PUBLIC UTILITIES COMMISSION
505 Van Ness Avenue
San Francisco CA 94102-3298

Southern California Edison Company
ELC (Corp ID 338)
Status of Advice Letter 5535E
As of December 22, 2025

Subject: Submission of Revised 2023 Electric Program Investment Charge (EPIC) Annual Report

Division Assigned: Energy

Date Filed: 04-25-2025

Date to Calendar: 04-30-2025

Authorizing Documents: D1205037

Authorizing Documents: D2304042

Disposition:	**Accepted**
Effective Date:	**12-18-2025**

Resolution Required: No

Resolution Number: None

Commission Meeting Date: None

CPUC Contact Information:

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STATE OF CALIFORNIA **GAVIN NEWSOM,** *Governor*

PUBLIC UTILITIES COMMISSION
505 Van Ness Avenue
San Francisco CA 94102-3298

To: Energy Company Filing Advice Letter

From: Energy Division PAL Coordinator

Subject: Your Advice Letter Filing

The Energy Division of the California Public Utilities Commission has processed your recent Advice Letter (AL) filing and is returning an AL status certificate for your records.

The AL status certificate indicates:

Advice Letter Number
Name of Filer
CPUC Corporate ID number of Filer
Subject of Filing
Date Filed
Disposition of Filing (Accepted, Rejected, Withdrawn, etc.)
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Other Miscellaneous Information (e.g., Resolution, if applicable, etc.)

The Energy Division has made no changes to your copy of the Advice Letter Filing; please review your Advice Letter Filing with the information contained in the AL status certificate, and update your Advice Letter and tariff records accordingly.

All inquiries to the California Public Utilities Commission on the status of your Advice Letter Filing will be answered by Energy Division staff based on the information contained in the Energy Division's PAL database from which the AL status certificate is generated. If you have any questions on this matter please contact the:

Energy Division's Tariff Unit by e-mail to
edtariffunit@cpuc.ca.gov

ADVICE LETTER (AL) SUSPENSION NOTICE
ENERGY DIVISION

Utility Name: Southern California Edison Company (SCE)
Utility Number/Type: 338-E
Advice Letter Number(s): 5535-E
Date AL(s) Filed: 4/25/2025
Utility Contact Person: Darrah Morgan
Utility Phone No.: (626) 302-2086

Date Utility Notified: 9/19/2025
[x] E-Mailed to: AdviceTariffManager@sce.com
ED Staff Contact: Fredric Beck
ED Staff Email: Fredric.beck@cpuc.ca.gov
ED Staff Phone No.: 415-703-5432

☐ **INITIAL SUSPENSION (up to 120 DAYS from the expiration of the initial review period)**

This is to notify that the above-indicated AL is suspended for up to 120 days beginning **May 23, 2025** (30 days after the Advice Letter is filed) for the following reason(s) below. If the AL requires a Commission resolution and the Commission's deliberation on the resolution prepared by Energy Division extends beyond the expiration of the initial suspension period, the advice letter will be automatically suspended for up to 180 days beyond the initial suspension period.

☐A Commission Resolution is Required to Dispose of the Advice Letter

☐ Advice Letter Requests a Commission Order

☐ Advice Letter Requires Staff Review

The expected duration of initial suspension period is 120 days

☒ **FURTHER SUSPENSION (up to 180 DAYS beyond initial suspension period)**

The AL requires a Commission resolution and the Commission's deliberation on the resolution prepared by Energy Division has extended beyond the expiration of the initial suspension period. The advice letter is suspended for up to 180 days beyond the initial suspension period.

If you have any questions regarding this matter, please contact Fredric Beck at fredric.beck@cpuc.ca.gov.

cc:
ED Tariff Unit
Cheryl Cox

* Note: reference – Decision D.02-02-049, dated February 21, 2002, and Rule 7.5 in appendix A of D.O7-01-024

SOUTHERN CALIFORNIA EDISON
An EDISON INTERNATIONAL® Company

Connor J Flanigan
Managing Director, State Regulatory Operations

April 25, 2025

ADVICE 5535-E
(U 338-E)

PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA
COMMUNICATIONS DIVISION

SUBJECT: Submission of Revised 2023 Electric Program Investment Charge (EPIC) Annual Report

PURPOSE AND BACKGROUND

On April 30, 2024, Southern California Edison Company (SCE) submitted Advice Letter No. 5290-E, which transmitted SCE's 2023 Electric Program Investment Charge (EPIC) Annual Report pursuant to Ordering Paragraph 16 of the California Public Utilities Commission's (Commission) Decision No. 12-05-037 and Ordering Paragraph 8 of Decision No. 23-04-042.

On March 26, 2025, the Commission issued a disposition letter that approved, in part, SCE's Advice Letter 5290-E.[1] The Commission indicated SCE's Advice Letter 5290-E demonstrated compliance with the Commission's order in all areas except for the following: (1) The completeness and accuracy of SCE EPIC project data in the EPIC database, and (2) Inclusion of the mandatory language on the ratepayer funding of EPIC.[2] The Commission required SCE to resubmit its 2023 EPIC Annual Report in both a clean version (Appendix A to this Advice Letter) and a track-changes version (Appendix B to this Advice Letter) via a Tier 2 advice letter within 30 days of the disposition letter (i.e., April 25, 2025).[3]

[1] March 26, 2025 Disposition Letter to SCE from Leuwam Tesfai, Director of the CPUC's Energy Division and Deputy Executive Director for Energy and Climate Policy.
[2] March 26, 2025 Disposition Letter, p. 1.
[3] March 26, 2025 Disposition Letter, pp. 1-2.

SCE's UPDATES TO THE EPIC DATABASE AND 2023 ANNUAL REPORT

A. Completeness of EPIC Database Project Data

Decision No. 18-10-052 established the Policy + Innovation Coordination Group (PICG), including the EPIC database.[4] In its March 26, 2025 disposition letter, the Commission indicated that its consultant who manages the EPIC database identified "[m]issing or incomplete data includes project updates, state policy support, projected project benefits, ratepayer benefits, impacts, getting to scale, and key learnings for some, but not all projects" in the database.[5] In coordination with the Commission's Energy Division staff, SCE developed a plan to address these discrepancies, namely, that SCE will address the gaps identified within two months of submission of this Tier 2 Advice Letter.

SCE notes that many early EPIC projects were completed before the database was launched. The requirement to capture specific topics in the database did not exist when some of these projects were completed, and so project teams did not always collect data or perform the analysis that would support some of the data fields in database, as these areas were not part of the projects' required scope. Some of the identified gaps came from these projects that were completed before the database requirements were established. Consequently, while SCE will make best efforts to provide additional information where possible, this data might not be available for all of the older projects.

In addition, under the rules of the database, some of the data fields, like "ratepayer benefits" and "key learnings," are fields that Administrators are allowed to update only when a project is complete. While the identification of ratepayer benefits and key learnings are integral across the project lifecycle and are captured as such internally, because of the database rules, SCE cannot update these fields until it completes the project. Some of the gaps from these fields came from projects that are still active. For those projects that are still active, SCE will update the data fields when SCE completes the projects.

B. Compliance with Requirement for Mandatory Language

Decision No. 23-04-042 requires all EPIC administrators to include in their annual reports a statement indicating that the EPIC program is funded by California utility customers under the auspices of the Commission.[6] In its March 26, 2025 disposition letter, the Commission observed that SCE's 2023 Annual Report (submitted as part of SCE's Advice Letter 5290-E) did not contain the required statement.[7] SCE has made

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[4] Ordering Paragraph 8 in Decision No. 18-10-052.
[5] March 26, 2025 Disposition Letter, p. 2.
[6] Ordering Paragraph 9 in Decision No. 23-04-042.
[7] March 26, 2025 Disposition Letter, p. 2.

this correction in its revised 2023 Electric Program Investment Charge Annual Report, which is attached to this Advice Letter. In addition, SCE has made non-substantive, formatting changes to the revised report.

ADVICE LETTER INFORMATION

No cost information is required for this advice filing.

This advice filing will not increase any rate or charge, cause the withdrawal, of service, or conflict with any other schedule or rule.

TIER DESIGNATION

Pursuant to the direction in the Commission's March 26, 2025 disposition letter, this advice letter is submitted with a Tier 2 designation.

EFFECTIVE DATE

This advice filing will become effective on May 25, 2025, the 30th calendar day after the date submitted.

NOTICE

Anyone wishing to protest this advice letter may do so only electronically. Protests must be received no later than 20 days after the date of this advice letter. Protests should be submitted to the CPUC Energy Division at:

E-mail: EDTariffUnit@cpuc.ca.gov

In addition, protests and all other correspondence regarding this advice letter should also be sent electronically to the attention of:

Connor Flanigan
Managing Director, State Regulatory Operations
Southern California Edison Company
E-mail: AdviceTariffManager@sce.com

Adam Smith
Director, Regulatory Relations
Southern California Edison Company
c/o Karyn Gansecki
E-mail: Karyn.Gansecki@sce.com

Gloria Ing
Senior Attorney
Southern California Edison Company
E-mail: Gloria.Ing@sce.com

and

Richard Kwee
Program Manager
Southern California Edison Company
E-mail: richard.1.kwee@sce.com

There are no restrictions on who may submit a protest, but the protest shall set forth specifically the grounds upon which it is based and must be received by the deadline shown above.

In accordance with General Rule 4 of GO 96-B, SCE is serving copies of this advice letter to the interested parties shown on the attached GO 96-B and R.13-11-005 service list. Address change requests to the GO 96-B service list should be directed by electronic mail to AdviceTariffManager@sce.com or at (626) 302-6838. For changes to all other service lists, please contact the Commission's Process Office at (415) 703-2021 or by electronic mail at Process_Office@cpuc.ca.gov. Pursuant to the directions in the CPUC's March 26, 2025 disposition letter, SCE is also serving this advice letter on all parties that Advice Letter 5290-E was served to. As such, pursuant to Ordering Paragraph 16 of Decision No. 12-05-037, SCE is also serving a copy of this advice letter on (1) parties on the A. 22-10-001 and R. 19-10-005 service lists, which are the most recent EPIC proceedings, (2) parties on the service list of A. 23-05-010, A. 22-05-016, and A. 21-06-021, which are the most recent general rate case proceedings of the electric investor owned utilities and EPIC administrators, and (3) the applicants seeking EPIC awards in 2023. Pursuant to the Energy Division's directions in its April 24, 2024 email, SCE is also submitting this Advice Letter directly to the Energy Division.

To view other SCE advice letters submitted with the Commission, log on to SCE's web site at https://www.sce.com/wps/portal/home/regulatory/advice-letters.

For questions, please contact Gloria Ing at (626) 302-1999 or by electronic mail at Gloria.Ing@sce.com.

Southern California Edison Company

/s/ Connor J Flanigan
Connor J Flanigan

Enclosures

cc: Leuwam.Tesfai@cpuc.ca.gov
Fredric.Beck@cpuc.ca.gov

Appendix A
Revised 2023 Electric Program Investment Charge (EPIC) Annual Report
April 25, 2025

EPIC ADMINISTRATOR ANNUAL REPORT FOR 2023 ACTIVITIES

EPIC ADMINISTRATOR ANNUAL REPORT FOR 2023 ACTIVITIES

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1. Executive Summary

a) Overview of Programs/Plan Highlights

The SCE project teams made notable advancements throughout 2023 across SCE's EPIC project portfolio. This program is funded by California utility customers under the auspices of the California Public Utilities Commission. Advancements included preparing to test a fully digital substation concept. For the Storage Based DC Project, SCE completed a power systems analysis and implemented a user-friendly graphical interface for the circuit tie controllers to dynamically balance load between the battery and two circuits. SCE also achieved milestones for the Fenwick Microgrid Lab project by successfully demonstrating 6 simulation use cases. One of the lab simulation use cases included the ability to disconnect from the grid and place the microgrid system into island mode with a Battery Energy Storage Systems (BESS) which is critical for maintaining microgrid stability.

Key findings and lessons learned emphasize the importance of ensuring that the lab testing is sufficient to meet SCE's requirements before deploying into a pilot or field operation. Such rigorous evaluation methods have proven effective in determining the feasibility of utilizing a DC link system. This innovative approach promises several strategic advantages, including bolstering energy security, stabilizing the grid, optimizing renewable energy use, increasing grid flexibility, and support for DERs.

Despite encountering challenges such as delays in procurement and vendor issues, the teams have effectively managed these setbacks and continue to drive the projects to completion.

2023 represented the tenth full year of implementing EPIC program operations since receiving the California Public Utilities Commission (Commission) approval of SCE's EPIC 1 application[1] on November 19, 2013.[2] Furthermore, 2023 represented nearly the eighth full year of implementing program operations of SCE's 2015 – 2017 Investment Plan Application[3] (EPIC 2) after receiving

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1 A.12-11-001.
2 D.13-11-025, OP8.
3 A.14-05-005.

Commission approval on April 9, 2015.[4] Lastly, 2023 represented SCE's fifth full year of implementing program operations of SCE's 2018 – 2020 Investment Plan Application[5] (EPIC 3) after receiving approval on October 25, 2018.

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

(1) 2012-2014 Investment Plan

Between January 1 and December 31, 2023, SCE expended a total of $45 toward project costs and $0 toward program administrative costs[6]. SCE's cumulative expenses over the span of its 2012 – 2014 Investment Plan amount to $38,661,721.

SCE executed 16 projects from its approved EPIC 1 portfolio. This includes the completion of three projects in 2015, four projects in 2016, four projects in 2017, two projects in 2018, two projects in 2019 and one project in 2020. A list of completed projects is included in the Conclusion of this Report (section 5). In accordance with the Commission's directives,[7] SCE has prepared Final Project Reports for each completed project and included them in the Annual Reports according to the years completed. No EPIC 1 projects remain in execution as of December 31, 2023.

(2) 2015-2017 Investment Plan

Between January 1 and December 31, 2023, SCE expended $414,599 toward project costs and $174,703 toward administrative costs for a grand total of $589,302. SCE's cumulative expenses for its 2015 – 2017 Investment Plan amount to $38,270,358. SCE committed $1,775,009 toward projects and encumbered $590,774 through executed purchase orders during this period. SCE has no uncommitted EPIC 2 funding as of December 31, 2023.

SCE initiated 13 projects from its approved EPIC 2 portfolio. As of December 31, 2023, three projects have been cancelled for the reasons described in their respective project updates

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[4] D.15-04-020, OP1.
[5] A.17-05-005.
[6] SCE is reviewing these costs.
[7] D.13-11-025, OP14.

sections.[8] Project execution activities continued for the remaining ten projects. Of those 10 projects, SCE completed one project in 2017, three projects in 2018, two projects in 2019, one project in 2020, one project in 2021, and one project in 2022. One demonstration project (System Intelligence and Situational Awareness Capabilities) remains in execution for 2023.

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

Between January 1 and December 31, 2023, SCE expended a total of $4,097,841 toward project costs and $383,366 toward administrative costs for a grand total of $4,481,207. SCE's cumulative expenses over the span of its 2018 – 2020 Investment Plan amount to $24,888,482. SCE committed $10,319,780 toward projects and encumbered $5,226,231 through executed purchase orders during this period. SCE has no uncommitted EPIC 3 project funding as of December 31, 2023.

SCE received approval from the Commission for two replacement projects in 2022: Wildfire Prevention & Resiliency Technologies Demonstration and Beyond Lithium-Ion Energy Storage Demonstration, both of which were included in the Joint Utilities Research Administration Plan (RAP) Application. SCE initiated 19 projects from its approved portfolio. Four of the EPIC 3 projects were either previously canceled or deferred. Project execution activities continued for the remaining fifteen projects. Of those fifteen projects, one was completed in 2021 and one was completed in 2022. During 2023, SCE completed one additional project (Distributed Energy Resources Dynamics Integration Demonstration) and continues to perform work on the remaining twelve projects. The following 12 projects from the EPIC 3 portfolio remain in execution:

1. Advanced Comprehensive Hazards Tool
2. Advanced Technology for Field Safety (ATFS)
3. Beyond Lithium-ion Energy Storage Demo
4. Control and Protection for Microgrids and Virtual Power Plants
5. Distributed PEV Charging Resource
6. Next Generation Distribution Automation III

[8] Starting at p. 13.

7. SA-3 Phase III Field Demonstrations
8. Service Center of the Future
9. Smart City Demonstration
10. Storage-Based Distribution DC Link
11. Vehicle-to-Grid Integration Using On-Board Inverter
12. Wildfire Prevention & Resiliency Technology Demonstration

2. Introduction and Overview

a) EPIC Background

In Decision (D.)12-05-037, the Commission established the EPIC Program to fund applied research and development, technology demonstration and deployment (TD&D), and market facilitation programs to provide ratepayer benefits. This program is funded by California utility customers under the auspices of the California Public Utilities Commission. D.12-05-037 further stipulates that the EPIC Program will continue through 2020[9] with an annual budget of $162 million,[10] adjusted for inflation.[11] Approximately 80% of the EPIC budget is administered by the California Energy Commission (CEC), and 20% is administered by the investor-owned utilities (IOUs). Additionally, 0.5% of the total EPIC budget funds Commission oversight of the Program.[12] The IOUs were also limited to performing TD&D activities.[13] SCE was allocated 41.1% of the IOU portion of the budget and administrative activities.[14]

The Commission approved SCE's 2012-2014 Investment Plan[15] in D.13-11-025 on November 19, 2013. SCE submitted its 2015-2017 Investment Plan Application[16] on May 1, 2014, and the Commission approved the Application in D.15-04-020 on April 9, 2015. SCE submitted its 2018-

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[9] D.12-05-037, OP1.
[10] D.12-05-037, OP7.
[11] Using the Consumer Price Index.
[12] *Id*, OP5.
[13] *Id*.
[14] D.12-05-037, OP 7, as modified by D.12-07-001.
[15] A.12-11-004.
[16] A.14-05-005.

2020 Application on May 1, 2017, and the Commission approved the Application in D.18-10-052 on October 25, 2018. SCE is currently executing its 2015-2017 and 2018-2020 EPIC Investment Plans.

In 2019, the Commission initiated a two-phase rulemaking[17] to determine the future of EPIC. In Phase 1 the Commission determined that EPIC would continue for ten years through 2030, and that each investment period would span five years (2021-2025 and 2026-2030). Additionally, the Commission authorized the CEC to continue its EPIC administrator role.[18] In Phase 2 of the rulemaking, the Commission determined that the Utilities should continue their roles as EPIC Administrators, along with the CEC.[19] SCE (along with PG&E and SDG&E) filed their respective EPIC 4 Investment Plans, covering 2021-2025, on October 1, 2022.[20] Per D.23-04-042, the EPIC Program Administrators are to file annual reports on April 30 of each year, via a Tier 2 Advice Letter that follow the outline in Appendix C.[21] The Commission approved SCE's, PG&E's and SDG&E's EPIC Investment Plans for 2021-2025 on November 30, 2023.

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

The Commission limited SCE's triennial investment applications in the EPIC Program to TD&D projects, per D.12-05-037 and reiterated in D.21-11-028. The Commission defines TD&D projects as installing and operating pre-commercial technologies or strategies at a scale sufficiently large, and in conditions sufficiently reflective of anticipated actual operating environments, to enable appraisal of the operational and performance characteristics and the associated financial risks.[22]

For EPIC 4, the Utilities coordinated with the CEC to define strategic objectives (program categories). However, for administration of its EPIC 1-3 Portfolios, the IOUs continue to successfully utilize the joint IOU framework developed for the 2012-2014 cycle (EPIC 1) and enhanced for the 2015-2017 (EPIC 2) and 2018-2020 (EPIC 3) cycles with updated strategic initiatives to support the

[17] R.19-10-005.
[18] D.20-08-042.
[19] D.21-11-028.
[20] A.22-10-005.
[21] D.23-04-042, OP8.
[22] D.12-05-037, OP3.B.

latest key drivers and policies. This includes the following four program categories: (1) energy resources integration, (2) grid modernization and optimization, (3) customer-focused products and services, and (4) cross-cutting/foundational strategies and technologies. SCE's 2012-2014, 2015-2017, and 2018-2020 Investment Plans proposed projects for each of these four areas, focusing on the ultimate goals of promoting greater reliability, lowering costs, increasing safety, decreasing greenhouse gas emissions, and supporting low-emission vehicles and economic development for ratepayers.

c) Coordination

The EPIC Administrators collaborated throughout 2023 on the execution of the 2015-2017 (EPIC 2) and 2018-2020 (EPIC 3) Investment Plans, as well as planning the EPIC 4 Investment Plan. Specific examples of the IOUs' coordination with the CEC include the Joint Utilities EPIC Workshop (June 27, 2023) and the virtual 2023 EPIC Symposium (October 3-4, 2023).

The Utility EPIC Administrators met on a near-weekly basis (and bi-weekly basis with the CEC) to discuss the items mentioned above, coordinate investment plan activities, and to plan and coordinate joint stakeholder workshops and the annual joint public symposium. Moreover, SCE held several collaborative meetings with the CEC to help further coordinate the respective investments plans.

d) Transparent and Public Process/CEC Solicitation Activities

In 2023, SCE supported the annual EPIC Symposium held virtually again due to the pandemic. SCE supported the CEC in a discussion on "Innovative Technologies and Strategies for Reducing Wildfire Risk". In addition to the Symposium, the Joint Utilities coordinated with the CEC on a public workshop hosted by SCE with a discussion on EPIC 3 projects moderated by EPRI.

SCE supported numerous parties applying for CEC EPIC funding in 2023. A total of 15 requests for Letters of Support (LOS) and Letters of Commitment (LOC) were received from a diverse array of parties including private vendors, universities, and national laboratories, showing interest in partnering on their bids for CEC projects. Of these 15 requests, SCE provided letters for 11. All were LOS, of which five were approved by the CEC.

For SCE, a LOS typically supports the premise of a project. In some instances, it will infer technical advisory support if the project is awarded to the recipient and the party and SCE come to a mutual understanding of what advisory support will be required.

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

3. Budget

a) Authorized Budget

(1) 2012 – 2014 Investment Plan

Table 1: 2012-2014 Authorized EPIC Budget (Annual)

2012-2014 (Jan 1 - Dec 31)	Administrative	Project Funding	Commission Regulatory Oversight Budget
SCE Program	$1.3M	$11.9M	$0.33M[23]
CEC Program	$5.3M	$47.7M	

(2) 2015 – 2017 Investment Plan

Table 2: 2015 – 2017 Authorized EPIC Budget (Annual)

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

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

(3) 2018 – 2020 Investment Plan

Table 3: 2018 – 2020 Authorized EPIC Budget (Annual)

2018-2020 (Jan 1 - Dec 31)	Administrative	Project Funding	Commission Regulatory Oversight Budget
SCE Program	$1.5M	$13.6M	$0.02M
CEC Program	$6.0M	$54.4M	

b) Commitments/Encumbrances

(1) 2012 – 2014 Investment Plan

As of December 31, 2023, SCE has committed $0 and encumbered $0 of its authorized 2012-2014 program budget.

(2) 2015 – 2017 Investment Plan

As of December 31, 2023, SCE has committed $1,775,009 and encumbered $590,774 of its authorized 2015-2017 program budget.

(3) 2018 – 2020 Investment Plan

As of December 31, 2023, SCE has committed $10,319,780 and encumbered $5,226,231 of its authorized 2018-2020 program budget.

(4) CEC & CPUC Remittances

For CEC remittances, SCE remitted $6,082,800 [24] for program administration, and $30,338,947 for encumbered projects during calendar year 2023.

For CPUC remittances, SCE remitted $380,175 in calendar year 2023.

c) Fund Shifting Above 15% between Strategic Initiatives

As of December 31, 2023, SCE does not have any pending fund shifting requests and/or approvals for the 2012-2014, 2015-2017 and 2018-2020 investment plans.

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[24] Due to the timing of the CPUC's Decision (D.)18-01-008, approving the EPIC III 2018-2020 budget in mid-January 2018 (Quarter 1). The Utilities are remitting the total CEC administrative budget over 11 quarters.

d) Uncommitted/Unencumbered Funds

As of December 31, 2023, SCE has no uncommitted/unencumbered funds for the 2012-2014, 2015-2017 and 2018-2020 investment plans.

4. Projects

a) High Level Summary

SCE provides a summary of project funding for SCE's 2012-2014, 2015-2017, and 2018-2020 Investment Plans, please refer to Table 4, Table 6, and Table 8

(1) 2012-2014 Investment Plan

As of December 31, 2023, SCE has expended $38,661,721 on program costs. In accordance with the Commission's directives,[25] SCE has prepared Final Project Reports for each completed project and included them in the Annual Reports according to the years completed. No projects remain in execution as of December 31, 2023. Table 4 summarizes the 2012-2014 Investment Plan projects by program category, completion year, and total funding.

Table 4: 2012 – 2014 Investment Plan Summary

1. Energy Resources Integration	**Total Funding**

Three projects funded
• Completed in 2016: Distribution Planning Tool
• Completed in 2018:
  • DOS Protection & Control Demonstration and
  • Advanced Voltage and VAR Control of SCE Transmission Project
	$1,988,964

2. Grid Modernization and Optimization	**Total Funding**
Five projects funded • Cancelled in 2014: Superconducting Transformer[26] • Completed in 2015: Portable End-to-End Test System • Completed in 2016: Dynamic Line Rating • Completed in 2017: Next Generation Distribution Automation, Phase 1 • Completed in 2020: Substation Automation 3 (SA-3), Phase 1	$11,133,289
3. Customer Focused Products and Services	**Total Funding**
Three projects funded	$3,624,299

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25 D.13-11-025, OP14.

26 SCE cancelled the Superconducting Transformer project in Q2, 2014. Please refer to the project's status update in Section 4 for additional details.

• Completed in 2015: Outage Management and Customer Voltage Data Analytics Demonstration • Completed in 2016: Submetering Enablement Demonstration • Completed in 2017: Beyond the Meter: Customer Device Communications Unification and Demonstration	
4. Cross-Cutting/Foundational Strategies and Technologies	**Total Funding**

Five projects funded
• Completed in 2015: Cyber-Intrusion Auto-Response and Policy Management System
• Completed in 2016: Enhanced Infrastructure Technology Report
• Completed in 2017:
  • State Estimation Using Phasor Measurement Technologies Project
  • Deep Grid Coordination Project (otherwise known as the Integrated Grid Project)
• Completed in 2019: Wide Area Management and Control
	$20,827,698

Total Projects Funded: 16 Total Authorized Project Budget: $37,656,998 [27] Total Project Spend: $37,102,164 Total Funding Committed: $472,088[28] Total Encumbered: 0[29] *Note: Due to intrinsic variability in TD&D/R&D projects, amounts shown are subject to change*	

Table 5 below summarizes SCE's 2023 administration expenses:

Table 5: 2012 – 2014 Investment Plan Administration Expenses

Total Authorized Budget:	$1,855,002[30]
Total Cumulative Cost:	$1,555,042
Total 2023 Cost:	$0

27 D.12-05-037, as updated by D.13-11-025. Includes $2,045,000 transfer from administrative funds to project funds.

28 *Ibid.*

29 *Ibid.*

30 2012-2014 EPIC I Administrative Budget is $3,812,000. SCE Program Management transferred $1,956,998 from the Administrative to the Project Budget, reducing the Authorized Budget to $1,855,002.

(2) 2015-2017 Investment Plan

As of December 31, 2023, SCE has expended $38,270,358[31] on program costs.

Table 6 below summarizes the current status and funding of SCE's EPIC 2 projects:

Table 6: 2015 – 2017 Investment Plan Summary

1. Energy Resources Integration	**Total Funding**

Three projects funded
• Canceled in 2016:
  • Bulk System Restoration under High Renewables Penetration project
  • Series Compensation for Load Flow Control project
• Cancelled in 2017: Optimized Control of Multiple Storage Systems
	$187,493

2. Grid Modernization and Optimization	**Total Funding**
Six projects funded • Completed in 2017: Advanced Grid Capabilities Using Smart Meter Data • Completed in 2018: Proactive Storm Impact Analysis Demonstration • Completed in 2019: Versatile Plug-in Auxiliary Power System • Completed in 2020: Dynamic Power Conditioner • Completed in 2022: Next-Generation Distribution Equipment & Automation, Phase 2 • Currently In Execution: System Intelligence and Situational Awareness Capabilities	$15,958,858
3. Customer Focused Products and Services	**Total Funding**

Three projects funded
• Completed in 2018:
  • DC Fast Charging
  • Integration of Big Data for Advanced Automated Customer Load Management
• Completed in 2019: Regulatory Mandates: Submetering Enablement Demonstration, Phase 2
	$2,440,504

4. Cross-Cutting/Foundational Strategies and Technologies	**Total Funding**
One project funded • Completed in 2021: Integrated Grid Project II	$18,917,345
Total Projects Funded: 13 Total Authorized Project Budget: $37,504,200 [32] Total Project Spend: $35,112,705 [33]	

[31] SCE's cumulative project expenses amounted to $35,112,705. SCE's cumulative administration expenses amounted to $3,157,656. These totals include SCE labor and overheads. As a result, SCE expended a total of $38,270,358 on program costs.

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

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

Total Funding Committed: $1,775,009 [34] Total Encumbered: $590,774 [35] *Note: Due to intrinsic variability in TD&D /R&D projects, amounts shown are subject to change*

Table 7 below summarizes SCE's 2023 administrative expenses.

Table 7: 2015 – 2017 Investment Plan Administration Expenses

Total Authorized Budget: Total Cumulative Cost: Total 2023 Cost:	$4,190,400 [36] $3,157,656 $174,703

(3) 2018-2020 Investment Plan

As of December 31, 2023, SCE has expended $24,888,482[37] on program costs.

Table 8 below summarizes the current status and funding of SCE's EPIC 3 projects.

Table 8: 2018 – 2020 Investment Plan Summary

1. Energy Resources Integration	**Total Funding**
Two projects funded • Completed in 2023: Distributed Energy Resources Dynamics Integration Demonstration • Currently in Execution: Smart City Demonstration	$5,826,512
2. Grid Modernization and Optimization	**Total Funding**

Six projects funded
• Cancelled in 2020: Power System Voltage and VAR Control Under High Renewables Penetration
• Hold/Deferred in 2020: Distribution Primary & Secondary Line Impedance Project
• Currently in Execution:
  • Beyond Lithium-ion Energy Storage Demo;
  • SA-3, Phase III Field Demonstrations;
  • Storage-Based Distribution DC Link; and
  • Next Generation Distribution Automation III project
	$12,495,525

[34] *Ibid.*

[35] *Ibid.*

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

[37] SCE's cumulative project expenses amounted to $21,252,578. SCE's cumulative administration expenses amounted to $3,610,840. These totals include SCE labor and overheads. As a result, SCE expended a total of $24,888,482, on program costs.

3. Customer Focused Products and Services	Total Funding

Four projects funded
• Currently in Execution:
  • Control and Protection for Microgrids and Virtual Power Plants;
  • Distributed PEV Charging Resource;
  • Service Center of the Future; and
  • Vehicle-to-Grid Integration Using On-Board Inverter
	$9,853,000

4. Cross-Cutting/Foundational Strategies and Technologies	**Total Funding**

Seven projects funded
• Cancelled in 2019: Energy System Cybersecurity Posturing
• Hold/Deferred in 2021: Advanced Data Analytics Technologies (ADAT)
• Completed in 2021: Distributed Cyber Threat Analysis Collaboration (DCTAC)
• Completed in 2022: Cybersecurity for Industrial Control Systems
• Currently in Execution:
  • Advanced Comprehensive Hazards Tool;
  • Advanced Technology for Field Safety (ATFS); and
  • Wildfire Prevention & Resiliency Technology Demonstration
	$12,456,813

Total Projects Funded: 19 Total Authorized Project Budget: $40,830,795 [38] Total Project Spend: $21,252,578 Total Funding Committed: $19,578,217[39] Total Encumbered: $5,226,231 [40] *Due to intrinsic variability in TD&D /R&D projects, amounts shown are subject to change*	

Table 9 below summarizes SCE's 2023 administrative expenses for the 2018 – 2020 investment plan.

Table 9: 2018 – 2020 Investment Plan Administration Expenses

Total Authorized Budget:	$4,562,100 [41]
Total Cumulative Cost:	$3,610,840
Total 2023 Cost:	$383,366

[38] D.18-01-008, at p. 38.
[39] *Ibid.*
[40] *Ibid.*
[41] D.18-01-008, at p. 38.

b) Project Status Report

The descriptions of the project objectives and scope reflect the proposals filed in the respective EPIC Investment Plans,[42] while the project status information reflects the progress through 2023. As a result of corrections made to address preliminary 2020 EPIC audit findings,[43] some dollar values for completed projects have changed.

(1) 2012 – 2014 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 high distributed energy resources (DER) penetration and increased adoption of distributed generation (DG) owned by consumers directly connected to SCE's distribution grid and on the customer side of the meter. This demonstration project is in effect the next step following the ISGD project. Therefore, this project focuses on the effects of introducing emerging and innovative technology into the utility and consumer end of the grid to account for this increase in DER resources. This scenario introduces the need for the utility (SCE) to assess technologies and controls necessary to stabilize the grid with increased DG adoption, and more importantly, consider possible economic models that would help SCE adapt to the changing regulatory policy and GRC structures. This value-oriented demonstration informs many key questions that have been asked: • What is the value of distributed generation and where is it most valuable? • What is the cost of intermittent resources? • What is the value of storage and where is it most valuable? • How are DER resources/devices co-optimized? • What infrastructure is required to enable an optimized solution? • What incentives/rate structure will enable an optimized solution?	
Schedule Q2 2014 – Q4 2017	
Status	

[42] The EPIC 1 Investment Plan Application (A.)12-11-004 was filed on November 1, 2012. The EPIC 2 Investment Plan A.14-05-005 was filed on May 1, 2014. The EPIC 3 Investment Plan A.17-05-005 on May 1, 2017.

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

The final project report is complete, was submitted with the 2017 Annual Report, and is available on PICG's public EPIC website.

2. Regulatory Mandates: Submetering Enablement Demonstration

Investment Plan Period 1st Triennial Plan (2012-2014)	**Assignment to Value Chain** Demand-Side Management
Objective & Scope On November 14, 2013, the Commission voted to approve the revised Proposed Decision (PD) Modifying the Requirements for the Development of a Plug-In Electric Vehicle Submetering Protocol set forth in D.11-07-029. The investor-owned utilities (IOUs) are to implement a two phased pilot beginning in May 2014, with funding for both phases provided by the EPIC. This project, Phase I of the pilot will (1) evaluate the demand for Single Customer of Record submetering, (2) estimate billing integration costs, (3) estimate communication costs, and (4) evaluate customer experience. IOUs and external stakeholders will finalize the temporary metering requirements, develop a template format used to report submetered, time-variant energy data, register Submeter Meter Data Management Agents and develop a Customer Enrollment Form, and finalize MDMA Performance Requirements. The IOUs will also solicit a 3rd party evaluator to evaluate customer experience.	
Schedule Q1 2014 – Q1 2017	
Status The final project report is complete, was submitted with the 2016 Annual Report, and is available on PICG's public EPIC website.	

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.	
Status The final project report is complete, was submitted with the 2016 Annual Report, and is available on PICG's public EPIC website.	

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

Investment Plan Period 1st Triennial Plan (2012-2014)	**Assignment to Value Chain** Demand-Side Management
Objective & Scope The Beyond the Meter (BTM) project will demonstrate the use of a DER management system to interface with and control DER based on customer and distribution grid use cases. It will also demonstrate the ability to communicate near-real time information on the customer's load management decisions and DER availability to SCE for grid management purposes. Three project objectives include: 1) develop a common set of requirements that support the needs of a variety of stakeholders including customers, distribution management, and customer program; 2) validate standardized interfaces, functionalities, and architectures required in new Rule 21 proceedings, IOU Implementation Guide, and UL 1741/IEEE 1547 standards; 3) collect and analyze measurement and cost/benefits data in order to inform the design of new tariffs, recommend the deployment of new technologies, and support the development of new programs.	
Status The EPIC 1 Final Report for the Beyond the Meter Project is complete, was submitted with the with the 2017 Annual Report, and is available on PICG's public EPIC website.	

5. Portable End-to-End Test System

Investment Plan Period 1st Triennial Plan (2012-2014)	**Assignment to Value Chain** Transmission
Objective & Scope End-to-end transmission circuit relay testing has become essential for operations and safety. SCE technicians currently test relay protection equipment during commissioning and routing testing. Existing tools provide a limited number of scenarios (disturbances) for testing and focus on testing protection elements; not testing system protection. This project will demonstrate a robust portable end-to-end toolset (PETS) that addresses: 1) relay protection equipment, 2) communications, and 3) provides a pass/fail grade based on the results of automated testing using numerous simulated disturbances. PETS will employ portable Real-Time Digital Simulators (RTDS's) in substations at each end of the transmission line being tested. Tests will be documented using a reporting procedure used in the Power Systems Lab today, which will help ensure that all test data is properly evaluated.	
Schedule Q1 2014 – Q4 2015	
Status The final project report is complete, was submitted with the 2015 Annual Report, and is available on PICG's public EPIC website.	

6. Voltage and VAR Control of SCE Transmission System

Investment Plan Period 1st Triennial Plan (2012-2014)	Assignment to Value Chain Transmission
Objective & Scope This project involves demonstrating software and hardware products that will enable automated substation volt/var control. Southern California Edison (SCE) will demonstrate a Substation Level Voltage Control (SLVC) unit working with a transmission control center Supervisory Central Voltage Coordinator (SCVC) unit to monitor and control substation voltage. The scope of this project includes systems engineering, testing, and demonstration of the hardware and software that could be operationally employed to manage substation voltage.	
Schedule Q1 2014 – Q4 2018	
Status The Final Report for the Voltage and VAR Control of SCE Transmission System is complete, was submitted with the 2018 Annual Report, and is available on PICG's public EPIC website.	

