2019 TRANSMISSION MAINTENANCE AND COMPLIANCE REVIEW (TMCR) REPORT

SOUTHERN CALIFORNIA EDISON®

Energy for What's Ahead®

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Version: Final

FINAL

Foreword to Final 2019 TMCR Report

This represents SCE's Final 2019 TMCR Report. SCE would like to thank those who participated in SCE's 2019 TMCR stakeholder process for your review of the Draft 2019 TMCR Report. SCE is also appreciative of comments provided by several stakeholders on the Draft 2019 TMCR Report. SCE's responses to comments it received on the Draft 2019 TMCR Report are included in a new Appendix C. SCE has also revised Appendix B and the body of the TMCR Report to remove certain CPUC-jurisdictional transformer and circuit breaker projects which were inadvertently included under the IR-Substation category. Additionally, SCE has corrected errors related to the Physical/Cyber Security investment forecast. Stakeholders have an opportunity to submit comments on this Final 2019 TMCR Report by September 11, 2019.

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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 (a) that 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 restrict 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 TMCR 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 08/2019	2021 FORECAST	2022 FORECAST	2023 FORECAST	TOTAL
TOTAL	**$ 208,427,312**	**$ 268,895,638**	**$ 262,526,262**	**$ 739,849,213**
COMPLIANCE	$ 102,555,959	$ 150,031,513	$ 172,114,623	$ 424,702,096
INFRASTRUCTURE REPLACEMENT	$ 70,927,423	$ 81,055,566	$ 67,862,654	$ 219,845,643
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	$ 22,835,758	$ 24,487,523	$ 12,568,171	$ 59,891,452

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 became effective on January 1, 2019) increases the RPS to 60% by 2030 and requires all of the 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 reduce 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 TMCR 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 inform the development of SCE's annual transmission rates. The annual process culminates with the publication of a final TMCR Report.

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

[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.

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 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 TMCR 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

[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.

later than 45 days after the deadline for stakeholder comment. After posting of the final TMCR Report, stakeholders may submit comments for consideration in 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, it includes 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 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, 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 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 (Nos. 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 (Nos. 3, 4, and 5 in Table 2) and indicated that its 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 into five categories: Compliance; Infrastructure Replacement; Work Performed by Operating Agent; Operations Support; and Physical Security. The forecasts for these categories are:

AS OF 08/2019	2021 FORECAST	2022 FORECAST	2023 FORECAST	TOTAL
TOTAL	**$ 208,427,312**	**$ 268,895,638**	**$ 262,526,262**	**$ 739,849,213**
COMPLIANCE	$ 102,555,959	$ 150,031,513	$ 172,114,623	$ 424,702,096
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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.

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

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

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	**$ 70,927,423**	**$ 81,055,566**	**$ 67,862,654**	**$ 219,845,643**
SUBSTATION	**$ 45,427,423**	**$ 52,555,566**	**$ 46,862,654**	**$ 144,845,643**
TRANSMISSION	$ 25,500,000	$ 28,500,000	$ 21,000,000	$ 75,000,000

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

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 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

SCE's draft TMCR Report identified six substation transformer bank replacement projects. As part of SCE's ongoing efforts to refine its project identification process, SCE has removed MIRA LOMA, LA CIENEGA, and PADUA transformers as they are not under CAISO control. There are three substation transformer replacement projects. Following are the project names and their corresponding targeted operating dates:

Substation Transformer Bank Replacement (AA-Bank & A-Bank) – ANTELOPE – 12/31/2021

Substation Transformer Bank Replacement (AA-Bank & A-Bank) – SERRANO – 12/31/2022

Substation Transformer Bank Replacement (AA-Bank & A-Bank) – VINCENT – 12/31/2023

SCE has also removed CHEVGEN 66 kV and RIVERTEX 115 kV circuit breakers from the TMCR Report since they are not under CAISO control (i.e., CPUC jurisdictional for cost recovery).

During 2021, 2022, and 2023, the Substation Infrastructure Replacement Program is estimated to cost approximately $45.4 million, $52.5 million and $46.9 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.

