2019 TRANSMISSION MAINTENANCE AND COMPLIANCE REVIEW (TMCR)

SOUTHERN CALIFORNIA EDISON®

Energy for What's Ahead®

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DRAFT

Foreword to *Draft* 2019 TMCR Report

Thank you for your participation in SCE's 2019 TMCR stakeholder process and your review of this *draft* 2019 TMCR Report. Through the TMCR stakeholder process, stakeholders will have an opportunity to provide input prior to the issuance of SCE's final 2019 TMCR Report. This draft 2019 TMCR Report represents SCE's current thinking on TMCR projects and estimated costs to be included in the 2021-23 time period. The projects and estimated costs identified in this draft 2019 TMCR may be revised prior to the issuance of the final 2019 TMCR Report.

I.Table of Contents

I. Executive Summary

Pursuant to Appendix XI of Southern California Edison's (SCE's) Transmission Owner Tariff, SCE's 2019 Transmission Maintenance and Compliance Review (TMCR) Report is part of SCE's annual public stakeholder process to provide additional transparency regarding transmission capital expenditures predominantly related to maintenance and regulatory compliance requirements to operate a safe and reliable transmission system. Such projects may include infrastructure replacement, projects to address compliance issues, or upgrades to transmission facilities owned by others for which SCE has a contractual entitlement. Transmission projects reviewed by the CAISO pursuant to its tariff are not in scope for SCE's TMCR stakeholder process. Other exemptions to the TMCR process include (1) facilities or projects that require an in-service date less than two years after their need being identified; (2) facilities or projects that (a) have less than 30% of their total individual capital costs included in SCE's wholesale transmission rate base and (b) where the FERC-jurisdictional portion of the project's estimated individual cost is less than $1 million; and (3) facilities or projects that address the physical security and cyber security needs of the transmission system. SCE's TMCR process does not impact or infringe upon any stakeholder's Section 206 rights or right to intervene and/or protest in any of SCE's regulatory proceedings, including SCE's transmission rate filings.

This 2019 Transmission Maintenance and Compliance Report covers the years 2021-2023 and organizes investments into five categories: "Compliance", "Infrastructure Replacement", "Work Performed by Operating Agent," "Operations Support" and "Physical/Cyber Security." The estimated total TMCR capital spend for 2021, 2022, and 2023 is:

AS OF 05/2019	**2021 FORECAST**	**2022 FORECAST**	**2023 FORECAST**	**TOTAL**
TOTAL	**$ 211,750,350**	**$ 268,742,498**	**$ 267,926,878**	**$ 748,419,729**
COMPLIANCE	$ 102,555,959	$ 150,031,513	$ 172,114,623	$ 424,702,096
INFRASTRUCTURE REPLACEMENT	$ 77,155,674	$ 85,951,664	$ 73,664,502	$ 236,771,840
WORK PERFORMED BY OPERATING AGENT	$ 835,800	$ 1,937,750	$ 878,050	$ 3,651,600
OPERATIONS SUPPORT	$ 11,272,372	$ 11,383,286	$ 9,102,764	$ 31,758,422
PHYSICAL SECURITY ENHANCEMENT PROGRAMS	$ 19,930,545	$ 19,438,285	$ 12,166,939	$ 51,535,770

II. Introduction

California is at the forefront in the adoption of significant energy-related measures to address climate change and air pollution. Over the course of the past two decades, the state's legislature has taken legislative action to implement initiatives aimed at reducing Green House Gas (GHG) emissions. The spectrum of such policy measures range from the establishment, in Senate Bill (SB) 350, of a Renewable Portfolio Standard (RPS) of 50% by 2030 to the codification, in SB 32, of a GHG target to reduce emissions 40% below 1990 levels by 2030 and a subsequent 80% reduction from the same baseline by 2050. Most recently, SB 100 which took effect on January 1, 2019, increases the RPS to 60% by 2030 and requires all state's electricity to come from carbon-free resources by 2045. SCE is committed to this clean energy future and embraces its role as a leader in the energy industry to reduce GHG emissions. Beyond the energy industry, SCE looks forward to integrating the transportation and industrial sectors, among others, to make significant inroads in reducing GHG emissions in those industries as well.

The state's ambitious energy policy goals require a robust and well-maintained electric grid, and such an electrical system requires capital expenditures to maintain a reliable grid and to meet compliance requirements. In this light, SCE undertakes an annual Transmission Maintenance and Compliance Review process to identify predominantly transmission maintenance and compliance projects to maintain the safe and reliable operation of its electrical grid. This review provides stakeholders with an open, coordinated and transparent process for consideration of SCE's asset management projects and activities, which informs the development of SCE's annual transmission rates. The annual process culminates with the publication of a final TMCR Report. An overview of how the TMCR Report is developed and a description of its contents are provided below in separate sections.

III. TMCR Process Overview

The annual TMCR shares information about proposed SCE transmission facilities and projects that will have their total individual capital costs included in SCE's wholesale transmission rate base.[1] Projects within the scope of TMCR may include infrastructure replacement, projects to address compliance issues, or upgrades to transmission facilities owned by non-PTOs for which SCE has a contractual entitlement. SCE organizes these projects into the following categories: "Compliance," "Infrastructure Replacement," "Work Performed by Operating Agent," "Operations Support," and "Physical/Cyber Security." Each TMCR will provide the basic methodology, criteria, and processes used for determining and including projects in the TMCR Report. The report also includes estimated projected costs for the facilities or projects.

Pursuant to Appendix XI to the TO Tariff, the following projects or facilities are outside the scope of the TMCR: (1) facilities or projects that are or would be identified through the California Independent System Operator's transmission planning process or generation interconnection process, including SCE's Wholesale Distribution Access Tariff interconnection processes; (2) facilities or projects that require an in-service date less than two years after their need being identified; (3) facilities or projects that (a) have less than 30% of

[1] Each TMCR describes transmission facilities or solutions to address identified needs in the second, third, and fourth years after its release. For example, the TMCR released in 2019 describes projects forecasted for years 2021, 2022 & 2023 and the reasons for such projects. Projects that are less than two years from their projected in-service date will not be included in the TMCR.

their total individual capital costs included in SCE's wholesale transmission rate base and (b) where the FERC-jurisdictional portion of the project's estimated individual cost is less than $1 million; and (4) facilities or projects that address the physical and cyber security needs of the transmission system. While the annual TMCR does not address the physical and cyber security needs of SCE's transmission facilities, SCE does provide aggregate cost information about such cyber and physical security needs.