7. Superconducting Transformer (SCX) Demonstration

Investment Plan Period 1st Triennial Plan (2012-2014)	Assignment to Value Chain Distribution
Objective & Scope This project was cancelled in 2014. No further work is planned. *Original Project Objective and Scope:* SCE will support this $21M American Reinvestment and Recovery Act (ARRA) Superconducting Transformer (SCX) project by providing technical expertise and installing and operating the transformer at SCE's MacArthur substation. The SCX prime contractor is SuperPower Inc. (SPI), teamed with SPX Transformer Solutions (SPX) {formerly Waukesha Electric Systems}. SCE has provided two letters of commitment for SCX. The SCX project will develop a 28 MVA High Temperature Superconducting, Fault Current Limiting (HTS-FCL) transformer. The transformer is expected to be installed in 2015. SCE is supporting this project and is not an ARRA grant sub-recipient. SCE is being reimbursed for its effort by EPIC. SCE's participation in this project was previously approved under the now-defunct California Energy Commission's PIER program.	
Status 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).
Schedule Q2 2014 – Q4 2017
Status The final project report is complete, was submitted with the 2017 Annual Report, and is available on PICG's public EPIC website.

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.	
Schedule Q2 2014 – Q1 2019	
Status The final project report is complete, was submitted with the 2019 Annual Report, and is available on PICG's public EPIC website.	

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

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

requirements for grid optimization and renewables integration with distributed energy storage devices. A second part of this project will investigate how energy storage devices located on distribution circuits can be used for reliability while also being bid into the CAISO markets to provide ancillary services. This is also known as dual-use energy storage. Initial use cases will be developed to determine the requirements for the control systems necessary to accomplish these goals.
Schedule Q2 2014 – Q4 2017
Status The Final Report for the Voltage and VAR Control of SCE Transmission System is complete, was submitted with the 2018 Annual Report, and is available on PICG's public EPIC website.

11. Outage Management and Customer Voltage Data Analytics Demonstration

Investment Plan Period 1st Triennial Plan (2012-2014)	**Assignment to Value Chain** Grid Operation/Market Design
Objective & Scope Voltage data and customer energy usage data from the Smart Meter network can be collected and leveraged for a range of initiatives focused on achieving operational benefits for Transmission & Distribution. Before a full implementation of this new approach can be considered, a demonstration project will be conducted to understand how voltage and consumption data can be best collected, stored, and integrated with T&D applications to provide analytics and visualization capabilities. Further, Smart Meter outage and restoration event (time stamp) data can be leveraged to improve customer outage duration and frequency calculations. Various stakeholders in T&D have identified business needs to pursue more effective and efficient ways of calculating SAIDI (System Average Interruption Duration Index), SAIFI (System Average Interruption Frequency Index), and MAIFI (Momentary Average Interruption Frequency Index) for internal and external reporting. Before a full implementation of this new approach can be considered, a demonstration project will be conducted to understand the feasibility and value of providing smart meter data inputs and enhanced methodology for calculating the Indexes. The demonstration will focus on a limited geography (SCE District or Region) to obtain the Smart Meter inputs to calculate the Indexes and compare that number with the current methodologies to identify any anomalies. A hybrid approach using the Smart Meter-based input data combined with a better comprehensive electric connectivity model obtained from GIS may provide a more efficient and effective way of calculating the Indexes. Additionally, an effort to evaluate the accuracy of the Transformer Load Mapping data will be carried out.	
Schedule Q1 2014 – Q4 2015	
Status The final project report is complete, was submitted with the 2015 Annual Report, and is available on PICG's public EPIC website.	

12. SA-3 Phase III Demonstration

Investment Plan Period 1st Triennial Plan (2012-2014)	Assignment to Value Chain: Transmission
Objective & Scope This project is intended to apply the findings from the Substation Automation Three (SA-3) Phase II (Irvine Smart Grid Demonstration) project to demonstrate real solutions to automation problems faced by SCE today. The project will demonstrate two standards-based automation solutions (sub-projects) as follows: Subproject 1 (Bulk Electric System) will address issues unique to transmission substations including the integration of centrally managed critical cyber security (CCS) systems and NERC CIP compliance. When the project was proposed Subproject 2 (Hybrid) intended to address the integration of SA-3 capabilities with SAS and SA-2 legacy systems. In 2016 SA-3 Hybrid scope was completely dropped from the EPIC SA-3 phase III Demonstration. Furthermore, as part of the systems engineering the SA-3 technical team will demonstrate two automation tools as follows: Subproject 3 (Intelligent Alarming) will allow substation operators to pin-point root cause issues by analyzing the various scenarios and implement an intelligent alarming system that can identify the source of the problem and give operators only the relevant information needed to make informed decisions; and Subproject 4 (Real Time Digital Simulator (RTDS) Mobile Testing) will explore the benefits of an automated testing using a mobile RTDS unit, and propose test methodologies that can be implemented into the factory acceptance testing (FAT) and site acceptance testing (SAT) testing process.	
Schedule Q1 2014 – Q3 2021	
Status The final project report is complete and is submitted as part of the 2020 Annual Report and is available on PICG's public EPIC website.	

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.
Schedule Q1 2014 – Q4 2017
Status The final project reports were completed and submitted with the 2017 Annual Report and are available on PICG's public EPIC website. SCE has completed an Executive Summary Report that ties the subprojects together, which was submitted with the 2018 Annual Report, and is available on PICG's public EPIC website.

14. Enhanced Infrastructure Technology Evaluation

Investment Plan Period 1st Triennial Plan (2012-2014)	**Assignment to Value Chain** Distribution
Objective & Scope At the request of Distribution Apparatus Engineering (DAE) group's lead Civil Engineer, Advanced Technology (AT) will investigate, demonstrate, and evaluate recommendations for enhanced infrastructure technologies. The project will focus on evaluating advanced distribution sectional poles (hybrid, coatings, etc.), concealed communications on assets, vault monitoring systems (temperature, water, etc.), and vault ventilation systems. Funding is needed to investigate the problem, engineering, demonstrate alternatives, and come up with recommendations. SCE sees the need for poles that can withstand fires and have a better life cycle cost and provide installation efficiencies when compared to existing wood pole replacements. Due to increased city restrictions, there is a need for more concealed communications on our assets such as streetlights (e.g., on the ISGD project, the City of Irvine would not allow SCE to install repeaters on streetlights due to aesthetics). DAE also sees the need for technologies that may minimize premature vault change-outs (avg. replacement cost is ~$250K). At present, DAE does not have the necessary real-time vault data to sufficiently address the increasing vault deterioration issue nor do we utilize a hardened ventilation system that would help this issue by removing the excess heat out of the vaults (blowers last ~ 2 years, need better bearings for blower motors, etc.).	
Schedule Q2 2014 – Q4 2016	
Status The final project report is complete and was submitted with the 2016 Annual Report, and is available on PICG's public EPIC website.	

15. Dynamic Line Rating Demonstration

Investment Plan Period 1st Triennial Plan (2012-2014)	**Assignment to Value Chain** Transmission
Objective & Scope Transmission line owners apply fixed thermal rating limits for power transmission lines. These limits are based on conservative assumptions of wind speed, ambient temperature, and solar radiation. They are established to help ensure compliance with safety codes, maintain the	

integrity of line materials, and help secure network reliability. Monitored transmission lines can be more fully utilized to improve network efficiency. Line tension is directly related to average conductor temperature. The tension of a power line is directly related to the current rating of the line. This project will demonstrate the CAT-1 dynamic line rating solution. The CAT-1 system will monitor the tension of transmission lines in real-time to calculate a dynamic daily rating. If successful, this solution will allow SCE to perform real-time calculations in order to determine dynamic daily rating of transmission lines, thus increasing transmission line capacity.
Schedule Q2 2014 – Q1 2016
Status The final project report is complete, was submitted with the 2016 Annual Report, and is available on PICG's public EPIC website.

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.	
Schedule Q3 2014 – Q3 2015	
Status The final project report is complete, was submitted with the 2015 Annual Report, and is available on PICG's public EPIC website.	

(2) 2015 – 2017 Investment Plan Projects

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

Investment Plan Period 2nd Triennial Plan (2015-2017)	**Assignment to Value Chain** Demand-Side Management
Objective & Scope This proposed project builds upon the "Beyond the Meter Advanced Device Communications" project from the first EPIC triennial investment plan and proposes to demonstrate how the concept of "big data"[44] 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	

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

Advanced Load Control System (ALCS) and by communicating to centralized energy hubs at the customer level to determine the optimal load management scheme.
Schedule Q1 2016 – Q4 2018
Status The Final Report for the Integration of Big Data for Advanced Automated Customer Load Management is complete, and was submitted with the 2018 Annual Report, and is available on PICG's public EPIC website.

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.	
Schedule Q3 2015 – Q1 2017	
Status The final project report is complete and, was submitted with the 2017 Annual Report, and is available on PICG's public EPIC website.	

3. Proactive Storm Impact Analysis Demonstration

Investment Plan Period 2nd Triennial Plan (2015-2017)	**Assignment to Value Chain** Distribution
Objective & Scope This project will demonstrate proactive storm analysis techniques prior to the storm's arrival and estimate its potential impact on utility operations. In this project, we will investigate certain technologies that can model a developing storm and its potential movement through the utility service territory based on weather projections. This information and model will then be integrated with the Geographic Information System (GIS) electrical connectivity model, Distribution Management System (DMS), and Outage Management System (OMS) capabilities, along with historical storm data, to predict the potential impact on the service to customers. In addition, this project will demonstrate the integration of near real-time meter voltage data with the GIS network to develop a simulated circuit model that can be effectively utilized to manage storm responses and activities and deploy field crews.	
Schedule Q3 2015 – Q4 2018	

Status
The Final Report for the Proactive Storm Impact Analysis Demonstration is complete, was submitted with the 2018 Annual Report, and is available on PICG's public EPIC website.

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

Investment Plan Period 2nd Triennial Plan (2015-2017)	**Assignment to Value Chain** Distribution
Objective & Scope This project will leverage lessons learned from the Next Generation Distribution Automation – Phase 1 project performed in the first EPIC triennial investment plan period. This project will focus on integrating advanced control systems, modern wireless communication systems, and the latest breakthroughs in distribution equipment and sensing technology to develop a complete system design that would serve as a standard for distribution automation and advanced distribution equipment.	
Schedule Q3 2016 – Q4 2022	
Status The final project is complete and was submitted with the 2022 Annual Report, and is available on PICG's public EPIC website.	

5. System Intelligence and Situational Awareness Capabilities

Investment Plan Period 2nd Triennial Plan (2015-2017)	**Assignment to Value Chain** Distribution
Objective & Scope This project will demonstrate system intelligence and situational awareness capabilities such as high impedance fault detection, intelligent alarming, predictive maintenance, and automated testing. This will be accomplished by integrating intelligent algorithms and advanced applications with the latest substation automation technologies, next generation control systems, latest breakthrough in substation equipment, sensing technology, and communications assisted protection schemes. This system will leverage the International Electrotechnical Commission (IEC) 61850 Automation Standard and will include cost saving technology such as process bus, peer-to-peer communications, and automated engineering and testing technology. This project will also inform complementary efforts at SCE aimed at meeting security and NERC CIP compliance requirements. This project will test end-to-end digital capabilities between various simulated switchyard gear and protection and control (P&C) devices via a digital interface using IEC 61850 process bus technology in a laboratory environment. The process bus technology is a key enabler to the digital substation, which will enable SCE to substitute engineering-intensive and costly point-to-point copper signaling wires with a safe, standardized optical communication bus (i.e., process bus). In doing so, SCE will remove the copper connections between its high-voltage switchgear and the various P&C devices needed to operate the substation. By retrofitting an existing distribution substation with IEC 61850 process bus technology and replacing protection relays with IEC 61850-capable Intelligent Electronic	

Devices (IEDs), SCE can develop a more flexible and cost-effective foundation for protecting substations amid increasing renewables and security standards. More specifically, the team anticipates the following potential benefits for its business stakeholders:

- Replacing complex point-to-point copper wires with safe, standardized optical communications will help reduce capital costs associated with the required footprint, construction, and testing of P&C systems.
- An IEC 61850 standard process bus makes it easier to update P&C applications and schemes by updating software configurations rather than hardwired reconfigurations, thereby reducing outage time and maintenance costs (O&M), and providing quicker responses to new protection challenges.
- Potential improvement to field worker safety due to the elimination of electrical connections between high-voltage switchgear and P&C devices—e.g., reducing the potential for inadvertently-opened Current Transformer (CT) circuits.
- The process bus will help increase SCE's understanding of what is occurring within the substation by enabling remote and on-site real-time system monitoring capabilities.
- Data and analysis from devices also enable near real-time asset monitoring, predictive analytics, and health indices to support "just-in-time" asset replacement, increasing the useful lives of capital assets.
- An IEC 61850 standard process bus enables interoperability between devices made by different manufacturers, allowing SCE to choose best-in-breed P&C devices and/or virtual applications.

Schedule

Q1 2016 – Q3 2025

Status Update

Accomplishment & Success Stories

- The project team onboarded vendors to advance the engineered drawings and to fabricate the testing equipment and began soliciting vendors to assist with testing.
- The project team procured all long-lead time material to avoid supply chain delays.
- The team completed all IT system architecture documentation.
- The engineering drawing vendor delivered the final product which was approved by SCE.
- The team completed the initial test plan.

Challenges or Setbacks

- During the planning phase the project team minimized the scope of the material necessary to successfully test the fully digital substation concept. It was noticed that additional material was necessary to fully test the anticipated scope so additional material needed to be procured.

Key Findings and Lessons Learned

- Through internal discussions with our stakeholders, we learned about additional testing needing to be performed in order for operation to accept and adopt the new technology. These additional test cases were added to the test plan.

- The project team is working to capture field concerns to be included in testing to ease a field implementation should this lab-only project prove successful.

Customer Benefits

- The team has not yet identified new sources of customer value as the project is still in the lab testing setup phase. Customer benefits expected to be identified as testing commences.

Anticipated RFPs

- The project team has begun soliciting vendors to support testing. This RFP will be sent, and a vendor selected and onboarded in Q1 2024.

Industry Advancement

- The project team attended the 2023 DistribuTECH conference and plans to present at the 2024 DistribuTECH conference.

6. Regulatory Mandates: Submetering Enablement Demonstration - Phase 2

Investment Plan Period 2nd Triennial Plan (2015-2017)	**Assignment to Value Chain** Demand-Side Management
Objective & Scope This project expands on the submetering project from the first EPIC triennial investment plan cycle to demonstrate plug-in electric vehicle (PEV) submetering at multi-dwelling and commercial facilities. Specifically, the project will leverage third party metering to conduct subtractive billing for various sites, including those with multiple customers of record.	
Schedule Q4 2015 – Q1 2019	
Status The Final Report for the Regulatory Mandates: Submetering Enablement Demonstration - Phase 2 is complete and was submitted with the 2019 Annual Report, and is available on PICG's public EPIC website.	

7. Bulk System Restoration Under High Renewables Penetration

Investment Plan Period 2nd Triennial Plan (2015-2017)	**Assignment to Value Chain** Transmission
Objective & Scope The Bulk System Restoration under High Renewable Penetration Project will evaluate system restoration plans following a blackout event under high penetration of wind and solar generation resources. Typically, the entire restoration plan consists of three main stages; Black Start, System Stabilization, and load pick-up. The Project will be divided into two phases: Phase I of the project will address the feasibility of new approaches to system restoration by reviewing the existing system restoration plans and its suitability for higher penetration of renewable generation. It will include a suitable RTDS Bulk Power system to be used in the first stage of system restoration, black start, and it will also include the modeling of wind and solar renewable resources.	

Phase II of the project will focus on on-line evaluation of restoration plans using scenarios created using (RTDS) with hardware in the loop such as generation, transformer, and transmission line protective relays. The RTDS is a well-known tool to assess and evaluate performance of protection and control equipment. This project intends to utilize the RTDS capabilities to evaluate and demonstrate system restoration strategies with variable renewable resources focusing on system stabilization and cold load pick-up. Furthermore, alternate restoration scenarios will be investigated. After the restoration process is evaluated, tested, and demonstrated in the RTDS Lab environment, we will provide a recommendation to system operations and transmission planning for their inputs to further develop this approach into an actual operational tool.
Status In December 2016, this project was cancelled by SCE Senior Leadership as a result of an internal organizational change that focused the organization on Distribution System strategic objectives. This was reported in the 2016 EPIC Annual Report.

8. Series Compensation for Load Flow Control

Investment Plan Period 2nd Triennial Plan (2015-2017)	**Assignment to Value Chain** Transmission
Objective & Scope The intent of this project is to demonstrate and deploy the use of Thyristor Controlled Series Capacitors (TCSC) for load flow control on series compensated transmission lines. On SCE's 500 kV system in particular, several long transmission lines are series-compensated using fixed capacitor segments that do not support active control of power flow. The existing fixed series capacitors use solid state devices as a protection method and are called Thyristor Protected Series Capacitors (TPSC).	
Status In 2016, it was determined that the deliverables for this project could easily be done via another project that was already in progress. Therefore, we ultimately determined that the project should be cancelled. This was reported in the 2016 Annual Report.	

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

Investment Plan Period 2nd Triennial Plan (2015-2017)	**Assignment to Value Chain** Distribution
Objective & Scope This project demonstrates the electrification of transportation and vocational loads that previously used internal combustion engines powered by petroleum fuels in the SCE fleet. The VAPS system uses automotive grade lithium-ion battery technology (Chevrolet Volt and Ford Focus EV) which is also used in notable stationary energy storage projects (Tehachapi 32 MWh Storage).	
Schedule Q3 2015 – Q1 2019	

Status The Final Report for the VAPS is complete and was submitted with the 2019 Annual Report, and is available on PICG's public EPIC website.

10. Dynamic Power Conditioner

Investment Plan Period 2nd Triennial Plan (2015-2017)	**Assignment to Value Chain** Distribution
Objective & Scope This project will demonstrate the use of the latest advances in power electronics and energy storage devices and controls to provide dynamic phase balancing. The project will also provide voltage control, harmonics cancellation, sag mitigation, and power factor control while fostering steady state operations such as injection and absorption of real and reactive power under scheduled duty cycles or external triggers. This project aims to mitigate the cause of high neutral currents and provide several power quality benefits by using actively controlled real and reactive power injection and absorption.	
Schedule Q3 2016 – Q4 2019	
Status The final project report is complete and was submitted as part of the 2020 Annual Report, and is available on PICG's public EPIC website.	

11. Optimized Control of Multiple Storage Systems

Investment Plan Period 2nd Triennial Plan (2015-2017)	**Assignment to Value Chain** Distribution
Objective & Scope This project aims to demonstrate the ability of multiple energy storage controllers to integrate with SCE's Distribution Management System (DMS) and other decision-making engines to realize optimum dispatch of real and reactive power based on grid needs.	
Status Update In 2017, the goals of this project were found to overlap significantly with those of the EPIC 2 Regional Grid Optimization Demo Phase 2 project (otherwise known as Integrated Grid Project (IGP) Phase 2). This project was then cancelled, and the proposed benefits will be realized through IGP Phase 2 project.	

12. DC Fast Charging Demonstration

Investment Plan Period 2nd Triennial Plan (2015-2017)	**Assignment to Value Chain** Demand-Side Management
Objective & Scope The goal of this project is to demonstrate public DC fast charging stations at SCE facilities near freeways in optimal locations to benefit electric vehicle miles traveled (eVMT) by plug-in electric vehicles (PEVs) while implementing smart grid equipment and techniques to minimize system	

impact. The Transportation Electrification (TE) Organization is actively pursuing several strategic objectives, including optimizing TE fueling from the grid to improve asset utilization. Deploying a limited number of fast charging stations at selected SCE facilities that are already equipped to deliver power at this level (without additional infrastructure upgrade) will support this objective. The project will leverage SCE's vast service territory and its facilities to help PEV reach destinations that would otherwise be out-of-range.
Schedule Q1 2016 – Q1 2018
Status The Final Report for the DC Fast Charging Demonstration is complete and was submitted with the 2018 Annual Report, and is available on PICG's public EPIC website.

13. Integrated Grid Project II

Investment Plan Period	**Assignment to Value Chain**
2^{nd} Triennial Plan (2015-2017)	Cross-Cutting/Foundational Strategies & Technologies
Objective & Scope The project will deploy, field test and measure innovative technologies that emerge from the design phase of the Integrated Grid Project (IGP) that address the impacts of distributed energy resources (DERs) owned by both 3^{rd} parties and the utility. The objectives are to demonstrate the next generation grid infrastructure that manages, operates, and optimizes the DERs on SCE's system. The results will help determine the controls and protocols needed to manage DER, how to optimally manage an integrated distribution system to provide safe, reliable, affordable service and also how to validate locational value of DERs and understand impacts to future utility investments.	
Schedule Q3 2016 – Q4 2021	
Status Update Final Report for the Integrated Grid Project II is complete and was submitted with the 2021 Annual Report, and is available on PICG's public EPIC website.	

(3) 2018 – 2020 Investment Plan Projects

1. Cybersecurity for Industrial Control Systems

Investment Plan Period	**Assignment to Value Chain**
3^{rd} Triennial Plan (2018-2020)	Grid Operation/Market Design
Objective & Scope This project will demonstrate the ability to deploy adaptive security controls and dynamically re-zone operational networks while the Industrial Control System (ICS) is either under cyberattack or subject to an increased threat level. The concept of dynamic zoning allows for isolation of threats to certain segments of the ICS and could include both vertical (isolating data flows from SCADA masters to substation endpoints) and horizontal (containing data flows between	

substations, for example, under a state of manual control when the SCADA master cannot be trusted). Adaptive Controls/Dynamic Zoning (AC/DZ) has the potential to benefit the national grid and ratepayers by bolstering a more resilient and secure grid through the ability to identify and isolate core grid operational functions while under a cyber-attack or incident. The benefits are also cross cutting in that AC/DZ will drive grid operations and cybersecurity together for collaboration to address controls for zones to be defined risk impact mitigations.
Schedule Q2 2019 – Q4 2022
Status The final project report is complete and was submitted with the 2022 Annual Report, and is available on PICG's public EPIC website.

2. Advanced Data Analytics Technologies

Investment Plan Period 3rd Triennial Plan (2018-2020)	**Assignment to Value Chain** Grid Operation/Market Design
Objective & Scope This project will demonstrate the possibility of using advanced data analytics technologies for Transmission and Distribution (T&D) and customer maintenance. This project will evaluate pattern recognition technologies that are capable of using new and/or existing data sources such as from sensors, smart meters, supervisory control, and data acquisition (SCADA), for predicting or providing alarms on the incipient failure of distribution system assets. These assets would include connectors, transformers, cables, and smart meters. <u>Use-case Scope</u> Use supervised machine learning techniques to train, validate, then demonstrate a time-to-failure model on a subset of SCE's distribution transformer installed base. The models will quantify the probability of failure (at the transformer-level) and estimate the remaining useful life (RUL) of distribution transformers. <u>Business Objective</u> 1. Inputs to the Transformer Asset Class Strategies a. Inform risk buy down calculations based on remaining useful life (RUL) b. Inform aggregation of like transformers based on level of RUL for decision making 2. Prevent an In-service Failure a. Avoid unplanned outage time (reduced CMI, reduce crew OT expense) b. Repair during planned outage (lessen customer impact) c. Avoid catastrophic failure and resulting consequences (damage to customer/public property, safety, surrounding equipment, wildfire ignition) 3. Procurement/Inventory Planning a. Pre-order replacement transformer if there are none in inventory	

b. Budget planning for future procurement (Inform future GRC Testimony)
Status This project was deferred in April 2021 to allow consideration of other projects which may offer greater benefits aligned with California and CPUC objectives.

3. Advanced Technology for Field Safety

Investment Plan Period 3rd Triennial Plan (2018-2020)	**Assignment to Value Chain** Distribution
Objective & Scope This project will demonstrate the possibility of using new advanced technologies to reduce T&D field crew exposure to customer hazards. The project will evaluate technologies that are capable of using data sources such as field sensors, smart meters, etc. to provide real/near real-time status of faulty equipment. This project will also evaluate technology that is capable of levering recent advancements in the Augmented Reality space.	
Schedule Q1 2020 – Q4 2027	
Status Update The project was relaunched in 2023, with the project team employing a design thinking approach to develop a problem statement, define the scope, and outline high-level use cases. A new project sponsor and major stakeholders were reintroduced to identify and engage with the new scope of the project. Project planning is currently underway and is expected to resume execution in 2024.	

4. Storage-Based Distribution DC Link

Investment Plan Period 3rd Triennial Plan (2018-2020)	**Assignment to Value Chain** Distribution
Objective & Scope This project will examine the benefits of a novel architecture for a distribution-connected energy storage system. Storage systems are typically connected to a single electrical point. This project will demonstrate an architecture that will allow the system to connect to two distribution circuits, using two power conversion systems tied to a single storage medium. This approach will allow the storage system to support both circuits, individually or simultaneously, and will also provide a means of dynamically exchanging power between the two circuits (DC link).	
Schedule Q4 2019 – Q3 2025	
Status Update: Accomplishment & Success Stories	

- Power systems study using CYME software was completed, using two circuits from SCE territory.
- The team made progress on a mockup for the graphical user interface that simplifies the tie controller status/operation so operators can easily understand the system status and control the device.
- A controls architecture diagram was completed that shows all communications and control paths between the various components.
- A factory acceptance test procedure was submitted and reviewed by the team.
- An Emulator was used to test the communications protocols between various network devices.
- An instrumentation and metering diagram was completed to document all measurement points in the laboratory installation.
- The team published a conference paper called "Improving DER Hosting Capacity with Tie Point Controllers and Smart BESS". It was accepted by the 2023 Grid of the Future Symposium.

Challenges or Setbacks

- The Grid Simulator that was intended to act as the second circuit was found to have a frequency offset and did not match the utility grid frequency exactly. As a result, it was decided to use a distribution switchboard for the second circuit source. This change will require a minor update to the electrical drawings.
- Some of the lab electrical support equipment was found to have long lead times, as much as 40 weeks to manufacture and deliver.

Key Findings and Lessons Learned

- Through internal discussions with our stakeholders, we learned that the capability to control the power flow that is transferred between two circuits is highly desirable and provides benefits by relieving overloaded conditions. It also improves the utilization of energy storage that is typically only connected to one circuit, allowing it to be effectively connect to a second circuit – providing capacity benefits to multiple circuits.
- A key benefit is that the DC Link allows circuits to be operated in a networked configuration, where typically the circuits are configured as "radial" design. A networked design allows the circuits to "share resources" so that an overloaded circuit can draw power from other circuits that have spare capacity.
- A key finding is that the protection design must be understood prior to installing a Tie Controller on actual circuits. The Tie Controller could have an effect on the main breaker operation of the substation, which could require an adjustment of the breaker settings.

Customer Benefits

- The team identified that utilizing a Tie Controller and existing BESS can significantly increase the hosting capacity to connect DER customers. This was verified by performing computer simulations on actual SCE circuits and calculating the power flow results. In addition, the Tie Controller and BESS could respond to real time changes in DER output by maintaining proper voltage levels. This is especially important with volatile generation sources such as photo-voltaic panels.

- The Tie Controller is expected to be able to defer capital upgrades like cable replacement, since cable overloads can be mitigated by transferring some power from the adjacent circuit.

Anticipated RFPs

- Installation labor for the lab supporting equipment, which includes two transformers, two switches, and two distribution panels.

Industry Advancement

- The team published and had a conference paper accepted for the 2023 Grid of the Future Symposium. The paper was titled "Improving DER Hosting Capacity with Tie Point Controllers and Smart BESS". This paper investigated how a Tie Controller working in conjunction with a BESS could allow additional DER generators to connect to a circuit by transferring power from a nearby circuit and optimizing power flow using an existing BESS system.

4. Smart City Demonstration

Investment Plan Period 3rd Triennial Plan (2018-2020)	**Assignment to Value Chain** Grid Operation/Market Design
Objective & Scope The project will demonstrate the electric utility role within a Smart City initiative. The demonstration has the following objectives: Increasing coordination between electric system and urban planning, coordinating infrastructure construction activities within a city, streamlining the interconnection process through automated systems between SCE and the city, partnering with cities to engage more customers in renewable resources (e.g. community solar PV, community storage) and creating more opportunities for electric transportation, working with cities to customize their resource portfolio to meet a Climate Action Plan goal (e.g. "Community Choice Aggregation Lite" or Community Choice Aggregation), leveraging assets (e.g. telecommunications, rights of way), coordinating communication on energy programs (e.g. energy efficiency, demand response, Charge Ready, Green Rate), and assisting large customers (i.e. the city as an energy customer) in more efficiently utilizing their energy resources and improving resiliency for critical operations center (e.g. emergency command centers).	
Schedule Q3 2019 – Q2 2025	
Status Update Accomplishment & Success Stories • The vendor along with SCE tech leads certified that the Fenwick Microgrid Lab test bed (Microgrid Control System) meets the contractual requirements, has successfully passed final commissioning and site acceptance testing, and successfully demonstrated all use cases. • Technical functional design specification (FDS) document completed. • Solution architecture definition (SAD) document completed and. • Discussions with the partnering city has resulted in an agreement with the Planning Review Committee, and satisfaction with the substance of the Easement drawings and Pre-Fire Plan.	

- Procured a photovoltaic inverter and a photovoltaic site controller.
- Completed power quality relay testing.
  - Provided requirements for microgrid and remote grid using power quality meter and Doble Amplifier and Protection Suite. This meter configuration can be leveraged for all future microgrid projects.
  - Completed logic diagram.
  - Completed final test plan and test report.
  - Completed conference paper to be submitted at the IEEE Power and Energy Society General Meeting (PESGM) 2024 Conference entitled “Power Quality Based Protection for Microgrid and Remote Grid Loads: Type Testing.”
- GTFPI (Gigabit-Transceiver Front Panel Interface) integration to Relays for QAS setup completed.
  - Auxiliary relays wiring for GTFPI completed.
  - Developed new profile for Doble in lab testbed for SAG and SWELL.
- New Battery Vendor RFP submitted in June 2023 and vendor scoring completed.

Challenges or Setbacks

- The project faced a substantial issue with the need to seek an alternative battery vendor due to legal issues with the awarded battery vendor, new RFP had to be submitted.
- Long lead time for needed to procure the transformers and switches for the Pomona Microgrid test pad.

Key Findings and Lessons Learned

- Knowledge gained of the network configuration for a microgrid system that can be used for all future microgrid projects.
  - A similar setup will be done for the Pomona Microgrid Test Pad
- Cribl Edge application is preferred by cyber engineering for Syslog on client servers/workstations/computers, not Splunk Universal Forwarder (universal will work but not preferred).
- Integrating additional elements like DERs and tie breakers into the microgrid model increases complexity, pushing our computational capacity to its limits due to real-time simulations and hardware interfacing. Consequently, further addition of DER assets, implying more control components, would exacerbate this strain.
- During transition modes (i.e., grid connected to islanded mode) the microgrid controller’s role in sending and receiving commands to/from the grid forming asset is critical for maintaining the microgrid stability.
  - Delay in sending / receiving commands needs to be optimized via the microgrid controller code.
- Having two Battery Energy Storage Systems (BESS) in one clustered microgrid would sometimes cause stability issues
  - Mitigated via optimizing inverter controller parameters.

Industry Advancement

- Completed conference paper to be submitted at the IEEE Power and Energy Society General Meeting (PESGM) 2024 Conference entitled "Power Quality Based Protection for Microgrid and Remote Grid Loads: Type Testing."

6. Next Generation Distribution Automation III

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

Objective & Scope

This project will leverage lessons learned from the Next Generation Distribution Automation II project. It will integrate new FAN wireless radio to automation devices and continue to improve control functionalities. It will provide greater situational awareness to allow system operators to manage the grid with higher DER penetration and be ready to support Distribution System Operators (DSOs). It will integrate advanced control systems, modern wireless communication systems, and the latest breakthroughs in distribution equipment and sensing technology to develop a complete system design that would be a standard for distribution automation and advanced distribution equipment. This project will demonstrate technologies that are applicable for both overhead and underground distribution circuits.

This project is composed of the following sub-projects:

1) Duct Bank Monitoring will demonstrate the capability to use an accurate duct bank temperature modeling tool and/or scalable real-time monitoring system. This system would allow for the avoidance of excessive duct bank temperature due to circuit overloading which could lead to premature, catastrophic cable failure. Monitoring of the system could provide better situational awareness to proactively manage circuit loading.
2) IEC 61850 to the Edge aims to explore improvements upon legacy DNP communications for distribution automation by testing and assessing a standardized communication protocol using IEC 61850 to manage field devices for passive activities including commissioning, updates, retirement, and cybersecurity patches. The intent is for the results of the testing to enable uniform, accelerated configuration and enhanced cybersecurity, extending the protocol used by Substation Automation (SA) to the distribution grid.
3) Standard for GMS Field Connected Devices will provide a lab-only demonstration of next generation distribution automation controller devices, capable of using the DNP v3 SAV5 secure protocol, to communicate with a lab sandbox Field Device Management Platform (FDMP). The intent of the lab test system is to validate the ability of the next generation controller devices to send/receive messages required for SCE device management.

Schedule

Q4 2019 – Q3 2024

Status Update

Standard for GMS Field Connected Devices:

Standard for GMS Field Connected Devices was intended to demonstrate lab-only capabilities of the next-generation distribution automation controller devices, capable of using the DNP3.0 Secure Authentication Ver5 (SAv5) protocol, to communicate with a lab sandbox Field Device Management Platform (FDMP). Unfortunately, several vendor device solutions did not meet the IEEE 1815-2012 DNP3.0 standards. As a result, SCE has decided to close out the DNP3.0 SAV5 secure authentication protocol deliverable, of NGDA III and will report findings in the NGDA III Final Report when the entire project is concluded.

<u>Challenges or Setbacks</u>

- The project faced a substantial issue with various vendor devices not meeting the IEEE 1815-2012 DNP3.0 standards.
- Team decided not to continue evaluating the DNP3.0 SAV5 protocol since vendor solutions do not meet IEEE 1815-2012 DNP3.0 standards requirements.

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

A. DNP3.0 SAV5
   - The Aggressive mode in IEEE 1815-2012 DNP3.0 standards was not sufficiently defined which caused confusion and mis-interpretations from vendors/suppliers.
   - The Confirmations in Aggressive Mode feature is confusing and hard to understand which cause vendors to design it incorrectly.
   - The vendor's field device solutions provided limited configuration capabilities and was unable to be used to fully test the IEEE 1815-2012 DNP3.0 standards.
   - Through internal stakeholder discussions, SCE learned that field device vendors/suppliers' current solution with SAv5 do not meet the IEEE 1815-2012 DNP3.0 standards. Vendor's strategy is to design their device solutions with future SAV6 using zero-trust architecture.
B. <u>Device Management DvM Key Findings and Lessons Learned</u>
   - Field Device Management Platform (FDMP) is still in a beta version. FDMP is not ready for on-premises evaluation and testing.
   - API enhancements with vendor's approval and collaborations are required to provide device remote configuration capabilities via Device Management platform.
   - The challenge of the existing back-office processes of configuring and maintaining Distribution Automation (DA) devices with NetComm wireless verses Field Area Network system will need to be revamped to meet Cyber's and Operation's requirements. Since the architecture for FAN network management system differs from the existing NetComm network management, the team has to enhance and re-test the new process flows to understand how new DA devices will be added, deleted and maintained in Device Management platform.

<u>Industry Advancement</u>

Standard for GMS Field Connected Devices:

- Completed a SAD (Solution Architecture Document) to provide vendors and suppliers with SCE's future distribution automation device requirements and specifications. As SCE

is building out the Field Area Network wireless communication infrastructure, the purpose of the Device Management platform is to manage and monitor the distribution automation field devices settings, configurations and firmware using the Field Area Network wireless MCD radio (Modular Communication Device).

7. SA-3 Phase III Field Demonstrations

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

Objective & Scope

The objective of this project is to successfully demonstrate a modern substation automation system for use in transmission substations by adopting scalable technology that enables advanced functionality to meet NERC CIP compliance and IT cybersecurity requirements. This project is to provide measurable engineering, operations, and maintenance benefits through improved cybersecurity and reliability for transmission substations. It will also provide interoperability and allow the system to work with relays from multiple vendors, prevent vendor lock-in due to proprietary software and hardware, and assure that SCE has the flexibility to implement the best solution available.

Today protection relays are dedicated appliances that receive inputs and outputs through hardwired connections. The IEC 61850 standard includes the concept of a process bus. Process bus replaces the hard wire I/O with fiber optic networking technology, thereby eliminating a significant portion of the wiring required for protection and automation systems.

The concept of virtualized protection relays goes one step further and eliminates the physical relay hardware in favor of a virtual environment. The concepts allow the relays to act as software appliances utilizing process bus signals to perform their functionality, similar to the virtualization that is being used on the Common Substation Platform (CSP).

With virtualized relays there are several foreseeable benefits.

1. Smaller footprint, simplified design, and reduced cost. Relays within a substation can be consolidated to a limited number of racks thereby reducing the footprint required by a substation control room and simplifying the design process. Additional benefits include reduced hardware cost.
2. Faster Deployment Timelines, Seamless Failure Recovery, and Multivendor Compatibility. Benefits of current virtualized environments such as redundancy, automated backups, and automated deployment tools can be utilized to improve engineering, testing and deployment cost and schedules.
3. Ease of testing new automation and protection applications. With a virtualized environment, new protection and automation applications can be implemented and tested without the need to physically redesign the system. This redesign will lead to minimal changes to the overall physical environment. Upgrades and transitions to new architectures will require minimal engineering.

This project seeks to form a partnership with relay vendors to demonstrate and evaluate a proof-of-concept system utilizing machine virtualization and process bus technology. The following outcomes are expected from this project:

- Proof of concept hardware and software
- Comprehensive evaluation and testing
- Recommendations for future projects
- All design documents (business requirements, system requirements, test plans, test reports, use cases, etc.)
- Share project lessons learned with industry by presenting at least one technical conference

Schedule

Q4 2019 – Q2 2025

Status Update

Resonant Grounded Substation

The project completed the testing and demonstration in 2022.

