all segments/aspects of SCE's grid – transmission, distribution and overall "reliable" power delivery cost to SCE customers (all tiers). This demonstration project is in effect the next step to the ISGD project. Therefore, this analysis will focus on the effects of introducing emerging and innovative technology into the utility and consumer end of the grid, predominantly the commercial and industrial customers with the ability to generate power with self-owned and operated renewable energy sources, but connected to the grid for "reliability" and "stability" operational reasons. This scenario introduces the need for the utility (SCE) to assess discriminative technology necessary for stabilizing the grid with increased DG adoption, and more importantly, consider possible economic models that would help SCE adopt to the changing regulatory policy and GRC structures.	8/15/2012	No	Grid Operation/Market Design	$ 8,859,484	$ 10,000,000	$ 3,427,227	$ 881,185	#REF!	N/A	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 Issued to the Following Vendor(s): @ Business Inc; Battelle Northwest; Black & Veatch Corporation; Bridgewater Consulting Group, Inc; Corepoint 1, Inc; Cyme International T&D Inc; Ixia; Landis & Gyr; Pacific Coast Engineering; Quanta Technology,LLC
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	$ 1,090,100	$ 2,195,000	$ 723,593	$ 91,844	#REF!	N/A	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
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	$ 558,391	$ 1,124,360	$ 563,651	$ 107,580	#REF!	N/A	N/A	N/A	N/A	N/A	Pay-for-Performance Contracts	SCE has no current patents or licensing agreements signed. Future Intellectual Property is to be determined.	Directed Awards Issued to the Following Vendor(s): Battelle Memorial Institute
1st triennial (2012-2014)	SCE	**Beyond the Meter: Customer Device Communications, Unification and Demonstration (Phase II)**	Customer Focused Products and Services	The Beyond the Meter (BTM) project will demonstrate the use of a DER management system to interface with and control DER based on customer and distribution grid use cases. It will also demonstrate the ability to communicate near-real time information on the customer's load management decisions and DER availability to SCE for grid management purposes. Three project objectives include: 1) development of a common set of requirements that support the needs of a variety of stakeholders including customers, distribution management, and customer program; 2) validation of standardized interfaces, functionalities, and architectures required in new Rule 21 proceedings, IOU Implementation Guide, and UL 1741/IEEE 1547 standards; 3) collection and analysis measurement and cost/benefits data in order to inform the design of new tariffs, recommend the deployment of new technologies, and support the development of new programs.	8/15/2012	No	Demand-Side Management	$ 1,781,200	$ 3,300,000	$ 910,171	$ 147,520	#REF!	N/A	N/A	N/A	N/A	N/A	Pay-for-Performance Contracts	SCE has no current patents or licensing agreements signed. Future Intellectual Property is to be determined.	Competitive Bid (Request for Proposals) & Directed Awards Directed Awards Issued to the Following Vendor(s): Autogrid Systems, Inc.; Qualitylogic, Inc.

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	$ 212,837	$ 40,318	$ 24,120	$ 13,151	#REF!	N/A	N/A	N/A	N/A	N/A	Pay-for-Performance Contracts	SCE has no current patents or licensing agreements signed. Future Intellectual Property is to be determined.	Directed Awards Issued to the Following Vendor(s): Doble Engineering Company; General Electric Company; RTDS Technologies Inc.; Schweitzer Engineering Labs Inc.
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	$ 37,875	$ 3,800,000	$ 22,468	$ 204,585	#REF!	N/A	N/A	N/A	N/A	N/A	Pay-for-Performance Contracts	SCE has no current patents or licensing agreements signed. Future Intellectual Property is to be determined.	Directed Awards Issued to the Following Vendor(s): Siemens Industry, Inc; The Mathworks, Inc
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	#REF!	N/A	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
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	$ 7,500	$ 826,571	$ 12,446	$ 27,010	#REF!	N/A	N/A	N/A	N/A	N/A	Pay-for-Performance Contracts	SCE has no current patents or licensing agreements signed. Future Intellectual Property is to be determined.	Directed Awards Issued to the Following Vendor(s): Power World Corporation
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	$ 618,450	$ 975,880	$ 221,511	$ 71,305	#REF!	N/A	N/A	N/A	N/A	N/A	Pay-for-Performance Contracts	SCE has no current patents or licensing agreements signed. Future Intellectual Property is to be determined.	Directed Awards Issued to the Following Vendor(s): V&R Energy Systems Research, Inc.; Siemens Industry, Inc
1st triennial (2012-2014)	SCE	**Distributed Optimized Storage (DOS)**	Energy Resources Integration	This field pilot will demonstrate 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	$ -	$ 4,500,000	$ -	$ 45,853	#REF!	N/A	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
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 Pilot 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 Pilot project will be conducted to understand the feasibility and value of providing smart meter data inputs and enhanced methodology for calculating the Indexes. The Pilot 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	$ 702,436	$ 1,013,803	$ 663,083	$ 315,720	#REF!	N/A	N/A	N/A	N/A	N/A	Pay-for-Performance Contracts	SCE has no current patents or licensing agreements signed. Future Intellectual Property is to be determined.	Directed Awards Issued to the Following Vendor(s): Cyient, Inc.; Nexant Inc

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	$ 909,702	$ 3,999,542	$ 539,532	$ 328,739	#REF!	N/A	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 Quotation) Directed Awards Issued to the Following Vendor(s): ABB Inc; GE Grid Solutions, LLC; General Networks;
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	$ 2,722,697	$ 4,073,758	$ 1,835,677	$ 740,870	#REF!	N/A	N/A	N/A	N/A	N/A	Pay-for-Performance Contracts	SCE has no current patents or licensing agreements signed. Future Intellectual Property is to be determined.	Competitive Bid Directed Awards Issued to the Following Vendor(s): Onesource Supply Solutions, LLC; On-Ramp Wireless, Inc.; Progressive Frame and Fabrication; Schweitzer Engineering Labs Inc; Sentient Energy, Inc.; Wesco Distribution Inc; Southwest Research Institute
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, pilot, 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, pilot 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	$ 24,606	$ 313,315	$ 30,342	$ 38,398	#REF!	N/A	N/A	N/A	N/A	TBD	Pay-for-Performance Contracts	SCE has no current patents or licensing agreements signed. Future Intellectual Property is to be determined.	Directed Awards Issued to the Following Vendor(s): American Restore, Inc.; Rivcomm, Inc.; California Turbo Inc
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	$ 249,970	$ 466,820	$ 382,279	$ 81,334	#REF!	N/A	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): Wesco Distribution Inc; Black & Veatch Corporation
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	$ 1,767,758	$ 1,804,650	$ 1,698,236	$ 106,414	#REF!	N/A	DOE & Duke Energy Contributions: $4,486,430	Viasat; Duke Energy	N/A	N/A	Pay-for-Performance Contracts	SCE has no current patents or licensing agreements signed. Future Intellectual Property is to be determined.	Directed Awards Issued to the Following Vendor(s): @ Business Inc; Magnetic Instrumentation Inc; Saker Systems, LLC; World Wide Technology Inc; Zones, Inc.; Accuvant Inc; Electric Power Group, LLC; Schweitzer Engineering Labs Inc