The Transmission Maintenance and Compliance Review is open to all interested stakeholders.[2] Pursuant to Appendix XI to the TO Tariff, SCE must release a draft TMCR Report by May 15 each calendar year and provide stakeholders an opportunity to review the draft. SCE will then host a stakeholder meeting to review the TMCR Report with interested parties and the parties will have an opportunity to pose questions, offer suggestions, or raise concerns directly with SCE. Stakeholders may submit written comments regarding the draft report and items covered during the stakeholder meeting not later than twenty business days after the date of the stakeholder meeting. No later than 10-days after the comment deadline, SCE will post all timely received comments. After reviewing and considering comments, SCE will release a final TMCR Report. As appropriate, SCE may modify the final TMCR Report to include revisions in light of stakeholder comments or other related developments. The TMCR Report is not subject to CAISO approval.

The annual Transmission Maintenance and Compliance Review provides open participation to all interested stakeholders. A meeting will be held each year where SCE personnel will present the draft TMCR Report and will be available to address questions from stakeholders. Stakeholders may then submit written comments. After consideration of stakeholder comments, SCE will finalize and release the TMCR Report no later than 45-days after the deadline for stakeholder comment. After posting of the final TMCR Report, stakeholders may submit comments on considerations for the following year's TMCR.

IV. TMCR Operational Plan

During the second quarter of each year, SCE embarks on its operational and budget planning process. The operational plans provide an estimated spend over the next 5 years, specifically, a more detailed look at the work identified for the next 1-2 years and forecasts for years 3-5. Many factors are considered as the work plans and forecasts are developed, including safety, risk mitigation, compliance, and operational performance. SCE's budgeting and forecasting strategy varies based upon the work activity. Some operating

[2] Pursuant to Section IV of Appendix XI, any Critical Energy Infrastructure Information ("CEII") or otherwise confidential and/or proprietary information provided pursuant to the Transmission Maintenance and Compliance Review shall be subject to non-disclosure agreements and other procedures provided by SCE.

plans use an aggregated historical average to derive the estimate while others use a bottom-up approach, where a list of projects/facilities are prioritized and slated to be replaced in a given year. Once the operating plans are developed SCE management follows a structured approval process prior to submission.

The details of the operational plans are consolidated into the Integrated Work Plan (IWP) and Master List. SCE has adopted and continues to build upon the IWP and Master List which are operational tools that are designed to manage the consolidation of capital project information used to coordinate planned work for Substation and Bulk Transmission projects (ISO and non-ISO). As projects progress through their life cycle, substantive changes to scope, schedule, and budget are also managed by the change control process. The IWP database does not track actual costs or operating dates (ODs), but is used to provide a snapshot of forecasted costs and ODs over the next 5 years, which may be revised throughout the calendar year.

Regarding TMCR governance, SCE management meets several times during the year to forecast a five-year work load. SCE identifies projects and programs as part of SCE's management process. Throughout this draft 2019 TMCR, SCE provides details relating to criteria and methodologies that inform SCE's mitigation plans; such as health index models, asset attributes (age, condition, manufacturing vintage), system topology and subject-matter expertise. This information outlines the factors SCE considers when determining where it is most appropriate to deploy resources. Note that these details will evolve in the future as SCE matures its ability to quantify risk.

The forecast capital expenditures for 2021-2023 are summarized in Section VI below.

V. Coordination with the CAISO's 2018-2019 Transmission Planning Process

Because an asset management project may result in an increase in transmission capacity that is not incidental, SCE submitted five potential TMCR projects to the CAISO for review as part of the 2018-2019 TPP (see Table 2, below). The CAISO did not identify a reliability need for two of those projects (numbers 1 and 2 in Table 2) and SCE is not pursuing those two projects at this time. The CAISO did not identify any concerns with the other three projects (numbers 3, 4, and 5 in Table 2) and indicated that CAISO approval of those projects was not required. Those three projects are included in the 2019 TMCR report to meet Transmission Line Rating Remediation needs (see TLRR Section, below).

Table 2 – Coordination with CAISO 2018-19 TPP

2018 Request Window Submissions – SCE Area

Ref. #	Project Name	Submitted by	In-Service Date	Cost ($M)	ISO Recommendation
1	Mountainview RAS Modification	SCE	2021	$2-$5	Reliability assessment did not identify any reliability need.
2	Etiwanda-Vista23 kV_Clearance Upgrade	SCE	2021	$3-$6	Reliability assessment did not identify any reliability need.
3	Control-Silver Peak 55 kV_Mitigation-TLRR	SCE	2025	$60-$75	No concerns identified with the project. No ISO approval required.
4	Coolwater-Ivanpah Corridor_Mitigation-TLRR	SCE	2025	$8-$15	No concerns identified with the project. No ISO approval required.
5	Coolwater-Kramer Corridor_Mitigation-TLRR	SCE	2025	$35-$50	No concerns identified with the project. No ISO approval required.
6	Red Bluff-Mira Loma_Reliability Project	NEETWest	2024	$850	Reliability assessment did not identify any reliability need. Insufficient BCR.
7	California Transmission Project	CTPC	2027	$1.83B	Insufficient BCR.
8	Red Bluff-Victorville-Lugo 500 kV	NEER	2024	$1,011	Reliability assessment did not identify any reliability need.