IEC 61850 Programmable Automation Controller

The project completed the testing and demonstration in December 2021.

Accomplishment & Success Stories

Virtual Substation Relays

- The Project onboarded all three vendors planned for the project. Two vendors are providing their prototype virtual protection relay equipment and a third is performing settings, configurations, and testing across both solutions.
- One of the two vendors delivered their solution on time, and the equipment was fully set up in the lab environment in preparation of testing.
- The project team completed all IT setup and Cyber Security testing of the vendor equipment.
- The team has also begun to develop the test plan and all testing scenarios.

Challenges or Setbacks:

- The project faced a delay in receiving the prototype equipment from one of the two vendors. This resulted from a last-minute request by the vendor to sign a proprietary protection legal document. Legal representatives from the vendor and SCE met frequently to work through the vendor concerns and develop a legal agreement agreeable to both sides which was signed and approved. This process, however, caused a delay in the shipment of the vendor's equipment to be set up in the lab.
- Another challenge occurred when one of the equipment vendors shipped their equipment to SCE. The vendor invoice exceeded the amount agreed upon in the Purchase Order, as tax was included where it was not specified in the PO. This was resolved following SCE providing tax exemption, and a corrected invoice was sent and processed. This challenge did not result in any negative impact to the project scope, budget, or schedule.

Key Findings and Lessons Learned

- Through the legal document situation with our vendor the project team learned to discuss legal documentation requirements at the beginning of the project and not assume the standard SCE agreements covered all of the potential concerns.
- The tax situation taught the project team to ensure tax exemption is considered when project procurement involves material or a blend of material and services.
- As the vendor equipment was received and installed it was learned that an aspect of the planned testing, Real Time Data Simulation, was not an expertise known to be needed originally and wasn't possessed by either SCE or the settings, configuration, and testing vendor. This gap has since been remedied but will be accounted for during the planning phase for future projects.

Customer Benefits

- There have been no customer benefits identified as of yet, considering this project has only recently entered the test readiness phase. Customer benefits and impact to the system are anticipated to be discovered as test results are returned.

Anticipated RFPs

- There are currently no RFPs anticipated through the remainder of this project. All vendors have been onboarded and will provide the necessary support.

Industry Advancement

- The project team has not yet presented at any industry forums, but is expected to present at both DistribuTECH and IEEE in 2024.
- When this project was initiated there were few vendors offering this virtual protection relay solution. The market is quickly expanding in this area, with the number of vendors entering this market segment increasing.

8. Distributed Cyber Threat Analysis Collaboration

Investment Plan Period 3rd Triennial Plan (2018-2020)	**Assignment to Value Chain** Grid Operation/Market Design
Objective & Scope This project will demonstrate the ability to standardize utility cybersecurity threat analysis by developing a Distributed Cyber Threat Analysis Collaboration framework to conduct local utility collaboration with utility peers and sharing with National analysis centers to support expedient cyber threat feed analysis. This framework will demonstrate the capability to effectively consume internal and external sourcing threat feeds, process them for legitimacy, and identify utility risk impact, and potential response measures through collaboration with utility peers and National analysis centers to validate and verify threats as well as significantly shorten the time needed to respond to a cyber compromise of the electric grid.	
Schedule Q2 2019 – Q4 2021	
Status	

The Final Report Distributed Cyber Threat Analysis Collaboration is complete, was submitted with the 2021 Annual Report, and is posted on PICG's public EPIC website.

9. Energy System Cybersecurity Posturing (ESCP)

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

10. Distribution Primary & Secondary Line Impedance

Investment Plan Period 3rd Triennial Plan (2018-2020)	**Assignment to Value Chain** Distribution
Objective & Scope This project will examine the possibility of establishing primary and secondary line impedance information for distribution circuits by examining the voltage and power signatures at the meter and transformer levels, leveraging a basic connectivity model of the circuits, and utilizing SCADA data. The availability of complete primary line impedance information can improve the accuracy of load flow / distribution state estimation results, greater real-time management of the distribution grid, and greater utilization of capacity within the existing installed infrastructure before requiring new assets.	
Status Due to budget constraints SCE put this project on hold in 2020.	

11. Advanced Comprehensive Hazards Tool

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

Objective & Scope This project will demonstrate a new and innovative approach to integrate emerging and mature hazard assessment tools. This demonstration will use a centralized data architecture that integrates various types of SCE asset data from non-electric, generation, and grid infrastructure. The project aims to identify vulnerabilities across different types of infrastructure to understand the overall risk to the grid. The project will demonstrate hazard scenarios and the impacts of those scenarios to the SCE system. The project will demonstrate a comprehensive natural hazard web application with multi-layer mapping capabilities that provide an integrated, holistic view of hazards in the service territory (e.g., earthquake, flood, fire, and extreme weather events). The application will have the ability to conduct risk analysis that allows for asset data to be referenced with hazard exposure and probability of failure or consequence (fragility) to arrive at risk profiles for the assets. This project will integrate: • Various types of asset data from non-electric, generation, and grid infrastructure sources, to provide decision-support on hazard impact and mitigation options before, during, and after a significant event (e.g., extreme weather events, wildfires, and earthquakes, etc.). • Hazard risk assessment / severity index capabilities allowing a comprehensive assessment of vulnerability and exposure across the service territory. A Final Report will be created detailing lessons learned, areas for maturity, and potential synergies with other internal or external efforts.
Schedule Q4 2019 – Q1 2024
Status Update This project is evaluating tools for enhancing grid resilience against earthquakes and wind. It utilized the CHaT tool to simulate seismic and storm threats, and the GRIP tool, in collaboration with DOE's SLAC Lab, to model environmental interactions and assess power system reliability. These demonstrations aim to mitigate the impact of extreme weather on power infrastructure, contributing to fewer power shutdowns during emergencies. <u>Accomplishment & Success Stories</u> The Comprehensive Hazards Tool (CHaT) project successfully integrated hazard assessment tools and consolidated data sources to improve grid vulnerability analysis. Key achievements include: • Standardizing internal tools for hazard risk assessment. • Demonstrated capabilities to improve seismic hazard mitigation planning and provide early situational awareness. • Successfully integrating CHaT software with SCE and 3rd party data for validation and testing. The GRIP project demonstrated and tested the GRIP software. Achievements include: • Performing initial validation with real SCE data in a remotely accessible lab environment by SLAC (Stanford Linear Accelerator Center) researchers. • Successfully deploying GRIP in the lab environment at SCE for validation and testing.

- Integrating grid infrastructure data for 4 circuits to perform core testing of functionality.
- Completed initial testing of pole vulnerability and tree fall/vegetation conductor contact.

Challenges or Setbacks

CHaT

- A setback encountered early in the project occurred when the first selected vendor declined to participate after an extensive period of time was used to negotiate terms and conditions that would satisfy all party members. The vendor was not comfortable with the terms stated in EPIC flow downs nor in the SCE master software licensing agreements.
- A challenge encountered during project execution was the ability to provide members from the selected vendors access to SCE Critical Energy Infrastructure datasets. This was mitigated by onboarding the individuals who required access to the data. The vendor did not meet the cybersecurity vendor risk assessment requirements to gain access to the data without onboarding.
- The final challenge relates to the maturity of climate-related risk assessment methodologies and models for electric utilities from both industry and academia. Initiatives such as EPRI's Climate READi will provide much needed contributions for this area of knowledge.

GRIP

- The included CYME circuit model to Grid-lab-D Hi-pas converter had to be tested on 14 circuits and modified to integrated asset model information from circuit libraries (conductors, poles, etc.). A number of converter issues were identified for CYME 9 Rev 6. Six critical issues were resolved with 100% success rate for all 14 circuits.
- During the initial data integration period from Aug 23 to Dec 23, modifications were made to several thousand code deletions and additions (28,285 additions and 19,374 deletions), to successfully integrate and run all simulation models in the GRIP simulation pipeline. 15 changed files were released and checked into github under release 4.3.3 on December 1, 2023.
- Accessing wind speed data near the location of pole failures was challenging using the USGS National Weather services and internal sources. Access to better weather station locations with historical data were sourced through a weather data service from Synoptic data.

Key Findings and Lessons Learned

- The CHaT tool is effective for seismic studies, but quantifying the impacts of climate and weather on electric utility assets is challenging. Transmission lines, substations, and distribution lines are vulnerable to various weather events. Understanding these vulnerabilities is crucial for long-term planning, especially considering the expected increase in extreme weather. Additional efforts are needed to enhance these capabilities such as multi-hazard events. Multi-hazard events such as atmospheric "blocking" events can cause weather systems to stall, leading to persistent warm, dry and still conditions when they occur in the summer. Coincidence of high temperatures and low wind events could further limit transmission line capacity. Systems may be further stressed if high temperatures lead to higher loads. Another example is an "atmospheric river" event combined with extreme wind conditions. Distribution poles are prone to failure due to high winds, excessive rainfall and/or flooding.

- The GRIP project's successful demonstration of data installation and integration into its software platform has significant implications for reducing Public Safety Power Shutoff (PSPS) events. By conducting initial validation tests on pole vulnerability and the potential for vegetation or tree falls, the project is actively working towards refining the criteria for PSPS events. This could lead to more accurate assessments of infrastructure resilience and environmental risks, ultimately decreasing the frequency and duration of power shutoffs necessary to ensure public safety during extreme weather conditions. Ongoing validation efforts aim to further lower PSPS thresholds, enhancing power stability and reliability for communities.
- Analysis of weather data indicates that pole failures were triggered by two distinct wind conditions: a swift escalation in wind velocity within a six-hour period and prolonged exposure to high winds for over 36 hours. A significant number of these failures were localized in a specific region, occurring at wind speeds slightly lower than the thresholds set for wind resistance design. Interestingly, not every instance of pole damage led to power outages, suggesting some redundancies in the power grid infrastructure that prevent service disruptions despite the damage.

Customer Benefits

CHaT

- Enhances grid reliability, lowers costs, and improves safety by informing optimal design and mitigation strategies for natural hazard events.
- Reduces repair frequencies and durations by hardening the grid in high-risk areas.
- Mitigates loss and damage from hazard events, facilitating more efficient recovery efforts.
- With a high likelihood of a major earthquake in Southern California, CHaT could inform earthquake risk mitigation for critical utility assets like substations.
- Improving public and utility worker safety: By improving grid resiliency and response to hazards, CHaT can reduce public exposure to dangerous situations (like wildfires) and lessen the need for workers to operate in hazardous conditions.

GRIP

- Provides opportunities to reduce risk by identifying and replacing high-risk poles (203 broken pole failures from 2021 to 2024).
- Helps address challenges posed by high winds in Southern California, such as those experienced in Hawaii, to prevent incidents such as wildfires.
- The benefits of enhancing climate adaptation capabilities are multifaceted. Firstly, it leads to improved reliability and resilience for customers, ensuring consistent service despite varying climate conditions. Secondly, creating a lab partnership environment allows for the practical validation of DOE-funded technologies using real-world data. This not only accelerates innovation but also ensures that the technologies developed are aligned with the actual needs and challenges faced by customers, thereby providing tangible benefits.

- Informs new utility capabilities for climate adaptation, planning and hardening strategies, field crew staging for storm recovery, vegetation mitigation planning, and reducing PSPS outages.

Anticipated RFPs/ Next Steps

CHaT

- CHaT can be scaled for production-scale demonstrations and SCE’s Enterprise Analytics Platform with a comprehensive technology transfer plan in place.
- Next steps involve installing and simulating CHaT software earthquake analysis for operationalization within SCE’s substations as part of the business resiliency plan, comparing results with SCE's current software for validation.

GRIP

- Informing SCE's climate adaptation and vulnerability assessment (CAVA) work and supporting DOE projects to overcome technology challenges.
- Originally created on the Google Cloud Platform, GRIP can be migrated from the lab environment to perform analysis at scale using Kubernetes-managed containers.
- Integration of SCE lidar data (pole tilt, vegetation) and scaling and evaluating pole and conductor/tree fall vulnerability for the system are planned after sufficient validation by SLAC.
- After additional validation and full lidar integration, identifying at-risk trees and additional conductors requiring covered conductor in high-fire areas is planned to mitigate wildfire risk.
- Generate a risk-prioritized investment plan and vegetation work practice recommendations based on climate projections for winds.

Industry Advancement

CHaT

- Reducing outage numbers, frequency, and duration: The tool's hazard mitigation and response capabilities can enhance grid resiliency and enable faster responses to hazards, potentially reducing or eliminating prolonged power outages and equipment damage.

GRIP

- Collaboration with experts: Meetings were held with industry experts in wind simulation modeling to introduce them to GRIP's capabilities.
- Publication: An article about the work completed by SCE and the consultant is being reviewed for publication, highlighting the project's achievements.
- Continued validation and improvement of the GRIP platform are being conducted under the US Dept of Energy Grid Modernization Lab Consortium project, with results expected in the 4th quarter of 2024. The test environment setup funded by EPIC will remain in place for continued validation by SLAC, with lower support from SCE once additional validation data is provided.
- Shares benefits and potential with other utilities facing similar risks worldwide.

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

Investment Plan Period 3rd Triennial Plan (2018-2020)	**Assignment to Value Chain** Distribution
Objective & Scope The project will assess and evaluate new interconnection requirements, Vehicle-to-Grid (V2G) related technologies and standards, and utility and third-party controls to demonstrate how V2G direct current (V2G-DC) and V2G alternating current (V2G-AC) capable EVs and EV chargers can discharge to the grid and be used to support charging during grid outages. The project will assess and evaluate, in a laboratory environment, the proposed V2G-AC Rule 21 interconnection processes, proposed SAE and UL standards, and the function of automaker OEM battery/inverter systems to support vehicle-grid integration (VGI) services, integration of project 3rd party aggregators with SCE's Grid Management System (GMS)/DER Management System (DERMS), and partner with an existing Rialto Unified School District DOE V2G school bus project (and its Charge Ready Transport application) to provide an interconnection pathway by demonstrating functional requirements in the lab; and the field evaluation of deployed systems.	
Schedule Q3 2019 – Q3 2024	

Status Update
<u>Accomplishment & Success Stories</u>
• Competed OEM automaker demonstration and initial demonstration report.
• OEM automaker V2G-AC software and hardware deployed in the SCE lab.
    o Completed integration testing Q4 2023.
    o Type testing and end-to-end testing to be completed in 2024.
 	
<u>Challenges or Setbacks</u>
• Procurement of a V2G-DC vendor for the V2G-DC demonstration delayed due to contractual negotiations.
    o The team is mitigating the issue by looking into possible alternative vendors for the demonstration.
• Full V2G-AC implementation not available for testing until 2024.
    o V2H subsystem available May 2024.
 	
<u>Key Findings and Lessons Learned</u>
• Standardization is critical for V2G-AC implementation. The EPIC project has spent significant time enabling V2G-AC integration.
• Customer preferences are critical to enabling V2G-AC but are not easily implemented. Utilities are not in a position to support this and will need to look to Aggregators to engage their customers.
 	
<u>Customer Benefits</u>
• Findings will be compiled at the end of the project.	

<u>Industry Advancement</u>
• V2G Technical Advisory Board (TAB)
    o The V2G TAB hosted a V2G Forum at SCE Energy Education Center in Irwindale, CA, on 2/28/23.
    o The V2G TAB working groups for V2G-AC, V2G Harmonization, and V2G Cybersecurity initiated.
    o The V2G TAB working groups presented at the V2G Forum in Detroit, MI, October 2023.
• Continued support for UL 1741 SC, SAE J3072, SunSpec IEEE 2030.5 profile for SAE J3072, and V2G related CPUC Proceedings (Rule 21, High DER, etc.).
• Coordination with California IOUs on the topic of V2G interconnection.
• Presentations on the V2G EPIC Demonstration and V2G standards at various forums (EPRI IWC, DistribuTECH, etc.).
• V2G-AC systems will be demonstrated to SCE's Interconnection group and other internal stakeholders in 2024.
• Engagement with SCE's Grid Modernization group (GMS/DERMS) for future integration of V2G.The V2G TAB working groups will report out on findings and recommendations at the V2G Forum April 30th through May 2nd 2024 in San Diego, CA.

13. Distributed Plug-In Electric Vehicle Charging Resources

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

Schedule Q4 2019 – Q3 2025
Status Update <u>Accomplishment & Success Stories</u> • Lab Only Testing. The demonstration, testing, and evaluation of electric vehicle charging coupled with energy storage will be performed at Pomona TSD. We will model the charging behavior with a fast charger and a mini battery system already at the Electric Vehicle Test Center. • Received an EV F-150 Lighting for testing and calibration with the fast charger system. • Facilitated progress with anti-islanding use case by utilizing the Microgrid Testpad in conjunction with the other projects. • Received and integrated the following critical equipment components: Charge Management System (CMS) and Re-van EV Emulator for testing and calibration. • Finalized the single Line drawing to enable the vendor to begin the process to start installation. • Installed the DC Fast Charger to assist with the testing of the use cases. <u>Challenges or Setbacks</u> • The project encountered significant challenges due to delays in procuring power systems. SCE faced difficulties in acquiring necessary equipment promptly, largely due to the epidemic. <u>Key Findings and Lessons Learned</u> • Through discussions with our vendors, we were able to mitigate the procurement of critical components with similar equipment with less delays. • Second-life batteries remain scarce, constraining the expansion of energy storage systems. Integrating rapid charging technology with these systems can boost load factors, ensuring reliable customer service. The size of these storage units and their power components will dictate their efficiency within specific duty cycles.

14. Service and Distribution Centers of the Future

Investment Plan Period 3rd Triennial Plan (2018-2020)	**Assignment to Value Chain** Distribution
Objective & Scope The objective of this project is to evaluate the ability to fully electrify a fleet service center with building electrification technologies (e.g., space and water heating), EVSEs and employee charging while managing any associated impacts to the local grid system. The results could inform future efforts to electrify other service centers, while also supporting commercial customer electric vehicle loads. This project will demonstrate an advanced SCE service center with electrified utility crew trucks, together with employee workplace charging, connected to a local service area with high	

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

This project will examine the benefits of moving toward electric transportation for SCE's fleet and along with many customers' fleets. Installing charging infrastructure to fully electrify those fleets can reach constraints, as large numbers of heavy-duty vehicles will need very high power and energy capacity - approaching 30 MW per location in some cases. Challenges are not only at the individual depot with deploying electrical infrastructure to support the vehicles and manage costs, but also in surrounding areas. SCE has grid reliability and modernization plans in process which will provide new tools for managing the system. Meanwhile, high demand for PV distributed generation, energy storage, and concentrated EV charging can result in local challenges adjacent to and connected to the fleet base. In addition, SCE's Clean Power Pathway identifies the need for general electrification of facilities and full integration of energy management tools. This project will demonstrate a fleet service center supporting large EV charging demands, supporting elements such as energy storage, PV, and controlled (V1G) and bidirectional (V2G) EV charging, and electrified space and water heating - all controlled by an innovative site energy management system to maintain safe and reliable operation and minimize costs. The location will be in a disadvantaged community (Dominguez Hills, Compton, CA). The site will facilitate connection to SCE's grid data and operational management systems to enable local distribution system support.

Schedule
Q3 2019 – Q1 2026

Status Update

Accomplishment & Success Stories

- The project was successful with microgrid testing at our Fenwick Lab location in Westminster.
- The team met with internal partners to discuss the plan site drawings for Dominguez Hills, which led to an approach to completing the engineering drawing for our SCE facility.
- The team continues to evaluate the Real Time Digital Simulator (RTDS) model to establish the lab architecture for the SCE Lab in Pomona.

Challenges or Setbacks

- The project faced a substantial issue when the site location changed from LA Metro to finding the new site at Dominguez Hills, due to challenges finding a location that meets the project space requirements and other criteria. The new location is located in a disadvantaged community.

- The team mitigated the issue by finding space within an existing SCE service center that could provide grid connection, has appropriate space requirements, and meets all of the criteria of the project specifications.
- Finding space at Dominguez Hills has resolved the project location challenge.

- A major vehicle supplier pulled out of the project due to privacy issues with Fleet Management Software. The project is going to go out to RFP for a new vendor in 2024.

Key Findings and Lessons Learned

- One of the top vehicles suppliers in the industry does not meet the SCE standards for cybersecurity.
- It was proven through testing (control and protection) that the microgrid controller and relays offer a practical solution for advancing SCE's microgrid designs. These systems will support fleet electrification for Service Center of the Future initiatives.

Customer Benefits

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

Anticipated RFPs

Upcoming RFPs Include:

- Building Management System (BMS).
- Four Electric Vehicle Chargers.
- Charge Management System (CMS).
- Design consultant.

Industry Advancement

- Final report will show results and provide recommendations to enable further deployment of such facilities.
- The team presented at ISGT 2023 Conference for the microgrid Hardware in The Loop (HIL) Testbed.

15. Control and Protection for Microgrids and Virtual Power Plants

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

Objective & Scope

This project will examine control and protection schemes for safe and reliable operation of distribution systems with customer-owned nested[45] microgrids (MGs) and virtual power plants (VPPs). Standardized control and protection schemes and streamlined operation practices will be designed to support the integrity of the grid and to facilitate grid operation in the context of high penetration of renewable resources and highly variable loads.

The aim of this project is to create a laboratory-based microgrid testbed, which will facilitate the design, prototyping, and performance evaluation of microgrid controls. This testbed will act as a springboard for delving into the extensive potential of microgrid technologies. With the establishment of this testbed, we will be able to forecast and scrutinize various scenarios, thereby gaining insights into the performance of our Microgrid Control System (MCS) under diverse conditions such as black start, islanded mode, and grid reconnection. Furthermore, this testbed will empower us to conduct a range of tests, yielding vital data that will enhance our comprehension of microgrids. In essence, this project is a steppingstone towards the development of sophisticated and dependable microgrid technologies for the future.

Schedule

Q3 2019 – Q2 2024

Status Update

Accomplishment & Success Stories

- First time implementation of a RTDS test bed configuration interfaced with a microgrid controller.
- First time to introduce a Microgrid RSCAD model configuration.
- Evaluated the performance of the Microgrid controller for six use cases.
- Completed the RSCAD model, the complex software model of the microgrid university campus system used in our lab simulation testing and protection studies.
- Installed and configured the Microgrid Control System (MCS) equipment at our Fenwick Lab and demonstrated functional control system testing.
- Completed the interface between the MCS and the RTDS system.
- Completed Factory Acceptance Testing (FAT) at the vendor facility in Pullman, WA. Successfully demonstrated all six use cases.
- Grid Services completed installation / configuration of new IE5000 switches, configuration of firewall rules, compute server and OS install / config in preparation for Network Testing with vendor.
    - IP Configuration validation completed for all MCS devices.

[45] Consist of several separate DERs and/or microgrids connected to the same utility grid circuit segment and serve a wide geographic area.

- Fenwick Lab test bed fully functional with HIL testing successfully demonstrating the six use cases.
- The vendor along with SCE tech leads certified that the Fenwick Microgrid Lab test bed MCS meets the contractual requirements, has successfully passed final commissioning and site acceptance testing, and successfully demonstrated all use cases.
- Protection design activities for the microgrid RSCAD model completed with protection groups from our vendor and SCE.

Challenges or Setbacks

- The project faced issues with the RSCAD model during the initial round of FAT testing, which were resolved by fine tuning the control parameters of the BESS inverter controller along with minimizing the round-trip delay in the MCS during transition modes.
- Long lead time for Hardware in the Loop (HIL) equipment, switched over to a different vendor to procure the equipment sooner.
- Firewall rule missing from MCS device. Network testing took place at Fenwick Lab, the first two days concentrated on configuration work to resolve the issue.

Key Findings and Lessons Learned

- Knowledge was gained of the network configuration for a microgrid system that can be used for all future microgrid projects.
- A similar setup will be done for the Pomona Microgrid Test Pad.
- Cribl Edge application is preferred by Cyber engineering for Syslog on client servers/workstations/computers, not Splunk Universal Forwarder (universal will work but not preferred).
- Vendor performed protection studies on RSCAD model using SKM software. SCE needed to purchase SKM software license to read files.
- Adding complication (additional elements such as DERs and tie breakers) to the microgrid model makes it more difficult to perform tests, protection studies, troubleshooting and obtaining results.
- During transition modes the microgrid controller's role in sending and receiving commands to / from the grid forming asset is critical for maintaining microgrid stability.
- Delay in sending / receiving commands needs to be optimized via the microgrid controller code.
- Having two Battery Energy Storage Systems (BESS) in one clustered microgrid would sometimes cause stability issues.
- Mitigated via optimizing inverter controller parameters.
- During a black start procedure, it is advisable to avoid connecting the generation units, especially the inverter-based resources, simultaneously. This is because such a connection can cause significant disturbances, which may trigger frequency and voltage protection elements. To mitigate this issue, it is recommended to create time intervals for connecting generation units in the grid restoration scheme.

- The successful operation of the microgrid depends not only on the implementation of reliable and resilient control schemes but also on the establishment of a fast and reliable communications.
- The system restoration plan during the black start process should be meticulously defined and fine-tuned to minimize disturbances at each step, to ensure stable restoration.
- Conducting studies before field deployment can preempt potential issues, allowing for the fine-tuning of control schemes, settings, and other parameters.
- The MCS relay connected to the wye-to-ground/wye-to-ground PT can help detect the ground fault on the 12 kV system and act as backup protection for the DER. This finding underscores the need for comprehensive protection schemes.
- The testing showed that fuses added on the 12 kV side of all load transformers cannot be coordinated with corresponding relays due to the use of a generic fuse size 40E. This highlights the need for careful selection and sizing of protective devices.
- The testing performed revealed that ground fault availability on the 12 kV system during Scenario 2a is dependent on the transformers from the BESS breakers. This is an important consideration for system design and operation.

Customer Benefits

- The project's outcomes contribute to the development of more resilient and reliable microgrids. By conducting studies before field deployment, we can preempt potential issues, leading to the fine-tuning of control schemes, settings, and other parameters. This proactive approach aligns with EPIC's goal of advancing innovative clean energy solutions.
- For SCE customers, this translates into more reliable microgrid operations, minimizing disruptions and ensuring a stable power supply. The project's findings will guide future implementations, contributing to the development of robust and efficient microgrids.

Industry Advancement

- Submitted an IEEE Paper to the Innovative Smart Grid Technologies (ISGT) Latin America conference entitled "Performance Assessment of a Centralized Microgrid Controller via a Control Hardware-in-the-Loop Testbed in Southern California Edison". This paper was featured at the conference along with the presentation of a poster board by the SCE tech lead.
- Lab testing results provided deep insight of electrical dynamic transients that may occur during microgrid use cases. Via improved inverter modeling these transients will be able to be addressed in the following MG projects: Smart City and Service Center of Future.
- A successful MCS demonstration in our Fenwick Lab was performed for the UC Irvine Microgrid Team and the Honda Corporation.
- A successful demonstration of the MCS and RTDS system was performed at the Internal Business Briefing at Ontario Fairplex.

16. Distributed Energy Resources (DER) Dynamics Integration Demonstration

Investment Plan Period 3rd Triennial Plan (2018-2020)	Assignment to Value Chain Distribution

Objective & Scope

This project aims to evaluate the two key technical challenges related to high DER penetration—protection system impacts and adverse interactions between multiple types of DERs.

The project will be comprised of both hardware and software components: solar PV inverters, a lab testbed, and computer models of inverters, synchronous and induction generators, protective relay and one SCE sample feeder.

Test smart inverter functional capabilities on SCE distribution feeder with high DER penetration levels, it will be able to establish DER Operating Standards and leverage Smart Inverters for System-wide reliability.

Enhance interoperable controls capability at SCE to provide flexibility to the operation of the grid.

Schedule

Q4 2019 – Q4 2023

Status Update

The EPIC Final Report for the Distributed Energy Resources (DER) Dynamics Integration Demonstration Project is complete and is being submitted with the 2023 Annual Report and will be posted on PICG's public EPIC website.

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

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

Objective & Scope

This project will demonstrate in a lab setting the effect of a voltage and VAR management and control algorithm that optimizes the operation of the power grid, for both the transmission and distribution systems, by regulating voltage and controlling VAR resources optimally while maintaining the secure operation of the power grid.

Status Update

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

18. Beyond Lithium-ion Energy Storage Demonstration

Investment Plan Period 3rd Triennial Plan (2018-2020)	Assignment to Value Chain Distribution

Objective & Scope This project will demonstrate the next wave of next-generation, precommercial, "beyond lithium-ion" energy storage technologies that have a high probability of commercial viability but require real world field experience to reduce technology and adoption barriers on the path to commercialization. This project will focus on advanced energy storage technologies that are non-lithium ion based (e.g., advanced electrochemical batteries, flow batteries, thermal storage, etc.). This project will demonstrate non-lithium-ion storage systems for a variety of traditional use cases (e.g., the CPUC's energy storage use cases outlined in D.13-10-040), and emerging use cases (e.g., regional/community resiliency, etc.). Lastly, this project will demonstrate a complete energy storage system, including the storage technology, power conditioning systems, product/systems integration, and grid interconnection. The objectives of this project are to identify technologies most likely to achieve commercial viability within the next 3-5 years, and opportunities to accelerate the commercialization process. The adoption and integration of lithium-ion based energy storage systems has increased significantly in recent years, to the extent that it is widely considered a mature technology. Furthermore, advancements over the past decade in lithium-ion based energy storage systems have been facilitated by investment from federal and state government funding programs. SCE has been a leader in this regard, based on the company's successful energy storage demonstration completed under the federal government's American Reinvestment and Recovery Act (ARRA) via the Tehachapi Storage Project (TSP), the Irvine Smart Grid Demonstration (ISGD), and the energy storage systems deployed as a part of the Energy Storage Integration Project (ESIP). To achieve California's ambitious long-term energy policy goals, and SCE's own Clean Power and Electrification Pathway 2045, the marketplace will require a diversity of cost-competitive energy storage products. This project will help to advance the industry's knowledge of lithium-ion alternatives to ensure new storage products can "cross the chasm" and compete with traditional storage technologies in the near-future.
Schedule Q4 2020 – Q1 2026
Status Update <u>Accomplishment & Success Stories</u> • Engaged multiple vendors in non-lithium energy storage technologies that are close to being commercially available. • A preferred vendor has been selected for system integration and testing support, offering alternative energy storage solutions that do not rely on lithium. This choice underscores a commitment to exploring and utilizing innovative energy technologies. The collaboration with this vendor is expected to enhance the system's performance while adhering to sustainability principles. • Engaged Power Engineers to consult on deployment standards and requirements. • The team has met with internal partners to discuss contracting agreements with vendors to determine assumption of risk and liability.

- The team continues to evaluate alternative solutions on procuring non-lithium battery due to contracting concerns.

Challenges or Setbacks

- The project faced a substantial issue with vendor's acceptance of SCE's Terms and Conditions. This posed a significant risk in terms of a project schedule delay and timeline to procure and deliver battery to TSD.
- The team addressed the issue/risk by presenting leadership with a substitute plan, which involved collaborating with an authorized vendor to secure the battery for SCE. This proactive approach not only resolved the immediate concern but also demonstrated the team's commitment to finding effective solutions.

Key Findings and Lessons Learned

- Non-lithium-ion energy storage systems such as Flow batteries have shown indications of reducing fire hazards under heavy loads compared to traditional lithium-ion batteries. In parallel, they have also shown potential for increases in energy capacity and efficiency.

19. Wildfire Prevention & Resiliency Technology Demonstration

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

Objective & Scope:

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

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

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

Schedule
Q4 2019 – Q4 2026

Status Update

Accomplishments & Success Stories

Distribution Waveform Analytics:

- The Distribution Waveform Analytics team concluded deployment of an automated data pipeline in early Q2 2023. This data pipeline brings power system waveform data from a fleet of digital fault records in the form of event and continuous timeseries data. The data is parsed into large database tables to be used for the testing of analytic techniques for anomalous event identification.
- Upon completion of an RFP in Q4 2022, a selected vendor was onboarded to the project in Q2 2023 to provide resources such as a Data Scientist, Data Engineer, and a Full Stack Developer. The vendor has been testing analytical techniques for the system events, such as anomalous event extraction from continuous time series data, featuring engineering for power systems event signatures to be used in clustering and classification algorithms. The team also extracted distribution SCADA and AMI data and integrated it with the DFR database to be used in conjunction with event identification. The vendor is also required to implement a visual web application in parallel. The model enhancements are expected to conclude in Q2 2024. The project is expected to conduct an end-to-end lab demonstration in Q3 2024.

Machine Learning at the Edge:

- The Machine Learning at the Edge team initiated the execution phase in January 2023. The project team completed two RFIs (Requests for Information) for drone procurement and integration support services in Q3-Q4 2023. The RFI outcomes are being studied to prepare a Statement of Work for the upcoming RFP expected to initiate in Q1 2024. Note that the RFP Statement of Work will require vendors to deliver hardware and integration support services in compliance with the latest National Defense Authorization Act (NDAA) guidelines.
- The project team possessed various versions of SCE's object and defect detection models and conducted benchmarking exercises by running them across different devices. This approach allowed for comprehensive performance evaluations, providing valuable insights into the models' efficacy across diverse hardware configurations. By doing this, the team gained a deeper understanding of their scalability, efficiency, and suitability for deployment in various environments.

Challenges or Setbacks

Distribution Waveform Analytics:

- Growing pains of learning, configuring, and finding stabilization on a new data and analytics platform.
- Internally, SCE has few resources for non-production work in the data analytics platform, making resolving issues lengthy and challenging.

- Worked through software bugs with supplier. Additionally working in an outdated platform not receiving software updates presents odd workarounds to certain issues that may have been resolved in later updates. However, the project is locked into a 2018 dated system due to hardware limitations. Working in a cloud-based environment could resolve this.
- The volume of data to process takes time, requiring adapting Python to run in Spark using PySpark.
- Unexpected issues with GPS clocks such as improper time zones, daylight savings settings, clocks coming out of sync resulted in loss of some data to poor quality where time synchronization is critical. Attention to device management and proper device configuration during deployment needs to be stronger.
- DWA is domain heavy in signal processing and power systems, which took data scientists from outside the domain time to get familiar with.
- Ambiguity in the nature of power systems events with little ground truth data to use for testing implies more attention needs to be given in root cause analysis to produce a strong dataset of ground truth events.

Machine Learning at the Edge:

- The project faced a substantial issue with procuring the GPU developer kit to be able to test SCE's models due to the necessity of being NDAA compliant.
- The team mitigated the issue/risk by conducting research to identify NDAA compliant vendors.
- Internet connection of the edge devices for setting up them was another challenge.
- Finding a desired vendor for both Hardware Procurement and Integration Services Support and that is compliance with NDAA guidelines is a challenge.

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

Distribution Waveform Analytics:

- A stable and well-performing data platform for databasing waveform data can be implemented easily with commercially-available big data tools. Efficient data engineering lies at the core of this work to get the expected performance from the platform.
- Creating a custom python library for working with the waveform data designed around the nature of the sensor class makes performing data analytics easier and more approachable for the data users.
- Anomaly detection from continuous waveform data is more complicated than initially expected. A one size fits all solution may not be attainable and specially tailored techniques for certain anomaly types may be necessary.
- Event clustering purely on the event's FFT vector produced inconclusive results, implying a more in-depth feature engineering process is required in order to form valid clusters based on anomaly class. The team is exploring feature engineering in 2024.
- A more targeted approach aimed at specific anomaly classes and focus on developing reliable ground truth data for testing is required. The team is working on this for 2024.

<u>Anticipated RFPs</u>

Machine Learning at the Edge:

- The Machine Learning at Edge team is on schedule to initiate one RFP for the project in Q1 2024. The RFP scope will be to procure drone hardware and integration support services.

Industry Advancement

Distribution Waveform Analytics:

- The Distribution Waveform Analytics team wrote a technical paper on the big data analytics platform implemented in the DWA project. The paper was accepted for publication in conference proceedings for the 2024 IEEE PES T&D conference. The team is also contributing learning on continuous point-on-wave data processing in the IEEE Task Force "Big Data Analytics for Synchro-Waveform Measurements" and slated to present at the IEEE Joint Technical Committee Meeting in Q1 2024. To bring situational awareness, the team will share Distribution Waveform Analytics project overview, platform architecture components, Digital Fault Recorder (DFR) database schema design, various technical challenges, and lessons learned.

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, 2023, SCE expended a total of $45 toward project costs and $0 toward administrative costs for a grand total of $45. SCE's cumulative expenses over the lifespan of its 2012 – 2014 EPIC 1 program amount to $38,661,721.

SCE executed 16 projects, cancelled one project, and completed 15 projects. Three of these projects were completed during the calendar year 2015, four projects were completed in 2016, four projects were completed in 2017, two projects were completed in 2018, one project was completed in 2019, and one project was completed in 2020.

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

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

6. Portable End-to-End Test System;
7. State Estimation Using Phasor Measurement Technologies;
8. Deep Grid Coordination (otherwise known as the Integrated Grid Project);
9. DOS Protection & Control Demonstration;
10. Advanced Voltage and VAR Control of SCE Transmission;
11. Outage Management and Customer Voltage Data Analytics Demonstration;
12. Cyber-Intrusion Auto-Response and Policy Management System (CAPMS);
13. Next Generation Distribution Automation, Phase 1;
14. Wide Area Reliability Management and Control; and
15. SA-3 Phase III Demonstration.

(2) 2015-2017 Investment Plan

For the period between January 1 and December 31, 2023, SCE expended a total of $414,598 toward project costs and $174,703 toward administrative costs for a grand total of $589,302. SCE's cumulative expenses over the lifespan of its 2015 – 2017 EPIC 2 program amount to $38,270,358. SCE committed $1,775,009 toward projects and encumbered $590,774 through executed purchase orders during this period. SCE has no uncommitted EPIC 2 funding for this period.