Please note that the cost originally provided in the Draft 2019 TMCR Report for physical security contained both FERC and CPUC, therefore SCE has corrected 2021-2023 forecast expenditures for physical security to be 100% FERC and to exclude any CPUC cost. The correct forecast figures are provided here as well as in Attachment B: $22.8M, $24.5M, and $12.6M 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. Appendix C contains SCE's responses to stakeholders' comments on the Draft 2019 TMCR Report.

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 posted meeting notice and draft TMCR report
May 29, 2019	SCE conducted stakeholder meeting and posts comments template
June 26, 2019	Stakeholders submitted comments on draft TMCR report
July 10, 2019	SCE posted 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

Appendix B – Underlying Financial Data for Major Program Categories

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2019 TMCR Forecast

PIN	Project Title	OD	WBS	FERC 2021	FERC 2022	FERC 2023	FERC Total	Unit Count (if available)
Compliance								
	Big Creek No 1 - Rector	2021	CET-PD-OT-PJ-729800	14,201,823	-	-	14,201,823	
	Colorado River - Red Bluff No 1	2021	CET-PD-OT-PJ-729800	12,744,000	-	-	12,744,000	
	Ellis - Santiago	2021	CET-PD-OT-PJ-729800	342,200	-	-	342,200	
	Gould - Sylmar - Metro West	2021	CET-PD-OT-PJ-729800	442,500	-	-	442,500	
	Gould - Sylmar - North Coast	2021	CET-PD-OT-PJ-729800	216,333	-	-	216,333	
	Johanna - Santiago	2021	CET-PD-OT-PJ-729800	200,600	-	-	200,600	
	Pardee - Pastoria - North Coast	2021	CET-PD-OT-PJ-729800	6,096,057	-	-	6,096,057	
	Big Creek No 3 - Big Creek No 4	2022	CET-PD-OT-PJ-729800	11,800	11,800	-	23,600	
	Big Creek No 3 - Rector 1	2022	CET-PD-OT-PJ-729800	17,723,600	17,711,800	-	35,435,400	
	Pardee - Pastoria - Warne - North Coast	2022	CET-PD-OT-PJ-729800	200,600	1,274,400	-	1,475,000	
	Bailey - Pardee	2023	CET-PD-OT-PJ-729800	7,434,000	9,152,080	6,490,000	23,076,080	
	Big Creek No 1 - Big Creek No 2	2023	CET-PD-OT-PJ-729800	11,800	413,000	2,328,111	2,752,911	
	Big Creek No 2 - Big Creek No 3	2023	CET-PD-OT-PJ-729800	59,000	1,261,800	3,813,318	5,134,118	
	Big Creek No 3 - Rector 2	2023	CET-PD-OT-PJ-729800	613,600	11,800	9,204,000	9,829,400	
	Serrano - Valley - San Jac	2023	CET-PD-OT-PJ-729800	-	2,976,371	2,964,571	5,940,942	
	Big Creek No 2 - Big Creek No 8	2024	CET-PD-OT-PJ-729800	11,800	11,800	11,800	35,400	
	Big Creek No 3 - Big Creek No 8	2024	CET-PD-OT-PJ-729800	11,800	11,800	755,200	778,800	
	Eagle Mountain - Blythe	2024	CET-PD-OT-PJ-729800	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	CET-PD-OT-PJ-786700	10,534,617	20,577,151	13,459,556	44,571,324	
07905	TLRR Control-Haiwee 115kV Subtrans	2024	CET-PD-OT-PJ-790500	9,847,369	26,372,022	36,190,445	72,409,836	
07904	TLRR Ivanpah-Coolwater-Kramer-Inyokern 115kV Subtrans	2025	CET-PD-OT-PJ-790400	13,764,619	46,986,481	69,317,509	130,068,609	
07906	TLRR Control-Silver Peak 55kV Subtrans	2025	CET-PD-OT-PJ-790700	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**	