VI. 2021-2023 TMCR Forecast

SCE organizes its TMCR forecast for specific needs into five categories: Compliance; Infrastructure Replacement; Work Performed by Operating Agent; Operations Support; and Physical Security. The forecasts for these categories are:

AS OF 05/2019	2021 FORECAST	2022 FORECAST	2023 FORECAST	TOTAL
TOTAL	**$ 211,750,350**	**$ 268,742,498**	**$ 267,926,878**	**$ 748,419,729**
COMPLIANCE	$ 102,555,959	$ 150,031,513	$ 172,114,623	$ 424,702,096
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PHYSICAL SECURITY ENHANCEMENT PROGRAMS	$ 19,930,545	$ 19,438,285	$ 12,166,939	$ 51,535,770

Each category is explained in more detail below.

A. Compliance

This category includes electric transmission projects that are needed to meet the compliance requirements—set forth by the North American Electric Reliability Corporation (NERC), the Western Electricity Coordinating Council (WECC), the California Public Utilities Commission (CPUC), or other agencies—for existing electric transmission infrastructure.

	2021 FORECAST	2022 FORECAST	2023 FORECAST	TOTAL
TOTAL	**$ 102,555,959**	**$ 150,031,513**	**$ 172,114,623**	**$ 424,702,096**
TRANSMISSION LINE REMEDIATION RATING (TLRR)	**$ 102,555,959**	**$ 150,031,513**	**$ 172,114,623**	**$ 424,702,096**

1. Transmission Line Rating Remediation (TLRR)

Description

SCE conducted a rating assessment of its California Independent System Operator (CAISO) controlled and 115kV radial lines built before 2005 to identify spans potentially not meeting California Public Utilities Commission's (CPUC's) General Order (GO) 95 clearance requirements under certain operating and atmospheric conditions. SCE committed to NERC/WECC to remediate all identified potential clearance issues for the CAISO controlled facilities by 2025 and the 115 kV radial lines by 2030. To the extent this remediation program reduces risk related to transmission line discrepancies in High Fire Risk Areas (HFRA), it has important secondary wildfire risk mitigation benefits.

Due to the above-described compliance deadlines, work in this category is expected to continue to increase and be the largest program in the TMCR over the next few years.

Methodology

SCE has taken a programmatic approach to the remediation work by utilizing new technologies and construction methods to minimize overall project impacts along with CPUC licensing requirements. The program identified the projects that require licensing early, so the rigorous process required for CPUC permitting would not impact SCE meeting the compliance requirement. Aligning scope with other programs and initiatives minimizes redundant work, outage impacts, and resource constraints.

There are three major categories of discrepancies SCE is mitigating:

- Bulk Transmission- 500kV and 220kV
- Transmission- 161kV, 115kV, 66kV and 55kV- CAISO controlled
- Distribution- 115kV radial

There are four remediation strategies within all categories:

- Projects anticipated to require licensing – expected to go through SCE's GO 131 D Committee and result in a decision that the project is not exempt
- Major rebuilds – lines with greater than 25% discrepancies with partial rebuilds

- Minor remediation – projects that do not fall in the above definitions or a distribution/other sub-category
- Distribution – where a distribution line modification or another modification (e.g. relocation of a street light) can remediate the discrepancy

SCE is analyzing entire circuits holistically to identify the most cost-efficient and least-disruptive strategy to remediate the discrepancies. SCE considers the following factors when identifying the most cost-efficient and least-disruptive strategy to remediate circuits:

- Geographic proximity
- Government land or land agency overlap
- Permitting similarities
- Engineering design
- Construction methods
- Outage opportunities or restrictions
- Material and procurement efficiency
- Distribution work

TLRR discrepancies are being initiated and planned based on the following constraints:

- Outage constraints and opportunities with other TLRR and SCE projects
  - Alignment of scope with other known projects requiring similar outage windows
  - Staggering scope based on known outage restrictions on certain circuits
- Government land and other agency permitting schedule impacts
- Balancing of workload to ensure work can be performed safely and efficiently
- Bundling of projects for construction efficiencies that include the same scope in similar regions

The following corrective actions have been identified for a vast majority of the discrepancies:

- Lower distribution
- Underground distribution
- Lower crossing transmission
- Grading
- Lower/remove object (such as light pole)
- Change out insulators raise upper crossing transmission
- Raise structure
- Add interset structure
- Replace tower
- Retension
- Reconductor

Criteria

Criteria for identifying these respective discrepancies are outlined in Table 1 of Section III of GO 95,[3] titled "Basic Minimum Allowable Vertical Clearance of Wires Above Railroads, Thoroughfares, Ground or Water Surfaces; Also Clearances from Poles, Buildings, Structures or Other Objects."

Results

During the period of 2021-2023, SCE's anticipated spend is estimated to be $102.6 million, $150.0 million, and $172.1 million, respectively. The expected ramp up in 2022 is due in part to the TLRR licensing projects that are expected to start construction during this time period. The licensed projects are the Eldorado-Pisgah-Lugo, Control-Haiwee, Ivanpah-Coolwater-Kramer-Inyokern and Control-Silver Peak projects.

2. Transmission Deteriorated Pole Replacement

Description

There are approximately 140,000 thousand transmission wood poles in SCE's system. Poles are inspected routinely through intrusive inspections and detailed visual inspections, as required by G.O. 165. SCE is maintaining the number of grid-based transmission intrusive inspections at approximately 10,000 per year through the rate case cycle. Poles that do pass inspection are marked for replacement on a priority basis.

Methodology

"Intrusive" inspections involve drilling into the pole's interior in order to measure the extent of any internal decay, which is typically undetectable with external observation only. Detailed inspections involve visual examination of the pole's exterior condition as well as the condition of components on the pole. Detailed inspections are performed on a ten-year cycle in accordance with GO 165. Like intrusive inspections, detailed inspections can result in the creation of work orders, which result in requests for pole replacements.

Poles will also be identified for replacement from a variety of other sources. These "Other Program" poles can include those identified by Senior Patrolman as part of transmission grid maintenance and identified as being unsuitable for climbing, insufficiently strong to support new equipment, or poles initially identified for repair but later concluded to be too deteriorated.