SCE executed 13 projects from its approved portfolio. As of this report, 3 projects have been cancelled for the reasons described in their respective project updates section. Of the remaining ten projects, one project was completed in 2017, three projects were completed in 2018, two projects were completed in 2019, one project was completed in 2020, and one project was completed in 2021. One project remains in execution for the 2015-2017 Investment Plan.

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

1. Advanced Grid Capabilities Using Smart Meter Data;
2. DC Fast Charging;
3. Proactive Storm Impact Analysis Demonstration;

4. Integration of Big Data for Advanced Automated Customer Load Management;
5. Versatile Plug-in Auxiliary Power System;
6. Regulatory Mandates: Submetering Enablement Demonstration - Phase 2;
7. Dynamic Power Conditioner;
8. The Integrated Grid Project; and
9. Next-Generation Distribution Equipment & Automation - Phase 2.

(3) __2018-2020 Investment Plan__

For the period between January 1 and December 31, 2023, SCE expended a total of $4,097,842 toward project costs and $383,366 toward administrative costs for a grand total of $4,481,207. SCE's cumulative expenses over the lifespan of its 2018 – 2020 EPIC 3program amount to $24,888,482. SCE committed $10,319,780 toward projects and encumbered $5,226,231 through executed purchase orders during this period. SCE has no uncommitted EPIC 3 project funding for this period. SCE cancelled two projects and has begun executing 14 projects from its approved portfolio, and three have been completed. SCE's 2018 – 2020 EPIC 3 program is currently composed of the following twelve (12) projects that remain in execution:

1. Advanced Comprehensive Hazards Tool;
2. Advanced Technology for Field Safety (ATFS);
3. Beyond Lithium-ion Energy Storage Demo;
4. Control and Protection for Microgrids and Virtual Power Plants;
5. Distributed PEV Charging Resource;
6. Next Generation Distribution Automation III;
7. SA-3 Phase III Field Demonstrations;
8. Service Center of the Future;
9. Smart City Demonstration;
10. Storage-Based Distribution DC Link;

11. Vehicle-to-Grid Integration Using On-Board Inverter; and

12. Wildfire Prevention & Resiliency Technology Demonstration.

b) <u>Next Steps for EPIC Investment Plan (stakeholder workshops etc.)</u>

The progress made by SCE project teams across multiple initiatives is commendable, despite facing procurement delays and vendor challenges. The Fenwick Microgrid Lab project has been a significant step forward, highlighting the importance of rigorous testing, operational readiness, and collaborative efforts with vendors. All the projects are expected to deliver substantial benefits to customers, enhancing the resilience and sophistication of utility infrastructure.

SCE's proactive engagement with regulatory bodies and stakeholders has been crucial in advancing its EPIC 4 Investment Plan Application. The company has also made significant progress in the EPIC successor program's rulemaking process. The focus has been on completing the 2015-2017 Investment Plan and advancing the projects from the 2018-2020 cycle. The comprehensive approach taken by SCE ensures that the company continues to enhance its service delivery and stabilize the grid.

SCE maintained collaboration with the Policy Innovation + Coordination (PICG) Coordinator on the project database and will continue its open dialogue with the stakeholders through public engagement in 2024. Following the approval of the EPIC 4 Investment Plans, SCE and other Utilities will be convened to strategize on portfolio implementation. SCE hosted workshops to explore strategic initiatives, addressing opportunities, challenges, and community needs, with a focus on engaging disadvantaged communities. Public workshops and the annual Symposium served as platforms for SCE and EPIC Administrators to discuss key topics with stakeholders and the Commission, sharing achievements and insights from the EPIC programs.

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

In 2024, SCE is committed to the effective completion of its final project under the EPIC 2 Investment Plan. Additionally, SCE will progress with the execution of the 12 remaining projects within its EPIC 3 Investment Plan. In 2023, SCE encountered delays related to supply chain issues and incurred costs that exceeded projections. Moving forward, SCE will persist in vigilantly overseeing potential project postponements, including those stemming from production and supply chain disruptions.

APPENDIX A

DISTRIBUTED ENERGY RESOURCES (DER) DYNAMICS INTEGRATION DEMONSTRATION

FINAL PROJECT REPORT

Distributed Energy Resources (DER) Dynamics Integration Demonstration
EPIC Phase III Final Project Report

Developed by
SCE Transmission & Distribution, Asset Management, Strategy and Engineering
Version Date: 08/10/2023

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1 EXECUTIVE SUMMARY

By 2045, California will undergo a remarkable evolution. Supported by its residents, the state will achieve carbon neutrality to reduce the threat of climate change. This will require substantial decarbonization of all sectors of the economy and will necessitate rigorous planning to keep energy safe, reliable, and affordable.

Southern California Edison's (SCE) "Pathway 45"[46] examines the energy implications of California's long-term decarbonization goals on both the economy and the electric sector and maps out a feasible and low-cost path to reaching these goals.

To economically meet both the 2030 (interim) and 2045 decarbonization goals, the electric sector must decarbonize more quickly than currently required. Eighty gigawatts (GW) of new utility-scale clean generation and 30 GW of utility-scale energy storage will be required in the next 20-plus years. Thirty (30) additional GW of generation capacity and 10 GW of storage will come from Distributed Energy Resources (DERs) – small-scale local resources often installed/used at a customer's home or business, such as rooftop solar, onsite energy storage, electric vehicles, and energy management systems. Up to 50% of single-family homes in California are projected to have customer-sited solar by 2045.

Increased DER integration into the distribution grid presents both challenges and opportunities. Recent utility experience demonstrates that smart inverters (those with advanced control functions) have the potential to enable DERs to support grid needs when combined with new capabilities that facilitate the full integration of DERs into grid planning and operations. (DERs can provide uninterrupted power to customers in the event of a grid connection failure, and also can replace fossil fuel generation – thus reducing carbon emissions.) This experience has identified multiple factors for allowing smart inverter-enabled DERs to minimize potential grid impacts at higher DER penetration levels.

To further address this issue, SCE undertook the DER Dynamics Integration Demonstration project, with a primary goal of examining how various DER penetration scenarios would impact distribution feeder protection. The project included multiple investigation techniques through simulation studies and laboratory demonstrations with the use of advanced DERs (in this case photovoltaic, or PV), traditional DERS, and smart and legacy inverter technologies.

Project stakeholders identified seven research questions (see Section 2.5.3: Research Questions) to address via both the simulation studies and laboratory demonstrations.

When it came to the final question – whether there is a need for any new method of distribution feeder protection for systems with high DER penetration – the overall results indicated that no distribution feeder protection impact was identified based on the rigorous analysis conducted through both project phases.

2 PROJECT SUMMARY

The primary goal of the DER Dynamics Integration Demonstration project was to examine how various DER penetration scenarios would impact distribution feeder protection. Specifically, the project was designed to determine the following based on questions developed by stakeholders:

[46] https://www.edison.com/our-perspective/pathway-2045.

- The effect on SCE's relaying distribution feeder protection systems due to high penetration of Electric Rule 21[47] and Institute of Electrical and Electronics Engineers (IEEE)-1547 (standard)[48] smart inverters.
- The interaction between traditional DERs and smart inverter-enabled DERs with advanced functions.
- The interaction between multiple models of inverters using different anti-islanding detection algorithms.[49]
- The level of an inverter's capability on the IEEE 2030.5[50] communication requirement.
- New methods of distribution feeder protection needed, if applicable, for systems with high DER penetration.

The investigation was conducted via both simulation studies and demonstrations. This work used simulation and Power Hardware-in-the-Loop (PHIL) demonstration, including inverter configuration and settings for optimal distribution feeder protection and operation of smart inverters under high DER penetration scenarios.

2.1 Electric Program Investment Charge Overview

SCE's DER Dynamics Integration Demonstration project was implemented through the California Public Utilities Commission's (CPUC) Electric Program Investment Charge (EPIC) III program[51]. EPIC supports the development of new, emerging, and pre-commercialized clean energy innovations in California. These projects must be designed to ensure benefits in the form of equitable access to safe, affordable, reliable, and environmentally sustainable energy for electricity ratepayers. EPIC consists of three program areas: Applied Research and Development (Applied R&D), Technology Demonstration and Deployment (TD&D), and Market Facilitation.

Per the EPIC Investment Framework for Utilities (Figure 1), this project contributed to the strategic area of Renewables and Distributed Energy Resources Integration, and supported the guiding principles of Safety, Reliability, and Affordability, by:

- Adding to learnings about integration of high concentrations of renewable resources at lower costs, thus benefitting SCE and its ratepayers.
- Delivering findings on the impacts of widescale DER deployment, as well as safe and reliable smart inverter operations. The operational flexibility of smart inverter functionality may be used to enhance grid reliability when combined with other grid modernization elements, such as a Distributed Energy Resources Management System (DERMS).
- Increasing SCE's ability to anticipate impacts on distribution feeder protection in high DER penetration situations.
- Providing information that can be used to update existing DER interconnection criteria (if necessary).
- Producing a reusable smart inverter testbed that can be utilized for other DER and smart inverter use case testing.

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[47] Electric Rule 21 describes the interconnection, operating, and metering requirements for generation facilities to be connected to a utility's distribution system, over which the CPUC has jurisdiction. https://www.sce.com/business/generating-your-own-power/Grid-Interconnections/Interconnecting-Generation-under-Rule-21.

[48] **IEEE Standard for Interconnection and Interoperability of Distributed Energy Resources with Associated Electric Power Systems Interfaces. https://sagroups.ieee.org/scc21/standards/1547rev/.**

[49] An islanding scenario occurs when a DER provides power despite being electrically isolated from the distribution system.

[50] IEEE Standard for Smart Energy Profile Application Protocol. https://standards.ieee.org/ieee/2030.5/5897/.

[51] EPIC 3 – SCE 2018-2020 Investment Plan Application. A17-050005. https://www.sce.com/regulatory/epic/regulatory-filings.

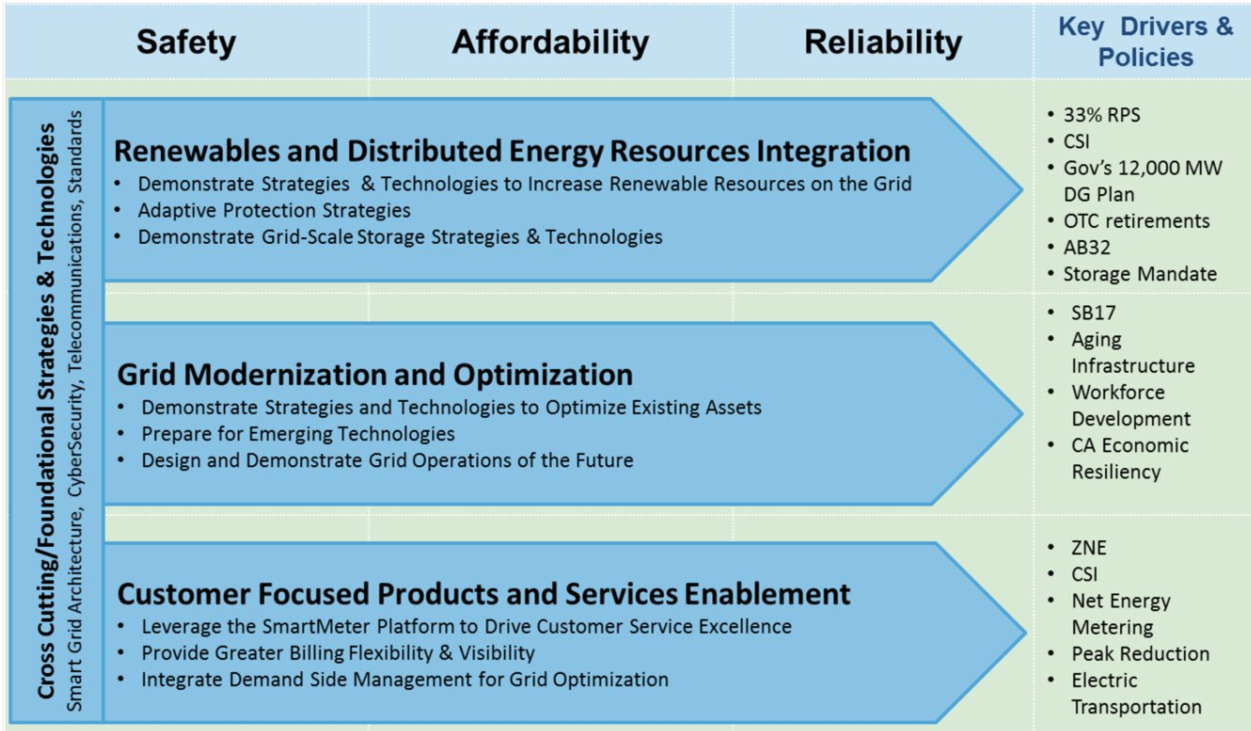

Figure 1. EPIC Investment Framework for Utilities

2.2 Standards

This project addressed the Electric Rule 21 tariff, which describes the interconnection, operating, and metering requirements for generation facilities to be connected to a utility's distribution system, over which the CPUC has jurisdiction. Testing was conducted during the project's demonstration portion to confirm that the PV inverters utilized were Electric Rule 21-compliant. No new standards were established during or as a result of the project.

2.3 Problem Statement

With the growing adoption of DERs, utility experience demonstrates that smart inverters potentially can enable these resources to support grid needs when combined with new capabilities that facilitate the full integration of DERs into grid planning and operations. This experience has identified multiple factors for allowing smart inverter-enabled DERs to minimize potential grid impacts at higher DER penetration levels. At SCE, the distribution feeder protection system impact is the leading technical grid challenge related to high DER penetration that has not been satisfactorily addressed, and the primary reason SCE undertook this project.

2.4 Confidential Information

This report excludes proprietary business information from the project implementation.

2.5 Project Scope

To assess how SCE distribution feeder protection would be impacted by various DER penetration scenarios, the DER Dynamics Integration Demonstration project included multiple investigation techniques through simulation studies and laboratory demonstrations with the use of smart and legacy inverter technologies. Various generation mix and

DER combinations were considered for analysis, including traditional rotating machine-based and inverter-based DERs.

2.5.1 Simulation Studies

The project's simulation studies examined the performance of distribution feeder protection systems in the presence of high DER penetration (e.g., 120% of peak load), where single-phase inverters[52] are dominant and voltages across the feeder are within permissible ranges.
This work incorporated modeling and validation of DER integration in existing and emerging software tools for detailed representation of power electronics and controls. The DER types and control system components that were modeled by following the project's technical requirements and applicable industry standards were:

- Advanced DERs:
  - PV based on smart inverters: defined as inverters with advanced control functions, which have the capability to improve system performance.
- Traditional DERs:
  - PV based on legacy inverters: defined as non-smart inverters without advanced functions.
  - Induction generator for wind systems.
  - Synchronous generator for gas/diesel engines or gas turbines.
- Anti-islanding protection schemes: control schemes – in this case Sandia Voltage Shift (SVS) and Sandia Frequency Shift (SFS) techniques – that sense and prevent the formation of an unintended island, meaning a condition in which one or more generating facilities delivers power to customers using a portion of the distribution system that is electrically isolated from the remainder of the distribution system.
- Feeder model: based on the selected feeder with expected high penetration of behind-the-meter PV installations.

The following diagram shows the DER types used in the project:

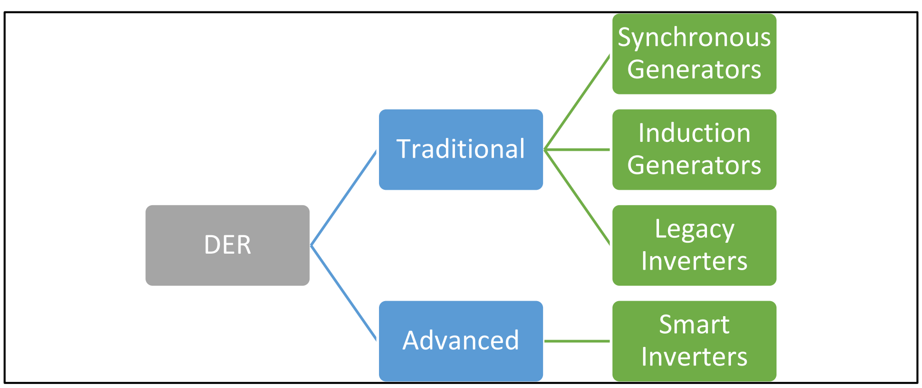

Figure 2. DER Types Used in the Project

The DER model components were validated against expected functionalities or any data available from the project vendors or captured in the laboratory.

52 With PV installations, an inverter converts the electricity produced by the system from direct current (DC) to alternating current (AC) for customer use.

2.5.2 Demonstrations

The project's laboratory demonstrations focused on 1) confirming that the PV inverters utilized during the testing were Electric Rule 21-compliant, and 2) demonstrating and recording the research questions posed during the simulation study (see Section 2.5.3: Research Questions).
This work utilized a mix of simulated traditional DER technologies and actual inverter-based DERs integrated into a Real-Time Digital Simulator (RTDS) system in the laboratory's Power-Hardware-in-the-Loop (PHIL) testbed. The PHIL was created by integrating three systems: RTDS, relay, and inverter (a mix of smart and legacy inverters). Several monitoring devices were required to verify and capture measurements to execute the demonstration scenarios in the testbed, which is shown in this diagram:

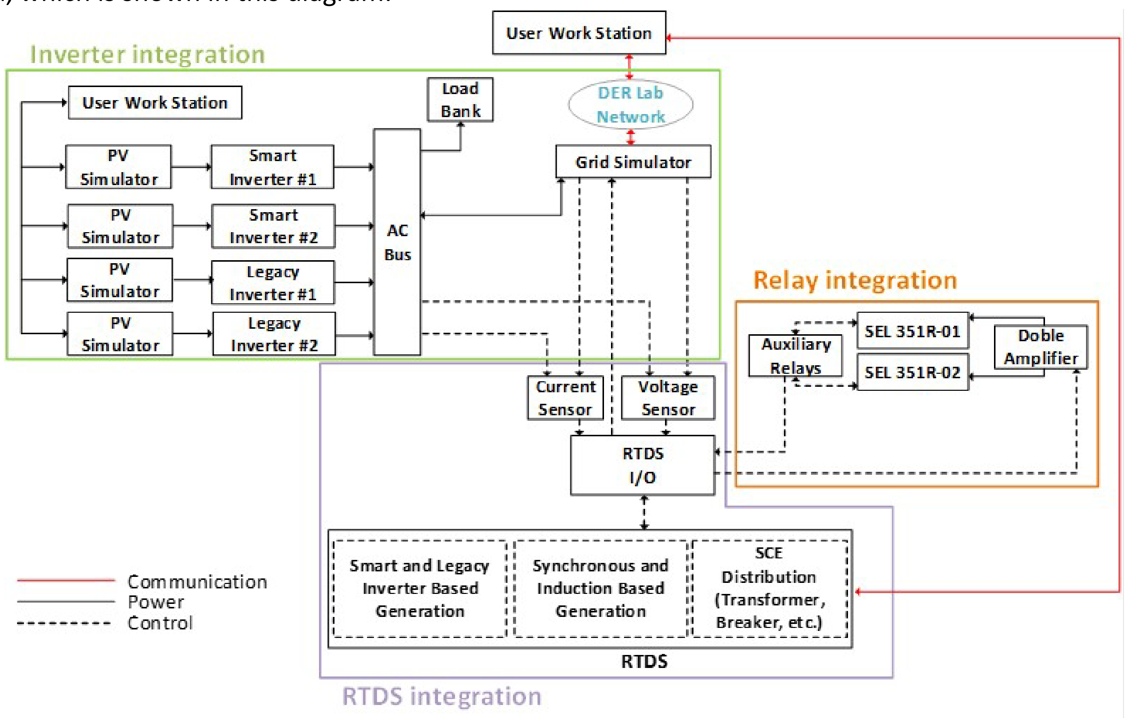

Figure 3. Power Hardware-in-the-Loop Testbed for Project Demonstrations

Following are the Electric Rule 21 function requirements the project team needed to validate for the PV inverters:

- Volt/VAR support
- Anti-islanding capability
- Frequency/watt support
- Volt/watt support
- Voltage and frequency (V/F) ride-through option
- Standard ramp-up rate
- Fixed power factor operation

2.5.3 Research Questions

The simulation studies and demonstrations were designed to address the following research questions from the project stakeholders.

- **Question 1**: How does high penetration of Electric Rule 21 smart inverters (IEEE-1547-2018 standard) and legacy inverters (IEEE-1547-2003 standard) affect distribution feeder protection schemes normally applied in SCE's distribution system?
- **Question 2**: What is the interaction between traditional DERs (synchronous generator, induction generator, legacy inverters) and smart inverter-enabled DERs with advanced functions and how they impact the distribution feeder protection systems?
- **Question 3**: What is the interaction between multiple inverter models using different anti-islanding detection algorithms?
- **Question 4**: What are the critical functions of the inverter and are they are addressed in the model?
- **Question 5**: What are the critical settings and IEEE 2030.5 capability of the developed inverter models?
- **Question 6**: What happens to the harmonics[53] at a low-voltage (LV) bus[54] that has multiple inverters?
- **Question 7**: Is there a need for any new method of distribution feeder protection for systems with high DER penetration?

2.5.4 Cybersecurity

In accordance with the SCE cybersecurity standards, policies, and industry standards, the DER project must develop a robust cybersecurity strategy and incorporate and integrate applicable technologies and techniques to best secure the DER systems. Security measures were identified and applied as necessary to ensure the successful operation of the project goals and objectives.
Additionally, there will be cybersecurity testing requirements that the project will need to meet. This testing will encompass evaluating the project's data protection, authentication, encryption, and other relevant areas to be determined at each phase.

2.6 Schedule and Milestones/Deliverables

The project milestones/deliverables and completion dates were as follows:

Milestone/Deliverable	Completion Date
Project kickoff	5-Feb-2020
Functional/non-functional requirements approved	30-Mar-2020
Cybersecurity functional requirements assessment completed	10-Apr-2020
Lab Architecture Brief (LAB) approved	4-Aug-2020
Design ready-for-build phase completed	28-Jan-2021
PV Model (PSCAD™) and Smart Inverter Model completed	25-Feb-2021

53 Harmonics can distort a pure sine wave, thus negatively impacting the power quality of an output voltage or current. Furthermore, it can lead to equipment operational issues. For example, current harmonics can cause **unwanted overheating, while voltage** harmonics can cause equipment maloperation.

54 Bus definition: a system of electrical conductors in a generating or receiving station on which power is concentrated for distribution.

Power wiring of DER lab by SCE completed	25-Feb-2021
Hardware procured	2-Mar-2021
Smart Inverter Switching Model (value addition) completed	17-Jun-2021
Legacy Inverter Model (PSCAD) and Computer-Aided Protection Engineering (CAPE) completed	17-Jun-2021
Induction and Synchronous Generator Model (PSCAD and CAPE) completed	6-Jul-2021
Anti-Islanding Protection Algorithm Model, Distribution Feeder Model development completed	1-Nov-2021
PSCAD development and simulation completed	15-Apr-2022
Final simulation report completed	5-Apr-2022
Build Inverter Assessment Power Hardware-in-the-Loop (PHIL) testbed completed	19-Jan-2022
Acceptance test procedures completed	18-Jan-2022
PHIL testbed ready for demonstration	3-May-2022
All use case demonstrations completed	30-Jun-2022
Acceptance test results completed	08-Aug-2022
Documentation (including simulation, demonstration, and control logic block diagrams) completed	12-Jan-2023

Table 10. DER Dynamics Integration Project Schedule and Milestones/Deliverables

3 PROJECT RESULTS

Overall, the DER Dynamics Integration Demonstration project found that high penetration of PVs for the specific SCE distribution feeder under study did not introduce any adverse impact on distribution feeder protection performance. It is well understood that the legacy inverters and any rotating machine-type DER would not support advanced functions and would not interact with the feeder voltages during the steady-state operation, or in response to faults, in the way expected from advanced inverter technologies.

Following is a summary of specific results of the simulation studies and demonstrations conducted to address the project's research questions. Testing to validate the compliance of the PV inverters with Electric Rule 21 functions took place after the simulation studies and before the laboratory demonstration work. Results of the function testing are shown in Table 2.

Question 1: How does high penetration of Electric Rule 21 smart inverters (IEEE-1547-2018 standard) and legacy inverters (IEEE-1547-2003 standard) affect distribution feeder protection schemes normally applied in SCE's distribution system?

Simulation Study Results: A range of penetration levels was studied in PSCAD (an advanced tool for power system electromagnetic transient (EMT) simulations) for a specific SCE distribution feeder, with a focus on penetration levels of 120%. The results showed changes in fault current range due to high DER penetration. However, because of smart inverter functions, the difference was not significant enough to cause any maloperation of protective devices.

Demonstration Results: Fault studies performed at different feeder locations were used to assess how the distribution feeder protection system would be impacted by a range of DER penetration levels. The Real-Time Digital Simulator (RTDS)-based Power Hardware-in-the-Loop (PHIL) testbed was used for a specific SCE distribution feeder, with a focus on penetration levels of 120%. The results showed that high penetration of DERs in the particular feeder under study did not adversely impact distribution feeder protection performance.

Question 2: What is the interaction between traditional DERs (synchronous generator, induction generator, legacy inverters) and smart inverter-enabled DERs with advanced functions and how they impact the distribution feeder protection systems?

Simulation Study Results: This study utilized a combination of traditional and advanced DERs to analyze the impact on the distribution feeder protection systems. A fault analysis was performed at several feeder locations, and a corresponding current was observed at the main circuit breaker and reclosers. The maximum reverse phase current seen by the feeder head relay was well below the current distribution feeder protection setting, confirming no impact on the existing distribution feeder protection settings.

Demonstration Results: This demonstration applied single- and three-phase-to-ground faults at three locations of the feeder, which comprised the modeled synchronous generator, induction generator, and both legacy-inverter-based and smart-inverter-based generation resources, plus two actual smart and legacy inverters. It was observed that the high penetration of PVs for the specific feeder under study did not adversely impact distribution feeder protection performance.

Question 3: What is the interaction between multiple inverter models using different anti-islanding detection algorithms?

Simulation Study Results: The performance of smart inverters with Sandia Voltage Shift (SVS) and Sandia Frequency Shift (SFS) anti-islanding schemes was observed and analyzed. The purpose was to evaluate whether an anti-islanding protection scheme can effectively detect islanding scenarios (meaning when a DER provides power despite being electrically isolated from the distribution system) and differentiate them from faults. The results showed that the SVS anti-islanding scheme performed better for high DER penetration and was more effective for behind-the-meter inverter installations.

In addition, a few scenarios were observed during a variation of synchronous generation over total generation ratio that may require further attention, and an operational procedure will be developed to address the scenarios in the near future.

Demonstration Results: The testing showed that all inverters (both legacy and smart) responded very quickly (in a few milliseconds) upon grid connection failure, even for very low power mismatch scenarios.

Question 4: What are the critical functions of the inverter and are they are addressed in the model?

Simulation Study Results: The key functions that were modeled and evaluated included:

- the active anti-islanding scheme
- volt-VAR scheme
- volt-watt scheme
- frequency-watt scheme
- ramp rate control
- rate of change of frequency (ROCOF) scheme
- voltage and frequency ride-through
- a momentary cessation

The testing showed that the volt-VAR scheme for smart inverters plays a very critical role in maintaining feeder voltages within the limits in steady-state operation, to the extent that reactive power control is available. Ride-through and momentary cessation schemes of smart inverters were noted as very effective in response to faults and for quick system recovery after fault clearing.
Demonstration Results: For demonstration purposes, in the RSCAD® (simulation software)/RTDS (simulator) environment, the advanced functions of the inverters also were incorporated. The results showed that the smart inverter functions in the hardware inverter properly followed the characteristics and performance expected in the Electric Rule 21 tariff. This indicated that the smart inverters can provide grid support functions and perform effectively enough to achieve the mitigation levels defined in Electric Rule 21.

Question 5: What are the critical settings and IEEE 2030.5 capability of the developed inverter models?
Simulation Study and Demonstration Results: None of the inverters in the lab and part of the PHIL testbed supported the IEEE 2030.5 protocol. Hence, the use of this standard was not evaluated. In general, most inverter vendors are not yet ready to offer such a communication protocol. (It should be noted that IEEE2030.5 is under revision for refinements.)

Question 6: What happens to the harmonics at a low-voltage (LV) bus that has multiple inverters?

Simulation Study Results: This study analyzed the current and voltage harmonic contents via developed use cases. A fault was applied to the circuit, and IEEE Standard 519[55] was used to determine voltage and current harmonic limits at different harmonic components.

The simulation results for the voltage harmonics measured at the LV side of the service transformer were below the standard limit. In the case of current harmonics, all phases were well below the limit except the individual second harmonic, which was above the limit. Further investigation was recommended to understand the dynamics of the current harmonic contents.
Demonstration Results: It was observed that once all of the actual inverters operated in parallel in the testbed, the measured current Total Harmonic Distortion (THD) at the LV AC bus of inverters was less than 2%, which is well below the limit imposed by Electric Rule 21 and the IEEE-1547-2018 standard.

Question 7: Is there a need for any new method of distribution feeder protection for systems with high DER penetration?

Simulation Study and Demonstration Results: No distribution feeder protection impact was identified based on the rigorous analysis conducted through the project's simulation studies and demonstrations.
This table shows the results of the testing conducted after the simulation studies and before the demonstrations to validate the compliance of the PV inverters with Electric Rule 21 functions.

Electric Rule 21 Function	Testing Observations
Volt/VAR Support	The volt-VAR curve of the smart inverters followed the expected theoretical curve described in the Electric Rule 21 tariff. In other words, the volt-VAR scheme of smart inverters and its contribution in maintaining the voltage matched the simulation results and thus can effectively mitigate issues associated with an increase in voltage.
Anti-Islanding Capability	All inverters (both legacy and smart) responded very quickly (in a few milliseconds) upon grid connection failure, even for very low power mismatch scenarios.

[55] IEEE Standard for Harmonic Control in Electric Power Systems. https://standards.ieee.org/ieee/519/10677/ .

Frequency/Watt Support	The smart inverters complied with the Electric Rule 21 frequency-watt curve. In addition, in the testing the smart PV inverters curtailed active power with a response time of less than 5 seconds following the Electric Rule 21 frequency-watt curve.
Volt/Watt Support	The actual volt-watt curve for the smart inverters was similar to the Electric Rule 21 curve. The inverters tripped as expected when the operational boundary was violated.
Voltage and Frequency (V/F) Ride-Through Option	Smart inverters' grid reliability functions (voltage and frequency ride-through) might not comply with Electric Rule 21 in specific vendors' operations.
Standard Ramp-Up Rate	After applying a step change in the irradiance level of the PV simulator, the inverter's responses complied with the response time as mandated by Electric Rule 21.
Fixed Power Factor Operation	The smart inverters followed the fixed power factor settings when the power factor was varied from unity power factor to 0.9 lagging. (A lagging power factor occurs when the load current lags behind the supply voltage.)

Table 11. Observations from Electric Rule 21 Function Testing of PV Inverters

3.1 Achievements

As noted in Section 2.1: Electric Program Investment Charge overview:
Per the EPIC Investment Framework for Utilities (Figure 1), the project contributed to the strategic area of Renewables and Distributed Energy Resources Integration, and supported the guiding principles of Safety, Reliability, and Affordability, by:

- Adding to learnings about integration of high concentrations of renewable resources at lower costs, thus benefitting SCE and its ratepayers.
- Delivering findings on the impacts of widescale DER deployment, as well as safe and reliable smart inverter operations. The operational flexibility of smart inverter functionality may be used to enhance grid reliability when combined with other grid modernization elements, such as a Distributed Energy Resources Management System (DERMS).
- Increasing SCE's ability to anticipate impacts on distribution feeder protection in high DER penetration situations.
- Providing information that can be used to update existing DER interconnection criteria (if necessary).
- Producing a reusable smart inverter testbed that can be utilized for other DER and smart inverter use case testing.

3.2 Scalability

The project studies/demonstrations focused on one SCE distribution feeder, but the investigation's principle and results can be applied to other SCE distribution feeders.

3.3 Value Proposition

This project supported the following objectives and capabilities in SCE's Strategy, Planning & Operational Performance (SPOP) Technology Roadmap:

- Improve visibility, control, and coordination of operations to reliably integrate energy resources.
- Develop distribution feeder protection technologies to accommodate the changing resource mix.

- Improve the value of DERs to customers and the grid by enabling load management capabilities and other services (e.g., volt/VAR support).
- Enable device-level integrated, interoperable controls that provide flexibility.

3.4 Identified Project Metrics

Two of the metrics identified for the SCE DER Dynamics Integration Demonstration project were:

- **Identification of barriers or issues resolved that prevented widespread deployment of technology or strategy:** *Description of the issues, project(s), and the results or outcomes:* With the growing adoption of DERs – which will play a key role in decarbonizing SCE's power system over the next two decades – it is necessary to understand how high DER penetration levels could impact the distribution feeder protection system. SCE undertook this project to address this issue. As noted in this report, the results indicated that no distribution feeder protection impact was identified. While the project focused on one SCE distribution feeder, the principle and results can be applied to other distribution feeders.
- **Effectiveness of information dissemination**: *Number of reports and fact sheets published online:* To date project team members have made presentations on the project at seven conferences (see Section 3.6.1: Information Dissemination for details).

3.4.1 Additional Metrics

DERs can help meet California's greenhouse gas (GHG) emission reduction goals, help customers reduce electricity use, and support grid reliability.[56] The DER Dynamics Integration Demonstration project was not designed to address/quantify specific metrics such as ratepayer benefits, GHG emission reductions, energy savings, and infrastructure cost reduction; however, the project did provide valuable learnings about increased DER integration into the grid.

3.5 Technical Lessons Learned and Recommendations

Following are technical lessons learned and recommendations related to the project procedures and results.

- The relay used in the project could not be triggered from the Real-Time Digital Simulator (RTDS) signal only. An amplifier was needed to transfer the low-power signal from the RTDS to a high-powered relay signal.
- Simulation of the high DER penetration level with a high-fidelity switching model of the inverter required extensive time; thus, a high-processing computer is recommended.
- The laboratory testing confirmed that – with use of proper simulation models – the simulation analysis and offline software modeling approaches were accurate enough for assessments of transient and dynamic events, and evaluation of distribution feeder protection schemes associated with feeders. It was recommended to use detailed Electromagnetic Transients Program (EMTP)-type analysis for distribution feeder protection and calculation of relay settings (reclosers and interconnection settings) in high DER penetration scenarios.
- The simulation study to evaluate the performance of anti-islanding schemes of smart inverters suggested that a high synchronous generation over total generation ratio may require further attention. It is recommended to develop an operational procedure to avoid any potential issues.

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[56] https://www.edison.com/innovation/distributed-energy-resources.

- A key recommendation from the studies was to further evaluate the settings for volt-VAR and volt-watt schemes of the smart inverters to coordinate with the acceptable voltage range for the feeders.
- Per the demonstration observations, further investigation is recommended to understand the dynamics of the current harmonic contents and the aggregated effect of multiple inverter harmonics under a high penetration scenario.

3.6 Technology/Knowledge Transfer Plan

Project information and findings have been widely published/presented by SCE subject matter experts to transfer knowledge gained to the power and energy industry and the engineering and technology community.

3.6.1 Information Dissemination

Conference presentations to date include:

1. Md Arifujjaman, Roger Salas, Anthony Johnson, Jorge Araiza, Farhad Elyasichamazkoti, Ahmadreza Momeni, Shadi Chuangpishit, Farid Katiraei. "DER Dynamics Integration Demonstration Using Power Hardware-in-the-Loop (PHIL) Testbed in Southern California Edison." IEEE Power & Energy Society (PES) General Meeting, Orlando, Florida, July 16–20, 2023.
2. Md Arifujjaman, Jordan Smith. "Distributed Energy Resources Dynamics Integration Demonstration." 2023 Joint Utilities EPIC Workshop, CPUC, Online, June 27, 2023.
3. Md Arifujjaman, Roger Salas, Anthony Johnson, Jorge Araiza, Farhad Elyasichamazkoti, Ahmadreza Momeni, Shadi Chuangpishit, Farid Katiraei. "Development, Demonstration, and Validation of Power Hardware-in-the-Loop (PHIL) Testbed for DER Dynamics Integration in Southern California Edison." IEEE Power & Energy Society (PES) Grid Edge Technologies Conference and Exposition, San Diego, California, April 10–13, 2023.
4. Md Arifujjaman. "A Power Hardware-in-the-Loop (PHIL) Testbed for Inverter Testing in Southern California Edison." Sixth International Workshop on Grid Simulator Testing of Energy Systems and Wind Turbine Drivetrains, National Renewable Energy Laboratory (NREL), Golden, Colorado, November 9–10, 2022.
5. Md Arifujjaman, Jordan Smith. "Demonstration of a Power Hardware-in-the-Loop (PHIL) Testbed for the Rule 21 Inverters." Hybrid and EV Technologies Symposium, SAE International, Garden Grove, California, September 13–15, 2022.
6. Md Arifujjaman, Roger Salas, Anthony Johnson, Jorge Araiza, Vatandeep Singh, Mohammadreza Dorostkar Ghamsari, Shadi Chuangpishit, Amin Zamani, Farid Katiraei, Reza Salehi. "Impacts of High Penetration of Single-Phase PV Inverters on Protection of Distribution Systems." IEEE Green Energy and Smart Systems Conference (IGESSC), Long Beach, California, November 7–8, 2022.
7. Md Arifujjaman, Roger Salas, Anthony P. Johnson, Austen D'Lima, Jorge Araiza. "Modeling and Development of a HIL Testbed for DER Dynamics Integration Demonstration." IEEE Green Energy and Smart Systems Conference (IGESSC), Long Beach, California, November 2–3, 2020.

3.7 Procurement

The project was completed on time and on budget.