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	$ -	$ 802,128	$ -	$ 14,693	$ 14,693	$ 1,717	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
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	$ -	$ 366,348	$ -	$ 88,253	$ 88,253	$ 4,324	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
2nd triennial (2015-2017)	SCE	**Proactive Storm Impact Analysis Demonstration**	Grid Modernization and Optimization	This project will demonstrate proactive storm analysis techniques prior to its arrival and estimate its potential impact on utility operations. In this project, we will investigate some technologies that can model a developing storm and its potential movement through the utility service territory based on weather projections. This information and model will then be integrated with the Geographic Information System (GIS) electrical connectivity model, Distribution Management System (DMS), and Outage Management System (OMS) functionalities, along with historical storm data to predict the potential impact on the service to customers. In addition, this project will demonstration the integration of near real time meter voltage data with the GIS network to develop a simulated circuit model that can be effectively utilized fo rstorm management an dfield crew deployment.	11/17/2014	Yes	Distribution	$ -	$ 1,557,327	$ -	$ 77,582	$ 77,582	$ 5,799	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
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	$ -	$ 5,939,999	$ -	$ -	$ -	$ -	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
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	$ -	$ 968,603	$ -	$ -	$ -	$ -	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
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	$ -	$ 2,258,001	$ 25,043	$ 258	$ 25,301	$ 3,939	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
2nd triennial (2015-2017)	SCE	**Bulk System Restoration Under High Renewables Penetration**	Renewables/DER Resource Integration	The Bulk System Restoration under High Renewable Penetration Project will evaluate system restoration plans following a blackout event under high penetration of wind and solar generation resources. Typically the entire restoration plan consists of three main stages; Black Start, System Stabilization, and load pick-up. The Project will be divided into two phases: * Phase I of the project will address the feasibility of new approaches to system restoration by reviewing the existing system restoration plans and it's suitability for higher penetration of renewable generation. It will include a suitable RTDS Bulk Power system to be used in the first stage of system restoration, black start and it will also include the modeling of wind and solar renewable resources. * Phase II of the project will focus on on-line evaluation of restoration plans using scenarios created using (RTDS) with hardware in the loop such as generation, transformer and transmission line protective relays. The RTDS is a well-known tool to assess and evaluate performance of protection and control equipment. This project intends to utilize the RTDS capabilities to evaluate and demonstrate system restoration strategies with variable renewable resources focusing on system stabilization and cold load pick-up. Furthermore alternate restoration scenarios will be investigated. After the restoration process is evaluated, tested, and demonstrated in the RTDS Lab environment, a recommendation will be provided to system operations and transmission planning for their inputs for further developing this approach into an actual operational tool.	11/17/2014	Yes	Transmission	$ -	$ 528,580	$ -	$ 2,726	$ 2,726	$ 1,020	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
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	$ -	$ 1,300,000	$ -	$ -	$ -	$ -	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

2nd triennial (2015-2017)	SCE	**Versatile Plug-in Auxiliary Power System (VAPS)**	Grid Modernization and Optimization	This project demonstrates the electrification of transportation and vocational loads that previously used internal combustion engines powered by petroleum fuels in the SCE fleet. The VAPS system uses automotive grade lithium ion battery technology (Chevrolet Volt and Ford Focus EV) which is also used in notable stationary energy storage projects (Tehachapi 32 MWh Storage)	11/17/2014	Yes	Distribution	$ -	$ 1,578,415	$ -	$ 8,385	$ 8,385	$ 771	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
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	$ -	$ 3,917,750	$ -	$ 930	$ 930	$ 131	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
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	$ -	$ 3,500,000	$ -	$ -	$ -	$ -	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
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	$ -	$ 35,000	$ -	$ -	$ -	$ -	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