Criteria

[3] Available at http://www.cpuc.ca.gov/gos/GO95/go_95_table_1.html.

Pole replacements are prioritized based on remaining shell strength and pole load calculations based upon pole load assessment.

A. Priority 1: Immediate remedial action is required. Remedial action may be reported as work-in-progress and depending on the identified condition, following initial repairs, a lower priority rating may be assigned.

B. Priority 2: Remedial action is required, however, there is time to plan, schedule and complete the work within one year.

C. Priority 3: Remedial action is required, however, there is time to plan, schedule, and complete the work within three years.

D. Priority 4: A discrepancy exists, however, reliable service can be expected without effecting repairs through the next routine patrol cycle. Any corrective action undertaken may be performed in the course of routine work or with scheduled Priority 2 or Priority 3 work.

Results

In this 2019 TMCR, there are no transmission costs associated with this element.

3. Disturbance Monitoring

Description

NERC requires each Transmission Owner to install Disturbance Monitoring Equipment (DME) and report on disturbance data to facilitate analysis of events and verify system models. Each Transmission Owner must have adequate data available to facilitate analysis of Bulk Electric System (BES) disturbances. SCE installs Digital Fault Recorders (DFR) and Phasor Measurement Unit (PMU) devices for post event analysis, situational awareness, and for use with mis-operation investigations. Transmission Owners must be compliant with NERC PRC 002-2 by July 1, 2022.

Methodology

Replacement of obsolete DFRs is accomplished through a combination of infrastructure replacement work and bundled capital projects. SCE takes advantage of substation construction projects to upgrade DFRs when possible, as efficiencies can be realized by coupling the DFR installation with other capital work. DFR upgrades are prioritized based on obsolescence of hardware, while ensuring that SCE's PRC-002-2 sites are upgraded in time to meet the compliance deadline. SCE also prioritizes requests from its Grid Control Center (GCC) for upgrades to ensure GCC personnel have the necessary situational awareness.

Criteria

NERC PRC-002-2[4] provides requirements and measurements for Transmission Owners with regards to identification, notification, and evaluation of any type of disturbance on their system. SCE meets the compliance requirements of PRC-002-2 through installation of DFRs and PMUs.

Results

In this 2019 TMCR, there are no transmission costs associated with this element.

B. Infrastructure Replacement

Infrastructure Replacement (IR) is defined as the programmatic replacement of aged assets that are nearing the end of the asset lifecycle; assets that are becoming obsolete in the industry; or assets that are problematic to the resiliency of the system. The replacement could be "in kind" or could involve installation of currently available equipment that has additional standard features. Examples include, but are not limited to: circuit breakers; batteries; switches; transmission poles and other structures; replacement of deteriorated conductors and insulators; and underground cables.

	2021 FORECAST	2022 FORECAST	2023 FORECAST	TOTAL
TOTAL	**$ 77,155,674**	**$ 85,951,664**	**$ 73,664,502**	**$ 236,771,840**
SUBSTATION	$ 51,655,674	$ 57,451,664	$ 52,664,502	$ 161,771,840
TRANSMISSION	$ 25,500,000	$ 28,500,000	$ 21,000,000	$ 75,000,000

1. Substation

Description

Substation-IR (Sub-IR) reduces the impact of aging infrastructure on the reliability and safety of SCE's grid by replacing substation equipment and structures before they cause an unplanned outage that risks public and employee safety. The program looks to optimize Operations and Maintenance (O&M) and capital

[4] *Available at* https://www.nerc.com/_layouts/15/PrintStandard.aspx?standardnumber=PRC-002-2&title=Disturbance%20Monitoring%20and%20Reporting%20Requirements&jurisdiction=United%20States

expenditures, continuously understand risk and consequences of equipment failures, and better determine end of life on equipment.

Criteria

Sub-IR focuses on a variety of commodities: Bulk Power Circuit Breakers; Bulk Power Switches; Substation Rebuilds (Switchracks); Bulk Transformer Replacements; Bulk Relay Replacements; and Substation Miscellaneous Equipment Additions & Betterment. This category also includes the FERC Emergency Equipment Program (EEP) and Spare Transformer Equipment Program (STEP). Many of these commodities can be grouped with regard to identification for replacement and priority of replacement.

- Transformer replacements are identified primarily through the Health Index tool. The Health Index is a tool that determines a score to reflect or characterize the condition of the transformer bank and its likely performance. The tool aides in prioritizing the replacement for the transformer population with the highest risk and consequence failure. To derive an asset's health index, the tool uses a multiplicative formulation that incorporates information such as inspections data, Predictive Maintenance Assessment (PMA), Transformer Oil Analysis (TOA), Oil Tap Changer Analysis (OTA), Dissolved Gas Analysis (DGA), notification, equipment test data, and field condition assessment.
- Circuit Breaker replacements are identified primarily by the Health Index tool. An asset's Health Index is a numerically represented score to reflect or characterize asset condition and thus likely asset performance in terms of the asset's role. It aides in prioritizing and replacing the correct asset population with the highest risk and consequence of failure. To derive an asset's Health Index, the tool uses a multiplicative formulation that incorporates information such as inspection data, overstress percentage, Predictive Maintenance Assessment (PMA), circuit breaker analysis (CBA), Oil Circuit Breaker Analysis (OCBA), notification, and field condition that determines the degradation and deterioration of a circuit breaker.
- Relay replacements are based on a number of factors: age of the relay; relay obsolescence; level of effort required to maintain a complex and unique relay model; system criticality; and current protection and compliance requirements.
  - Age of the relay: Relays that have reached their end of life, or that have become obsolete and no longer serviceable are targeted for replacement. Relays testing out of tolerance during routine testing that cannot be repaired are also targeted by the program. Another

aspect of older relays is that they may not be recording events. The replacement of these relays help with data recording when an event occurs.