3.8 Stakeholder Engagement

SCE's Integrated System Planning organization served as the project sponsor. Regular meetings were held on the project status with the internal stakeholders:

- IT-Power Systems Control
- Distribution Engineering
- Distribution System Operator (DSO) Implementation
- Protection & Automation Standards and Innovation
- Grid Technology Innovation (GTI) Lab Operations
- Cybersecurity (IT)
- SCE EPIC Program

In addition, SCE presented project work to the following external stakeholders, which share interest in this issue:

- Rule 21 Working Group
- Unintentional Islanding Working Group (UIWG)
- Pacific Gas and Electric (PG&E)
- San Diego Gas & Electric (SDG&E)

List of Acronyms

AC	Alternating Current
CAPE	Computer-Aided Protection Engineering
CPUC	California Public Utilities Commission
DC	Direct Current
DER	Distributed Energy Resource
DERMS	Distributed Energy Resources Management System
DSO	Distribution System Operator
EMT	Electromagnetic Transient
EMTP	Electromagnetic Transients Program
EPIC	Electric Program Investment Charge
GHG	Greenhouse Gas
GTI	Grid Technology Innovation
GW	Gigawatts
IEEE	Institute of Electrical and Electronics Engineers
IEEE PES	IEEE Power & Energy Society
IGESSC	IEEE Green Energy and Smart Systems Conference
IT	Information Technology
LAB	Lab Architecture Brief
LV	Low Voltage
NREL	National Renewable Energy Laboratory

PG&E	Pacific Gas and Electric
PHIL	Power Hardware-in-the-Loop
PV	Photovoltaic
R&D	Research and Development
ROCOF	Rate of Change of Frequency
RTDS	Real-Time Digital Simulator
SCE	Southern California Edison
SDG&E	San Diego Gas & Electric
SFS	Sandia Frequency Shift
SPOP	Strategy, Planning & Operational Performance
SVS	Sandia Voltage Shift
TD&D	Technology Demonstration and Deployment
THD	Total Harmonic Distortion
UIWG	Unintentional Islanding Working Group
VAR	Volt-Amps Reactive
V/F	Voltage/Frequency

Appendix B
Revised 2023 Electric Program Investment Charge (EPIC) Annual Report (Redline)
April 25, 2025

EPIC ADMINISTRATOR ANNUAL REPORT FOR 2023 ACTIVITIES

EPIC ADMINISTRATOR ANNUAL REPORT FOR 2023 ACTIVITIES

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Executive Summary

Overview of Programs/Plan Highlights

The SCE project teams made notable advancements throughout 2023 across SCE's EPIC project portfolio. This program is funded by California utility customers under the auspices of the California Public Utilities Commission. ~~This~~ Advancements included preparing to test a fully digital substation concept. For the Storage Based DC Project, SCE completed a power systems analysis and implemented a user-friendly graphical interface for the circuit tie controllers to dynamically balance load between the battery and two circuits. SCE also achieved milestones for the Fenwick Microgrid Lab project by successfully demonstrating 6 simulation use cases. One of the lab simulation use cases included the ability to disconnect from the grid and place the microgrid system into island mode with a Battery Energy Storage Systems (BESS) which is critical for maintaining microgrid stability.

Key findings and lessons learned emphasize the importance of ensuring that the lab testing is sufficient to meet SCE's requirements before deploying into a pilot or field operation. Such rigorous evaluation methods have proven effective in determining the feasibility of utilizing a DC link system. This innovative approach promises several strategic advantages, including bolstering energy security, stabilizing the grid, optimizing renewable energy use, increasing grid flexibility, and support for DERs.

Despite encountering challenges such as delays in procurement and vendor issues, the teams have effectively managed these setbacks and continue to drive the projects to completion.

2023 represented the tenth full year of implementing EPIC program operations since receiving the California Public Utilities Commission (Commission) approval of SCE's EPIC 1 application[1] on November 19, 2013.[2] Furthermore, 2023 represented nearly the eighth full year of implementing program operations of SCE's 2015 – 2017 Investment Plan Application[3] (EPIC 2) after receiving

[1] A.12-11-001.
[2] D.13-11-025, OP8.
[3] A.14-05-005.

Commission approval on April 9, 2015.[4] Lastly, 2023 represented SCE's fifth full year of implementing program operations of SCE's 2018 – 2020 Investment Plan Application[5] (EPIC 3) after receiving approval on October 25, 2018.

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

2012-2014 Investment Plan

Between January 1 and December 31, 2023, SCE expended a total of $45 toward project costs and $0 toward program administrative costs[6]. SCE's cumulative expenses over the span of its 2012 – 2014 Investment Plan amount to $38,661,721.

SCE executed 16 projects from its approved EPIC 1 portfolio. This includes the completion of three projects in 2015, four projects in 2016, four projects in 2017, two projects in 2018, two projects in 2019 and one project in 2020. A list of completed projects is included in the Conclusion of this Report (section 0). In accordance with the Commission's directives,[7] SCE has prepared Final Project Reports for each completed project and included them in the Annual Reports according to the years completed. No EPIC 1 projects remain in execution as of December 31, 2023.

2015-2017 Investment Plan

Between January 1 and December 31, 2023, SCE expended $414,599 toward project costs and $174,703 toward administrative costs for a grand total of $589,302. SCE's cumulative expenses for its 2015 – 2017 Investment Plan amount to $38,270,358. SCE committed $1,775,009 toward projects and encumbered $590,774 through executed purchase orders during this period. SCE has no uncommitted EPIC 2 funding as of December 31, 2023.

SCE initiated 13 projects from its approved EPIC 2 portfolio. As of December 31, 2023, three projects have been cancelled for the reasons described in their respective project updates

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4 D.15-04-020, OP1.
5 A.17-05-005.
6 SCE is reviewing these costs.
7 D.13-11-025, OP14.

sections.[8] Project execution activities continued for the remaining ten projects. Of those 10 projects, SCE completed one project in 2017, three projects in 2018, two projects in 2019, one project in 2020, one project in 2021, and one project in 2022. One demonstration project (System Intelligence and Situational Awareness Capabilities) remains in execution for 2023.

2018-2020 Investment Plan

Between January 1 and December 31, 2023, SCE expended a total of $4,097,841 toward project costs and $383,366 toward administrative costs for a grand total of $4,481,207. SCE's cumulative expenses over the span of its 2018 – 2020 Investment Plan amount to $24,888,482. SCE committed $10,319,780 toward projects and encumbered $5,226,231 through executed purchase orders during this period. SCE has no uncommitted EPIC 3 project funding as of December 31, 2023.

SCE received approval from the Commission for two replacement projects in 2022: Wildfire Prevention & Resiliency Technologies Demonstration and Beyond Lithium-Ion Energy Storage Demonstration, both of which were included in the Joint Utilities Research Administration Plan (RAP) Application. SCE initiated 19 projects from its approved portfolio. Four of the EPIC 3 projects were either previously canceled or deferred. Project execution activities continued for the remaining fifteen projects. Of those fifteen projects, one was completed in 2021 and one was completed in 2022. During 2023, SCE completed one additional project (Distributed Energy Resources Dynamics Integration Demonstration) and continues to perform work on the remaining twelve projects. The following 12 projects from the EPIC 3 portfolio remain in execution:

1. Advanced Comprehensive Hazards Tool
2. Advanced Technology for Field Safety (ATFS)
3. Beyond Lithium-ion Energy Storage Demo
4. Control and Protection for Microgrids and Virtual Power Plants
5. Distributed PEV Charging Resource
6. Next Generation Distribution Automation III

[8] Starting at p. 13.

7. SA-3 Phase III Field Demonstrations
8. Service Center of the Future
9. Smart City Demonstration
10. Storage-Based Distribution DC Link
11. Vehicle-to-Grid Integration Using On-Board Inverter
12. Wildfire Prevention & Resiliency Technology Demonstration

Introduction and Overview

EPIC Background

In Decision (D.)12-05-037, the Commission established the EPIC Program to fund applied research and development, technology demonstration and deployment (TD&D), and market facilitation programs to provide ratepayer benefits. This program is funded by California utility customers under the auspices of the California Public Utilities Commission. ~~This Decision~~ D.12-05-037 further stipulates that the EPIC Program will continue through 2020[9] with an annual budget of $162 million,[10] adjusted for inflation.[11] Approximately 80% of the EPIC budget is administered by the California Energy Commission (CEC), and 20% is administered by the investor-owned utilities (IOUs). Additionally, 0.5% of the total EPIC budget funds Commission oversight of the Program.[12] The IOUs were also limited to performing TD&D activities.[13] SCE was allocated 41.1% of the IOU portion of the budget and administrative activities.[14]

The Commission approved SCE's 2012-2014 Investment Plan[15] in D.13-11-025 on November 19, 2013. SCE submitted its 2015-2017 Investment Plan Application[16] on May 1, 2014, and

[9] D.12-05-037, OP1.
[10] D.12-05-037, OP7.
[11] Using the Consumer Price Index.
[12] *Id*, OP5.
[13] *Id*.
[14] D.12-05-037, OP 7, as modified by D.12-07-001.
[15] A.12-11-004.
[16] A.14-05-005.

the Commission approved the Application in D.15-04-020 on April 9, 2015. SCE submitted its 2018-2020 Application on May 1, 2017, and the Commission approved the Application in D.18-10-052 on October 25, 2018. SCE is currently executing its 2015-2017 and 2018-2020 EPIC Investment Plans.

In 2019, the Commission initiated a two-phase rulemaking[17] to determine the future of EPIC. In Phase 1 the Commission determined that EPIC would continue for ten years through 2030, and that each investment period would span five years (2021-2025 and 2026-2030). Additionally, the Commission authorized the CEC to continue its EPIC administrator role.[18] In Phase 2 of the rulemaking, the Commission determined that the Utilities should continue their roles as EPIC Administrators, along with the CEC.[19] SCE (along with PG&E and SDG&E) filed their respective EPIC 4 Investment Plans, covering 2021-2025, on October 1, 2022.[20] Per D.23-04-042, the EPIC Program Administrators are to file annual reports on April 30 of each year, via a Tier 2 Advice Letter that follow the outline in Appendix C.[21] The Commission approved SCE's, PG&E's and SDG&E's EPIC Investment Plans for 2021-2025 on November 30, 2023.

EPIC Program Components

The Commission limited SCE's triennial investment applications in the EPIC Program to TD&D projects, per D.12-05-037 and reiterated in D.21-11-028. The Commission defines TD&D projects as installing and operating pre-commercial technologies or strategies at a scale sufficiently large, and in conditions sufficiently reflective of anticipated actual operating environments, to enable appraisal of the operational and performance characteristics and the associated financial risks.[22]

For EPIC 4, the Utilities coordinated with the CEC to define strategic objectives (program categories). However, for administration of its EPIC 1-3 Portfolios, the IOUs continue to successfully utilize the joint IOU framework developed for the 2012-2014 cycle (EPIC 1) and enhanced for the

[17] R.19-10-005.
[18] D.20-08-042.
[19] D.21-11-028.
[20] A.22-10-005.
[21] D.23-04-042, OP8.
[22] D.12-05-037, OP3.B.

2015-2017 (EPIC 2) and 2018-2020 (EPIC 3) cycles with updated strategic initiatives to support the latest key drivers and policies. This includes the following four program categories: (1) energy resources integration, (2) grid modernization and optimization, (3) customer-focused products and services, and (4) cross-cutting/foundational strategies and technologies. SCE's 2012-2014, 2015-2017, and 2018-2020 Investment Plans proposed projects for each of these four areas, focusing on the ultimate goals of promoting greater reliability, lowering costs, increasing safety, decreasing greenhouse gas emissions, and supporting low-emission vehicles and economic development for ratepayers.

Coordination

The EPIC Administrators collaborated throughout 2023 on the execution of the 2015-2017 (EPIC 2) and 2018-2020 (EPIC 3) Investment Plans, as well as planning the EPIC 4 Investment Plan. Specific examples of the IOUs' coordination with the CEC include the Joint Utilities EPIC Workshop (June 27, 2023) and the virtual 2023 EPIC Symposium (October 3-4, 2023).

The Utility EPIC Administrators met on a near-weekly basis (and bi-weekly basis with the CEC) to discuss the items mentioned above, coordinate investment plan activities, and to plan and coordinate joint stakeholder workshops and the annual joint public symposium. Moreover, SCE held several collaborative meetings with the CEC to help further coordinate the respective investments plans.

Transparent and Public Process/CEC Solicitation Activities

In 2023, SCE supported the annual EPIC Symposium held virtually again due to the pandemic. SCE supported the CEC in a discussion on "Innovative Technologies and Strategies for Reducing Wildfire Risk". In addition to the Symposium, the Joint Utilities coordinated with the CEC on a public workshop hosted by SCE with a discussion on EPIC 3 projects moderated by EPRI.

SCE supported numerous parties applying for CEC EPIC funding in 2023. A total of 15 requests for Letters of Support (LOS) and Letters of Commitment (LOC) were received from a diverse array of parties including private vendors, universities, and national laboratories, showing interest in partnering on their bids for CEC projects. Of these 15 requests, SCE provided letters for 11. All were LOS, of which five were approved by the CEC.

For SCE, a LOS typically supports the premise of a project. In some instances, it will infer technical advisory support if the project is awarded to the recipient and the party and SCE come to a mutual understanding of what advisory support will be required.

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

Budget

Authorized Budget

2012 – 2014 Investment Plan

Table 1: 2012-2014 Authorized EPIC Budget (Annual)

2012-2014 (Jan 1 - Dec 31)	Administrative	Project Funding	Commission Regulatory Oversight Budget
SCE Program	$1.3M	$11.9M	$0.33M[23]
CEC Program	$5.3M	$47.7M	

2015 – 2017 Investment Plan

Table 2: 2015 – 2017 Authorized EPIC Budget (Annual)

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

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

2018 – 2020 Investment Plan

Table 3: 2018 – 2020 Authorized EPIC Budget (Annual)

2018-2020 (Jan 1 - Dec 31)	Administrative	Project Funding	Commission Regulatory Oversight Budget
SCE Program	$1.5M	$13.6M	$0.02M
CEC Program	$6.0M	$54.4M	

Commitments/Encumbrances

2012 – 2014 Investment Plan

As of December 31, 2023, SCE has committed $0 and encumbered $0 of its authorized 2012-2014 program budget.

2015 – 2017 Investment Plan

As of December 31, 2023, SCE has committed $1,775,009 and encumbered $590,774 of its authorized 2015-2017 program budget.

2018 – 2020 Investment Plan

As of December 31, 2023, SCE has committed $10,319,780 and encumbered $5,226,231 of its authorized 2018-2020 program budget.

CEC & CPUC Remittances

For CEC remittances, SCE remitted $6,082,800 [24] for program administration, and $30,338,947 for encumbered projects during calendar year 2023.

For CPUC remittances, SCE remitted $380,175 in calendar year 2023.

Fund Shifting Above 15% between Strategic Initiatives

As of December 31, 2023, SCE does not have any pending fund shifting requests and/or approvals for the 2012-2014, 2015-2017 and 2018-2020 investment plans.

[24] Due to the timing of the CPUC's Decision (D.)18-01-008, approving the EPIC III 2018-2020 budget in mid-January 2018 (Quarter 1). The Utilities are remitting the total CEC administrative budget over 11 quarters.

Uncommitted/Unencumbered Funds

As of December 31, 2023, SCE has no uncommitted/unencumbered funds for the 2012-2014, 2015-2017 and 2018-2020 investment plans.

Projects

High Level Summary

SCE provides a summary of project funding for SCE's 2012-2014, 2015-2017, and 2018-2020 Investment Plans, please refer to Table 4, Table 6, and Table 8

2012-2014 Investment Plan

As of December 31, 2023, SCE has expended $38,661,721 on program costs. In accordance with the Commission's directives,[25] SCE has prepared Final Project Reports for each completed project and included them in the Annual Reports according to the years completed. No projects remain in execution as of December 31, 2023. Table 4 summarizes the 2012-2014 Investment Plan projects by program category, completion year, and total funding.

Table 4: 2012 – 2014 Investment Plan Summary

1. Energy Resources Integration	**Total Funding**

Three projects funded
• Completed in 2016: Distribution Planning Tool
• Completed in 2018:
  • DOS Protection & Control Demonstration and
  • Advanced Voltage and VAR Control of SCE Transmission Project
	$1,988,964

2. Grid Modernization and Optimization	**Total Funding**
Five projects funded • Cancelled in 2014: Superconducting Transformer[26] • Completed in 2015: Portable End-to-End Test System • Completed in 2016: Dynamic Line Rating • Completed in 2017: Next Generation Distribution Automation, Phase 1 • Completed in 2020: Substation Automation 3 (SA-3), Phase 1	$11,133,289
3. Customer Focused Products and Services	**Total Funding**
Three projects funded	$3,624,299

25 D.13-11-025, OP14.

26 SCE cancelled the Superconducting Transformer project in Q2, 2014. Please refer to the project's status update in Section 4 for additional details.

• Completed in 2015: Outage Management and Customer Voltage Data Analytics Demonstration • Completed in 2016: Submetering Enablement Demonstration • Completed in 2017: Beyond the Meter: Customer Device Communications Unification and Demonstration	
4. Cross-Cutting/Foundational Strategies and Technologies	**Total Funding**

Five projects funded
• Completed in 2015: Cyber-Intrusion Auto-Response and Policy Management System
• Completed in 2016: Enhanced Infrastructure Technology Report
• Completed in 2017:
  • State Estimation Using Phasor Measurement Technologies Project
  • Deep Grid Coordination Project (otherwise known as the Integrated Grid Project)
• Completed in 2019: Wide Area Management and Control
	$20,827,698

Total Projects Funded: 16 Total Authorized Project Budget: $37,656,998 [27] Total Project Spend: $37,102,164 Total Funding Committed: $472,088[28] Total Encumbered: 0[29] *Note: Due to intrinsic variability in TD&D/R&D projects, amounts shown are subject to change*	

Table 5 below summarizes SCE's 2023 administration expenses:

Table 5: 2012 – 2014 Investment Plan Administration Expenses

Total Authorized Budget:	$1,855,002[30]
Total Cumulative Cost:	$1,555,042
Total 2023 Cost:	$0

[27] D.12-05-037, as updated by D.13-11-025. Includes $2,045,000 transfer from administrative funds to project funds.

[28] *Ibid.*

[29] *Ibid.*

[30] 2012-2014 EPIC I Administrative Budget is $3,812,000. SCE Program Management transferred $1,956,998 from the Administrative to the Project Budget, reducing the Authorized Budget to $1,855,002.

2015-2017 Investment Plan

As of December 31, 2023, SCE has expended $38,270,358[31] on program costs.

Table 6 below summarizes the current status and funding of SCE's EPIC 2 projects:

Table 6: 2015 – 2017 Investment Plan Summary

1. Energy Resources Integration	**Total Funding**

Three projects funded
• Canceled in 2016:
  • Bulk System Restoration under High Renewables Penetration project
  • Series Compensation for Load Flow Control project
• Cancelled in 2017: Optimized Control of Multiple Storage Systems
	$187,493

2. Grid Modernization and Optimization	**Total Funding**
Six projects funded • Completed in 2017: Advanced Grid Capabilities Using Smart Meter Data • Completed in 2018: Proactive Storm Impact Analysis Demonstration • Completed in 2019: Versatile Plug-in Auxiliary Power System • Completed in 2020: Dynamic Power Conditioner • Completed in 2022: Next-Generation Distribution Equipment & Automation, Phase 2 • Currently In Execution: System Intelligence and Situational Awareness Capabilities	$15,958,858
3. Customer Focused Products and Services	**Total Funding**

Three projects funded
• Completed in 2018:
  • DC Fast Charging
  • Integration of Big Data for Advanced Automated Customer Load Management
• Completed in 2019: Regulatory Mandates: Submetering Enablement Demonstration, Phase 2
	$2,440,504

4. Cross-Cutting/Foundational Strategies and Technologies	**Total Funding**
One project funded • Completed in 2021: Integrated Grid Project II	$18,917,345
Total Projects Funded: 13 Total Authorized Project Budget: $37,504,200 [32] Total Project Spend: $35,112,705 [33]	

[31] SCE's cumulative project expenses amounted to $35,112,705. SCE's cumulative administration expenses amounted to $3,157,656. These totals include SCE labor and overheads. As a result, SCE expended a total of $38,270,358 on program costs.

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

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

Total Funding Committed: $1,775,009 [34] Total Encumbered: $590,774 [35] *Note: Due to intrinsic variability in TD&D /R&D projects, amounts shown are subject to change*

Table 7 below summarizes SCE's 2023 administrative expenses.

Table 7: 2015 – 2017 Investment Plan Administration Expenses

Total Authorized Budget:	$4,190,400[36]
Total Cumulative Cost:	$3,157,656
Total 2023 Cost:	$174,703

<u>2018-2020 Investment Plan</u>

As of December 31, 2023, SCE has expended $24,888,482[37] on program costs.

Table 8 below summarizes the current status and funding of SCE's EPIC 3 projects.

Table 8: 2018 – 2020 Investment Plan Summary

1. Energy Resources Integration	**Total Funding**
Two projects funded • <u>Completed in 2023</u>: Distributed Energy Resources Dynamics Integration Demonstration • <u>Currently in Execution</u>: Smart City Demonstration	$5,826,512
2. Grid Modernization and Optimization	**Total Funding**

Six projects funded
• <u>Cancelled in 2020</u>: Power System Voltage and VAR Control Under High Renewables Penetration
• <u>Hold/Deferred in 2020</u>: Distribution Primary & Secondary Line Impedance Project
• <u>Currently in Execution</u>:
  • Beyond Lithium-ion Energy Storage Demo;
  • SA-3, Phase III Field Demonstrations;
  • Storage-Based Distribution DC Link; and
  • Next Generation Distribution Automation III project
	$12,495,525

[34] *Ibid.*

[35] *Ibid.*

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

[37] SCE's cumulative project expenses amounted to $21,252,578. SCE's cumulative administration expenses amounted to $3,610,840. These totals include SCE labor and overheads. As a result, SCE expended a total of $24,888,482, on program costs.

3. Customer Focused Products and Services	Total Funding

Four projects funded
• Currently in Execution:
  • Control and Protection for Microgrids and Virtual Power Plants;
  • Distributed PEV Charging Resource;
  • Service Center of the Future; and
  • Vehicle-to-Grid Integration Using On-Board Inverter
	$9,853,000

4. Cross-Cutting/Foundational Strategies and Technologies	**Total Funding**

Seven projects funded
• Cancelled in 2019: Energy System Cybersecurity Posturing
• Hold/Deferred in 2021: Advanced Data Analytics Technologies (ADAT)
• Completed in 2021: Distributed Cyber Threat Analysis Collaboration (DCTAC)
• Completed in 2022: Cybersecurity for Industrial Control Systems
• Currently in Execution:
  • Advanced Comprehensive Hazards Tool;
  • Advanced Technology for Field Safety (ATFS); and
  • Wildfire Prevention & Resiliency Technology Demonstration
	$12,456,813

Total Projects Funded: 19 Total Authorized Project Budget: $40,830,795 [38] Total Project Spend: $21,252,578 Total Funding Committed: $19,578,217[39] Total Encumbered: $5,226,231 [40] *Due to intrinsic variability in TD&D /R&D projects, amounts shown are subject to change*	

Table 9 below summarizes SCE's 2023 administrative expenses for the 2018 – 2020 investment plan.

Table 9: 2018 – 2020 Investment Plan Administration Expenses

Total Authorized Budget:	$4,562,100 [41]
Total Cumulative Cost:	$3,610,840
Total 2023 Cost:	$383,366

[38] D.18-01-008, at p. 38.
[39] *Ibid.*
[40] *Ibid.*
[41] D.18-01-008, at p. 38.

Project Status Report

The descriptions of the project objectives and scope reflect the proposals filed in the respective EPIC Investment Plans,[42] while the project status information reflects the progress through 2023. As a result of corrections made to address preliminary 2020 EPIC audit findings,[43] some dollar values for completed projects have changed.

2012 – 2014 Investment Plan Projects

1. Integrated Grid Project – Phase 1

<table>
<tr><td>Investment Plan Period:
1st Triennial Plan (2012-2014)</td><td>Assignment to Value Chain:
Grid Operation/Market Design</td></tr>
<tr><td colspan="2">Objective & Scope
The project will demonstrate, evaluate, analyze, and propose options that address the impacts of high distributed energy resources (DER) penetration and increased adoption of distributed generation (DG) owned by consumers directly connected to SCE's distribution grid and on the customer side of the meter. This demonstration project is in effect the next step following the ISGD project. Therefore, this project focuses on the effects of introducing emerging and innovative technology into the utility and consumer end of the grid to account for this increase in DER resources. This scenario introduces the need for the utility (SCE) to assess technologies and controls necessary to stabilize the grid with increased DG adoption, and more importantly, consider possible economic models that would help SCE adapt to the changing regulatory policy and GRC structures.
This value-oriented demonstration informs many key questions that have been asked:
What is the value of distributed generation and where is it most valuable?
What is the cost of intermittent resources?
What is the value of storage and where is it most valuable?
How are DER resources/devices co-optimized?
What infrastructure is required to enable an optimized solution?
What incentives/rate structure will enable an optimized solution?</td></tr>
<tr><td colspan="2">Schedule
Q2 2014 – Q4 2017</td></tr>
<tr><td colspan="2">Status</td></tr>
</table>

[42] The EPIC 1 Investment Plan Application (A.)12-11-004 was filed on November 1, 2012. The EPIC 2 Investment Plan A.14-05-005 was filed on May 1, 2014. The EPIC 3 Investment Plan A.17-05-005 on May 1, 2017.

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

The final project report is complete, was submitted with the 2017 Annual Report, and is available on PICG's public EPIC website.

2. Regulatory Mandates: Submetering Enablement Demonstration

Investment Plan Period 1st Triennial Plan (2012-2014)	**Assignment to Value Chain** Demand-Side Management
Objective & Scope On November 14, 2013, the Commission voted to approve the revised Proposed Decision (PD) Modifying the Requirements for the Development of a Plug-In Electric Vehicle Submetering Protocol set forth in D.11-07-029. The investor-owned utilities (IOUs) are to implement a two phased pilot beginning in May 2014, with funding for both phases provided by the EPIC. This project, Phase I of the pilot will (1) evaluate the demand for Single Customer of Record submetering, (2) estimate billing integration costs, (3) estimate communication costs, and (4) evaluate customer experience. IOUs and external stakeholders will finalize the temporary metering requirements, develop a template format used to report submetered, time-variant energy data, register Submeter Meter Data Management Agents and develop a Customer Enrollment Form, and finalize MDMA Performance Requirements. The IOUs will also solicit a 3rd party evaluator to evaluate customer experience.	
Schedule Q1 2014 – Q1 2017	
Status The final project report is complete, was submitted with the 2016 Annual Report, and is available on PICG's public EPIC website.	

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.	
Status The final project report is complete, was submitted with the 2016 Annual Report, and is available on PICG's public EPIC website.	

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

Investment Plan Period 1st Triennial Plan (2012-2014)	**Assignment to Value Chain** Demand-Side Management
Objective & Scope The Beyond the Meter (BTM) project will demonstrate the use of a DER management system to interface with and control DER based on customer and distribution grid use cases. It will also demonstrate the ability to communicate near-real time information on the customer's load management decisions and DER availability to SCE for grid management purposes. Three project objectives include: 1) develop a common set of requirements that support the needs of a variety of stakeholders including customers, distribution management, and customer program; 2) validate standardized interfaces, functionalities, and architectures required in new Rule 21 proceedings, IOU Implementation Guide, and UL 1741/IEEE 1547 standards; 3) collect and analyze measurement and cost/benefits data in order to inform the design of new tariffs, recommend the deployment of new technologies, and support the development of new programs.	
Status The EPIC 1 Final Report for the Beyond the Meter Project is complete, was submitted with the with the 2017 Annual Report, and is available on PICG's public EPIC website.	

5. Portable End-to-End Test System

Investment Plan Period 1st Triennial Plan (2012-2014)	**Assignment to Value Chain** Transmission
Objective & Scope End-to-end transmission circuit relay testing has become essential for operations and safety. SCE technicians currently test relay protection equipment during commissioning and routing testing. Existing tools provide a limited number of scenarios (disturbances) for testing and focus on testing protection elements; not testing system protection. This project will demonstrate a robust portable end-to-end toolset (PETS) that addresses: 1) relay protection equipment, 2) communications, and 3) provides a pass/fail grade based on the results of automated testing using numerous simulated disturbances. PETS will employ portable Real-Time Digital Simulators (RTDS's) in substations at each end of the transmission line being tested. Tests will be documented using a reporting procedure used in the Power Systems Lab today, which will help ensure that all test data is properly evaluated.	
Schedule Q1 2014 – Q4 2015	
Status The final project report is complete, was submitted with the 2015 Annual Report, and is available on PICG's public EPIC website.	

6. Voltage and VAR Control of SCE Transmission System

Investment Plan Period	Assignment to Value Chain
1st Triennial Plan (2012-2014)	Transmission
Objective & Scope This project involves demonstrating software and hardware products that will enable automated substation volt/var control. Southern California Edison (SCE) will demonstrate a Substation Level Voltage Control (SLVC) unit working with a transmission control center Supervisory Central Voltage Coordinator (SCVC) unit to monitor and control substation voltage. The scope of this project includes systems engineering, testing, and demonstration of the hardware and software that could be operationally employed to manage substation voltage.	
Schedule Q1 2014 – Q4 2018	
Status The Final Report for the Voltage and VAR Control of SCE Transmission System is complete, was submitted with the 2018 Annual Report, and is available on PICG's public EPIC website.	

7. Superconducting Transformer (SCX) Demonstration

Investment Plan Period	Assignment to Value Chain
1st Triennial Plan (2012-2014)	Distribution
Objective & Scope This project was cancelled in 2014. No further work is planned. *Original Project Objective and Scope:* SCE will support this $21M American Reinvestment and Recovery Act (ARRA) Superconducting Transformer (SCX) project by providing technical expertise and installing and operating the transformer at SCE's MacArthur substation. The SCX prime contractor is SuperPower Inc. (SPI), teamed with SPX Transformer Solutions (SPX) {formerly Waukesha Electric Systems}. SCE has provided two letters of commitment for SCX. The SCX project will develop a 28 MVA High Temperature Superconducting, Fault Current Limiting (HTS-FCL) transformer. The transformer is expected to be installed in 2015. SCE is supporting this project and is not an ARRA grant sub-recipient. SCE is being reimbursed for its effort by EPIC. SCE's participation in this project was previously approved under the now-defunct California Energy Commission's PIER program.	
Status SCE formally cancelled this project in Q3 2014.	

8. State Estimation Using Phasor Measurement Technologies

Investment Plan Period	Assignment to Value Chain
1st Triennial Plan (2012-2014)	Grid Operation/Market Design
Objective & Scope Accurate and timely power system state estimation data is essential for understanding system health and provides the basis for corrective action that could avoid failures and outages. This project will demonstrate the utility of improved static system state estimation using Phasor	

Measurement Unit (PMU) data in concert with existing systems. Enhancements to static state estimation will be investigated using two approaches: 1) by using GPS time to synchronize PMU data with Supervisory Control and Data Acquisition (SCADA) system data; 2) by augmenting SCE's existing conventional state estimator with a PMU based Linear State Estimator (LSE).
Schedule Q2 2014 – Q4 2017
Status The final project report is complete, was submitted with the 2017 Annual Report, and is available on PICG's public EPIC website.

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.	
Schedule Q2 2014 – Q1 2019	
Status The final project report is complete, was submitted with the 2019 Annual Report, and is available on PICG's public EPIC website.	

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

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

requirements for grid optimization and renewables integration with distributed energy storage devices. A second part of this project will investigate how energy storage devices located on distribution circuits can be used for reliability while also being bid into the CAISO markets to provide ancillary services. This is also known as dual-use energy storage. Initial use cases will be developed to determine the requirements for the control systems necessary to accomplish these goals.
Schedule Q2 2014 – Q4 2017
Status The Final Report for the Voltage and VAR Control of SCE Transmission System is complete, was submitted with the 2018 Annual Report, and is available on PICG's public EPIC website.

11. Outage Management and Customer Voltage Data Analytics Demonstration

Investment Plan Period 1st Triennial Plan (2012-2014)	**Assignment to Value Chain** Grid Operation/Market Design
Objective & Scope Voltage data and customer energy usage data from the Smart Meter network can be collected and leveraged for a range of initiatives focused on achieving operational benefits for Transmission & Distribution. Before a full implementation of this new approach can be considered, a demonstration project will be conducted to understand how voltage and consumption data can be best collected, stored, and integrated with T&D applications to provide analytics and visualization capabilities. Further, Smart Meter outage and restoration event (time stamp) data can be leveraged to improve customer outage duration and frequency calculations. Various stakeholders in T&D have identified business needs to pursue more effective and efficient ways of calculating SAIDI (System Average Interruption Duration Index), SAIFI (System Average Interruption Frequency Index), and MAIFI (Momentary Average Interruption Frequency Index) for internal and external reporting. Before a full implementation of this new approach can be considered, a demonstration project will be conducted to understand the feasibility and value of providing smart meter data inputs and enhanced methodology for calculating the Indexes. The demonstration will focus on a limited geography (SCE District or Region) to obtain the Smart Meter inputs to calculate the Indexes and compare that number with the current methodologies to identify any anomalies. A hybrid approach using the Smart Meter-based input data combined with a better comprehensive electric connectivity model obtained from GIS may provide a more efficient and effective way of calculating the Indexes. Additionally, an effort to evaluate the accuracy of the Transformer Load Mapping data will be carried out.	
Schedule Q1 2014 – Q4 2015	
Status The final project report is complete, was submitted with the 2015 Annual Report, and is available on PICG's public EPIC website.	

12. SA-3 Phase III Demonstration

Investment Plan Period 1st Triennial Plan (2012-2014)	Assignment to Value Chain: Transmission
Objective & Scope This project is intended to apply the findings from the Substation Automation Three (SA-3) Phase II (Irvine Smart Grid Demonstration) project to demonstrate real solutions to automation problems faced by SCE today. The project will demonstrate two standards-based automation solutions (sub-projects) as follows: Subproject 1 (Bulk Electric System) will address issues unique to transmission substations including the integration of centrally managed critical cyber security (CCS) systems and NERC CIP compliance. When the project was proposed Subproject 2 (Hybrid) intended to address the integration of SA-3 capabilities with SAS and SA-2 legacy systems. In 2016 SA-3 Hybrid scope was completely dropped from the EPIC SA-3 phase III Demonstration. Furthermore, as part of the systems engineering the SA-3 technical team will demonstrate two automation tools as follows: Subproject 3 (Intelligent Alarming) will allow substation operators to pin-point root cause issues by analyzing the various scenarios and implement an intelligent alarming system that can identify the source of the problem and give operators only the relevant information needed to make informed decisions; and Subproject 4 (Real Time Digital Simulator (RTDS) Mobile Testing) will explore the benefits of an automated testing using a mobile RTDS unit, and propose test methodologies that can be implemented into the factory acceptance testing (FAT) and site acceptance testing (SAT) testing process.	
Schedule Q1 2014 – Q3 2021	
Status The final project report is complete and is submitted as part of the 2020 Annual Report and is available on PICG's public EPIC website.	

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.
Schedule Q1 2014 – Q4 2017
Status The final project reports were completed and submitted with the 2017 Annual Report and are available on PICG's public EPIC website. SCE has completed an Executive Summary Report that ties the subprojects together, which was submitted with the 2018 Annual Report, and is available on PICG's public EPIC website.

14. Enhanced Infrastructure Technology Evaluation

Investment Plan Period	**Assignment to Value Chain**
1st Triennial Plan (2012-2014)	Distribution
Objective & Scope At the request of Distribution Apparatus Engineering (DAE) group's lead Civil Engineer, Advanced Technology (AT) will investigate, demonstrate, and evaluate recommendations for enhanced infrastructure technologies. The project will focus on evaluating advanced distribution sectional poles (hybrid, coatings, etc.), concealed communications on assets, vault monitoring systems (temperature, water, etc.), and vault ventilation systems. Funding is needed to investigate the problem, engineering, demonstrate alternatives, and come up with recommendations. SCE sees the need for poles that can withstand fires and have a better life cycle cost and provide installation efficiencies when compared to existing wood pole replacements. Due to increased city restrictions, there is a need for more concealed communications on our assets such as streetlights (e.g., on the ISGD project, the City of Irvine would not allow SCE to install repeaters on streetlights due to aesthetics). DAE also sees the need for technologies that may minimize premature vault change-outs (avg. replacement cost is ~$250K). At present, DAE does not have the necessary real-time vault data to sufficiently address the increasing vault deterioration issue nor do we utilize a hardened ventilation system that would help this issue by removing the excess heat out of the vaults (blowers last ~ 2 years, need better bearings for blower motors, etc.).	
Schedule Q2 2014 – Q4 2016	
Status The final project report is complete and was submitted with the 2016 Annual Report, and is available on PICG's public EPIC website.	

15. Dynamic Line Rating Demonstration

Investment Plan Period	**Assignment to Value Chain**
1st Triennial Plan (2012-2014)	Transmission
Objective & Scope Transmission line owners apply fixed thermal rating limits for power transmission lines. These limits are based on conservative assumptions of wind speed, ambient temperature, and solar radiation. They are established to help ensure compliance with safety codes, maintain the	

integrity of line materials, and help secure network reliability. Monitored transmission lines can be more fully utilized to improve network efficiency. Line tension is directly related to average conductor temperature. The tension of a power line is directly related to the current rating of the line. This project will demonstrate the CAT-1 dynamic line rating solution. The CAT-1 system will monitor the tension of transmission lines in real-time to calculate a dynamic daily rating. If successful, this solution will allow SCE to perform real-time calculations in order to determine dynamic daily rating of transmission lines, thus increasing transmission line capacity.
Schedule Q2 2014 – Q1 2016
Status The final project report is complete, was submitted with the 2016 Annual Report, and is available on PICG's public EPIC website.