If competitively selected, provide the number of bidders passing the initial pass/fail screening for project	If competitively selected, provide the name of selected bidder.	If competitively selected, provide the rank of the selected bidder in the selection process.	If competitively selected, explain why the bidder was not the highest scoring bidder, explain why a lower scoring bidder was selected.	If interagency or sole source agreement, specify date of notification to the Joint Legislative Budget Committee (JLBC) was notified and date of JLBC authorization.	Does the recipient for this award identify as a California-based entity, small business, or businesses owned by women, minorities, or disabled veterans?	How the project leads to technological advancement or breakthroughs to overcome barriers to achieving the state's statutory energy goals	Applicable metrics
4	Navigant Consulting Inc.	1st	Does not apply; Highest scoring bidder was selected for award.	N/A; Applicable to CEC only.	Navigant Consulting Inc: California-based entity @ Business, Inc.: California-based entity Battelle Northwest: N/A Black & Veatch Corporation: California-based entity Bridgewater Consulting Group, Inc: California-based entity; Small Business; DBE Corepoint 1, Inc: California-based entity Cyme International T&D Inc: N/A Ixia: California-based entity Landis & Gyr: California-based entity Pacific Coast Engineering: California-based entity; Small Business Quanta Technology, LLC: California-based entity	N/A; Applicable to CEC only.	1a. Number and total nameplate capacity of distributed generation facilities 1b. Total electricity deliveries from grid-connected distributed generation facilities 1c. Avoided procurement and generation costs 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);
The ED opened the Phase 1 Pilot Submetering MDMA participation to all companies. Four companies applied: Electric Motor Werks, KnGrid, NRG and Ohmconnect. All four passed the initial pass/fail ED screening.	All four companies were approved by the ED to participate in the Phase 1 Submetering Pilot. Electric Motor Werks, KnGrid, NRG and Ohmconnect	There was no ranking provided by the ED. The four companies were free to choose which of the three IOU territories it wanted to participate in. Three companies, Electric Motor Werks, NRG and Ohmconnect selected to participate in SCE's territory. Note: PO process is not yet complete for Electric Motor Werks.	ED did not provide any scoring of the applicants.	N/A; Applicable to CEC only.	NRG: N/A Ohmconnect: California-based entity; Small Business Electric Motor Werks: California-based entity; Small Business	N/A; Applicable to CEC only.	6a. TOTAL number of SCE customer participants (Phase 1 & 2 each have 500 submeter limit) 6b. Number of SCE NEM customer participants (Phase 1 & 2 each have 100 submeter limit of 500 total) 6c. Submeter MDMA on-time delivery of customer submeter interval usage data 6d. Submeter MDMA accuracy of customer submeter interval usage data
N/A	N/A	N/A	N/A	N/A; Applicable to CEC only.	Battelle Memorial Institute: N/A	N/A; Applicable to CEC only.	1d. Number and percentage of customers on time variant or dynamic pricing tariffs 1g. Percentage of demand response enabled by automated demand response technology (e.g. Auto DR) 5c. Forecast accuracy improvement 7b. Increased use of cost-effective digital information and control technology to improve reliability, security, and efficiency of the electric grid (PU Code § 8360) 7c. Dynamic optimization of grid operations and resources, including appropriate consideration for asset management and utilization of related grid operations and resources, with cost-effective full cyber security (PU Code § 8360) 7e. Development and incorporation of cost-effective demand response, demand-side resources, and energy-efficient resources (PU Code § 8360); 8c. Number of times reports are cited in scientific journals and trade publications for selected projects. 8d. Number of information sharing forums held. 8f. Technology transfer 9b. Number of technologies eligible to participate in utility energy efficiency, demand response or distributed energy resource rebate programs 9c. EPIC project results referenced in regulatory proceedings and policy reports. 9d. Successful project outcomes ready for use in California IOU grid (Path to market).
2	Saker Systems, LLC	1	Does not apply; Highest scoring bidder was selected for award.	N/A; Applicable to CEC only.	Saker Systems LLC: California-base entity; DBE Autogrid Systems, Inc: California-base entity Qualitylogic, Inc.: California-base entity	N/A; Applicable to CEC only.	1a. Number and total nameplate capacity of distributed generation facilities 1b. Total electricity deliveries from grid-connected distributed generation facilities 1c. Avoided procurement and generation costs 1e. Peak load reduction (MW) from summer and winter programs 1f. Avoided customer energy use (kWh saved) 1g. Percentage of demand response enabled by automated demand response technology (e.g. Auto DR) 3f. Improvements in system operation efficiencies stemming from increased utility dispatchability of customer demand side management 5b. Electric system power flow congestion reduction 5f. Reduced flicker and other power quality differences 5i. Increase in the number of nodes in the power system at monitoring points 7b. Increased use of cost-effective digital information and control technology to improve reliability, security, and efficiency of the electric grid (PU Code § 8360); 7c. Dynamic optimization of grid operations and resources, including appropriate consideration for asset management and utilization of related grid operations and resources, with cost-effective full cyber security (PU Code § 8360); 7d. Deployment and integration of cost-effective distributed resources and generation, including renewable resources (PU Code § 8360); 7e. Development and incorporation of cost-effective demand response, demand-side resources, and energy-efficient resources (PU Code § 8360); 7f. Deployment of cost-effective smart technologies, including real time, automated, interactive technologies that optimize the physical operation of appliances and consumer devices for metering, communications concerning grid operations and status, and distribution automation (PU Code § 8360); 7g. Integration of cost-effective smart appliances and consumer devices (PU Code § 8360); 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

N/A	N/A	N/A	N/A	N/A; Applicable to CEC only.	Doble Engineering Company: N/A General Electric Company: N/A RTDS Technologies Inc.: N/A Schweitzer Engineering Labs Inc: California-based entity	N/A; Applicable to CEC only.	3a. Maintain / Reduce operations and maintenance costs 5a. Outage number, frequency and duration reductions 6a. Reduction in testing cost 6b. Number of terminals tested on a line (more than 2 terminals/substations) 7b. Increased use of cost-effective digital information and control technology to improve reliability, security, and efficiency of the electric grid (PU Code § 8360); 8b. Number of reports and fact sheets published online 8d. Number of information sharing forums held. 8f. Technology transfer 9c. EPIC project results referenced in regulatory proceedings and policy reports. 9e. Technologies available for sale in the market place (when known).
TBD	TBD	TBD	TBD	N/A; Applicable to CEC only.	Siemens Industry, Inc: California-based entity The Mathworks, Inc: California-based entity	N/A; Applicable to CEC only.	3a. Maintain / Reduce operations and maintenance costs 3c. Reduction in electrical losses in the transmission and distribution system 3d. Number of operations of various existing equipment types (such as voltage regulation) before and after adoption of a new smart grid component, as an indicator of possible equipment life extensions from reduced wear and tear 7b. Increased use of cost-effective digital information and control technology to improve reliability, security, and efficiency of the electric grid (PU Code § 8360) 7c. Dynamic optimization of grid operations and resources, including appropriate consideration for asset management and utilization of related grid operations and resources, with cost-effective full cyber security (PU Code § 8360) 8b. Number of reports and fact sheets published online 8d. Number of information sharing forums held. 8f. Technology transfer 9c. EPIC project results referenced in regulatory proceedings and policy reports. 9d. Successful project outcomes ready for use in California IOU grid (Path to market).
N/A	N/A	N/A	N/A	N/A; Applicable to CEC only.	N/A; Project is cancelled.	N/A; Applicable to CEC only.	N/A; Project is cancelled
TBD	TBD	TBD	TBD	N/A; Applicable to CEC only.	Power World Corporation: California-based entity	N/A; Applicable to CEC only.	6a. Enhanced grid monitoring and on-line analysis for resiliency 7b. Increased use of cost-effective digital information and control technology to improve reliability, security, and efficiency of the electric grid (PU Code § 8360); 8b. Number of reports and fact sheets published online 8d. Number of information sharing forums held. 8f. Technology transfer 9d. Successful project outcomes ready for use in California IOU grid (Path to market). 9e. Technologies available for sale in the market place (when known).
N/A	N/A	N/A	N/A	N/A; Applicable to CEC only.	V&R Energy Systems Research, Inc.: California-based entity Siemens Industry, Inc.: California-based entity	N/A; Applicable to CEC only.	6a. Enhanced contingency planning for minimizing cascading outages 8b. Number of reports and fact sheets published online 8d. Number of information sharing forums held. 8f. Technology transfer
TBD	TBD	TBD	TBD	N/A; Applicable to CEC only.	TBD	N/A; Applicable to CEC only.	1c. Avoided procurement and generation costs 1i. Nameplate capacity (MW) of grid-connected energy storage 3b. Maintain / Reduce capital costs 5f. Reduced flicker and other power quality differences 5i. Increase in the number of nodes in the power system at monitoring points 6a. Benefits in energy storage sizing through device operation optimization 6b. Benefits in distributed energy storage deployment vs. centralized energy storage deployment 7a. Description of the issues, project(s), and the results or outcomes 7b. Increased use of cost-effective digital information and control technology to improve reliability, security, and efficiency of the electric grid (PU Code § 8360) 7c. Dynamic optimization of grid operations and resources, including appropriate consideration for asset management and utilization of related grid operations and resources, with cost-effective full cyber security (PU Code § 8360) 7l. Identification and lowering of unreasonable or unnecessary barriers to adoption of smart grid technologies, practices, and services (PU Code § 8360) 8b. Number of reports and fact sheets published online 8d. Number of information sharing forums held. 8f. Technology transfer 9c. EPIC project results referenced in regulatory proceedings and policy reports.
N/A	N/A	N/A	N/A	N/A; Applicable to CEC only.	Cyient, Inc.: N/A Nexant Inc: California-based entity	N/A; Applicable to CEC only.	3a. Maintain / Reduce operations and maintenance costs 5c. Forecast accuracy improvement 5f. Reduced flicker and other power quality differences 6a. Enhance Outage Reporting Accurary and SAIDI/SAIFI Calculation 8b. Number of reports and fact sheets published online 8f. Technology transfer 9c. EPIC project results referenced in regulatory proceedings and policy reports.