- Relay obsolescence: Another driver is the need to have more functionality in a relay such as added protection capabilities, event recording and alarming for failure. SCE may want to replace an electromechanical relay with a digital relay for added functions that are included with a digital relay.
- Level of required effort: There are some relays that require excessive resources to maintain. It may not be cost effective to keep maintaining such relays due to the complexity and uniqueness of the relay and a need for unique, specified knowledge to maintain them.
- System criticality: The criticality of the system the relay protects is also taken into consideration if a relay were to fail or have a mis-operation. In this scenario, SCE decides to replace an older relay proactively than react to a failure.
- Current protection and compliance requirements: The current relay may not be capable of new compliance requirement or protection needs such as relay coordination parameters.

- Substation Rebuilds, also known as Switchracks, are the demolition of the existing switchrack and the construction of a new substation or switchrack structure. These replacements are identified as transformers and circuit breakers are replaced. Rebuilds are triggered for at least one of the following three reasons:
  - Switchracks are often very old and/or determined to fall outside of current compliance requirements, may have deteriorated lattice steel, pipe-steel, wood-pole, or cubicle switchgear components;
  - Physical congestion/clearance issues in existing switchrack areas may create unsafe operating conditions;
  - The existing switchrack structure may be unable to support or safely accommodate new equipment installations.

  Switchrack replacements are also considered when installing new driveways, moving existing fences, or adding a new Mechanical Electrical Equipment Room (MEER) to house substation relays and battery systems. SCE continuously evaluates alternatives in lieu of rebuilding, but occasionally it is more cost effective to substantially rebuild the substation. In this 2019 TMCR, there are no costs associated with this element.

- Substation Miscellaneous Equipment Additions & Betterment is planned maintenance capital that is typically driven by substation inspection and maintenance programs to indicate imminent equipment failure or possible safety issues. All equipment classes, including the major equipment categories (circuit breakers, transformers and relays) can be replaced for reactive reasons in this category. These replacements are predominantly like-for-like replacement with limited engineering. Equipment that is identified as requiring replacement must be replaced in a timely manner because substation equipment failures may lead to prolonged outages, unsafe operating conditions, or more expensive reactive solutions. This typically includes trench covers, PT's, CT's, as well as emergent circuit breakers, B-banks and disconnect replacements that are not covered under the specific commodity capital program.

- The Emergency Equipment Program (EEP) maintains an inventory of major substation equipment such as power transformers, circuit breakers, and disconnect switches not readily available in the marketplace for procurement and delivery. In order to avoid or mitigate potential reductions in reliability, SCE maintains a reserve inventory of such equipment..
- The Spare Transformer Equipment Program (STEP), which is maintained within the EEP, is a voluntary transformer sharing program put together to help mitigate the impact of a Terrorist Event that targets key substation equipment. The program focuses on large transformers, as the lead times are well over a year. The sharing agreement is triggered by an act of sabotage on a utility substation. The impacted utility must use up its own available resource to mitigate the damage prior to call on the sharing agreement.

Methodology

SCE relies on relevant information gathered during a scoping job walk, where additional or required scope can be identified. This work is then bundled whenever possible with existing capital projects to reduce additional outages, for efficient use of resources, and to decrease costs of the overall program.

Results

During 2021, 2022, and 2023, the Substation Infrastructure Replacement Program is estimated to cost approximately $51.7 million, $57.5million, and $52.7 million, respectively.

2. Transmission Replacement

Description

The programmatic replacement of aged transmission assets that are nearing the end of the asset lifecycle or special projects placed into the Infrastructure Replacement program.

Criteria

The Transmission-IR program looks to replace the following commodities for the following reasons:

- Switch Replacement Program: Replacement of switches that are obsolete and no longer manufactured. On annual basis, switches are identified for replacement and added to the Transmission-IR program. Replacements are scheduled based on order of importance and risk level. In this 2019 TMCR, there are no transmission costs associated with this element.

- Pothead Replacement Program: Older style potheads show propensity to fail after 20-25 years of use. As a best practice, the older style potheads (nearing 20 years) are systematically replaced. The replacements are scheduled based on order of importance and risk level. In this 2019 TMCR, there are no transmission costs associated with this element.
- Underground Cable Replacement Program: Through cable analytics, poor performing underground cables are identified to be replaced. The Outage Database and Reliability Metrics (ODRM) tracking system is used to log interruptions and prioritize poor performing cables to be replaced. These are also tracked by Systems, Applications and Products (SAP) maintenance items. The analytics on these along with feedback from certified and trained field personnel determine priority and need of replacement. In this 2019 TMCR, there are no transmission costs associated with this element.
- Overhead Conductor Replacement Program: Overhead (OH) conductor analytics and poor performing circuits are replaced by using ODRM outage tracking systems to log interruptions and prioritize poor performing OH conductors to be replaced. Similarly, this commodity is cross-referenced with the expertise of the trained personnel in the field to determine the remaining lifespan of the conductor. As a practice the smaller, more brittle, conductor is targeted for replacement. Transmission costs associated with this element are included as part of Infrastructure Replacement - Transmission in this 2019 TMCR.
- Pole Replacement Program: This program is generally limited to non-deteriorated pole replacement, primarily geared to replace wood poles at freeway crossings with steel poles. An example of this type of work is wood poles that need upgrading to steel poles for those that support freeway crossings. This program is coming to an end and most poles have been replaced. In this 2019 TMCR, there are no transmission costs associated with this element.
- Line Relocation Program: Based on safety, reliability, and need to relocate which could be tracked by ODRM. These line relocations could be due to flooding, wash outs, property disputes, access issues, etc. These are identified by trained field personnel that see potential hazards under certain conditions. In this 2019 TMCR, there are no transmission costs associated with this element.
- Tower Corrosion: For transmission towers, where in-service failures can have more significant consequences, visual inspection is performed to assess external corrosion which can result in equipment being replaced prior to an in-service failure. Transmission towers are among SCE’s largest and most important assets. SCE operates in excess of 27,000 towers across the SCE territory including out-of-state interties. These structures and lattice towers are mostly comprised of galvanized/painted

steel and typically range from 50 to 300 feet in height. Seventy-eight percent (78%) of these structures were built between 1900 and 1990. As of the year 2020, 93% of SCE's tower portfolio will be 30 years and older and subject to some level of corrosion. Tower structures will be inspected and ranked based on the magnitude of the corrosion and mitigated by repair and protective coating or replacement for the unsalvageable steel. These are identified by trained field personnel that see potential hazards under certain conditions. Transmission costs associated with this element are included as part of Infrastructure Replacement - Transmission in this 2019 TMCR.