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.	
Schedule Q3 2014 – Q3 2015	
Status The final project report is complete, was submitted with the 2015 Annual Report, and is available on PICG's public EPIC website.	

2015 – 2017 Investment Plan Projects

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

Investment Plan Period 2nd Triennial Plan (2015-2017)	**Assignment to Value Chain** Demand-Side Management
Objective & Scope This proposed project builds upon the "Beyond the Meter Advanced Device Communications" project from the first EPIC triennial investment plan and proposes to demonstrate how the concept of "big data"[44] 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	

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

Advanced Load Control System (ALCS) and by communicating to centralized energy hubs at the customer level to determine the optimal load management scheme.
Schedule Q1 2016 – Q4 2018
Status The Final Report for the Integration of Big Data for Advanced Automated Customer Load Management is complete, and was submitted with the 2018 Annual Report, and is available on PICG's public EPIC website.

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.	
Schedule Q3 2015 – Q1 2017	
Status The final project report is complete and, was submitted with the 2017 Annual Report, and is available on PICG's public EPIC website.	

3. Proactive Storm Impact Analysis Demonstration

Investment Plan Period 2nd Triennial Plan (2015-2017)	**Assignment to Value Chain** Distribution
Objective & Scope This project will demonstrate proactive storm analysis techniques prior to the storm's arrival and estimate its potential impact on utility operations. In this project, we will investigate certain technologies that can model a developing storm and its potential movement through the utility service territory based on weather projections. This information and model will then be integrated with the Geographic Information System (GIS) electrical connectivity model, Distribution Management System (DMS), and Outage Management System (OMS) capabilities, along with historical storm data, to predict the potential impact on the service to customers. In addition, this project will demonstrate the integration of near real-time meter voltage data with the GIS network to develop a simulated circuit model that can be effectively utilized to manage storm responses and activities and deploy field crews.	
Schedule Q3 2015 – Q4 2018	

Status
The Final Report for the Proactive Storm Impact Analysis Demonstration is complete, was submitted with the 2018 Annual Report, and is available on PICG's public EPIC website.

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

Investment Plan Period 2nd Triennial Plan (2015-2017)	**Assignment to Value Chain** Distribution
Objective & Scope This project will leverage lessons learned from the Next Generation Distribution Automation – Phase 1 project performed in the first EPIC triennial investment plan period. This project will focus on integrating advanced control systems, modern wireless communication systems, and the latest breakthroughs in distribution equipment and sensing technology to develop a complete system design that would serve as a standard for distribution automation and advanced distribution equipment.	
Schedule Q3 2016 – Q4 2022	
Status The final project is complete and was submitted with the 2022 Annual Report, and is available on PICG's public EPIC website.	

5. System Intelligence and Situational Awareness Capabilities

Investment Plan Period 2nd Triennial Plan (2015-2017)	**Assignment to Value Chain** Distribution
Objective & Scope This project will demonstrate system intelligence and situational awareness capabilities such as high impedance fault detection, intelligent alarming, predictive maintenance, and automated testing. This will be accomplished by integrating intelligent algorithms and advanced applications with the latest substation automation technologies, next generation control systems, latest breakthrough in substation equipment, sensing technology, and communications assisted protection schemes. This system will leverage the International Electrotechnical Commission (IEC) 61850 Automation Standard and will include cost saving technology such as process bus, peer-to-peer communications, and automated engineering and testing technology. This project will also inform complementary efforts at SCE aimed at meeting security and NERC CIP compliance requirements. This project will test end-to-end digital capabilities between various simulated switchyard gear and protection and control (P&C) devices via a digital interface using IEC 61850 process bus technology in a laboratory environment. The process bus technology is a key enabler to the digital substation, which will enable SCE to substitute engineering-intensive and costly point-to-point copper signaling wires with a safe, standardized optical communication bus (i.e., process bus). In doing so, SCE will remove the copper connections between its high-voltage switchgear and the various P&C devices needed to operate the substation. By retrofitting an existing distribution substation with IEC 61850 process bus technology and replacing protection relays with IEC 61850-capable Intelligent Electronic	

Devices (IEDs), SCE can develop a more flexible and cost-effective foundation for protecting substations amid increasing renewables and security standards. More specifically, the team anticipates the following potential benefits for its business stakeholders:

- Replacing complex point-to-point copper wires with safe, standardized optical communications will help reduce capital costs associated with the required footprint, construction, and testing of P&C systems.
- An IEC 61850 standard process bus makes it easier to update P&C applications and schemes by updating software configurations rather than hardwired reconfigurations, thereby reducing outage time and maintenance costs (O&M), and providing quicker responses to new protection challenges.
- Potential improvement to field worker safety due to the elimination of electrical connections between high-voltage switchgear and P&C devices—e.g., reducing the potential for inadvertently-opened Current Transformer (CT) circuits.
- The process bus will help increase SCE's understanding of what is occurring within the substation by enabling remote and on-site real-time system monitoring capabilities.
- Data and analysis from devices also enable near real-time asset monitoring, predictive analytics, and health indices to support "just-in-time" asset replacement, increasing the useful lives of capital assets.
- An IEC 61850 standard process bus enables interoperability between devices made by different manufacturers, allowing SCE to choose best-in-breed P&C devices and/or virtual applications.

Schedule

Q1 2016 – Q3 2025

Status Update

Accomplishment & Success Stories

- The project team onboarded vendors to advance the engineered drawings and to fabricate the testing equipment and began soliciting vendors to assist with testing.
- The project team procured all long-lead time material to avoid supply chain delays.
- The team completed all IT system architecture documentation.
- The engineering drawing vendor delivered the final product which was approved by SCE.
- The team completed the initial test plan.

Challenges or Setbacks

- During the planning phase the project team minimized the scope of the material necessary to successfully test the fully digital substation concept. It was noticed that additional material was necessary to fully test the anticipated scope so additional material needed to be procured.

Key Findings and Lessons Learned

- Through internal discussions with our stakeholders, we learned about additional testing needing to be performed in order for operation to accept and adopt the new technology. These additional test cases were added to the test plan.

• The project team is working to capture field concerns to be included in testing to ease a field implementation should this lab-only project prove successful. Customer Benefits • The team has not yet identified new sources of customer value as the project is still in the lab testing setup phase. Customer benefits expected to be identified as testing commences. Anticipated RFPs • The project team has begun soliciting vendors to support testing. This RFP will be sent, and a vendor selected and onboarded in Q1 2024. Industry Advancement • The project team attended the 2023 DistribuTECH conference and plans to present at the 2024 DistribuTECH conference.

6. Regulatory Mandates: Submetering Enablement Demonstration - Phase 2

Investment Plan Period 2nd Triennial Plan (2015-2017)	**Assignment to Value Chain** Demand-Side Management
Objective & Scope This project expands on the submetering project from the first EPIC triennial investment plan cycle to demonstrate plug-in electric vehicle (PEV) submetering at multi-dwelling and commercial facilities. Specifically, the project will leverage third party metering to conduct subtractive billing for various sites, including those with multiple customers of record.	
Schedule Q4 2015 – Q1 2019	
Status The Final Report for the Regulatory Mandates: Submetering Enablement Demonstration - Phase 2 is complete and was submitted with the 2019 Annual Report, and is available on PICG's public EPIC website.	

7. Bulk System Restoration Under High Renewables Penetration

Investment Plan Period 2nd Triennial Plan (2015-2017)	**Assignment to Value Chain** Transmission
Objective & Scope The Bulk System Restoration under High Renewable Penetration Project will evaluate system restoration plans following a blackout event under high penetration of wind and solar generation resources. Typically, the entire restoration plan consists of three main stages; Black Start, System Stabilization, and load pick-up. The Project will be divided into two phases: Phase I of the project will address the feasibility of new approaches to system restoration by reviewing the existing system restoration plans and its suitability for higher penetration of renewable generation. It will include a suitable RTDS Bulk Power system to be used in the first stage of system restoration, black start, and it will also include the modeling of wind and solar renewable resources.	

Phase II of the project will focus on on-line evaluation of restoration plans using scenarios created using (RTDS) with hardware in the loop such as generation, transformer, and transmission line protective relays. The RTDS is a well-known tool to assess and evaluate performance of protection and control equipment. This project intends to utilize the RTDS capabilities to evaluate and demonstrate system restoration strategies with variable renewable resources focusing on system stabilization and cold load pick-up. Furthermore, alternate restoration scenarios will be investigated. After the restoration process is evaluated, tested, and demonstrated in the RTDS Lab environment, we will provide a recommendation to system operations and transmission planning for their inputs to further develop this approach into an actual operational tool.
Status In December 2016, this project was cancelled by SCE Senior Leadership as a result of an internal organizational change that focused the organization on Distribution System strategic objectives. This was reported in the 2016 EPIC Annual Report.

8. Series Compensation for Load Flow Control

Investment Plan Period 2nd Triennial Plan (2015-2017)	**Assignment to Value Chain** Transmission
Objective & Scope The intent of this project is to demonstrate and deploy the use of Thyristor Controlled Series Capacitors (TCSC) for load flow control on series compensated transmission lines. On SCE's 500 kV system in particular, several long transmission lines are series-compensated using fixed capacitor segments that do not support active control of power flow. The existing fixed series capacitors use solid state devices as a protection method and are called Thyristor Protected Series Capacitors (TPSC).	
Status In 2016, it was determined that the deliverables for this project could easily be done via another project that was already in progress. Therefore, we ultimately determined that the project should be cancelled. This was reported in the 2016 Annual Report.	

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

Investment Plan Period 2nd Triennial Plan (2015-2017)	**Assignment to Value Chain** Distribution
Objective & Scope This project demonstrates the electrification of transportation and vocational loads that previously used internal combustion engines powered by petroleum fuels in the SCE fleet. The VAPS system uses automotive grade lithium-ion battery technology (Chevrolet Volt and Ford Focus EV) which is also used in notable stationary energy storage projects (Tehachapi 32 MWh Storage).	
Schedule Q3 2015 – Q1 2019	

Status
The Final Report for the VAPS is complete and was submitted with the 2019 Annual Report, and is available on PICG's public EPIC website.

10. Dynamic Power Conditioner

Investment Plan Period	Assignment to Value Chain
2nd Triennial Plan (2015-2017)	Distribution
Objective & Scope	
This project will demonstrate the use of the latest advances in power electronics and energy storage devices and controls to provide dynamic phase balancing. The project will also provide voltage control, harmonics cancellation, sag mitigation, and power factor control while fostering steady state operations such as injection and absorption of real and reactive power under scheduled duty cycles or external triggers. This project aims to mitigate the cause of high neutral currents and provide several power quality benefits by using actively controlled real and reactive power injection and absorption.	
Schedule	
Q3 2016 – Q4 2019	
Status	
The final project report is complete and was submitted as part of the 2020 Annual Report, and is available on PICG's public EPIC website.	

11. Optimized Control of Multiple Storage Systems

Investment Plan Period	Assignment to Value Chain
2nd Triennial Plan (2015-2017)	Distribution
Objective & Scope	
This project aims to demonstrate the ability of multiple energy storage controllers to integrate with SCE's Distribution Management System (DMS) and other decision-making engines to realize optimum dispatch of real and reactive power based on grid needs.	
Status Update	
In 2017, the goals of this project were found to overlap significantly with those of the EPIC 2 Regional Grid Optimization Demo Phase 2 project (otherwise known as Integrated Grid Project (IGP) Phase 2). This project was then cancelled, and the proposed benefits will be realized through IGP Phase 2 project.	

12. DC Fast Charging Demonstration

Investment Plan Period	Assignment to Value Chain
2nd Triennial Plan (2015-2017)	Demand-Side Management
Objective & Scope	
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.
Schedule Q1 2016 – Q1 2018
Status The Final Report for the DC Fast Charging Demonstration is complete and was submitted with the 2018 Annual Report, and is available on PICG's public EPIC website.

13. Integrated Grid Project II

Investment Plan Period 2nd Triennial Plan (2015-2017)	**Assignment to Value Chain** Cross-Cutting/Foundational Strategies & Technologies
Objective & Scope The project will deploy, field test and measure innovative technologies that emerge from the design phase of the Integrated Grid Project (IGP) that address the impacts of distributed energy resources (DERs) owned by both 3rd parties and the utility. The objectives are to demonstrate the next generation grid infrastructure that manages, operates, and optimizes the DERs on SCE's system. The results will help determine the controls and protocols needed to manage DER, how to optimally manage an integrated distribution system to provide safe, reliable, affordable service and also how to validate locational value of DERs and understand impacts to future utility investments.	
Schedule Q3 2016 – Q4 2021	
Status Update Final Report for the Integrated Grid Project II is complete and was submitted with the 2021 Annual Report, and is available on PICG's public EPIC website.	

<u>2018 – 2020 Investment Plan Projects</u>

1. Cybersecurity for Industrial Control Systems

Investment Plan Period 3rd Triennial Plan (2018-2020)	**Assignment to Value Chain** Grid Operation/Market Design
Objective & Scope This project will demonstrate the ability to deploy adaptive security controls and dynamically re-zone operational networks while the Industrial Control System (ICS) is either under cyberattack or subject to an increased threat level. The concept of dynamic zoning allows for isolation of threats to certain segments of the ICS and could include both vertical (isolating data flows from SCADA masters to substation endpoints) and horizontal (containing data flows between	

substations, for example, under a state of manual control when the SCADA master cannot be trusted). Adaptive Controls/Dynamic Zoning (AC/DZ) has the potential to benefit the national grid and ratepayers by bolstering a more resilient and secure grid through the ability to identify and isolate core grid operational functions while under a cyber-attack or incident. The benefits are also cross cutting in that AC/DZ will drive grid operations and cybersecurity together for collaboration to address controls for zones to be defined risk impact mitigations.
Schedule Q2 2019 – Q4 2022
Status The final project report is complete and was submitted with the 2022 Annual Report, and is available on PICG's public EPIC website.

2. Advanced Data Analytics Technologies

Investment Plan Period 3rd Triennial Plan (2018-2020)	**Assignment to Value Chain** Grid Operation/Market Design
Objective & Scope This project will demonstrate the possibility of using advanced data analytics technologies for Transmission and Distribution (T&D) and customer maintenance. This project will evaluate pattern recognition technologies that are capable of using new and/or existing data sources such as from sensors, smart meters, supervisory control, and data acquisition (SCADA), for predicting or providing alarms on the incipient failure of distribution system assets. These assets would include connectors, transformers, cables, and smart meters. <u>Use-case Scope</u> Use supervised machine learning techniques to train, validate, then demonstrate a time-to-failure model on a subset of SCE's distribution transformer installed base. The models will quantify the probability of failure (at the transformer-level) and estimate the remaining useful life (RUL) of distribution transformers. <u>Business Objective</u> 1. Inputs to the Transformer Asset Class Strategies a. Inform risk buy down calculations based on remaining useful life (RUL) b. Inform aggregation of like transformers based on level of RUL for decision making 2. Prevent an In-service Failure a. Avoid unplanned outage time (reduced CMI, reduce crew OT expense) b. Repair during planned outage (lessen customer impact) c. Avoid catastrophic failure and resulting consequences (damage to customer/public property, safety, surrounding equipment, wildfire ignition) 3. Procurement/Inventory Planning a. Pre-order replacement transformer if there are none in inventory	

b. Budget planning for future procurement (Inform future GRC Testimony)
Status This project was deferred in April 2021 to allow consideration of other projects which may offer greater benefits aligned with California and CPUC objectives.

3. Advanced Technology for Field Safety

Investment Plan Period 3rd Triennial Plan (2018-2020)	**Assignment to Value Chain** Distribution
Objective & Scope This project will demonstrate the possibility of using new advanced technologies to reduce T&D field crew exposure to customer hazards. The project will evaluate technologies that are capable of using data sources such as field sensors, smart meters, etc. to provide real/near real-time status of faulty equipment. This project will also evaluate technology that is capable of levering recent advancements in the Augmented Reality space.	
Schedule Q1 2020 – Q4 2027	
Status Update The project was relaunched in 2023, with the project team employing a design thinking approach to develop a problem statement, define the scope, and outline high-level use cases. A new project sponsor and major stakeholders were reintroduced to identify and engage with the new scope of the project. Project planning is currently underway and is expected to resume execution in 2024.	

4. Storage-Based Distribution DC Link

Investment Plan Period 3rd Triennial Plan (2018-2020)	**Assignment to Value Chain** Distribution
Objective & Scope This project will examine the benefits of a novel architecture for a distribution-connected energy storage system. Storage systems are typically connected to a single electrical point. This project will demonstrate an architecture that will allow the system to connect to two distribution circuits, using two power conversion systems tied to a single storage medium. This approach will allow the storage system to support both circuits, individually or simultaneously, and will also provide a means of dynamically exchanging power between the two circuits (DC link).	
Schedule Q4 2019 – Q3 2025	
Status Update: Accomplishment & Success Stories	

- Power systems study using CYME software was completed, using two circuits from SCE territory.
- The team made progress on a mockup for the graphical user interface that simplifies the tie controller status/operation so operators can easily understand the system status and control the device.
- A controls architecture diagram was completed that shows all communications and control paths between the various components.
- A factory acceptance test procedure was submitted and reviewed by the team.
- An Emulator was used to test the communications protocols between various network devices.
- An instrumentation and metering diagram was completed to document all measurement points in the laboratory installation.
- The team published a conference paper called "Improving DER Hosting Capacity with Tie Point Controllers and Smart BESS". It was accepted by the 2023 Grid of the Future Symposium.

Challenges or Setbacks

- The Grid Simulator that was intended to act as the second circuit was found to have a frequency offset and did not match the utility grid frequency exactly. As a result, it was decided to use a distribution switchboard for the second circuit source. This change will require a minor update to the electrical drawings.
- Some of the lab electrical support equipment was found to have long lead times, as much as 40 weeks to manufacture and deliver.

Key Findings and Lessons Learned

- Through internal discussions with our stakeholders, we learned that the capability to control the power flow that is transferred between two circuits is highly desirable and provides benefits by relieving overloaded conditions. It also improves the utilization of energy storage that is typically only connected to one circuit, allowing it to be effectively connect to a second circuit – providing capacity benefits to multiple circuits.
- A key benefit is that the DC Link allows circuits to be operated in a networked configuration, where typically the circuits are configured as "radial" design. A networked design allows the circuits to "share resources" so that an overloaded circuit can draw power from other circuits that have spare capacity.
- A key finding is that the protection design must be understood prior to installing a Tie Controller on actual circuits. The Tie Controller could have an effect on the main breaker operation of the substation, which could require an adjustment of the breaker settings.

Customer Benefits

- The team identified that utilizing a Tie Controller and existing BESS can significantly increase the hosting capacity to connect DER customers. This was verified by performing computer simulations on actual SCE circuits and calculating the power flow results. In addition, the Tie Controller and BESS could respond to real time changes in DER output by maintaining proper voltage levels. This is especially important with volatile generation sources such as photo-voltaic panels.

• The Tie Controller is expected to be able to defer capital upgrades like cable replacement, since cable overloads can be mitigated by transferring some power from the adjacent circuit. Anticipated RFPs • Installation labor for the lab supporting equipment, which includes two transformers, two switches, and two distribution panels. Industry Advancement • The team published and had a conference paper accepted for the 2023 Grid of the Future Symposium. The paper was titled "Improving DER Hosting Capacity with Tie Point Controllers and Smart BESS". This paper investigated how a Tie Controller working in conjunction with a BESS could allow additional DER generators to connect to a circuit by transferring power from a nearby circuit and optimizing power flow using an existing BESS system.

4. Smart City Demonstration

Investment Plan Period 3rd Triennial Plan (2018-2020)	**Assignment to Value Chain** Grid Operation/Market Design
Objective & Scope The project will demonstrate the electric utility role within a Smart City initiative. The demonstration has the following objectives: Increasing coordination between electric system and urban planning, coordinating infrastructure construction activities within a city, streamlining the interconnection process through automated systems between SCE and the city, partnering with cities to engage more customers in renewable resources (e.g. community solar PV, community storage) and creating more opportunities for electric transportation, working with cities to customize their resource portfolio to meet a Climate Action Plan goal (e.g. "Community Choice Aggregation Lite" or Community Choice Aggregation), leveraging assets (e.g. telecommunications, rights of way), coordinating communication on energy programs (e.g. energy efficiency, demand response, Charge Ready, Green Rate), and assisting large customers (i.e. the city as an energy customer) in more efficiently utilizing their energy resources and improving resiliency for critical operations center (e.g. emergency command centers).	
Schedule Q3 2019 – Q2 2025	
Status Update Accomplishment & Success Stories • The vendor along with SCE tech leads certified that the Fenwick Microgrid Lab test bed (Microgrid Control System) meets the contractual requirements, has successfully passed final commissioning and site acceptance testing, and successfully demonstrated all use cases. • Technical functional design specification (FDS) document completed. • Solution architecture definition (SAD) document completed and. • Discussions with the partnering city has resulted in an agreement with the Planning Review Committee, and satisfaction with the substance of the Easement drawings and Pre-Fire Plan.	

- Procured a photovoltaic inverter and a photovoltaic site controller.
- Completed power quality relay testing.
  - Provided requirements for microgrid and remote grid using power quality meter and Doble Amplifier and Protection Suite. This meter configuration can be leveraged for all future microgrid projects.
  - Completed logic diagram.
  - Completed final test plan and test report.
  - Completed conference paper to be submitted at the IEEE Power and Energy Society General Meeting (PESGM) 2024 Conference entitled "Power Quality Based Protection for Microgrid and Remote Grid Loads: Type Testing."
- GTFPI (Gigabit-Transceiver Front Panel Interface) integration to Relays for QAS setup completed.
  - Auxiliary relays wiring for GTFPI completed.
  - Developed new profile for Doble in lab testbed for SAG and SWELL.
- New Battery Vendor RFP submitted in June 2023 and vendor scoring completed.

<u>Challenges or Setbacks</u>

- The project faced a substantial issue with the need to seek an alternative battery vendor due to legal issues with the awarded battery vendor, new RFP had to be submitted.
- Long lead time for needed to procure the transformers and switches for the Pomona Microgrid test pad.

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

- Knowledge gained of the network configuration for a microgrid system that can be used for all future microgrid projects.
  - A similar setup will be done for the Pomona Microgrid Test Pad
- Cribl Edge application is preferred by cyber engineering for Syslog on client servers/workstations/computers, not Splunk Universal Forwarder (universal will work but not preferred).
- Integrating additional elements like DERs and tie breakers into the microgrid model increases complexity, pushing our computational capacity to its limits due to real-time simulations and hardware interfacing. Consequently, further addition of DER assets, implying more control components, would exacerbate this strain.
- During transition modes (i.e., grid connected to islanded mode) the microgrid controller's role in sending and receiving commands to/from the grid forming asset is critical for maintaining the microgrid stability.
  - Delay in sending / receiving commands needs to be optimized via the microgrid controller code.
- Having two Battery Energy Storage Systems (BESS) in one clustered microgrid would sometimes cause stability issues
  - Mitigated via optimizing inverter controller parameters.

<u>Industry Advancement</u>

• Completed conference paper to be submitted at the IEEE Power and Energy Society General Meeting (PESGM) 2024 Conference entitled "Power Quality Based Protection for Microgrid and Remote Grid Loads: Type Testing."

6. Next Generation Distribution Automation III

Investment Plan Period 3rd Triennial Plan (2018-2020)	**Assignment to Value Chain** Distribution
Objective & Scope This project will leverage lessons learned from the Next Generation Distribution Automation II project. It will integrate new FAN wireless radio to automation devices and continue to improve control functionalities. It will provide greater situational awareness to allow system operators to manage the grid with higher DER penetration and be ready to support Distribution System Operators (DSOs). It will integrate advanced control systems, modern wireless communication systems, and the latest breakthroughs in distribution equipment and sensing technology to develop a complete system design that would be a standard for distribution automation and advanced distribution equipment. This project will demonstrate technologies that are applicable for both overhead and underground distribution circuits. This project is composed of the following sub-projects: 1) Duct Bank Monitoring will demonstrate the capability to use an accurate duct bank temperature modeling tool and/or scalable real-time monitoring system. This system would allow for the avoidance of excessive duct bank temperature due to circuit overloading which could lead to premature, catastrophic cable failure. Monitoring of the system could provide better situational awareness to proactively manage circuit loading. 2) IEC 61850 to the Edge aims to explore improvements upon legacy DNP communications for distribution automation by testing and assessing a standardized communication protocol using IEC 61850 to manage field devices for passive activities including commissioning, updates, retirement, and cybersecurity patches. The intent is for the results of the testing to enable uniform, accelerated configuration and enhanced cybersecurity, extending the protocol used by Substation Automation (SA) to the distribution grid. 3) Standard for GMS Field Connected Devices will provide a lab-only demonstration of next generation distribution automation controller devices, capable of using the DNP v3 SAV5 secure protocol, to communicate with a lab sandbox Field Device Management Platform (FDMP). The intent of the lab test system is to validate the ability of the next generation controller devices to send/receive messages required for SCE device management.	
Schedule Q4 2019 – Q3 2024	
Status Update Standard for GMS Field Connected Devices:	

Standard for GMS Field Connected Devices was intended to demonstrate lab-only capabilities of the next-generation distribution automation controller devices, capable of using the DNP3.0 Secure Authentication Ver5 (SAv5) protocol, to communicate with a lab sandbox Field Device Management Platform (FDMP). Unfortunately, several vendor device solutions did not meet the IEEE 1815-2012 DNP3.0 standards. As a result, SCE has decided to close out the DNP3.0 SAV5 secure authentication protocol deliverable, of NGDA III and will report findings in the NGDA III Final Report when the entire project is concluded.

Challenges or Setbacks

- The project faced a substantial issue with various vendor devices not meeting the IEEE 1815-2012 DNP3.0 standards.
- Team decided not to continue evaluating the DNP3.0 SAV5 protocol since vendor solutions do not meet IEEE 1815-2012 DNP3.0 standards requirements.

Key Findings and Lessons Learned

A. DNP3.0 SAV5
   - The Aggressive mode in IEEE 1815-2012 DNP3.0 standards was not sufficiently defined which caused confusion and mis-interpretations from vendors/suppliers.
   - The Confirmations in Aggressive Mode feature is confusing and hard to understand which cause vendors to design it incorrectly.
   - The vendor's field device solutions provided limited configuration capabilities and was unable to be used to fully test the IEEE 1815-2012 DNP3.0 standards.
   - Through internal stakeholder discussions, SCE learned that field device vendors/suppliers' current solution with SAv5 do not meet the IEEE 1815-2012 DNP3.0 standards. Vendor's strategy is to design their device solutions with future SAV6 using zero-trust architecture.

B. Device Management DvM Key Findings and Lessons Learned
   - Field Device Management Platform (FDMP) is still in a beta version. FDMP is not ready for on-premises evaluation and testing.
   - API enhancements with vendor's approval and collaborations are required to provide device remote configuration capabilities via Device Management platform.
   - The challenge of the existing back-office processes of configuring and maintaining Distribution Automation (DA) devices with NetComm wireless verses Field Area Network system will need to be revamped to meet Cyber's and Operation's requirements. Since the architecture for FAN network management system differs from the existing NetComm network management, the team has to enhance and re-test the new process flows to understand how new DA devices will be added, deleted and maintained in Device Management platform.

Industry Advancement

Standard for GMS Field Connected Devices:

- Completed a SAD (Solution Architecture Document) to provide vendors and suppliers with SCE's future distribution automation device requirements and specifications. As SCE

is building out the Field Area Network wireless communication infrastructure, the purpose of the Device Management platform is to manage and monitor the distribution automation field devices settings, configurations and firmware using the Field Area Network wireless MCD radio (Modular Communication Device).

7. SA-3 Phase III Field Demonstrations

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

Objective & Scope

The objective of this project is to successfully demonstrate a modern substation automation system for use in transmission substations by adopting scalable technology that enables advanced functionality to meet NERC CIP compliance and IT cybersecurity requirements. This project is to provide measurable engineering, operations, and maintenance benefits through improved cybersecurity and reliability for transmission substations. It will also provide interoperability and allow the system to work with relays from multiple vendors, prevent vendor lock-in due to proprietary software and hardware, and assure that SCE has the flexibility to implement the best solution available.

Today protection relays are dedicated appliances that receive inputs and outputs through hardwired connections. The IEC 61850 standard includes the concept of a process bus. Process bus replaces the hard wire I/O with fiber optic networking technology, thereby eliminating a significant portion of the wiring required for protection and automation systems.

The concept of virtualized protection relays goes one step further and eliminates the physical relay hardware in favor of a virtual environment. The concepts allow the relays to act as software appliances utilizing process bus signals to perform their functionality, similar to the virtualization that is being used on the Common Substation Platform (CSP).

With virtualized relays there are several foreseeable benefits.

1. Smaller footprint, simplified design, and reduced cost. Relays within a substation can be consolidated to a limited number of racks thereby reducing the footprint required by a substation control room and simplifying the design process. Additional benefits include reduced hardware cost.
2. Faster Deployment Timelines, Seamless Failure Recovery, and Multivendor Compatibility. Benefits of current virtualized environments such as redundancy, automated backups, and automated deployment tools can be utilized to improve engineering, testing and deployment cost and schedules.
3. Ease of testing new automation and protection applications. With a virtualized environment, new protection and automation applications can be implemented and tested without the need to physically redesign the system. This redesign will lead to minimal changes to the overall physical environment. Upgrades and transitions to new architectures will require minimal engineering.

This project seeks to form a partnership with relay vendors to demonstrate and evaluate a proof-of-concept system utilizing machine virtualization and process bus technology. The following outcomes are expected from this project:

- Proof of concept hardware and software
- Comprehensive evaluation and testing
- Recommendations for future projects
- All design documents (business requirements, system requirements, test plans, test reports, use cases, etc.)
- Share project lessons learned with industry by presenting at least one technical conference

Schedule

Q4 2019 – Q2 2025

Status Update

Resonant Grounded Substation

The project completed the testing and demonstration in 2022.

IEC 61850 Programmable Automation Controller

The project completed the testing and demonstration in December 2021.

<u>Accomplishment & Success Stories</u>

Virtual Substation Relays

- The Project onboarded all three vendors planned for the project. Two vendors are providing their prototype virtual protection relay equipment and a third is performing settings, configurations, and testing across both solutions.
- One of the two vendors delivered their solution on time, and the equipment was fully set up in the lab environment in preparation of testing.
- The project team completed all IT setup and Cyber Security testing of the vendor equipment.
- The team has also begun to develop the test plan and all testing scenarios.

<u>Challenges or Setbacks:</u>

- The project faced a delay in receiving the prototype equipment from one of the two vendors. This resulted from a last-minute request by the vendor to sign a proprietary protection legal document. Legal representatives from the vendor and SCE met frequently to work through the vendor concerns and develop a legal agreement agreeable to both sides which was signed and approved. This process, however, caused a delay in the shipment of the vendor's equipment to be set up in the lab.
- Another challenge occurred when one of the equipment vendors shipped their equipment to SCE. The vendor invoice exceeded the amount agreed upon in the Purchase Order, as tax was included where it was not specified in the PO. This was resolved following SCE providing tax exemption, and a corrected invoice was sent and processed. This challenge did not result in any negative impact to the project scope, budget, or schedule.

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

- Through the legal document situation with our vendor the project team learned to discuss legal documentation requirements at the beginning of the project and not assume the standard SCE agreements covered all of the potential concerns.
- The tax situation taught the project team to ensure tax exemption is considered when project procurement involves material or a blend of material and services.
- As the vendor equipment was received and installed it was learned that an aspect of the planned testing, Real Time Data Simulation, was not an expertise known to be needed originally and wasn't possessed by either SCE or the settings, configuration, and testing vendor. This gap has since been remedied but will be accounted for during the planning phase for future projects.

Customer Benefits

- There have been no customer benefits identified as of yet, considering this project has only recently entered the test readiness phase. Customer benefits and impact to the system are anticipated to be discovered as test results are returned.

Anticipated RFPs

- There are currently no RFPs anticipated through the remainder of this project. All vendors have been onboarded and will provide the necessary support.

Industry Advancement

- The project team has not yet presented at any industry forums, but is expected to present at both DistribuTECH and IEEE in 2024.
- When this project was initiated there were few vendors offering this virtual protection relay solution. The market is quickly expanding in this area, with the number of vendors entering this market segment increasing.

8. Distributed Cyber Threat Analysis Collaboration

Investment Plan Period 3rd Triennial Plan (2018-2020)	**Assignment to Value Chain** Grid Operation/Market Design
Objective & Scope This project will demonstrate the ability to standardize utility cybersecurity threat analysis by developing a Distributed Cyber Threat Analysis Collaboration framework to conduct local utility collaboration with utility peers and sharing with National analysis centers to support expedient cyber threat feed analysis. This framework will demonstrate the capability to effectively consume internal and external sourcing threat feeds, process them for legitimacy, and identify utility risk impact, and potential response measures through collaboration with utility peers and National analysis centers to validate and verify threats as well as significantly shorten the time needed to respond to a cyber compromise of the electric grid.	
Schedule Q2 2019 – Q4 2021	
Status	

The Final Report Distributed Cyber Threat Analysis Collaboration is complete, was submitted with the 2021 Annual Report, and is posted on PICG's public EPIC website.

9. Energy System Cybersecurity Posturing (ESCP)

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

10. Distribution Primary & Secondary Line Impedance

Investment Plan Period	**Assignment to Value Chain**
3rd Triennial Plan (2018-2020)	Distribution
Objective & Scope This project will examine the possibility of establishing primary and secondary line impedance information for distribution circuits by examining the voltage and power signatures at the meter and transformer levels, leveraging a basic connectivity model of the circuits, and utilizing SCADA data. The availability of complete primary line impedance information can improve the accuracy of load flow / distribution state estimation results, greater real-time management of the distribution grid, and greater utilization of capacity within the existing installed infrastructure before requiring new assets.	
Status Due to budget constraints SCE put this project on hold in 2020.	

11. Advanced Comprehensive Hazards Tool

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

Objective & Scope This project will demonstrate a new and innovative approach to integrate emerging and mature hazard assessment tools. This demonstration will use a centralized data architecture that integrates various types of SCE asset data from non-electric, generation, and grid infrastructure. The project aims to identify vulnerabilities across different types of infrastructure to understand the overall risk to the grid. The project will demonstrate hazard scenarios and the impacts of those scenarios to the SCE system. The project will demonstrate a comprehensive natural hazard web application with multi-layer mapping capabilities that provide an integrated, holistic view of hazards in the service territory (e.g., earthquake, flood, fire, and extreme weather events). The application will have the ability to conduct risk analysis that allows for asset data to be referenced with hazard exposure and probability of failure or consequence (fragility) to arrive at risk profiles for the assets. This project will integrate: • Various types of asset data from non-electric, generation, and grid infrastructure sources, to provide decision-support on hazard impact and mitigation options before, during, and after a significant event (e.g., extreme weather events, wildfires, and earthquakes, etc.). • Hazard risk assessment / severity index capabilities allowing a comprehensive assessment of vulnerability and exposure across the service territory. A Final Report will be created detailing lessons learned, areas for maturity, and potential synergies with other internal or external efforts.
Schedule Q4 2019 – Q1 2024
Status Update This project is evaluating tools for enhancing grid resilience against earthquakes and wind. It utilized the CHaT tool to simulate seismic and storm threats, and the GRIP tool, in collaboration with DOE's SLAC Lab, to model environmental interactions and assess power system reliability. These demonstrations aim to mitigate the impact of extreme weather on power infrastructure, contributing to fewer power shutdowns during emergencies. <u>Accomplishment & Success Stories</u> The Comprehensive Hazards Tool (CHaT) project successfully integrated hazard assessment tools and consolidated data sources to improve grid vulnerability analysis. Key achievements include: • Standardizing internal tools for hazard risk assessment. • Demonstrated capabilities to improve seismic hazard mitigation planning and provide early situational awareness. • Successfully integrating CHaT software with SCE and 3rd party data for validation and testing. The GRIP project demonstrated and tested the GRIP software. Achievements include: • Performing initial validation with real SCE data in a remotely accessible lab environment by SLAC (Stanford Linear Accelerator Center) researchers. • Successfully deploying GRIP in the lab environment at SCE for validation and testing.

- Integrating grid infrastructure data for 4 circuits to perform core testing of functionality.
- Completed initial testing of pole vulnerability and tree fall/vegetation conductor contact.

Challenges or Setbacks

CHaT

- A setback encountered early in the project occurred when the first selected vendor declined to participate after an extensive period of time was used to negotiate terms and conditions that would satisfy all party members. The vendor was not comfortable with the terms stated in EPIC flow downs nor in the SCE master software licensing agreements.
- A challenge encountered during project execution was the ability to provide members from the selected vendors access to SCE Critical Energy Infrastructure datasets. This was mitigated by onboarding the individuals who required access to the data. The vendor did not meet the cybersecurity vendor risk assessment requirements to gain access to the data without onboarding.
- The final challenge relates to the maturity of climate-related risk assessment methodologies and models for electric utilities from both industry and academia. Initiatives such as EPRI's Climate READi will provide much needed contributions for this area of knowledge.

GRIP

- The included CYME circuit model to Grid-lab-D Hi-pas converter had to be tested on 14 circuits and modified to integrated asset model information from circuit libraries (conductors, poles, etc.). A number of converter issues were identified for CYME 9 Rev 6. Six critical issues were resolved with 100% success rate for all 14 circuits.
- During the initial data integration period from Aug 23 to Dec 23, modifications were made to several thousand code deletions and additions (28,285 additions and 19,374 deletions), to successfully integrate and run all simulation models in the GRIP simulation pipeline. 15 changed files were released and checked into github under release 4.3.3 on December 1, 2023.
- Accessing wind speed data near the location of pole failures was challenging using the USGS National Weather services and internal sources. Access to better weather station locations with historical data were sourced through a weather data service from Synoptic data.