Procurement #1: 2 Procurement #2: 2 Procurement #3: 2	Procurement #1: Graybar Electric Company Inc.; Procurement #2: Onesource Supply Solutions, LLC. Procurement #3: Morris & Willner Partners	Procurement #1: 1 Procurement #2: 1 Procurement #3:2	Procurement #3: Morris & Willner Partners was selected over the higher scoring bidder due to their highly experience staff.	N/A; Applicable to CEC only.	Graybar Electric Company Inc.: California-based entity Onesource Supply Solutions, LLC.: California-based entity; Small Business; DBE Morris & Willner Partners: California-based entity ABB Inc: N/A GE Grid Solutions, LLC: California-based entity General Networks: California-based entity	N/A; Applicable to CEC only.	3a. Maintain / Reduce operations and maintenance costs 3b. Maintain / Reduce capital costs 5a. Outage number, frequency and duration reductions 5i. Increase in the number of nodes in the power system at monitoring points 6a. Increased cybersecurity 7b. Increased use of cost-effective digital information and control technology to improve reliability, security, and efficiency of the electric grid (PU Code § 8360); 7c. Dynamic optimization of grid operations and resources, including appropriate consideration for asset management and utilization of related grid operations and resources, with cost-effective full cyber security (PU Code § 8360); 7k. Develop standards for communication and interoperability of appliances and equipment connected to the electric grid, including the infrastructure serving the grid (PU Code § 8360); 8b. Number of reports and fact sheets published online 8d. Number of information sharing forums held. 8f. Technology transfer 9c. EPIC project results referenced in regulatory proceedings and policy reports. 9d. Successful project outcomes ready for use in California IOU grid (Path to market). 9e. Technologies available for sale in the market place (when known).
Siemens: 3	Siemens	Siemens:1	Siemens: highest score was selected	N/A; Applicable to CEC only.	Onesource Supply Solutions, LLC: California-based entity; Small Business; DBE On-Ramp Wireless, Inc.: California-based entity Progressive Frame and Fabrication: California-based entity Schweitzer Engineering Labs Inc: California-based entity Sentient Energy, Inc.: California-based entity Wesco Distribution Inc: California-based entity; DBE Siemens Industry: California-based entity Southwest Research Institute: California-based entity	N/A; Applicable to CEC only.	3a. Maintain / Reduce operations and maintenance costs 3d. Number of operations of various existing equipment types (such as voltage regulation) before and after adoption of a new smart grid component, as an indicator of possible equipment life extensions from reduced wear and tear 5a. Outage number, frequency and duration reductions 5c. Forecast accuracy improvement 5d. Public safety improvement and hazard exposure reduction 5e. Utility worker safety improvement and hazard exposure reduction 5i. Increase in the number of nodes in the power system at monitoring points 6a. Improve data accuracy for distribution substation planning process 7b. Increased use of cost-effective digital information and control technology to improve reliability, security, and efficiency of the electric grid (PU Code § 8360); 7c. Dynamic optimization of grid operations and resources, including appropriate consideration for asset management and utilization of related grid operations and resources, with cost-effective full cyber security (PU Code § 8360); 7d. Deployment and integration of cost-effective distributed resources and generation, including renewable resources (PU Code § 8360); 7k. Develop standards for communication and interoperability of appliances and equipment connected to the electric grid, including the infrastructure serving the grid (PU Code § 8360); 8b. Number of reports and fact sheets published online 8d. Number of information sharing forums held. 8f. Technology transfer 9c. EPIC project results referenced in regulatory proceedings and policy reports. 9d. Successful project outcomes ready for use in California IOU grid (Path to market). 9e. Technologies available for sale in the market place (when known).
N/A	N/A	N/A	N/A	N/A; Applicable to CEC only.	American Restore, Inc.: California-based entity Rivcomm, Inc.: California-based entity; Small Business California Turbo Inc: California-based entity	N/A; Applicable to CEC only.	3a. Maintain / Reduce operations and maintenance costs 3b. Maintain / Reduce capital costs 4g. Wildlife fatality reductions (electrocutions, collisions) 5a. Outage number, frequency and duration reductions 6a. Operating performance of underground vault monitoring equipment 8b. Number of reports and fact sheets published online 8d. Number of information sharing forums held. 8f. Technology transfer 9c. EPIC project results referenced in regulatory proceedings and policy reports.
N/A	N/A	N/A	N/A	N/A; Applicable to CEC only.	Wesco Distribution Inc: California-based entity; DBE Black & Veatch Corporation: California-based entity	N/A; Applicable to CEC only.	3b. Maintain / Reduce capital costs 5b. Electric system power flow congestion reduction 6a. Increased power flow throughput 7b. Increased use of cost-effective digital information and control technology to improve reliability, security, and efficiency of the electric grid (PU Code § 8360); 7c. Dynamic optimization of grid operations and resources, including appropriate consideration for asset management and utilization of related grid operations and resources, with cost-effective full cyber security (PU Code § 8360); 8b. Number of reports and fact sheets published online 8d. Number of information sharing forums held. 8f. Technology transfer 9c. EPIC project results referenced in regulatory proceedings and policy reports. 9d. Successful project outcomes ready for use in California IOU grid (Path to market). 9e. Technologies available for sale in the market place (when known).
N/A	N/A	N/A	N/A	N/A; Applicable to CEC only.	@ Business Inc: DBE Magnetic Instrumentation Inc: N/A Saker Systems, LLC: California-base entity; Small Business; DBE World Wide Technology Inc: DBE Zones, Inc.: DBE Accuvant Inc: California-based entity Electric Power Group, LLC: California-based entity Schweitzer Engineering Labs Inc: California-based entity	N/A; Applicable to CEC only.	5a. Outage number, frequency and duration reductions 7b. Increased use of cost-effective digital information and control technology to improve reliability, security, and efficiency of the electric grid (PU Code § 8360); 7l. Identification and lowering of unreasonable or unnecessary barriers to adoption of smart grid technologies, practices, and services (PU Code § 8360) 8b. Number of reports and fact sheets published online 8d. Number of information sharing forums held. 8f. Technology transfer 10a. Description or documentation of funding or contributions committed by others 10c. Dollar value of funding or contributions committed by others.