Methodology

Transmission-IR work is bundled with existing maintenance work whenever possible to ensure efficiency of resources, outage constraints, and permits that may be required. These commodities are updated and replaced while other larger work is being completed.

Results

During 2021-2023, SCE's anticipated spend for the Transmission Infrastructure Replacement Program is expected to cost approximately $25.5 million, $28.5 million, and $21 million, respectively.

C. Work Performed by Operating Agent

This category includes, but is not limited to line relocations, new service interconnections, and city-sponsored infrastructure project-related transmission system modifications.

	2021 FORECAST	2022 FORECAST	2023 FORECAST	TOTAL
TOTAL	**$ 835,800**	**$ 1,937,750**	**$ 878,050**	**$ 3,651,600**
LADWP	$ 835,800	$ 1,937,750	$ 878,050	$ 3,651,600

1. Los Angeles Department of Water and Power (LADWP)

Description

Under this category, work activities are coordinated with Los Angeles Department of Water and Power (LADWP) (operator of the Pacific Direct Current Intertie (PDCI). The activities include the replacement of approximately 80,000 old porcelain suspension insulators with new glass insulators. The project driver is the existing porcelain insulators are not compliant with current industry standards and the new insulators will support the PDCI rating increase from 3100MW to 3220MW.

Criteria

Prioritization and planning of work belongs to LADWP. As operator of the PDCI transmission line, LADWP is contractually responsible for the operations, maintenance, coordination, and execution of work.

Methodology

As a 50% joint owner of the PDCI, SCE is contractually obligated to cooperate with LADWP in any capital replacements, additions, and betterments related to the PDCI. LADWP submits its proposed capital project and obtains SCE approval. SCE is responsible to pay for its 50% share of the LADWP's capital costs.

Results

During 2021, 2022 and 2023, this program has expected costs of approximately $.8 million, $2.0 million, and $.9 million, respectively.

D. Operations Support

This category includes projects that support transmission operations by improving and securing operation facilities or by implementing information technology that enhances efficiency and flexibility to manage transmission system work. Facility maintenance examples include seismic mitigation of control buildings, grounds, fencing, etc. Technology examples include Emergency Management Systems, Remedial Action Schemes, Special Protection Schemes and other Information Technology infrastructure used to manage transmission related operational activities. In this TMCR cycle there are no technology costs associated with this element.

	2021 FORECAST	2022 FORECAST	2023 FORECAST	TOTAL
TOTAL	**$ 11,272,372**	**$ 11,383,286**	**$ 9,102,764**	**$ 31,758,422**
SUBSTATION CAPITAL MAINTENANCE	5,545,717	5,656,631	5,769,764	16,972,112
SEISMIC MITIGATION (LINES & SUBS)	5,726,655	5,726,655	3,333,000	14,786,310

1. Substation Capital Maintenance (ISO Facilities)

Description

SCE's Substation Capital Maintenance Program seeks to preserve the value of SCE's buildings, equipment, and grounds, making them as safe and productive as reasonably possible. Though facility work orders respond to incidents as they occur, proper asset management also requires a proactive capital maintenance program to repair or replace building systems and components that are damaged, degraded, non-operational, non-compliant, or have reached their end of useful life. This Program is addressed in ten categories: (1) Electrical/Fire systems, (2) Fencing and Walls, (3) HVAC, (4) Paving, (5) Roof Repairs, (7) Lighting, (8) Restroom Remodels, (9) Specialty Equipment and (10) Other Repairs. For this program, SCE will:

- Replace or upgrade the electrical, lighting, mechanical, and plumbing systems.
- Replace or upgrade other building infrastructure, systems, and sub-systems, such as asphalt, roofing, fire detection/prevention, fencing, and painting.
- Replace or remediate degraded interior building components such as doors, ceilings, and flooring.

Criteria

SCE has developed an Asset Management Methodology to prioritize facility and capital work. SCE evaluates three factors: (a) the condition of a facility (Facility Condition Index); (b) the need for a facility to deliver utility services to SCE customers (Asset Priority Index); and (c) the functionality and utility of a facility for business use(s) (Fitness for Purpose).

Methodology

Projects are prioritized based on safety, reliability, compliance, financial, and productivity risks and opportunities, as demonstrated via the Asset Management Methodology. Project planning also takes into consideration the appropriate sequencing of work and the volume of work that is achievable. Then, projects are pursued for analysis, planning, and approval, and scheduled based on available resources and funding.

Results

During 2021, 2022 and 2023, this program has estimated FERC costs of approximately $5.5 million, $5.7 million and $5.8 million, respectively.

2. Seismic Mitigation for Transmission Assets (Lines and Substations)

Description

The primary objectives of the Seismic Assessment and Mitigation Program are to: (1) assess SCE's electric infrastructure (transmission lines and substations), non-electric facilities and generation infrastructure to identify what seismic mitigations are needed, and (2) mitigate risks by making the necessary retrofits and improvements in order to reduce the risk of harm to workers, customers and communities due to a moderate or major earthquake. Examples include bracing and anchoring electrical equipment in substations, improving conductor slack, structural work to reinforce building wall to roofs connections, and replacing aged equipment with modern equipment designed to withstand greater levels of seismic forces. Other work includes more detailed assessments of transmission towers along the earthquake faults, and to determine possible landslide risk.