Key Findings and Lessons Learned

- The CHaT tool is effective for seismic studies, but quantifying the impacts of climate and weather on electric utility assets is challenging. Transmission lines, substations, and distribution lines are vulnerable to various weather events. Understanding these vulnerabilities is crucial for long-term planning, especially considering the expected increase in extreme weather. Additional efforts are needed to enhance these capabilities such as multi-hazard events. Multi-hazard events such as atmospheric "blocking" events can cause weather systems to stall, leading to persistent warm, dry and still conditions when they occur in the summer. Coincidence of high temperatures and low wind events could further limit transmission line capacity. Systems may be further stressed if high temperatures lead to higher loads. Another example is an "atmospheric river" event combined with extreme wind conditions. Distribution poles are prone to failure due to high winds, excessive rainfall and/or flooding.

- The GRIP project's successful demonstration of data installation and integration into its software platform has significant implications for reducing Public Safety Power Shutoff (PSPS) events. By conducting initial validation tests on pole vulnerability and the potential for vegetation or tree falls, the project is actively working towards refining the criteria for PSPS events. This could lead to more accurate assessments of infrastructure resilience and environmental risks, ultimately decreasing the frequency and duration of power shutoffs necessary to ensure public safety during extreme weather conditions. Ongoing validation efforts aim to further lower PSPS thresholds, enhancing power stability and reliability for communities.
- Analysis of weather data indicates that pole failures were triggered by two distinct wind conditions: a swift escalation in wind velocity within a six-hour period and prolonged exposure to high winds for over 36 hours. A significant number of these failures were localized in a specific region, occurring at wind speeds slightly lower than the thresholds set for wind resistance design. Interestingly, not every instance of pole damage led to power outages, suggesting some redundancies in the power grid infrastructure that prevent service disruptions despite the damage.

<u>Customer Benefits</u>

CHaT

- Enhances grid reliability, lowers costs, and improves safety by informing optimal design and mitigation strategies for natural hazard events.
- Reduces repair frequencies and durations by hardening the grid in high-risk areas.
- Mitigates loss and damage from hazard events, facilitating more efficient recovery efforts.
- With a high likelihood of a major earthquake in Southern California, CHaT could inform earthquake risk mitigation for critical utility assets like substations.
- Improving public and utility worker safety: By improving grid resiliency and response to hazards, CHaT can reduce public exposure to dangerous situations (like wildfires) and lessen the need for workers to operate in hazardous conditions.

GRIP

- Provides opportunities to reduce risk by identifying and replacing high-risk poles (203 broken pole failures from 2021 to 2024).
- Helps address challenges posed by high winds in Southern California, such as those experienced in Hawaii, to prevent incidents such as wildfires.
- The benefits of enhancing climate adaptation capabilities are multifaceted. Firstly, it leads to improved reliability and resilience for customers, ensuring consistent service despite varying climate conditions. Secondly, creating a lab partnership environment allows for the practical validation of DOE-funded technologies using real-world data. This not only accelerates innovation but also ensures that the technologies developed are aligned with the actual needs and challenges faced by customers, thereby providing tangible benefits.

- Informs new utility capabilities for climate adaptation, planning and hardening strategies, field crew staging for storm recovery, vegetation mitigation planning, and reducing PSPS outages.

Anticipated RFPs/ Next Steps

CHaT

- CHaT can be scaled for production-scale demonstrations and SCE’s Enterprise Analytics Platform with a comprehensive technology transfer plan in place.
- Next steps involve installing and simulating CHaT software earthquake analysis for operationalization within SCE’s substations as part of the business resiliency plan, comparing results with SCE's current software for validation.

GRIP

- Informing SCE's climate adaptation and vulnerability assessment (CAVA) work and supporting DOE projects to overcome technology challenges.
- Originally created on the Google Cloud Platform, GRIP can be migrated from the lab environment to perform analysis at scale using Kubernetes-managed containers.
- Integration of SCE lidar data (pole tilt, vegetation) and scaling and evaluating pole and conductor/tree fall vulnerability for the system are planned after sufficient validation by SLAC.
- After additional validation and full lidar integration, identifying at-risk trees and additional conductors requiring covered conductor in high-fire areas is planned to mitigate wildfire risk.
- Generate a risk-prioritized investment plan and vegetation work practice recommendations based on climate projections for winds.

Industry Advancement

CHaT

- Reducing outage numbers, frequency, and duration: The tool's hazard mitigation and response capabilities can enhance grid resiliency and enable faster responses to hazards, potentially reducing or eliminating prolonged power outages and equipment damage.

GRIP

- Collaboration with experts: Meetings were held with industry experts in wind simulation modeling to introduce them to GRIP's capabilities.
- Publication: An article about the work completed by SCE and the consultant is being reviewed for publication, highlighting the project's achievements.
- Continued validation and improvement of the GRIP platform are being conducted under the US Dept of Energy Grid Modernization Lab Consortium project, with results expected in the 4th quarter of 2024. The test environment setup funded by EPIC will remain in place for continued validation by SLAC, with lower support from SCE once additional validation data is provided.
- Shares benefits and potential with other utilities facing similar risks worldwide.

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

Investment Plan Period 3rd Triennial Plan (2018-2020)	**Assignment to Value Chain** Distribution
Objective & Scope The project will assess and evaluate new interconnection requirements, Vehicle-to-Grid (V2G) related technologies and standards, and utility and third-party controls to demonstrate how V2G direct current (V2G-DC) and V2G alternating current (V2G-AC) capable EVs and EV chargers can discharge to the grid and be used to support charging during grid outages. The project will assess and evaluate, in a laboratory environment, the proposed V2G-AC Rule 21 interconnection processes, proposed SAE and UL standards, and the function of automaker OEM battery/inverter systems to support vehicle-grid integration (VGI) services, integration of project 3rd party aggregators with SCE's Grid Management System (GMS)/DER Management System (DERMS), and partner with an existing Rialto Unified School District DOE V2G school bus project (and its Charge Ready Transport application) to provide an interconnection pathway by demonstrating functional requirements in the lab; and the field evaluation of deployed systems.	
Schedule Q3 2019 – Q3 2024	

Status Update
<u>Accomplishment & Success Stories</u>
• Competed OEM automaker demonstration and initial demonstration report.
• OEM automaker V2G-AC software and hardware deployed in the SCE lab.
    o Completed integration testing Q4 2023.
    o Type testing and end-to-end testing to be completed in 2024.
 	
<u>Challenges or Setbacks</u>
• Procurement of a V2G-DC vendor for the V2G-DC demonstration delayed due to contractual negotiations.
    o The team is mitigating the issue by looking into possible alternative vendors for the demonstration.
• Full V2G-AC implementation not available for testing until 2024.
    o V2H subsystem available May 2024.
 	
<u>Key Findings and Lessons Learned</u>
• Standardization is critical for V2G-AC implementation. The EPIC project has spent significant time enabling V2G-AC integration.
• Customer preferences are critical to enabling V2G-AC but are not easily implemented. Utilities are not in a position to support this and will need to look to Aggregators to engage their customers.
 	
<u>Customer Benefits</u>
• Findings will be compiled at the end of the project.	

Industry Advancement

- V2G Technical Advisory Board (TAB)
  - The V2G TAB hosted a V2G Forum at SCE Energy Education Center in Irwindale, CA, on 2/28/23.
  - The V2G TAB working groups for V2G-AC, V2G Harmonization, and V2G Cybersecurity initiated.
  - The V2G TAB working groups presented at the V2G Forum in Detroit, MI, October 2023.
- Continued support for UL 1741 SC, SAE J3072, SunSpec IEEE 2030.5 profile for SAE J3072, and V2G related CPUC Proceedings (Rule 21, High DER, etc.).
- Coordination with California IOUs on the topic of V2G interconnection.
- Presentations on the V2G EPIC Demonstration and V2G standards at various forums (EPRI IWC, DistribuTECH, etc.).
- V2G-AC systems will be demonstrated to SCE's Interconnection group and other internal stakeholders in 2024.
- Engagement with SCE's Grid Modernization group (GMS/DERMS) for future integration of V2G.The V2G TAB working groups will report out on findings and recommendations at the V2G Forum April 30th through May 2nd 2024 in San Diego, CA.

13. Distributed Plug-In Electric Vehicle Charging Resources

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

Objective & Scope

This project will demonstrate PEV fast charging stations with integrated energy storage that can be used to control the grid system impact of fast charging, allowing more of them to be accommodated for a particular cost, and also to respond to grid needs as distributed energy resources when not in use to charge a vehicle. Fast charging units currently demand 25 to 125 kW, and the load cannot be planned or scheduled. This demand is expected to climb to 350 kW or more as advertised by vehicle and charging system suppliers. This intermittent and unpredictable high demand could concern utility planning and could also challenge high deployment of such systems due to their low load factor and potentially alarming bill impacts to customers under current tariffs. Combining fast charging systems with energy storage can result in higher load factor, while still providing satisfactory service to customers. The size of such storage systems, along with power components, will determine their effectiveness in a particular duty cycle. This is demonstrated in the demands on the system from customers in the real world, which this project will show; the demands on such energy storage systems may be met by the capabilities of used batteries. These measures increase the likelihood of higher numbers of such stations becoming operational. Integrated energy storage provides reliability in the case of grid events – transient or otherwise – and improves charging service in the evolving modern system of increased renewable and distributed generation. This project will demonstrate the reliability improvement of such systems subject to grid events.

Schedule Q4 2019 – Q3 2025
Status Update <u>Accomplishment & Success Stories</u> • Lab Only Testing. The demonstration, testing, and evaluation of electric vehicle charging coupled with energy storage will be performed at Pomona TSD. We will model the charging behavior with a fast charger and a mini battery system already at the Electric Vehicle Test Center. • Received an EV F-150 Lighting for testing and calibration with the fast charger system. • Facilitated progress with anti-islanding use case by utilizing the Microgrid Testpad in conjunction with the other projects. • Received and integrated the following critical equipment components: Charge Management System (CMS) and Re-van EV Emulator for testing and calibration. • Finalized the single Line drawing to enable the vendor to begin the process to start installation. • Installed the DC Fast Charger to assist with the testing of the use cases. <u>Challenges or Setbacks</u> • The project encountered significant challenges due to delays in procuring power systems. SCE faced difficulties in acquiring necessary equipment promptly, largely due to the epidemic. <u>Key Findings and Lessons Learned</u> • Through discussions with our vendors, we were able to mitigate the procurement of critical components with similar equipment with less delays. • Second-life batteries remain scarce, constraining the expansion of energy storage systems. Integrating rapid charging technology with these systems can boost load factors, ensuring reliable customer service. The size of these storage units and their power components will dictate their efficiency within specific duty cycles.

14. Service and Distribution Centers of the Future

Investment Plan Period 3rd Triennial Plan (2018-2020)	**Assignment to Value Chain** Distribution
Objective & Scope The objective of this project is to evaluate the ability to fully electrify a fleet service center with building electrification technologies (e.g., space and water heating), EVSEs and employee charging while managing any associated impacts to the local grid system. The results could inform future efforts to electrify other service centers, while also supporting commercial customer electric vehicle loads. This project will demonstrate an advanced SCE service center with electrified utility crew trucks, together with employee workplace charging, connected to a local service area with high	

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

This project will examine the benefits of moving toward electric transportation for SCE's fleet and along with many customers' fleets. Installing charging infrastructure to fully electrify those fleets can reach constraints, as large numbers of heavy-duty vehicles will need very high power and energy capacity - approaching 30 MW per location in some cases. Challenges are not only at the individual depot with deploying electrical infrastructure to support the vehicles and manage costs, but also in surrounding areas. SCE has grid reliability and modernization plans in process which will provide new tools for managing the system. Meanwhile, high demand for PV distributed generation, energy storage, and concentrated EV charging can result in local challenges adjacent to and connected to the fleet base. In addition, SCE's Clean Power Pathway identifies the need for general electrification of facilities and full integration of energy management tools. This project will demonstrate a fleet service center supporting large EV charging demands, supporting elements such as energy storage, PV, and controlled (V1G) and bidirectional (V2G) EV charging, and electrified space and water heating - all controlled by an innovative site energy management system to maintain safe and reliable operation and minimize costs. The location will be in a disadvantaged community (Dominguez Hills, Compton, CA). The site will facilitate connection to SCE's grid data and operational management systems to enable local distribution system support.

Schedule
Q3 2019 – Q1 2026

Status Update

<u>Accomplishment & Success Stories</u>

- The project was successful with microgrid testing at our Fenwick Lab location in Westminster.
- The team met with internal partners to discuss the plan site drawings for Dominguez Hills, which led to an approach to completing the engineering drawing for our SCE facility.
- The team continues to evaluate the Real Time Digital Simulator (RTDS) model to establish the lab architecture for the SCE Lab in Pomona.

<u>Challenges or Setbacks</u>

- The project faced a substantial issue when the site location changed from LA Metro to finding the new site at Dominguez Hills, due to challenges finding a location that meets the project space requirements and other criteria. The new location is located in a disadvantaged community.

    - The team mitigated the issue by finding space within an existing SCE service center that could provide grid connection, has appropriate space requirements, and meets all of the criteria of the project specifications.
    - Finding space at Dominguez Hills has resolved the project location challenge.
- A major vehicle supplier pulled out of the project due to privacy issues with Fleet Management Software. The project is going to go out to RFP for a new vendor in 2024.

Key Findings and Lessons Learned

- One of the top vehicles suppliers in the industry does not meet the SCE standards for cybersecurity.
- It was proven through testing (control and protection) that the microgrid controller and relays offer a practical solution for advancing SCE's microgrid designs. These systems will support fleet electrification for Service Center of the Future initiatives.

Customer Benefits

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

Anticipated RFPs

Upcoming RFPs Include:

- Building Management System (BMS).
- Four Electric Vehicle Chargers.
- Charge Management System (CMS).
- Design consultant.

Industry Advancement

- Final report will show results and provide recommendations to enable further deployment of such facilities.
- The team presented at ISGT 2023 Conference for the microgrid Hardware in The Loop (HIL) Testbed.

15. Control and Protection for Microgrids and Virtual Power Plants

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

Objective & Scope

This project will examine control and protection schemes for safe and reliable operation of distribution systems with customer-owned nested[45] microgrids (MGs) and virtual power plants (VPPs). Standardized control and protection schemes and streamlined operation practices will be designed to support the integrity of the grid and to facilitate grid operation in the context of high penetration of renewable resources and highly variable loads.

The aim of this project is to create a laboratory-based microgrid testbed, which will facilitate the design, prototyping, and performance evaluation of microgrid controls. This testbed will act as a springboard for delving into the extensive potential of microgrid technologies. With the establishment of this testbed, we will be able to forecast and scrutinize various scenarios, thereby gaining insights into the performance of our Microgrid Control System (MCS) under diverse conditions such as black start, islanded mode, and grid reconnection. Furthermore, this testbed will empower us to conduct a range of tests, yielding vital data that will enhance our comprehension of microgrids. In essence, this project is a steppingstone towards the development of sophisticated and dependable microgrid technologies for the future.

Schedule

Q3 2019 – Q2 2024

Status Update

Accomplishment & Success Stories

- First time implementation of a RTDS test bed configuration interfaced with a microgrid controller.
- First time to introduce a Microgrid RSCAD model configuration.
- Evaluated the performance of the Microgrid controller for six use cases.
- Completed the RSCAD model, the complex software model of the microgrid university campus system used in our lab simulation testing and protection studies.
- Installed and configured the Microgrid Control System (MCS) equipment at our Fenwick Lab and demonstrated functional control system testing.
- Completed the interface between the MCS and the RTDS system.
- Completed Factory Acceptance Testing (FAT) at the vendor facility in Pullman, WA. Successfully demonstrated all six use cases.
- Grid Services completed installation / configuration of new IE5000 switches, configuration of firewall rules, compute server and OS install / config in preparation for Network Testing with vendor.
    - IP Configuration validation completed for all MCS devices.

[45] Consist of several separate DERs and/or microgrids connected to the same utility grid circuit segment and serve a wide geographic area.

- Fenwick Lab test bed fully functional with HIL testing successfully demonstrating the six use cases.
- The vendor along with SCE tech leads certified that the Fenwick Microgrid Lab test bed MCS meets the contractual requirements, has successfully passed final commissioning and site acceptance testing, and successfully demonstrated all use cases.
- Protection design activities for the microgrid RSCAD model completed with protection groups from our vendor and SCE.

Challenges or Setbacks

- The project faced issues with the RSCAD model during the initial round of FAT testing, which were resolved by fine tuning the control parameters of the BESS inverter controller along with minimizing the round-trip delay in the MCS during transition modes.
- Long lead time for Hardware in the Loop (HIL) equipment, switched over to a different vendor to procure the equipment sooner.
- Firewall rule missing from MCS device. Network testing took place at Fenwick Lab, the first two days concentrated on configuration work to resolve the issue.

Key Findings and Lessons Learned

- Knowledge was gained of the network configuration for a microgrid system that can be used for all future microgrid projects.
- A similar setup will be done for the Pomona Microgrid Test Pad.
- Cribl Edge application is preferred by Cyber engineering for Syslog on client servers/workstations/computers, not Splunk Universal Forwarder (universal will work but not preferred).
- Vendor performed protection studies on RSCAD model using SKM software. SCE needed to purchase SKM software license to read files.
- Adding complication (additional elements such as DERs and tie breakers) to the microgrid model makes it more difficult to perform tests, protection studies, troubleshooting and obtaining results.
- During transition modes the microgrid controller's role in sending and receiving commands to / from the grid forming asset is critical for maintaining microgrid stability.
- Delay in sending / receiving commands needs to be optimized via the microgrid controller code.
- Having two Battery Energy Storage Systems (BESS) in one clustered microgrid would sometimes cause stability issues.
- Mitigated via optimizing inverter controller parameters.
- During a black start procedure, it is advisable to avoid connecting the generation units, especially the inverter-based resources, simultaneously. This is because such a connection can cause significant disturbances, which may trigger frequency and voltage protection elements. To mitigate this issue, it is recommended to create time intervals for connecting generation units in the grid restoration scheme.

- The successful operation of the microgrid depends not only on the implementation of reliable and resilient control schemes but also on the establishment of a fast and reliable communications.
- The system restoration plan during the black start process should be meticulously defined and fine-tuned to minimize disturbances at each step, to ensure stable restoration.
- Conducting studies before field deployment can preempt potential issues, allowing for the fine-tuning of control schemes, settings, and other parameters.
- The MCS relay connected to the wye-to-ground/wye-to-ground PT can help detect the ground fault on the 12 kV system and act as backup protection for the DER. This finding underscores the need for comprehensive protection schemes.
- The testing showed that fuses added on the 12 kV side of all load transformers cannot be coordinated with corresponding relays due to the use of a generic fuse size 40E. This highlights the need for careful selection and sizing of protective devices.
- The testing performed revealed that ground fault availability on the 12 kV system during Scenario 2a is dependent on the transformers from the BESS breakers. This is an important consideration for system design and operation.

Customer Benefits

- The project's outcomes contribute to the development of more resilient and reliable microgrids. By conducting studies before field deployment, we can preempt potential issues, leading to the fine-tuning of control schemes, settings, and other parameters. This proactive approach aligns with EPIC's goal of advancing innovative clean energy solutions.
- For SCE customers, this translates into more reliable microgrid operations, minimizing disruptions and ensuring a stable power supply. The project's findings will guide future implementations, contributing to the development of robust and efficient microgrids.

Industry Advancement

- Submitted an IEEE Paper to the Innovative Smart Grid Technologies (ISGT) Latin America conference entitled "Performance Assessment of a Centralized Microgrid Controller via a Control Hardware-in-the-Loop Testbed in Southern California Edison". This paper was featured at the conference along with the presentation of a poster board by the SCE tech lead.
- Lab testing results provided deep insight of electrical dynamic transients that may occur during microgrid use cases. Via improved inverter modeling these transients will be able to be addressed in the following MG projects: Smart City and Service Center of Future.
- A successful MCS demonstration in our Fenwick Lab was performed for the UC Irvine Microgrid Team and the Honda Corporation.
- A successful demonstration of the MCS and RTDS system was performed at the Internal Business Briefing at Ontario Fairplex.

16. Distributed Energy Resources (DER) Dynamics Integration Demonstration

Investment Plan Period 3rd Triennial Plan (2018-2020)	Assignment to Value Chain Distribution
Objective & Scope This project aims to evaluate the two key technical challenges related to high DER penetration—protection system impacts and adverse interactions between multiple types of DERs. The project will be comprised of both hardware and software components: solar PV inverters, a lab testbed, and computer models of inverters, synchronous and induction generators, protective relay and one SCE sample feeder. Test smart inverter functional capabilities on SCE distribution feeder with high DER penetration levels, it will be able to establish DER Operating Standards and leverage Smart Inverters for System-wide reliability. Enhance interoperable controls capability at SCE to provide flexibility to the operation of the grid.	
Schedule Q4 2019 – Q4 2023	
Status Update The EPIC Final Report for the Distributed Energy Resources (DER) Dynamics Integration Demonstration Project is complete and is being submitted with the 2023 Annual Report and will be posted on PICG's public EPIC website.	

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

Investment Plan Period 3rd Triennial Plan (2018-2020)	Assignment to Value Chain Grid Operation/Market Design
Objective & Scope This project will demonstrate in a lab setting the effect of a voltage and VAR management and control algorithm that optimizes the operation of the power grid, for both the transmission and distribution systems, by regulating voltage and controlling VAR resources optimally while maintaining the secure operation of the power grid.	
Status Update During project planning, additional research would be required for completion, which is not currently available, nor allowable for the Utilities to conduct under current EPIC requirements. SCE cancelled this EPIC project in 2020 with the intent of looking into alternative funding sources outside of EPIC.	

18. Beyond Lithium-ion Energy Storage Demonstration

Investment Plan Period 3rd Triennial Plan (2018-2020)	Assignment to Value Chain Distribution

Objective & Scope This project will demonstrate the next wave of next-generation, precommercial, "beyond lithium-ion" energy storage technologies that have a high probability of commercial viability but require real world field experience to reduce technology and adoption barriers on the path to commercialization. This project will focus on advanced energy storage technologies that are non-lithium ion based (e.g., advanced electrochemical batteries, flow batteries, thermal storage, etc.). This project will demonstrate non-lithium-ion storage systems for a variety of traditional use cases (e.g., the CPUC's energy storage use cases outlined in D.13-10-040), and emerging use cases (e.g., regional/community resiliency, etc.). Lastly, this project will demonstrate a complete energy storage system, including the storage technology, power conditioning systems, product/systems integration, and grid interconnection. The objectives of this project are to identify technologies most likely to achieve commercial viability within the next 3-5 years, and opportunities to accelerate the commercialization process. The adoption and integration of lithium-ion based energy storage systems has increased significantly in recent years, to the extent that it is widely considered a mature technology. Furthermore, advancements over the past decade in lithium-ion based energy storage systems have been facilitated by investment from federal and state government funding programs. SCE has been a leader in this regard, based on the company's successful energy storage demonstration completed under the federal government's American Reinvestment and Recovery Act (ARRA) via the Tehachapi Storage Project (TSP), the Irvine Smart Grid Demonstration (ISGD), and the energy storage systems deployed as a part of the Energy Storage Integration Project (ESIP). To achieve California's ambitious long-term energy policy goals, and SCE's own Clean Power and Electrification Pathway 2045, the marketplace will require a diversity of cost-competitive energy storage products. This project will help to advance the industry's knowledge of lithium-ion alternatives to ensure new storage products can "cross the chasm" and compete with traditional storage technologies in the near-future.
Schedule Q4 2020 – Q1 2026
Status Update Accomplishment & Success Stories • Engaged multiple vendors in non-lithium energy storage technologies that are close to being commercially available. • A preferred vendor has been selected for system integration and testing support, offering alternative energy storage solutions that do not rely on lithium. This choice underscores a commitment to exploring and utilizing innovative energy technologies. The collaboration with this vendor is expected to enhance the system's performance while adhering to sustainability principles. • Engaged Power Engineers to consult on deployment standards and requirements. • The team has met with internal partners to discuss contracting agreements with vendors to determine assumption of risk and liability.

- The team continues to evaluate alternative solutions on procuring non-lithium battery due to contracting concerns.

Challenges or Setbacks

- The project faced a substantial issue with vendor's acceptance of SCE's Terms and Conditions. This posed a significant risk in terms of a project schedule delay and timeline to procure and deliver battery to TSD.
- The team addressed the issue/risk by presenting leadership with a substitute plan, which involved collaborating with an authorized vendor to secure the battery for SCE. This proactive approach not only resolved the immediate concern but also demonstrated the team's commitment to finding effective solutions.

Key Findings and Lessons Learned

- Non-lithium-ion energy storage systems such as Flow batteries have shown indications of reducing fire hazards under heavy loads compared to traditional lithium-ion batteries. In parallel, they have also shown potential for increases in energy capacity and efficiency.

19. Wildfire Prevention & Resiliency Technology Demonstration

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

Objective & Scope:

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

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

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

Schedule

Q4 2019 – Q4 2026

Status Update

Accomplishments & Success Stories

Distribution Waveform Analytics:

- The Distribution Waveform Analytics team concluded deployment of an automated data pipeline in early Q2 2023. This data pipeline brings power system waveform data from a fleet of digital fault records in the form of event and continuous timeseries data. The data is parsed into large database tables to be used for the testing of analytic techniques for anomalous event identification.
- Upon completion of an RFP in Q4 2022, a selected vendor was onboarded to the project in Q2 2023 to provide resources such as a Data Scientist, Data Engineer, and a Full Stack Developer. The vendor has been testing analytical techniques for the system events, such as anomalous event extraction from continuous time series data, featuring engineering for power systems event signatures to be used in clustering and classification algorithms. The team also extracted distribution SCADA and AMI data and integrated it with the DFR database to be used in conjunction with event identification. The vendor is also required to implement a visual web application in parallel. The model enhancements are expected to conclude in Q2 2024. The project is expected to conduct an end-to-end lab demonstration in Q3 2024.

Machine Learning at the Edge:

- The Machine Learning at the Edge team initiated the execution phase in January 2023. The project team completed two RFIs (Requests for Information) for drone procurement and integration support services in Q3-Q4 2023. The RFI outcomes are being studied to prepare a Statement of Work for the upcoming RFP expected to initiate in Q1 2024. Note that the RFP Statement of Work will require vendors to deliver hardware and integration support services in compliance with the latest National Defense Authorization Act (NDAA) guidelines.
- The project team possessed various versions of SCE’s object and defect detection models and conducted benchmarking exercises by running them across different devices. This approach allowed for comprehensive performance evaluations, providing valuable insights into the models' efficacy across diverse hardware configurations. By doing this, the team gained a deeper understanding of their scalability, efficiency, and suitability for deployment in various environments.

Challenges or Setbacks

Distribution Waveform Analytics:

- Growing pains of learning, configuring, and finding stabilization on a new data and analytics platform.
- Internally, SCE has few resources for non-production work in the data analytics platform, making resolving issues lengthy and challenging.

- Worked through software bugs with supplier. Additionally working in an outdated platform not receiving software updates presents odd workarounds to certain issues that may have been resolved in later updates. However, the project is locked into a 2018 dated system due to hardware limitations. Working in a cloud-based environment could resolve this.
- The volume of data to process takes time, requiring adapting Python to run in Spark using PySpark.
- Unexpected issues with GPS clocks such as improper time zones, daylight savings settings, clocks coming out of sync resulted in loss of some data to poor quality where time synchronization is critical. Attention to device management and proper device configuration during deployment needs to be stronger.
- DWA is domain heavy in signal processing and power systems, which took data scientists from outside the domain time to get familiar with.
- Ambiguity in the nature of power systems events with little ground truth data to use for testing implies more attention needs to be given in root cause analysis to produce a strong dataset of ground truth events.

Machine Learning at the Edge:

- The project faced a substantial issue with procuring the GPU developer kit to be able to test SCE's models due to the necessity of being NDAA compliant.
- The team mitigated the issue/risk by conducting research to identify NDAA compliant vendors.
- Internet connection of the edge devices for setting up them was another challenge.
- Finding a desired vendor for both Hardware Procurement and Integration Services Support and that is compliance with NDAA guidelines is a challenge.

Key Findings and Lessons Learned

Distribution Waveform Analytics:

- A stable and well-performing data platform for databasing waveform data can be implemented easily with commercially-available big data tools. Efficient data engineering lies at the core of this work to get the expected performance from the platform.
- Creating a custom python library for working with the waveform data designed around the nature of the sensor class makes performing data analytics easier and more approachable for the data users.
- Anomaly detection from continuous waveform data is more complicated than initially expected. A one size fits all solution may not be attainable and specially tailored techniques for certain anomaly types may be necessary.
- Event clustering purely on the event's FFT vector produced inconclusive results, implying a more in-depth feature engineering process is required in order to form valid clusters based on anomaly class. The team is exploring feature engineering in 2024.
- A more targeted approach aimed at specific anomaly classes and focus on developing reliable ground truth data for testing is required. The team is working on this for 2024.

Anticipated RFPs

Machine Learning at the Edge:

- The Machine Learning at Edge team is on schedule to initiate one RFP for the project in Q1 2024. The RFP scope will be to procure drone hardware and integration support services.

Industry Advancement

Distribution Waveform Analytics:

- The Distribution Waveform Analytics team wrote a technical paper on the big data analytics platform implemented in the DWA project. The paper was accepted for publication in conference proceedings for the 2024 IEEE PES T&D conference. The team is also contributing learning on continuous point-on-wave data processing in the IEEE Task Force "Big Data Analytics for Synchro-Waveform Measurements" and slated to present at the IEEE Joint Technical Committee Meeting in Q1 2024. To bring situational awareness, the team will share Distribution Waveform Analytics project overview, platform architecture components, Digital Fault Recorder (DFR) database schema design, various technical challenges, and lessons learned.

Conclusion

Key Results for the Year for SCE's EPIC Program

2012-2014 Investment Plan

For the period between January 1 and December 31, 2023, SCE expended a total of $45 toward project costs and $0 toward administrative costs for a grand total of $45. SCE's cumulative expenses over the lifespan of its 2012 – 2014 EPIC 1 program amount to $38,661,721.

SCE executed 16 projects, cancelled one project, and completed 15 projects. Three of these projects were completed during the calendar year 2015, four projects were completed in 2016, four projects were completed in 2017, two projects were completed in 2018, one project was completed in 2019, and one project was completed in 2020.

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

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

6. Portable End-to-End Test System;
7. State Estimation Using Phasor Measurement Technologies;
8. Deep Grid Coordination (otherwise known as the Integrated Grid Project);
9. DOS Protection & Control Demonstration;
10. Advanced Voltage and VAR Control of SCE Transmission;
11. Outage Management and Customer Voltage Data Analytics Demonstration;
12. Cyber-Intrusion Auto-Response and Policy Management System (CAPMS);
13. Next Generation Distribution Automation, Phase 1;
14. Wide Area Reliability Management and Control; and
15. SA-3 Phase III Demonstration.

2015-2017 Investment Plan

For the period between January 1 and December 31, 2023, SCE expended a total of $414,598 toward project costs and $174,703 toward administrative costs for a grand total of $589,302. SCE's cumulative expenses over the lifespan of its 2015 – 2017 EPIC 2 program amount to $38,270,358. SCE committed $1,775,009 toward projects and encumbered $590,774 through executed purchase orders during this period. SCE has no uncommitted EPIC 2 funding for this period.

SCE executed 13 projects from its approved portfolio. As of this report, 3 projects have been cancelled for the reasons described in their respective project updates section. Of the remaining ten projects, one project was completed in 2017, three projects were completed in 2018, two projects were completed in 2019, one project was completed in 2020, and one project was completed in 2021. One project remains in execution for the 2015-2017 Investment Plan.

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

1. Advanced Grid Capabilities Using Smart Meter Data;
2. DC Fast Charging;
3. Proactive Storm Impact Analysis Demonstration;

4. Integration of Big Data for Advanced Automated Customer Load Management;
5. Versatile Plug-in Auxiliary Power System;
6. Regulatory Mandates: Submetering Enablement Demonstration - Phase 2;
7. Dynamic Power Conditioner;
8. The Integrated Grid Project; and
9. Next-Generation Distribution Equipment & Automation - Phase 2.

2018-2020 Investment Plan

For the period between January 1 and December 31, 2023, SCE expended a total of $4,097,842 toward project costs and $383,366 toward administrative costs for a grand total of $4,481,207. SCE's cumulative expenses over the lifespan of its 2018 – 2020 EPIC 3program amount to $24,888,482. SCE committed $10,319,780 toward projects and encumbered $5,226,231 through executed purchase orders during this period. SCE has no uncommitted EPIC 3 project funding for this period. SCE cancelled two projects and has begun executing 14 projects from its approved portfolio, and three have been completed. SCE's 2018 – 2020 EPIC 3 program is currently composed of the following twelve (12) projects that remain in execution:

1. Advanced Comprehensive Hazards Tool;
2. Advanced Technology for Field Safety (ATFS);
3. Beyond Lithium-ion Energy Storage Demo;
4. Control and Protection for Microgrids and Virtual Power Plants;
5. Distributed PEV Charging Resource;
6. Next Generation Distribution Automation III;
7. SA-3 Phase III Field Demonstrations;
8. Service Center of the Future;
9. Smart City Demonstration;
10. Storage-Based Distribution DC Link;

11. Vehicle-to-Grid Integration Using On-Board Inverter; and

12. Wildfire Prevention & Resiliency Technology Demonstration.

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

The progress made by SCE project teams across multiple initiatives is commendable, despite facing procurement delays and vendor challenges. The Fenwick Microgrid Lab project has been a significant step forward, highlighting the importance of rigorous testing, operational readiness, and collaborative efforts with vendors. All the projects are expected to deliver substantial benefits to customers, enhancing the resilience and sophistication of utility infrastructure.

SCE's proactive engagement with regulatory bodies and stakeholders has been crucial in advancing its EPIC 4 Investment Plan Application. The company has also made significant progress in the EPIC successor program's rulemaking process. The focus has been on completing the 2015-2017 Investment Plan and advancing the projects from the 2018-2020 cycle. The comprehensive approach taken by SCE ensures that the company continues to enhance its service delivery and stabilize the grid.

SCE maintained collaboration with the Policy Innovation + Coordination (PICG) Coordinator on the project database and will continue its open dialogue with the stakeholders through public engagement in 2024. Following the approval of the EPIC 4 Investment Plans, SCE and other Utilities will be convened to strategize on portfolio implementation. SCE hosted workshops to explore strategic initiatives, addressing opportunities, challenges, and community needs, with a focus on engaging disadvantaged communities. Public workshops and the annual Symposium served as platforms for SCE and EPIC Administrators to discuss key topics with stakeholders and the Commission, sharing achievements and insights from the EPIC programs.

Issues That May Have Major Impact on Progress in Projects

In 2024, SCE is committed to the effective completion of its final project under the EPIC 2 Investment Plan. Additionally, SCE will progress with the execution of the 12 remaining projects within its EPIC 3 Investment Plan. In 2023, SCE encountered delays related to supply chain issues and incurred costs that exceeded projections. Moving forward, SCE will persist in vigilantly overseeing potential project postponements, including those stemming from production and supply chain disruptions.

APPENDIX A

DISTRIBUTED ENERGY RESOURCES (DER) DYNAMICS INTEGRATION DEMONSTRATION

FINAL PROJECT REPORT

Distributed Energy Resources (DER) Dynamics Integration Demonstration
EPIC Phase III Final Project Report

Developed by
SCE Transmission & Distribution, Asset Management, Strategy and Engineering
Version Date: 08/10/2023

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1 EXECUTIVE SUMMARY

By 2045, California will undergo a remarkable evolution. Supported by its residents, the state will achieve carbon neutrality to reduce the threat of climate change. This will require substantial decarbonization of all sectors of the economy and will necessitate rigorous planning to keep energy safe, reliable, and affordable.

Southern California Edison's (SCE) "Pathway 45"[46] examines the energy implications of California's long-term decarbonization goals on both the economy and the electric sector and maps out a feasible and low-cost path to reaching these goals.

To economically meet both the 2030 (interim) and 2045 decarbonization goals, the electric sector must decarbonize more quickly than currently required. Eighty gigawatts (GW) of new utility-scale clean generation and 30 GW of utility-scale energy storage will be required in the next 20-plus years. Thirty (30) additional GW of generation capacity and 10 GW of storage will come from Distributed Energy Resources (DERs) – small-scale local resources often installed/used at a customer's home or business, such as rooftop solar, onsite energy storage, electric vehicles, and energy management systems. Up to 50% of single-family homes in California are projected to have customer-sited solar by 2045.

Increased DER integration into the distribution grid presents both challenges and opportunities. Recent utility experience demonstrates that smart inverters (those with advanced control functions) have the potential to enable DERs to support grid needs when combined with new capabilities that facilitate the full integration of DERs into grid planning and operations. (DERs can provide uninterrupted power to customers in the event of a grid connection failure, and also can replace fossil fuel generation – thus reducing carbon emissions.) This experience has identified multiple factors for allowing smart inverter-enabled DERs to minimize potential grid impacts at higher DER penetration levels.

To further address this issue, SCE undertook the DER Dynamics Integration Demonstration project, with a primary goal of examining how various DER penetration scenarios would impact distribution feeder protection. The project included multiple investigation techniques through simulation studies and laboratory demonstrations with the use of advanced DERs (in this case photovoltaic, or PV), traditional DERS, and smart and legacy inverter technologies. Project stakeholders identified seven research questions (see Section 2.5.3: Research Questions) to address via both the simulation studies and laboratory demonstrations.

When it came to the final question – whether there is a need for any new method of distribution feeder protection for systems with high DER penetration – the overall results indicated that no distribution feeder protection impact was identified based on the rigorous analysis conducted through both project phases.

2 PROJECT SUMMARY

The primary goal of the DER Dynamics Integration Demonstration project was to examine how various DER penetration scenarios would impact distribution feeder protection. Specifically, the project was designed to determine the following based on questions developed by stakeholders:

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[46] https://www.edison.com/our-perspective/pathway-2045.