TBD	TBD	TBD	TBD	N/A; Applicable to CEC only.	TBD	N/A; Applicable to CEC only.	Metrics plan TBD
TBD	TBD	TBD	TBD	N/A; Applicable to CEC only.	TBD	N/A; Applicable to CEC only.	3a. Maintain / Reduce operations and maintenance costs 7b. Increased use of cost-effective digital information and control technology to improve reliability, security, and efficiency of the electric grid (PU Code § 8360) 8d. Number of information sharing forums held 8f. Technology transfer
TBD	TBD	TBD	TBD	N/A; Applicable to CEC only.	TBD	N/A; Applicable to CEC only.	2a. Hours worked in California and money spent in California for each project 3a. Maintain / Reduce operations and maintenance costs 3b. Maintain / Reduce capital costs 5a. Outage number, frequency and duration reductions 5c. Forecast accuracy improvement 5d. Public safety improvement and hazard exposure reduction 8f. Technology transfer 9d. Successful project outcomes ready for use in California IOU grid (Path to market) 9e. Technologies available for sale in the market place (when known)
TBD	TBD	TBD	TBD	N/A; Applicable to CEC only.	TBD	N/A; Applicable to CEC only.	Metrics plan TBD
TBD	TBD	TBD	TBD	N/A; Applicable to CEC only.	TBD	N/A; Applicable to CEC only.	Metrics plan TBD
TBD	TBD	TBD	TBD	N/A; Applicable to CEC only.	TBD	N/A; Applicable to CEC only.	1d. Number and percentage of customers on time variant or dynamic pricing tariffs 1h. Customer bill savings (dollars saved) 3e. Non-energy economic benefits 4a. GHG emissions reductions (MMTCO2e) 6a. The 3rd Party Evaluator, Nexant, in collaboration with the Energy Division and IOUs, will develop a set of metrics for Phase 2 to be included in the final report. 7h. Deployment and integration of cost-effective advanced electricity storage and peak-shaving technologies, including plug-in electric and hybrid electric vehicles, and thermal-storage air-conditioning (PU Code § 8360) 7j. Provide consumers with timely information and control options (PU Code § 8360): 7k. Develop standards for communication and interoperability of appliances and equipment connected to the electric grid, including the infrastructure serving the grid (PU Code § 8360) 7l. Identification and lowering of unreasonable or unnecessary barriers to adoption of smart grid technologies, practices, and services (PU Code § 8360) 8e. Stakeholders attendance at workshops 8f. Technology transfer 9c. EPIC project results referenced in regulatory proceedings and policy reports 9d. Successful project outcomes ready for use in California IOU grid (Path to market) 9e. Technologies available for sale in the market place (when known)
TBD	TBD	TBD	TBD	N/A; Applicable to CEC only.	TBD	N/A; Applicable to CEC only.	Metrics plan TBD
TBD	TBD	TBD	TBD	N/A; Applicable to CEC only.	TBD	N/A; Applicable to CEC only.	Metrics plan TBD

TBD	TBD	TBD	TBD	N/A; Applicable to CEC only.	TBD	N/A; Applicable to CEC only.	Metrics plan TBD
TBD	TBD	TBD	TBD	N/A; Applicable to CEC only.	TBD	N/A; Applicable to CEC only.	Metrics plan TBD
TBD	TBD	TBD	TBD	N/A; Applicable to CEC only.	TBD	N/A; Applicable to CEC only.	Metrics plan TBD
TBD	TBD	TBD	TBD	N/A; Applicable to CEC only.	TBD	N/A; Applicable to CEC only.	Metrics plan TBD