Criteria

SCE conducts hazard and vulnerability assessments on its infrastructure in order to (1) understand the seismic exposure and impacts of seismic events, (2) assess the functionality and stability of the infrastructure if a seismic event occurred, and (3) identify applicable design standards and codes. Assessments utilize a combination of site surveys, seismic modeling, and geographic information systems. The Seismic Assessment and Mitigation Program applies a three-phase approach. Phase I commences with a broad assessment of electric and non-electric infrastructure using readily available data against two probabilistic scenarios provided by the U.S. Geological Survey. In this first phase, completed in 2016, SCE identified areas to conduct Phase II detailed assessments. Detailed assessments and mitigation identification are a Phase II activity, and completing the mitigations shall be implemented in Phase III. Given the volume and variety of infrastructure, various assets may be in Phase II assessments and Phase III mitigation at any given time.

Methodology

Seismic mitigations are prioritized with a focus on keeping people safe and minimizing interruptions in electric service. Projects with the highest safety, reliability, and compliance impact will be executed first. This includes highly populated buildings and visitor centers, then transmission, distribution and generation infrastructure critical to maintaining stability and operational reliability. Projects related to high-hazards dams with pending FERC reviews will be prioritized accordingly.

Results

During 2021-2023, this program has expected FERC costs of approximately $5.7 million, $5.7 million and $3.3 million, respectively.

E. Physical/Cyber Security

Description

This category includes projects that further enhance the security of SCE's substations which is driven by SCE's need to:

- Make physical security upgrades resulting from the NERC CIP-014 assessments to protect critical facilities against attacks
- Install systems and processes needed to comply with NERC CIP V6 requirements for protecting Low Impact BES Cyber Assets.
- Upgrade elements of existing security systems at facilities that create unacceptable risk due to disrepair or obsolescence.
- Install security and access control systems at locations that have no existing security system or centrally managed access controls.

The expected cost is approximately $19.9 million, $19.4 million, and $12.2 million for 2021, 2022, and 2023, respectively.

F. Description of Appendices

Appendices following this TMCR provide greater detail regarding the stakeholder process timeline and the underlying data for the major TMCR project categories. Appendix A is a calendar summary of the relevant milestones and corresponding due dates for the stakeholder process. Appendices B provides the underlying financial data for all the major project categories.

APPENDICES

Appendix A – Calendar Summary of Stakeholder Process

Stakeholder Meeting and Related Activities

During each TMCR cycle, SCE will conduct a stakeholder meeting to review the TMCR with interested parties and the parties will have an opportunity to pose questions, offer suggestions, or raise concerns directly with SCE. Stakeholders then have an opportunity to provide written comments to SCE. No later than 10-days after the comment deadline, SCE will post all timely received comments. After reviewing and considering comments, SCE will release a final TMCR. As appropriate, SCE may modify the final TMCR to include revisions in light of stakeholder comments.

Schedule for the 2019 TMCR

DUE DATE	ACTIVITY
May 15, 2019	SCE posts meeting notice and draft TMCR report
May 29, 2019	SCE conducts stakeholder meeting and posts comments template
June 26, 2019	Stakeholders submit comments on draft TMCR report
July 10, 2019	SCE posts stakeholder comments on draft TMCR report
August 28, 2019	SCE posts final TMCR report
September 11, 2019	Stakeholders submit comments on final TMCR report
September 25, 2019	SCE posts stakeholder comments on final TMCR report

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Appendix B – Underlying Financial Data for Major Program Categories

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2019 TMCR Forecast

PIN	Project Title	OD	FERC 2021	FERC 2022	FERC 2023	FERC Total	Unit Count (if available)
Compliance							
	Big Creek No 1 - Rector	**2021**	14,201,823	-	-	14,201,823	
	Colorado River - Red Bluff No 1	**2021**	12,744,000	-	-	12,744,000	
	Ellis - Santiago	**2021**	342,200	-	-	342,200	
	Gould - Sylmar - Metro West	**2021**	442,500	-	-	442,500	
	Gould - Sylmar - North Coast	**2021**	216,333	-	-	216,333	
	Johanna - Santiago	**2021**	200,600	-	-	200,600	
	Pardee - Pastoria - North Coast	**2021**	6,096,057	-	-	6,096,057	
	Big Creek No 3 - Big Creek No 4	**2022**	11,800	11,800	-	23,600	
	Big Creek No 3 - Rector 1	**2022**	17,723,600	17,711,800	-	35,435,400	
	Pardee - Pastoria - Warne - North Coast	**2022**	200,600	1,274,400	-	1,475,000	
	Bailey - Pardee	**2023**	7,434,000	9,152,080	6,490,000	23,076,080	
	Big Creek No 1 - Big Creek No 2	**2023**	11,800	413,000	2,328,111	2,752,911	
	Big Creek No 2 - Big Creek No 3	**2023**	59,000	1,261,800	3,813,318	5,134,118	
	Big Creek No 3 - Rector 2	**2023**	613,600	11,800	9,204,000	9,829,400	
	Serrano - Valley - San Jac	**2023**	-	2,976,371	2,964,571	5,940,942	
	Big Creek No 2 - Big Creek No 8	**2024**	11,800	11,800	11,800	35,400	
	Big Creek No 3 - Big Creek No 8	**2024**	11,800	11,800	755,200	778,800	
	Eagle Mountain - Blythe	**2024**	236,000	12,221,045	8,825,000	21,282,045	
07298	**Transmission Line Rating Remediation (Exempt from Licensing)**		**$ 60,557,513**	**$ 45,057,696**	**$ 34,391,999**	**$ 140,007,209**	
07867	TLRR Eldorado-Lugo-Pisgah 220kV Transmission	**2024**	10,534,617	20,577,151	13,459,556	44,571,324	
07905	TLRR Control-Haiwee 115kV Subtrans	**2024**	9,847,369	26,372,022	36,190,445	72,409,836	
07904	TLRR Ivanpah-Coolwater-Kramer-Inyokern 115kV Subtrans	**2025**	13,764,619	46,986,481	69,317,509	130,068,609	
07906	TLRR Control-Silver Peak 55kV Subtrans	**2025**	7,851,841	11,038,163	18,755,114	37,645,118	
	Total Transmission Line Rating Remediation (TLRR)		**$ 102,555,959**	**$ 150,031,513**	**$ 172,114,623**	**$ 424,702,096**	
	Total Compliance		**$ 102,555,959**	**$ 150,031,513**	**$ 172,114,623**	**$ 424,702,096**	