- The effect on SCE's relaying distribution feeder protection systems due to high penetration of Electric Rule 21[47] and Institute of Electrical and Electronics Engineers (IEEE)-1547 (standard)[48] smart inverters.
- The interaction between traditional DERs and smart inverter-enabled DERs with advanced functions.
- The interaction between multiple models of inverters using different anti-islanding detection algorithms.[49]
- The level of an inverter's capability on the IEEE 2030.5[50] communication requirement.
- New methods of distribution feeder protection needed, if applicable, for systems with high DER penetration.

The investigation was conducted via both simulation studies and demonstrations. This work used simulation and Power Hardware-in-the-Loop (PHIL) demonstration, including inverter configuration and settings for optimal distribution feeder protection and operation of smart inverters under high DER penetration scenarios.

2.1 Electric Program Investment Charge Overview

SCE's DER Dynamics Integration Demonstration project was implemented through the California Public Utilities Commission's (CPUC) Electric Program Investment Charge (EPIC) III program[51]. EPIC supports the development of new, emerging, and pre-commercialized clean energy innovations in California. These projects must be designed to ensure benefits in the form of equitable access to safe, affordable, reliable, and environmentally sustainable energy for electricity ratepayers. EPIC consists of three program areas: Applied Research and Development (Applied R&D), Technology Demonstration and Deployment (TD&D), and Market Facilitation.

Per the EPIC Investment Framework for Utilities (Figure 1), this project contributed to the strategic area of Renewables and Distributed Energy Resources Integration, and supported the guiding principles of Safety, Reliability, and Affordability, by:

- Adding to learnings about integration of high concentrations of renewable resources at lower costs, thus benefitting SCE and its ratepayers.
- Delivering findings on the impacts of widescale DER deployment, as well as safe and reliable smart inverter operations. The operational flexibility of smart inverter functionality may be used to enhance grid reliability when combined with other grid modernization elements, such as a Distributed Energy Resources Management System (DERMS).
- Increasing SCE's ability to anticipate impacts on distribution feeder protection in high DER penetration situations.
- Providing information that can be used to update existing DER interconnection criteria (if necessary).
- Producing a reusable smart inverter testbed that can be utilized for other DER and smart inverter use case testing.

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[47] Electric Rule 21 describes the interconnection, operating, and metering requirements for generation facilities to be connected to a utility's distribution system, over which the CPUC has jurisdiction. https://www.sce.com/business/generating-your-own-power/Grid-Interconnections/Interconnecting-Generation-under-Rule-21.

[48] **IEEE Standard for Interconnection and Interoperability of Distributed Energy Resources with Associated Electric Power Systems Interfaces. https://sagroups.ieee.org/scc21/standards/1547rev/.**

[49] An islanding scenario occurs when a DER provides power despite being electrically isolated from the distribution system.

[50] IEEE Standard for Smart Energy Profile Application Protocol. https://standards.ieee.org/ieee/2030.5/5897/.

[51] EPIC 3 – SCE 2018-2020 Investment Plan Application. A17-050005. https://www.sce.com/regulatory/epic/regulatory-filings.

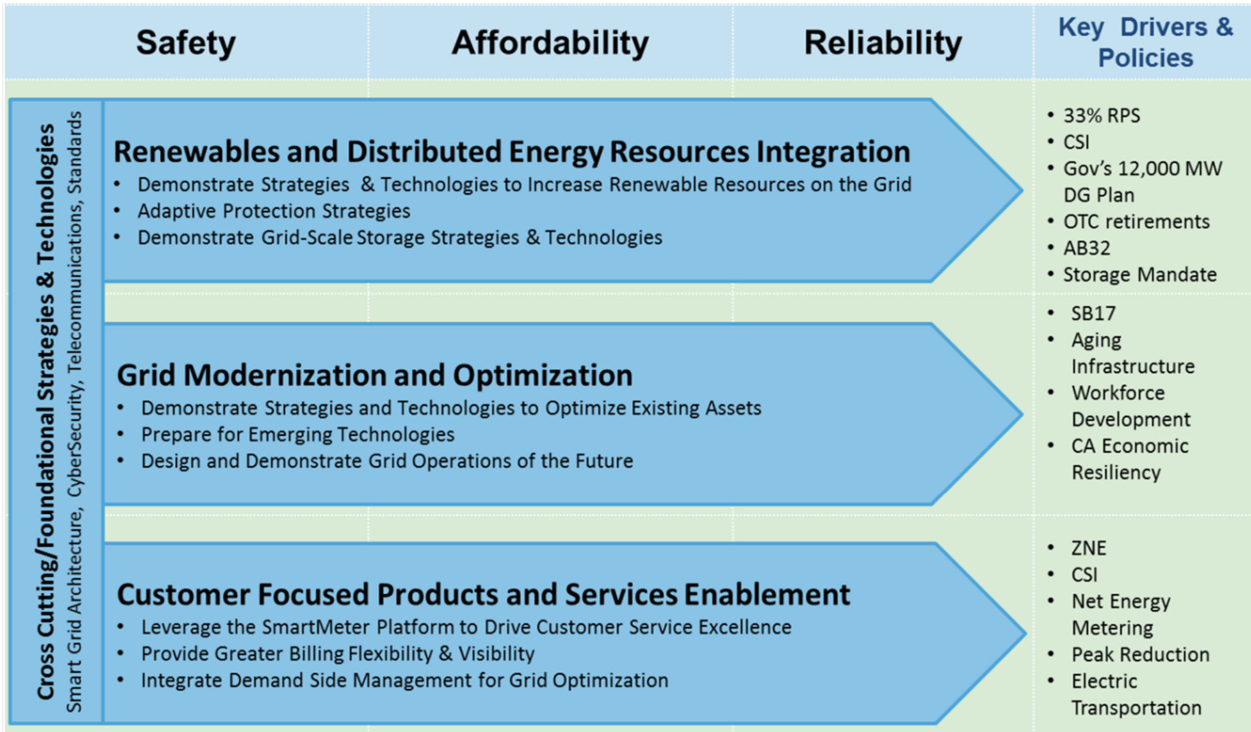

Figure 1. EPIC Investment Framework for Utilities

2.2 Standards

This project addressed the Electric Rule 21 tariff, which describes the interconnection, operating, and metering requirements for generation facilities to be connected to a utility's distribution system, over which the CPUC has jurisdiction. Testing was conducted during the project's demonstration portion to confirm that the PV inverters utilized were Electric Rule 21-compliant. No new standards were established during or as a result of the project.

2.3 Problem Statement

With the growing adoption of DERs, utility experience demonstrates that smart inverters potentially can enable these resources to support grid needs when combined with new capabilities that facilitate the full integration of DERs into grid planning and operations. This experience has identified multiple factors for allowing smart inverter-enabled DERs to minimize potential grid impacts at higher DER penetration levels. At SCE, the distribution feeder protection system impact is the leading technical grid challenge related to high DER penetration that has not been satisfactorily addressed, and the primary reason SCE undertook this project.

2.4 Confidential Information

This report excludes proprietary business information from the project implementation.

2.5 Project Scope

To assess how SCE distribution feeder protection would be impacted by various DER penetration scenarios, the DER Dynamics Integration Demonstration project included multiple investigation techniques through simulation studies and laboratory demonstrations with the use of smart and legacy inverter technologies. Various generation mix and

DER combinations were considered for analysis, including traditional rotating machine-based and inverter-based DERs.

2.5.1 Simulation Studies

The project's simulation studies examined the performance of distribution feeder protection systems in the presence of high DER penetration (e.g., 120% of peak load), where single-phase inverters[52] are dominant and voltages across the feeder are within permissible ranges.

This work incorporated modeling and validation of DER integration in existing and emerging software tools for detailed representation of power electronics and controls. The DER types and control system components that were modeled by following the project's technical requirements and applicable industry standards were:

- Advanced DERs:
  - PV based on smart inverters: defined as inverters with advanced control functions, which have the capability to improve system performance.
- Traditional DERs:
  - PV based on legacy inverters: defined as non-smart inverters without advanced functions.
  - Induction generator for wind systems.
  - Synchronous generator for gas/diesel engines or gas turbines.
- Anti-islanding protection schemes: control schemes – in this case Sandia Voltage Shift (SVS) and Sandia Frequency Shift (SFS) techniques – that sense and prevent the formation of an unintended island, meaning a condition in which one or more generating facilities delivers power to customers using a portion of the distribution system that is electrically isolated from the remainder of the distribution system.
- Feeder model: based on the selected feeder with expected high penetration of behind-the-meter PV installations.

The following diagram shows the DER types used in the project:

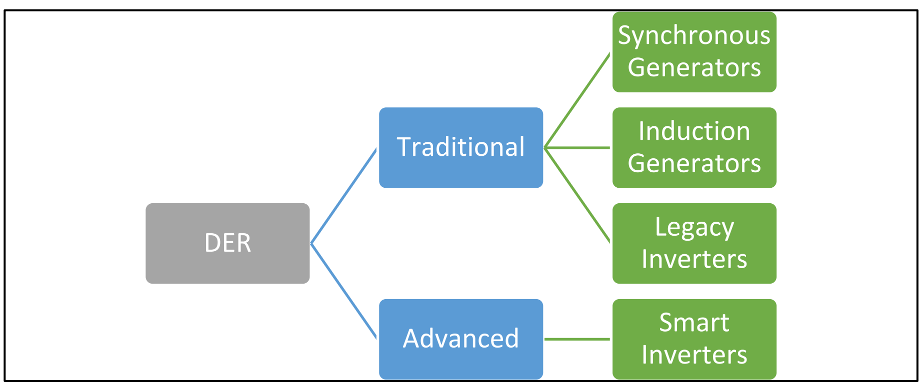

Figure 2. DER Types Used in the Project

The DER model components were validated against expected functionalities or any data available from the project vendors or captured in the laboratory.

[52] With PV installations, an inverter converts the electricity produced by the system from direct current (DC) to alternating current (AC) for customer use.

2.5.2 Demonstrations

The project's laboratory demonstrations focused on 1) confirming that the PV inverters utilized during the testing were Electric Rule 21-compliant, and 2) demonstrating and recording the research questions posed during the simulation study (see Section 2.5.3: Research Questions).
This work utilized a mix of simulated traditional DER technologies and actual inverter-based DERs integrated into a Real-Time Digital Simulator (RTDS) system in the laboratory's Power-Hardware-in-the-Loop (PHIL) testbed. The PHIL was created by integrating three systems: RTDS, relay, and inverter (a mix of smart and legacy inverters). Several monitoring devices were required to verify and capture measurements to execute the demonstration scenarios in the testbed, which is shown in this diagram:

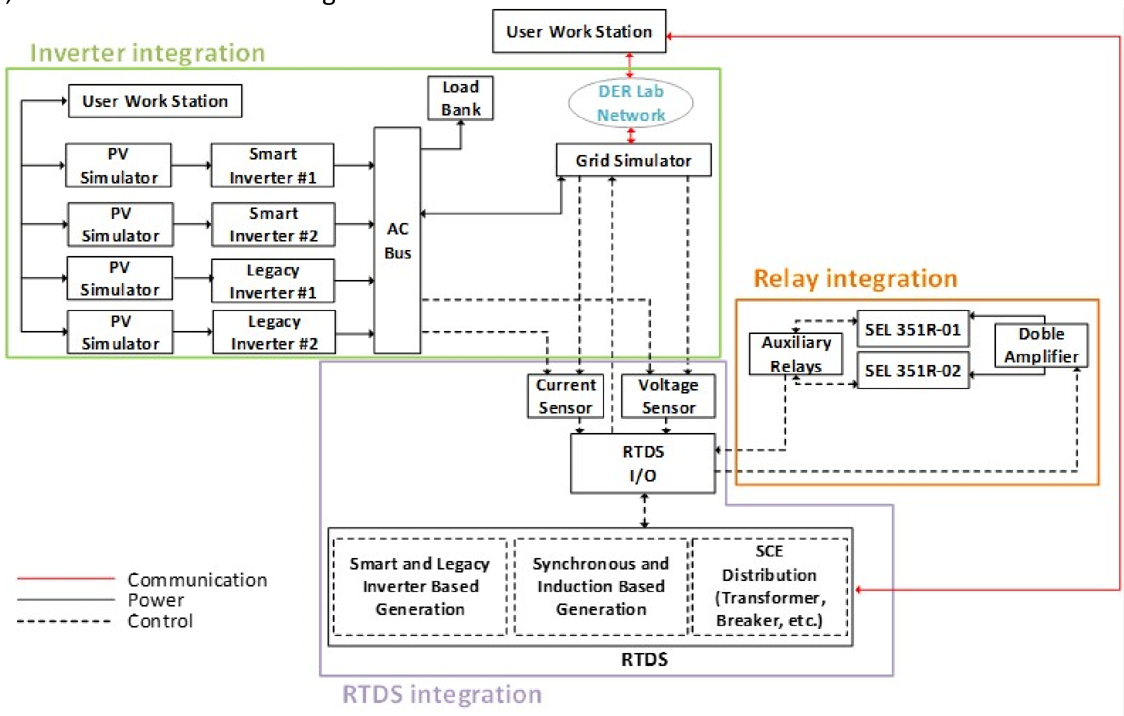

Figure 3. Power Hardware-in-the-Loop Testbed for Project Demonstrations

Following are the Electric Rule 21 function requirements the project team needed to validate for the PV inverters:

- Volt/VAR support
- Anti-islanding capability
- Frequency/watt support
- Volt/watt support
- Voltage and frequency (V/F) ride-through option
- Standard ramp-up rate
- Fixed power factor operation

2.5.3 Research Questions

The simulation studies and demonstrations were designed to address the following research questions from the project stakeholders.

- **Question 1**: How does high penetration of Electric Rule 21 smart inverters (IEEE-1547-2018 standard) and legacy inverters (IEEE-1547-2003 standard) affect distribution feeder protection schemes normally applied in SCE's distribution system?
- **Question 2**: What is the interaction between traditional DERs (synchronous generator, induction generator, legacy inverters) and smart inverter-enabled DERs with advanced functions and how they impact the distribution feeder protection systems?
- **Question 3**: What is the interaction between multiple inverter models using different anti-islanding detection algorithms?
- **Question 4**: What are the critical functions of the inverter and are they are addressed in the model?
- **Question 5**: What are the critical settings and IEEE 2030.5 capability of the developed inverter models?
- **Question 6**: What happens to the harmonics[53] at a low-voltage (LV) bus[54] that has multiple inverters?
- **Question 7**: Is there a need for any new method of distribution feeder protection for systems with high DER penetration?

2.5.4 Cybersecurity

In accordance with the SCE cybersecurity standards, policies, and industry standards, the DER project must develop a robust cybersecurity strategy and incorporate and integrate applicable technologies and techniques to best secure the DER systems. Security measures were identified and applied as necessary to ensure the successful operation of the project goals and objectives.
Additionally, there will be cybersecurity testing requirements that the project will need to meet. This testing will encompass evaluating the project's data protection, authentication, encryption, and other relevant areas to be determined at each phase.

2.6 Schedule and Milestones/Deliverables

The project milestones/deliverables and completion dates were as follows:

Milestone/Deliverable	Completion Date
Project kickoff	5-Feb-2020
Functional/non-functional requirements approved	30-Mar-2020
Cybersecurity functional requirements assessment completed	10-Apr-2020
Lab Architecture Brief (LAB) approved	4-Aug-2020
Design ready-for-build phase completed	28-Jan-2021
PV Model (PSCAD™) and Smart Inverter Model completed	25-Feb-2021

53 Harmonics can distort a pure sine wave, thus negatively impacting the power quality of an output voltage or current. Furthermore, it can lead to equipment operational issues. For example, current harmonics can cause **unwanted overheating, while voltage** harmonics can cause equipment maloperation.

54 Bus definition: a system of electrical conductors in a generating or receiving station on which power is concentrated for distribution.

Power wiring of DER lab by SCE completed	25-Feb-2021
Hardware procured	2-Mar-2021
Smart Inverter Switching Model (value addition) completed	17-Jun-2021
Legacy Inverter Model (PSCAD) and Computer-Aided Protection Engineering (CAPE) completed	17-Jun-2021
Induction and Synchronous Generator Model (PSCAD and CAPE) completed	6-Jul-2021
Anti-Islanding Protection Algorithm Model, Distribution Feeder Model development completed	1-Nov-2021
PSCAD development and simulation completed	15-Apr-2022
Final simulation report completed	5-Apr-2022
Build Inverter Assessment Power Hardware-in-the-Loop (PHIL) testbed completed	19-Jan-2022
Acceptance test procedures completed	18-Jan-2022
PHIL testbed ready for demonstration	3-May-2022
All use case demonstrations completed	30-Jun-2022
Acceptance test results completed	08-Aug-2022
Documentation (including simulation, demonstration, and control logic block diagrams) completed	12-Jan-2023

Table 10. DER Dynamics Integration Project Schedule and Milestones/Deliverables

3 PROJECT RESULTS

Overall, the DER Dynamics Integration Demonstration project found that high penetration of PVs for the specific SCE distribution feeder under study did not introduce any adverse impact on distribution feeder protection performance. It is well understood that the legacy inverters and any rotating machine-type DER would not support advanced functions and would not interact with the feeder voltages during the steady-state operation, or in response to faults, in the way expected from advanced inverter technologies.
Following is a summary of specific results of the simulation studies and demonstrations conducted to address the project's research questions. Testing to validate the compliance of the PV inverters with Electric Rule 21 functions took place after the simulation studies and before the laboratory demonstration work. Results of the function testing are shown in Table 2.
Question 1: How does high penetration of Electric Rule 21 smart inverters (IEEE-1547-2018 standard) and legacy inverters (IEEE-1547-2003 standard) affect distribution feeder protection schemes normally applied in SCE's distribution system?
Simulation Study Results: A range of penetration levels was studied in PSCAD (an advanced tool for power system electromagnetic transient (EMT) simulations) for a specific SCE distribution feeder, with a focus on penetration levels of 120%. The results showed changes in fault current range due to high DER penetration. However, because of smart inverter functions, the difference was not significant enough to cause any maloperation of protective devices.

Demonstration Results: Fault studies performed at different feeder locations were used to assess how the distribution feeder protection system would be impacted by a range of DER penetration levels. The Real-Time Digital Simulator (RTDS)-based Power Hardware-in-the-Loop (PHIL) testbed was used for a specific SCE distribution feeder, with a focus on penetration levels of 120%. The results showed that high penetration of DERs in the particular feeder under study did not adversely impact distribution feeder protection performance.

Question 2: What is the interaction between traditional DERs (synchronous generator, induction generator, legacy inverters) and smart inverter-enabled DERs with advanced functions and how they impact the distribution feeder protection systems?

Simulation Study Results: This study utilized a combination of traditional and advanced DERs to analyze the impact on the distribution feeder protection systems. A fault analysis was performed at several feeder locations, and a corresponding current was observed at the main circuit breaker and reclosers. The maximum reverse phase current seen by the feeder head relay was well below the current distribution feeder protection setting, confirming no impact on the existing distribution feeder protection settings.

Demonstration Results: This demonstration applied single- and three-phase-to-ground faults at three locations of the feeder, which comprised the modeled synchronous generator, induction generator, and both legacy-inverter-based and smart-inverter-based generation resources, plus two actual smart and legacy inverters. It was observed that the high penetration of PVs for the specific feeder under study did not adversely impact distribution feeder protection performance.

Question 3: What is the interaction between multiple inverter models using different anti-islanding detection algorithms?

Simulation Study Results: The performance of smart inverters with Sandia Voltage Shift (SVS) and Sandia Frequency Shift (SFS) anti-islanding schemes was observed and analyzed. The purpose was to evaluate whether an anti-islanding protection scheme can effectively detect islanding scenarios (meaning when a DER provides power despite being electrically isolated from the distribution system) and differentiate them from faults. The results showed that the SVS anti-islanding scheme performed better for high DER penetration and was more effective for behind-the-meter inverter installations.

In addition, a few scenarios were observed during a variation of synchronous generation over total generation ratio that may require further attention, and an operational procedure will be developed to address the scenarios in the near future.

Demonstration Results: The testing showed that all inverters (both legacy and smart) responded very quickly (in a few milliseconds) upon grid connection failure, even for very low power mismatch scenarios.

Question 4: What are the critical functions of the inverter and are they are addressed in the model?

Simulation Study Results: The key functions that were modeled and evaluated included:

- the active anti-islanding scheme
- volt-VAR scheme
- volt-watt scheme
- frequency-watt scheme
- ramp rate control
- rate of change of frequency (ROCOF) scheme
- voltage and frequency ride-through
- a momentary cessation

The testing showed that the volt-VAR scheme for smart inverters plays a very critical role in maintaining feeder voltages within the limits in steady-state operation, to the extent that reactive power control is available. Ride-through and momentary cessation schemes of smart inverters were noted as very effective in response to faults and for quick system recovery after fault clearing.
Demonstration Results: For demonstration purposes, in the RSCAD® (simulation software)/RTDS (simulator) environment, the advanced functions of the inverters also were incorporated. The results showed that the smart inverter functions in the hardware inverter properly followed the characteristics and performance expected in the Electric Rule 21 tariff. This indicated that the smart inverters can provide grid support functions and perform effectively enough to achieve the mitigation levels defined in Electric Rule 21.

Question 5: What are the critical settings and IEEE 2030.5 capability of the developed inverter models?
Simulation Study and Demonstration Results: None of the inverters in the lab and part of the PHIL testbed supported the IEEE 2030.5 protocol. Hence, the use of this standard was not evaluated. In general, most inverter vendors are not yet ready to offer such a communication protocol. (It should be noted that IEEE2030.5 is under revision for refinements.)

Question 6: What happens to the harmonics at a low-voltage (LV) bus that has multiple inverters?

Simulation Study Results: This study analyzed the current and voltage harmonic contents via developed use cases. A fault was applied to the circuit, and IEEE Standard 519[55] was used to determine voltage and current harmonic limits at different harmonic components.

The simulation results for the voltage harmonics measured at the LV side of the service transformer were below the standard limit. In the case of current harmonics, all phases were well below the limit except the individual second harmonic, which was above the limit. Further investigation was recommended to understand the dynamics of the current harmonic contents.
Demonstration Results: It was observed that once all of the actual inverters operated in parallel in the testbed, the measured current Total Harmonic Distortion (THD) at the LV AC bus of inverters was less than 2%, which is well below the limit imposed by Electric Rule 21 and the IEEE-1547-2018 standard.

Question 7: Is there a need for any new method of distribution feeder protection for systems with high DER penetration?

Simulation Study and Demonstration Results: No distribution feeder protection impact was identified based on the rigorous analysis conducted through the project's simulation studies and demonstrations.
This table shows the results of the testing conducted after the simulation studies and before the demonstrations to validate the compliance of the PV inverters with Electric Rule 21 functions.

Electric Rule 21 Function	Testing Observations
Volt/VAR Support	The volt-VAR curve of the smart inverters followed the expected theoretical curve described in the Electric Rule 21 tariff. In other words, the volt-VAR scheme of smart inverters and its contribution in maintaining the voltage matched the simulation results and thus can effectively mitigate issues associated with an increase in voltage.
Anti-Islanding Capability	All inverters (both legacy and smart) responded very quickly (in a few milliseconds) upon grid connection failure, even for very low power mismatch scenarios.

55 IEEE Standard for Harmonic Control in Electric Power Systems. https://standards.ieee.org/ieee/519/10677/ .

Frequency/Watt Support	The smart inverters complied with the Electric Rule 21 frequency-watt curve. In addition, in the testing the smart PV inverters curtailed active power with a response time of less than 5 seconds following the Electric Rule 21 frequency-watt curve.
Volt/Watt Support	The actual volt-watt curve for the smart inverters was similar to the Electric Rule 21 curve. The inverters tripped as expected when the operational boundary was violated.
Voltage and Frequency (V/F) Ride-Through Option	Smart inverters' grid reliability functions (voltage and frequency ride-through) might not comply with Electric Rule 21 in specific vendors' operations.
Standard Ramp-Up Rate	After applying a step change in the irradiance level of the PV simulator, the inverter's responses complied with the response time as mandated by Electric Rule 21.
Fixed Power Factor Operation	The smart inverters followed the fixed power factor settings when the power factor was varied from unity power factor to 0.9 lagging. (A lagging power factor occurs when the load current lags behind the supply voltage.)

Table 11. Observations from Electric Rule 21 Function Testing of PV Inverters

3.1 Achievements

As noted in Section 2.1: Electric Program Investment Charge overview:
Per the EPIC Investment Framework for Utilities (Figure 1), the project contributed to the strategic area of Renewables and Distributed Energy Resources Integration, and supported the guiding principles of Safety, Reliability, and Affordability, by:

- Adding to learnings about integration of high concentrations of renewable resources at lower costs, thus benefitting SCE and its ratepayers.
- Delivering findings on the impacts of widescale DER deployment, as well as safe and reliable smart inverter operations. The operational flexibility of smart inverter functionality may be used to enhance grid reliability when combined with other grid modernization elements, such as a Distributed Energy Resources Management System (DERMS).
- Increasing SCE's ability to anticipate impacts on distribution feeder protection in high DER penetration situations.
- Providing information that can be used to update existing DER interconnection criteria (if necessary).
- Producing a reusable smart inverter testbed that can be utilized for other DER and smart inverter use case testing.

3.2 Scalability

The project studies/demonstrations focused on one SCE distribution feeder, but the investigation's principle and results can be applied to other SCE distribution feeders.

3.3 Value Proposition

This project supported the following objectives and capabilities in SCE's Strategy, Planning & Operational Performance (SPOP) Technology Roadmap:

- Improve visibility, control, and coordination of operations to reliably integrate energy resources.
- Develop distribution feeder protection technologies to accommodate the changing resource mix.

- Improve the value of DERs to customers and the grid by enabling load management capabilities and other services (e.g., volt/VAR support).
- Enable device-level integrated, interoperable controls that provide flexibility.

3.4 Identified Project Metrics

Two of the metrics identified for the SCE DER Dynamics Integration Demonstration project were:

- **Identification of barriers or issues resolved that prevented widespread deployment of technology or strategy:** *Description of the issues, project(s), and the results or outcomes:* With the growing adoption of DERs – which will play a key role in decarbonizing SCE's power system over the next two decades – it is necessary to understand how high DER penetration levels could impact the distribution feeder protection system. SCE undertook this project to address this issue. As noted in this report, the results indicated that no distribution feeder protection impact was identified. While the project focused on one SCE distribution feeder, the principle and results can be applied to other distribution feeders.
- **Effectiveness of information dissemination**: *Number of reports and fact sheets published online:* To date project team members have made presentations on the project at seven conferences (see Section 3.6.1: Information Dissemination for details).

3.4.1 Additional Metrics

DERs can help meet California's greenhouse gas (GHG) emission reduction goals, help customers reduce electricity use, and support grid reliability.[56] The DER Dynamics Integration Demonstration project was not designed to address/quantify specific metrics such as ratepayer benefits, GHG emission reductions, energy savings, and infrastructure cost reduction; however, the project did provide valuable learnings about increased DER integration into the grid.

3.5 Technical Lessons Learned and Recommendations

Following are technical lessons learned and recommendations related to the project procedures and results.

- The relay used in the project could not be triggered from the Real-Time Digital Simulator (RTDS) signal only. An amplifier was needed to transfer the low-power signal from the RTDS to a high-powered relay signal.
- Simulation of the high DER penetration level with a high-fidelity switching model of the inverter required extensive time; thus, a high-processing computer is recommended.
- The laboratory testing confirmed that – with use of proper simulation models – the simulation analysis and offline software modeling approaches were accurate enough for assessments of transient and dynamic events, and evaluation of distribution feeder protection schemes associated with feeders. It was recommended to use detailed Electromagnetic Transients Program (EMTP)-type analysis for distribution feeder protection and calculation of relay settings (reclosers and interconnection settings) in high DER penetration scenarios.
- The simulation study to evaluate the performance of anti-islanding schemes of smart inverters suggested that a high synchronous generation over total generation ratio may require further attention. It is recommended to develop an operational procedure to avoid any potential issues.

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[56] https://www.edison.com/innovation/distributed-energy-resources.

- A key recommendation from the studies was to further evaluate the settings for volt-VAR and volt-watt schemes of the smart inverters to coordinate with the acceptable voltage range for the feeders.
- Per the demonstration observations, further investigation is recommended to understand the dynamics of the current harmonic contents and the aggregated effect of multiple inverter harmonics under a high penetration scenario.

3.6 Technology/Knowledge Transfer Plan

Project information and findings have been widely published/presented by SCE subject matter experts to transfer knowledge gained to the power and energy industry and the engineering and technology community.

3.6.1 Information Dissemination

Conference presentations to date include:

1. Md Arifujjaman, Roger Salas, Anthony Johnson, Jorge Araiza, Farhad Elyasichamazkoti, Ahmadreza Momeni, Shadi Chuangpishit, Farid Katiraei. "DER Dynamics Integration Demonstration Using Power Hardware-in-the-Loop (PHIL) Testbed in Southern California Edison." IEEE Power & Energy Society (PES) General Meeting, Orlando, Florida, July 16–20, 2023.
2. Md Arifujjaman, Jordan Smith. "Distributed Energy Resources Dynamics Integration Demonstration." 2023 Joint Utilities EPIC Workshop, CPUC, Online, June 27, 2023.
3. Md Arifujjaman, Roger Salas, Anthony Johnson, Jorge Araiza, Farhad Elyasichamazkoti, Ahmadreza Momeni, Shadi Chuangpishit, Farid Katiraei. "Development, Demonstration, and Validation of Power Hardware-in-the-Loop (PHIL) Testbed for DER Dynamics Integration in Southern California Edison." IEEE Power & Energy Society (PES) Grid Edge Technologies Conference and Exposition, San Diego, California, April 10–13, 2023.
4. Md Arifujjaman. "A Power Hardware-in-the-Loop (PHIL) Testbed for Inverter Testing in Southern California Edison." Sixth International Workshop on Grid Simulator Testing of Energy Systems and Wind Turbine Drivetrains, National Renewable Energy Laboratory (NREL), Golden, Colorado, November 9–10, 2022.
5. Md Arifujjaman, Jordan Smith. "Demonstration of a Power Hardware-in-the-Loop (PHIL) Testbed for the Rule 21 Inverters." Hybrid and EV Technologies Symposium, SAE International, Garden Grove, California, September 13–15, 2022.
6. Md Arifujjaman, Roger Salas, Anthony Johnson, Jorge Araiza, Vatandeep Singh, Mohammadreza Dorostkar Ghamsari, Shadi Chuangpishit, Amin Zamani, Farid Katiraei, Reza Salehi. "Impacts of High Penetration of Single-Phase PV Inverters on Protection of Distribution Systems." IEEE Green Energy and Smart Systems Conference (IGESSC), Long Beach, California, November 7–8, 2022.
7. Md Arifujjaman, Roger Salas, Anthony P. Johnson, Austen D'Lima, Jorge Araiza. "Modeling and Development of a HIL Testbed for DER Dynamics Integration Demonstration." IEEE Green Energy and Smart Systems Conference (IGESSC), Long Beach, California, November 2–3, 2020.

3.7 Procurement

The project was completed on time and on budget.

3.8 Stakeholder Engagement

SCE's Integrated System Planning organization served as the project sponsor. Regular meetings were held on the project status with the internal stakeholders:

- IT-Power Systems Control
- Distribution Engineering
- Distribution System Operator (DSO) Implementation
- Protection & Automation Standards and Innovation
- Grid Technology Innovation (GTI) Lab Operations
- Cybersecurity (IT)
- SCE EPIC Program

In addition, SCE presented project work to the following external stakeholders, which share interest in this issue:

- Rule 21 Working Group
- Unintentional Islanding Working Group (UIWG)
- Pacific Gas and Electric (PG&E)
- San Diego Gas & Electric (SDG&E)

List of Acronyms

AC	Alternating Current
CAPE	Computer-Aided Protection Engineering
CPUC	California Public Utilities Commission
DC	Direct Current
DER	Distributed Energy Resource
DERMS	Distributed Energy Resources Management System
DSO	Distribution System Operator
EMT	Electromagnetic Transient
EMTP	Electromagnetic Transients Program
EPIC	Electric Program Investment Charge
GHG	Greenhouse Gas
GTI	Grid Technology Innovation
GW	Gigawatts
IEEE	Institute of Electrical and Electronics Engineers
IEEE PES	IEEE Power & Energy Society
IGESSC	IEEE Green Energy and Smart Systems Conference
IT	Information Technology
LAB	Lab Architecture Brief
LV	Low Voltage
NREL	National Renewable Energy Laboratory

PG&E	Pacific Gas and Electric
PHIL	Power Hardware-in-the-Loop
PV	Photovoltaic
R&D	Research and Development
ROCOF	Rate of Change of Frequency
RTDS	Real-Time Digital Simulator
SCE	Southern California Edison
SDG&E	San Diego Gas & Electric
SFS	Sandia Frequency Shift
SPOP	Strategy, Planning & Operational Performance
SVS	Sandia Voltage Shift
TD&D	Technology Demonstration and Deployment
THD	Total Harmonic Distortion
UIWG	Unintentional Islanding Working Group
VAR	Volt-Amps Reactive
V/F	Voltage/Frequency

California Public Utilities Commission

ADVICE LETTER SUMMARY
ENERGY UTILITY

MUST BE COMPLETED BY UTILITY (Attach additional pages as needed)

Company name/CPUC Utility No.: Southern California Edison Company (U 338-E)

Utility type:
- ☑ ELC
- ☐ GAS
- ☐ WATER
- ☐ PLC
- ☐ HEAT

Contact Person: Darrah Morgan
Phone #: (626) 302-2086
E-mail: AdviceTariffManager@sce.com
E-mail Disposition Notice to: AdviceTariffManager@sce.com

EXPLANATION OF UTILITY TYPE

ELC = Electric GAS = Gas WATER = Water
PLC = Pipeline HEAT = Heat

(Date Submitted / Received Stamp by CPUC)

Advice Letter (AL) #: 5535-E

Tier Designation: 2

Subject of AL: Submission of Revised 2023 Electric Program Investment Charge (EPIC) Annual Report

Keywords (choose from CPUC listing): Compliance,

AL Type: ☐ Monthly ☐ Quarterly ☑ Annual ☐ One-Time ☐ Other:

If AL submitted in compliance with a Commission order, indicate relevant Decision/Resolution #:
Decision 12-05-037 and Decision 23-04-042

Does AL replace a withdrawn or rejected AL? If so, identify the prior AL:

Summarize differences between the AL and the prior withdrawn or rejected AL:

Confidential treatment requested? ☐ Yes ☑ No

If yes, specification of confidential information:
Confidential information will be made available to appropriate parties who execute a nondisclosure agreement. Name and contact information to request nondisclosure agreement/ access to confidential information:

Resolution required? ☐ Yes ☑ No

Requested effective date: 5/25/25

No. of tariff sheets: -0-

Estimated system annual revenue effect (%):

Estimated system average rate effect (%):

When rates are affected by AL, include attachment in AL showing average rate effects on customer classes (residential, small commercial, large C/I, agricultural, lighting).

Tariff schedules affected: None

Service affected and changes proposed[1]:

Pending advice letters that revise the same tariff sheets: None

[1]Discuss in AL if more space is needed.

Clear Form

Protests and correspondence regarding this AL are to be sent via email and are due no later than 20 days after the date of this submittal, unless otherwise authorized by the Commission, and shall be sent to:

California Public Utilities Commission
Energy Division Tariff Unit Email:
EDTariffUnit@cpuc.ca.gov

Contact Name: Connor Flanigan
Title: Managing Director, State Regulatory Operations
Utility/Entity Name: Southern California Edison Company

Telephone (xxx) xxx-xxxx:
Facsimile (xxx) xxx-xxxx:
Email: AdviceTariffManager@sce.com

Contact Name: Adam Smith c/o Karyn Gansecki
Title: Director, Regulatory Relations
Utility/Entity Name: Southern California Edison Company

Telephone (xxx) xxx-xxxx:
Facsimile (xxx) xxx-xxxx:
Email: karyn.gansecki@sce.com

CPUC
Energy Division Tariff Unit
505 Van Ness Avenue
San Francisco, CA 94102

Clear Form

ENERGY Advice Letter Keywords

Affiliate	Direct Access	Preliminary Statement
Agreements	Disconnect Service	Procurement
Agriculture	ECAC / Energy Cost Adjustment	Qualifying Facility
Avoided Cost	EOR / Enhanced Oil Recovery	Rebates
Balancing Account	Energy Charge	Refunds
Baseline	Energy Efficiency	Reliability
Bilingual	Establish Service	Re-MAT/Bio-MAT
Billings	Expand Service Area	Revenue Allocation
Bioenergy	Forms	Rule 21
Brokerage Fees	Franchise Fee / User Tax	Rules
CARE	G.O. 131-D	Section 851
CPUC Reimbursement Fee	GRC / General Rate Case	Self Generation
Capacity	Hazardous Waste	Service Area Map
Cogeneration	Increase Rates	Service Outage
Compliance	Interruptible Service	Solar
Conditions of Service	Interutility Transportation	Standby Service
Connection	LIEE / Low-Income Energy Efficiency	Storage
Conservation	LIRA / Low-Income Ratepayer Assistance	Street Lights
Consolidate Tariffs	Late Payment Charge	Surcharges
Contracts	Line Extensions	Tariffs
Core	Memorandum Account	Taxes
Credit	Metered Energy Efficiency	Text Changes
Curtailable Service	Metering	Transformer
Customer Charge	Mobile Home Parks	Transition Cost
Customer Owned Generation	Name Change	Transmission Lines
Decrease Rates	Non-Core	Transportation Electrification
Demand Charge	Non-firm Service Contracts	Transportation Rates
Demand Side Fund	Nuclear	Undergrounding
Demand Side Management	Oil Pipelines	Voltage Discount
Demand Side Response	PBR / Performance Based Ratemaking	Wind Power
Deposits	Portfolio	Withdrawal of Service
Depreciation	Power Lines	

Clear Form