Update	Coordination with CPUC Proceedings or Legislation
In 2015, the IGP project team refined the project scope and demonstration design approach, and issued key Requests for Proposals (RFPs) for Control Systems and the Field Area Network. In addition, the project team took steps to align activities with the Distribution Resources Plan (DRP) requirements; going forward, the project will become the test bed for DRP Demonstration D. The site selection for IGP was reviewed in light of the DRP requirements and alternate demonstration locations are now being considered to ensure sufficient DER resources are available. The following activities were completed by the project team in 2015: • Completed IGP-Area circuit modeling • Participated in the development of the Grid Modernization Business Requirements and Concept of Operations • Aligned IGP's scope to Grid Modernization efforts by defining 8 corresponding demonstration sub-projects • Developed detailed IGP Use Cases (in accordance with the new Grid Modernization Architecture concepts) • Developed detailed Technical Specifications for Control System functionality (Volt/VAR, Power Flow, and Microgrid controls) • Issued RFP for IGP Control Systems • Developed detailed Technical Specifications for the Field Area Network (communication systems) • Issued RFP for the Field Area Network • Installed key components of the controls lab to evaluate IGP assets prior to field deployment • Tested control applications and systems from potential vendors (DVI, Spirae, Landis+Gyr) • Completed overall High Level IGP Conceptual Architecture • Completed Initial draft of the IGP System Requirements Document • Developed initial draft of the IGP System Design Document	Distribution Resources Plan, R.14-08-013; A.15-07-003 Integrated Demand-side Resource Program, R.14-10-003
SCE worked closely with the CPUC/ED and Submetering MDMAs to extend the Phase 1 Pilot six months to enroll 92 customers. SCE will provide its customers with subtractive billing to separately bill household and EV charging on their respective rates. SCE will support its customers during their Pilot participation by answering their questions and resolving their issues. SCE will provide a similar service to the three Submetering MDMAs. The Phase 1 Submetering Pilot is on schedule and under budget. The three Submeter MDMAs, (eMotorWerks, NRG and Ohmconnect) were issued purchase orders to enable SCE to pay the MDMAs for enrolling customers and providing SCE with monthly EV submeter usage data. Nexant was selected by the three IOUs to be the third party evaluator of the Submetering Pilots. PG&E contracted Nexant on behalf of the three IOUs who will share the costs equally as mandated by CPUC. SCE's share is $439,580 which is payable quarterly through 2018. Milestones achieved • Requested and received CPUC's approval to extend the Phase 1 Pilot enrollment period six months. • Submitted Tier 1 Advice Letter to CPUC to update Phase 1 Pilot tariff due to Pilot extension. • Enrolled 92 SCE customers in the Pilot by end of extended enrollment period August 31, 2015. • Supporting 92 customers during their 12 month participation in the Phase 1 Pilot.	
In 2015, SCE and Battelle continued the work which commenced in 2014 with the creation of additional GridLAB-D modules and add-on tools for Grid Command Distribution. The key accomplishments in 2015 included: • The development of a GridLAB-D Valuation tool which serves to capture the locational value or true cost of technologies including: Energy Storage, Demand Response, PV, Conservation Voltage Reduction, and Electric Vehicles • Additional functionality was added to the Commercial module making demand response events possible • Validation of the Commercial module and Commercial DR module • Additional scripting tools and functionalities in Grid Command Distribution were developed to aid in SCE Circuit model development • Training workshops and knowledge transfer sessions were conducted SCE has successfully implemented the modeling of representative circuit feeders in GridLab-D using the commercial models and tools developed and validated in collaboration with Battelle. As part of a core research project involving internal and external stakeholders, these models are being used to study the impact of high PV penetration and implementation of cost effective mitigation technologies which include demand response. Additional phases of the modeling work will continue in 2016.	Distribution Resources Plan, R.14-08-013; A.15-07-003
During 2015, the project team engaged stakeholder groups throughout SCE including Transportation Electrification and Customer Service to understand and document high-level requirements and use cases critical to the business. The technical team also conducted market research to identify technology and vendor capabilities, architectures, and availability of DER technologies. In addition, the team developed high level architectures. Finally, the team completed the scope, schedule, and budget; and updated the Project Management Plan to reflect new scope and budget modifications.	

In the process of developing the methodology to utilize the Portable End-to-End Test System (PETS) in the field, and through feedback from the end-users it was discovered that there were a limited number of test scenarios where the tool would be a great improvement over existing test procedures. As a result, the project team concluded that there was no substantial value in further pursuing the development of the PETS tool. Although the tool would be an improved method of testing system performance when conducting end-to-end relay tests, the implementation of a companywide PETS (utilizing a Real Time Digital Simulator system) proved to not be cost effective when compared to traditional test methods at this time. The major aspects that would drive the cost of implementing the PETS projects are: • Development of specialized training programs for field crews • Availability of the tool; it would be extremely costly to purchase several PETS test units to accommodate the different regions within SCE's territory when compared to purchasing existing standard tools • Dedicated engineering staff to support issues related to maintenance and training After careful deliberation of the benefits associated with proceeding with the PETS project, SCE has decided to halt further development of the technology and to close out the project. Furthermore, the early close-out of this project does not impact how protection schemes are tested today as it was intended to be a proof-of-concept demonstration project. More information will be provided in the final report.	
In 2015, the project team continued working in collaboration with the Portfolio Management Office (PMO) to gather all the information needed to complete the Emergent Project Evaluation Form (EPEF) process. Note: This process is needed to determine the substation installation schedule and associated cost estimate. During this period, all deployment requirements are gathered and all changes affecting existing substation equipment are studied. The project team worked with Grid Control Center (GCC) engineers, protection engineers and Substation Construction and Maintenance (SC&M) personnel to evaluate the work needed. On August 20, 2015, EPEF requirements were fulfilled and the process was approved for installation to start in January 2017. In addition, stakeholders were regularly engaged and updated of project progress and deployment schedule and updates. In an effort to publicize the novel work developed, the project team presented the work in two consecutive NASPI (North American Synchrophasor Initiative) meetings, worked on a NASPI focus paper, published an IEEE transactions paper, and published testing and simulation findings in the 49th HICSS (Hawaiian International Conference on Systems Sciences) conference. In addition, the team continued to finalize testing of the controller system and drafted a demonstration specification document to be utilized during the software implementation phase.	
SPX Transformer Solutions officially withdrew support from the project in Q2, 2014. As a result, SuperPower could no longer complete the delivery of the HTS-FCL transformer to SCE. SuperPower communicated the desire to identify a new transformer manufacturer as a partner, but was unable to secure one within a reasonable timeframe. At the time of SPX's withdrawal, SCE did not have an executed agreement with SuperPower. SCE formally cancelled this project in Q3 2014.	N/A - Cancelled.
SCE has worked with the selected vendor to specify, test, and validate state estimation techniques using PMU data. This data was used to validate the operation of the Linear State Estimator and data conditioning functions. For next steps, the project team will begin to implement applications and tools to demonstrate their use in real-time operations.	
In 2015, SCE and V&R Energy utilized the Potential Cascading Modes (PCM) tool to identify a list of initiating events for cascading outage analysis. In addition, the project team has demonstrated a cascading outage analysis framework to identify how cascading events performed under various levels of stress. For next steps, the project team will validate the demonstration environment, complete demonstrations, and develop the final project report.	
During 2015, the DOS project aligned itself with the Integrated Grid Project (IGP) and the SCE's Energy Storage Ownership Initiative (ESOI). Technical specifications required to procure energy storage devices are being developed based on current ESOI energy storage specifications in partnership with IGP and ESOI. These specifications will be used to procure the DOS storage devices in the 2016/2017 time frame. In addition, the project team has been working with landowners at potential installation sites within the Integrated Grid Project demonstration location in the Orange County area.	Energy Storage R,.15-03-011; D.14-10-040 & D.14-10-045 Resource Adequacy OIR, R.14-10-010
The project demonstrated an analytics and visualization application that used smart meter data for distribution grid operational benefits. The project also conducted a feasibility study to determine if the use of smart meter data could improve the Outage Management SAIDI/SAIFI/MAIFI (reliability) metric calculation process. The following project milestones were achieved: i. The application was demonstrated in a lab environment using smart meter data of approximately 20,000 customers on 14 distribution circuits. ii. The application demonstrated 13 use cases developed by SCE using customer meter voltage, consumption and event data. iii. The application successfully overlaid the meter data on SCE's distribution system GIS to provide a visualization of the condition of the network. iv. The application was successfully tested by electric distribution planners and engineers. v. The feasibility study for using smart meter data in the calculation of system reliability indices was completed and several manually-intensive steps were identified for elimination. The project was successfully completed in 2015 and the final report will be submitted in 2016.	