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PIN	Project Title	OD	FERC 2021	2022	2023	Total	Unit Count (if available)
	Infrastructure Replacement						
	Replace Bulk Power Circuit Breakers - CHEVGEN	**2021**	-	106,514	194,530	301,044	2
	Replace Bulk Power Circuit Breakers - DEVERS	**2021**	312,795	-	-	312,795	3
	Replace Bulk Power Circuit Breakers - DEVERS	**2022**	1,912,400	819,600	-	2,732,000	2
	Replace Bulk Power Circuit Breakers/Switches - VINCENT	**2023**	100,000	3,953,104	1,594,188	5,647,292	6
	Replace Bulk Power Circuit Breakers - RANCHO VISTA	**2021**	583,590	-	-	583,590	6
	Replace Bulk Power Circuit Breakers - PADUA	**2021**	179,901	-	-	179,901	1
	Replace Bulk Power Circuit Breakers - COOLWATER	**2021**	1,334,295	-	-	1,334,295	5
	Replace Bulk Power Circuit Breakers - MIRA LOMA	**2023**	-	1,912,400	819,600	2,732,000	2
	Replace Bulk Power Circuit Breakers - INYO	**2023**	-	217,880	180,320	398,200	1
	Replace Bulk Power Switches - VILLA PARK	**2021**	774,075	-	-	774,075	6
	Replace Bulk Power Switches - RIVERTEX	**2021**	97,265	-	-	97,265	1
04211	**Total Replace Bulk Power Circuit Breakers/Switches**		**$ 5,294,321**	**$ 7,009,498**	**$ 2,788,638**	**$ 15,092,457**	**35**
	Substation Transformer Bank Replacement (AA-Bank & A-Bank) - ANTELOPE	**2021**	2,100,000	-	-	2,100,000	1
	Substation Transformer Bank Replacement (AA-Bank & A-Bank) - MIRA LOMA	**2023**	1,168,191	4,789,584	5,607,318	11,565,093	2
	Substation Transformer Bank Replacement (AA-Bank & A-Bank) - LA CIENEGA	**2021**	2,862,795	-	-	2,862,795	1
	Substation Transformer Bank Replacement (AA-Bank & A-Bank) - PADUA	**2021**	2,100,000	-	-	2,100,000	1
	Substation Transformer Bank Replacement (AA-Bank & A-Bank) - SERRANO	**2022**	9,077,032	10,626,768	-	19,703,800	4
	Substation Transformer Bank Replacement (AA-Bank & A-Bank) - VINCENT	**2023**	1,660,443	6,807,773	7,970,076	16,438,292	3
05210	**Total Substation Transformer Bank Replacement Program (AA-Bank & A-Bank)**		**$ 18,968,461**	**$ 22,224,125**	**$ 13,577,394**	**$ 54,769,980**	**12**
	FERC Emergency Equipment Program (EEP)	**2021-2023**	2,961,871	8,873,013	1,441,606	13,276,490	6
	FERC Spare Transformer Equipment Program (STEP)	**2021-2023**	2,961,871		14,970,000	17,931,871	3
03362	**Total Critical Spare Equipment Program**		**$ 5,923,741**	**$ 8,873,013**	**$ 16,411,606**	**$ 31,208,360**	**9**
05089	Bulk Power 500kV & 220kV Line Relay Replacement	**2021-2023**	9,676,288	8,000,001	8,000,000	25,676,289	
04756	Substation Miscellaneous Equipment Additions & Betterment	**2023**	11,792,863	11,345,027	11,886,864	35,024,754	
	Total Substation Infrastructure Replacement		**$ 51,655,674**	**$ 57,451,664**	**$ 52,664,502**	**$ 161,771,840**	
	Chevmain-El Segundo Trans IR OH Conductor	**2022**	1,500,000	2,500,000		4,000,000	
	El Nido-El Segundo Trans IR OH Conductor	**2022**	1,500,000	2,500,000		4,000,000	
	Chevmain-El Nido Trans IR OH Conductor	**2022**	1,500,000	2,500,000		4,000,000	
07890	**Total Transmission IR OH Conductor**		**$ 4,500,000**	**$ 7,500,000**	**$ -**	**$ 12,000,000**	
03364	Tower Corrosion		21,000,000	21,000,000	21,000,000	63,000,000	
	Total Transmission Infrastructure Replacement		**$ 25,500,000**	**$ 28,500,000**	**$ 21,000,000**	**$ 75,000,000**	
	Total Infrastructure Replacement						

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PIN	Project Title	OD	FERC 2021	FERC 2022	FERC 2023	FERC Total	Unit Count (if available)
Work by Operating Agent							
03138	LADWP	**2021-2023**	835,800	1,937,750	878,050	3,651,600	
	Total Work by Operating Agent		**$ 835,800**	**$ 1,937,750**	**$ 878,050**	**$ 3,651,600**	
Operations Support							
07637	Substation Capital Maintenance (ISO Facilities)	**2021-2023**	5,545,717	5,656,631	5,769,764	16,972,112	
07392	Seismic Mitigations for Transmission Line and Substation Assets	**2021-2023**	5,726,655	5,726,655	3,333,000	14,786,310	
	Total Operations Support		**$ 11,272,372**	**$ 11,383,286**	**$ 9,102,764**	**$ 31,758,422**	
Physical Security Enhancement Programs							
7454/7820	Physical Security Systems (Electric Facilities) and NERC CIP-014	**2021-2023**	19,930,545	19,438,285	12,166,939	**$ 51,535,770**	
	Total Physical Security Enhancement Programs		**$ 19,930,545**	**$ 19,438,285**	**$ 12,166,939**	**$ 51,535,770**	

Total