Major activities for the Substation Automation Demonstration 3, Phase III (SA-3) project in 2015 involved: 1) identifying qualified vendors and conducting procurement activities for IEC 61850 compliant devices and systems; 2) working to identify and confirm the substation site to be used for the demonstration; and 3) working to finalize stakeholder agreement on demonstration objectives. Milestones achieved • Defined Business Requirements and Use Cases • Completed Functional Design and Technical Specifications • Completed the Substation Standard Review Team (SSRT) Pilot request for Olinda A-Substation • Completed SSRT Pilot approval for Olinda • Completed Preliminary Scope of Work and Design for Olinda • Completed the Stakeholder Job-walk for Olinda • Completed Re-evaluation of Olinda A-station • Resulted in relocation of the pilot to Viejo A-substation because of construction and civil work schedule impact • Completed SSRT Pilot approval for Viejo • Completed Preliminary Scope of Work for Viejo • Completed the Stakeholder Job-walk for Viejo • Completed Engineering contractor Job Walk • Started Preliminary Demonstration Design for Engineering contract award • Started lab Demonstration of new annunciator (Programmable Automation Controller (PAC)) system	
Remote Intelligent Switch (RIS) For 2015, SCE continued development of the RIS project and demonstration. Project specification and deliverables were finalized, and the RFP process was completed. After reviewing all RFP respondents, the team awarded the project to the highest scoring vendor, Siemens. Development of the RIS solution started, resulting in the initial algorithm programming, several demonstration of the RIS system's capabilities at Siemens's facility, and an initial delivery of pre-production evaluation cabinets. **High Impedance Fault Detection** Existing high impedance fault detection solutions available in the market focus on current and voltage monitoring; however, evaluation results demonstrate none of these technologies have been able to securely detect high impedance faults reliably (too many false alarms). As a result, a new approach is necessary and SCE's Advanced Technology considers the reflectometry-based solution as an innovative and promising approach. Advanced Technology and Apparatus Engineering are working with Southwest Research Institute (SWRI) to demonstrate the feasibility of implementing a reflectometry-based solution for detection of high impedance faults. **Overhead Remote Fault Indicator (RFI)** In 2015 SCE successfully evaluated and standardized the Overhead Remote Fault Indicator (RFI). The RFI is a device which provides local visualization and remote indication of a fault on distribution circuits. The RFI is used by our System Operators as a means of automatically and remotely detecting and identifying faults to reduce outage time. **Long Beach Network Situation Awareness** In the year 2015, the Long Beach situational Awareness Project had the following activities and accomplishments: • Finalized the scope of the project, identifying 12 sites impacted by the installation of Voltage/Current monitoring devices. • Out of the 12 sites, 9 sites will be installed with SCE's current Field Area Network Communication devices, Netcomm, while 3 remaining sites will be installed with IP Point to Multipoint radios. • Established two underground radio network access points at the Long Beach area and performed radio study of the signal coverage in Long Beach to determine the amount of Access Points (APs) required to fully cover the entire Long Beach electrical network. • Established communication with Consolidated Edison to benchmark SCE system with Con. Edison network monitoring and alarming system. **Intelligent Fuse** • Technical Specification were finalized for the Intelligent and went through the Request For Proposal (RFP) process • Two vendors(G&W and Siemens) responded and both solutions were evaluated and scored • G&W was awarded the winning bid	
In 2015, the project team accomplished the following: • Enhanced vault ventilation blower was specified, delivered, and is currently being field tested. • Developed draft specification for Hybrid Distribution Pole • Created conceptual insulator-antenna for initial communication testing • Installed vault temperature equipment for testing and monitoring	
The project team worked with the vendor to identify system requirements and the devices needed for the demonstration project. The project team worked with transmission engineering, system planning, and the Grid Control Center to identify the system stress points and congested transmission lines that are most suitable for the demonstration. The team worked with the vendor to pinpoint the locations of communication routing devices needed. The procurement process was completed and two instances of the CAT-1 monitoring system in addition to a communication repeater system were delivered. SCE requires adherence to the T&D pilot standards process when a project involves installation of non-standard equipment on a transmission line or a substation. The project team presented the project in both Substation Standards Review Team (SSRT) and the Transmission Standards Review Team (TSRT), worked with the vendor to develop training material, and drafted detailed deployment and maintenance procedures. In May 2015, Transmission and substation standards were approved to proceed, and standards were issued and published. In February 2015, the team initiated the deployment design process and both transmission and substation drawing packages were issued and published. Also, a CEII / NERC CIP Evaluation Processes is required when the project involves installations at the bulk power transmission system or at medium (or higher) level substations. The process was completed by altering the boxes to be in compliance with NERC-CIP requirements. After initiating installation of the system, it was discovered that there are some obstacles in the communication line-of-sight would require further testing. A decision was made not to continue the work after the vendor decided not to support Dynamic Line Rating after the end of the demonstration phase. SCE will work to close this project out in 2016, and write a final report in 2017.	
CAPMS completed the following activities in 2015, in no specific order: • Equipment was installed and configured in the SCE Advanced Technology laboratory to support test and demonstration activities. • Test system requirements were developed by SCE. • Threat scenarios were developed for use in system demonstration and test. • ViaSat completed CAPMS software development. • System and software integration and testing was accomplished in the SCE Advanced Technology laboratory and test reports were developed. • System test and demonstration was conducted using threat scenarios and CAPMS responses were observed and recorded by ViaSat. • A demonstration was held for the Department of Energy in September. • The final project report was developed and will be submitted with the EPIC annual report in February 2016.	California Energy Solutions for the 21st Century (CES-21). D.14-03-029

The project will demonstrate the use of an IEEE 2030.5 Distributed Energy Resource Management System. This project will launch in 2016. The project team plans to start the system requirements specification in early 2016; the demonstration will be performed in the 2016/2017 time frame.	
Improving accuracy of Transformer/Meter correlation model: The project demonstrated a statistical model that correlates the voltage signature of a meter with that of other meters connected to the transformer to identify mismatches and provide a "better match" alternative. It also demonstrated an algorithm that improved accuracy by comparing the time period of single transformer outages to smart meter outage events to identify incorrectly mapped meters. The following activities were completed in 2015: i. Demonstration of Voltage signature and single transformer Outage events algorithms in a lab environment using smart meter data of 3 distribution circuits. ii. Identified data challenges and limitations on the use of the algorithms. iii. Completed validation of algorithms' results through comparisons with field verified data. Phase identification of customers: It will demonstrate the algorithm developed in collaborative research by EPRI and SCE to identify the phase of a customer using SCADA, electrical network information and smart meter data. Additionally, the collaborative research by UC Riverside and SCE will be demonstrated in the later part of the project. i. Work on this subpart has been scheduled to start in 2016.	
During 2015, the project team engaged in Project Initiation and Project Planning activities, including execution of stakeholder engagement, requirements analysis, vendor and market research, and development of procurement documentation. The project successfully completed contract negotiations with two contractors and also obtained approval for the Project Management Plan. The project is on track to achieve key milestones outlined for Q1 of 2016.	Distribution Resources Plan, R.14-08-013; A.15-07-003 Integrated Demand-side Resource Program, R.14-10-003
The project will initiate the project planning phase in 2016.	Distribution Resources Plan, R.14-08-013; A.15-07-003 Integrated Demand-side Resource Program, R.14-10-003
The project will initiate the project planning phase in 2016.	
SCE recently initiated the preparations for the Phase 2 Submetering Pilot by participating in stakeholder kick off meetings hosted by CSOD. In addition, the CPUC hosted meetings that included the other IOUs and external stakeholders. The Phase 1 Pilot will start on November 1, 2016 and end in 18 months on April 30, 2018. Milestones achieved Held kickoff meeting with SCE stakeholders and with the CPUC including the other IOUs and external stakeholders. Established Work Group structure and schedule to address Phase 2 issues and requirements in preparation for finalizing the Phase 2 Tier 2 Advice Letter due June 30, 2016.	Charge Ready Application A.14-10-014; Plug-In Electric Vehicle Submetering Pilot, Advice Letter 3198-E
In 2015, this project was authorized to proceed with the planning phase of the project lifecycle. The team had numerous meetings both within the project team as well as with project stakeholders, sponsors, and advisors from SCE's Engineering, Planning, and Grid Operations groups to develop the detailed scope of work which culminated in the development of the Project Management Plan (PMP), which addresses the following. • A detailed Scope of Work statement • The project's work breakdown structure (WBS) and associated organization structure • The labor resource plan • A procurement plan that describes the materials and services that the project anticipates needing. • The project's milestone and deliverable schedule • The detailed project cost estimate The PMP is currently in the stages of being finalized and reviewed for approval, which is expected to happen early in 2016. Once the PMP is approved, the project will then receive authorization to proceed to the execution phase of the project lifecycle.	
In 2015 "Series Compensation for Load Flow Control" project was authorized to proceed according to SCE's Portfolio Management Office (PMO) processes. This project is currently in the planning stage to address the deliverables and milestones for the project activities.	

In 2015 a Request for Information (RFI) was sent to 12 qualified potential suppliers of Versatile Plug-in Auxiliary Power Systems (VAPS) with the primary function of electrically powering vehicle air conditioning systems. Applicability of such a system is very broad and includes all of SCE's light duty pickup trucks (typically Ford F150). Five responses to the RFI were received. Meetings were held with SCE's Transportation Services Department (TSD) in which both RFI responses and TSD fleet electrification priorities were reviewed and discussed in detail. In parallel with the RFI activity projects based on evaluating hybridized drivetrains of Class 2, 5 and 8 trucks were formally approved to proceed through SCE Advanced Technology's (AT) Project Selection Process. As of the end of the year a comprehensive project plan to procure and evaluate systems addressing each of these areas in the 2016-2017 timeframe was under development.	Charge Ready Application A.14-10-014; Plug-In Electric Vehicle Submetering Pilot, Advice Letter 3198-E
In 2015, the project team focused on gathering all of the requirements that will be needed for the demonstration phase of the project. The project team has been reaching out to vendors and several federal national labs to complete specification documents for hardware and software platforms.	
In 2015, the Optimized Control of Multiple Storage Systems project began to evaluate the requirements to align with the Integrated Grid Project and the SCE's Energy Storage Ownership Initiative (ESOI). This project will also leverage real-time circuit information to autonomously curtail load on the system and will have the ability to disconnect the Energy Storage Systems based on abnormal circuit conditions.	Energy Storage R,.15-03-011; D.14-10-040 & D.14-10-045 Resource Adequacy OIR, R.14-10-010
In 2015, the detailed project planning phase was initiated. In order to demonstrate the feasibility and effectiveness of installing fast charging stations, initial planning has been focused on assessing the impact of existing fast charging stations on the electric distribution system. A team of experts is being assembled, including Advanced Technology, Engineering, Electric System Planning, and Power Quality, and equipment is being specified to instrument approximately 25 stations. In addition, the project will include a plan to study the effects of associated storage to reduce system impact. Through the planning process, task definition and scheduling is being done in close collaboration with team experts. Project planning was on schedule as of the end of the year. Once SCE's plan is complete in early 2016, Tesla Motors, an automotive OEM responsible for much of the interest in DC fast charging, will be engaged as the project transitions into the execution phase	Charge Ready Application A.14-10-014; Plug-In Electric Vehicle Submetering Pilot, Advice Letter 3198-E

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE

STATE OF CALIFORNIA

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

CERTIFICATE OF SERVICE

I hereby certify that, pursuant to the Commission's Rules of Practice and Procedure, I have this day served a true copy of **SOUTHERN CALIFORNIA EDISON COMPANY'S (U-338-E) ANNUAL REPORT ON THE STATUS OF THE ELECTRIC PROGRAM INVESTMENT CHARGE PROGRAM** on all parties identified on the attached service list(s) A.12-11-001 (Consolidated), A.13-11-003, A.14-04-034 (Consolidated), A.14-11-003 (Consolidated), A.15-09-001. Service was effected by one or more means indicated below:

☒ Transmitting the copies via e-mail to all parties who have provided an e-mail address.

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CPUC
505 Van Ness Ave.
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Executed **February 29, 2016,** at Rosemead, California.

/s/Gina Leisure
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Service Lists

PROCEEDING: A1411003 - SDG&E - FOR AUTHORIT
FILER: SAN DIEGO GAS & ELECTRIC COMPANY
LIST NAME: LIST
LAST CHANGED: FEBRUARY 26, 2016

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