2019 TMCR Forecast

PIN	Project Title	OD	WBS	FERC 2021	FERC 2022	FERC 2023	FERC Total	Unit Count (if available)
Infrastructure Replacement								
	Replace Bulk Power Circuit Breakers - DEVERS	2021	CET-ET-IR-CB-432911	312,795	-	-	312,795	3
	Replace Bulk Power Circuit Breakers - DEVERS	2022	CET-ET-IR-CB-432911	1,912,400	819,600	-	2,732,000	2
	Replace Bulk Power Circuit Breakers/Switches - VINCENT	2023	CET-ET-IR-CB-432911	100,000	3,953,104	1,594,188	5,647,292	6
	Replace Bulk Power Circuit Breakers - RANCHO VISTA	2021	CET-ET-IR-CB-432911	583,590	-	-	583,590	6
	Replace Bulk Power Circuit Breakers - PADUA	2021	CET-ET-IR-CB-432911	179,901	-	-	179,901	1
	Replace Bulk Power Circuit Breakers - COOLWATER	2021	CET-ET-IR-CB-432911	1,334,295	-	-	1,334,295	5
	Replace Bulk Power Circuit Breakers - MIRA LOMA	2023	CET-ET-IR-CB-432911	-	1,912,400	819,600	2,732,000	2
	Replace Bulk Power Circuit Breakers - INYO	2023	CET-ET-IR-CB-432911	-	217,880	180,320	398,200	1
	Replace Bulk Power Switches - VILLA PARK	2021	CET-ET-IR-CB-432911	774,075	-	-	774,075	6
04211	**Total Replace Bulk Power Circuit Breakers/Switches**			**$ 5,197,056**	**$ 6,902,984**	**$ 2,594,108**	**$ 14,694,148**	**32**
	Substation Transformer Bank Replacement (AA-Bank & A-Bank) - ANTELOPE	2021	CET-ET-IR-TB-521001	2,100,000	-	-	2,100,000	1
	Substation Transformer Bank Replacement (AA-Bank & A-Bank) - SERRANO	2022	CET-ET-IR-TB-521001	9,077,032	10,626,768	-	19,703,800	4
	Substation Transformer Bank Replacement (AA-Bank & A-Bank) - VINCENT	2023	CET-ET-IR-TB-521001	1,660,443	6,807,773	7,970,076	16,438,292	3
05210	**Total Substation Transformer Bank Replacement Program (AA-Bank & A-Bank)**			**$ 12,837,475**	**$ 17,434,541**	**$ 7,970,076**	**$ 38,242,092**	**8**
	FERC Emergency Equipment Program (EEP)	2021-2023	CET-PD-CI-CI-CRINSP	2,961,871	8,873,013	1,441,606	13,276,490	6
	FERC Spare Transformer Equipment Program (STEP)	2021-2023	CET-PD-CI-CI-CRINSP	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	CET-ET-IR-RP-508900	9,676,288	8,000,001	8,000,000	25,676,289	
04756	Substation Miscellaneous Equipment Additions & Betterment	2023	CET-ET-IR-ME-475600	11,792,863	11,345,027	11,886,864	35,024,754	
	Total Substation Infrastructure Replacement			**$ 45,427,423**	**$ 52,555,566**	**$ 46,862,654**	**$ 144,845,643**	
	Chevmain-El Segundo Trans IR OH Conductor	2022	CET-PD-IR-TP-789000	1,500,000	2,500,000		4,000,000	
	El Nido-El Segundo Trans IR OH Conductor	2022	CET-PD-IR-TP-789000	1,500,000	2,500,000		4,000,000	
	Chevmain-El Nido Trans IR OH Conductor	2022	CET-PD-IR-TP-789000	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		CET-PD-IR-TS-TRSJAC	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			**$ 70,927,423**	**$ 81,055,566**	**$ 67,862,654**	**$ 219,845,643**	

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2019 TMCR Forecast

				FERC				
PIN	**Project Title**	**OD**	**WBS**	**2021**	**2022**	**2023**	**Total**	**Unit Count (if available)**
Work by Operating Agent								
03138	LADWP	2021-2023	CET-OT-OT-ME-313800, CET-OT-OT-ME-313802, CET-OT-OT-ME-313803	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	COS-00-RE-MA-NE7637	5,545,717	5,656,631	5,769,764	16,972,112	
07392	Seismic Mitigations for Transmission Line and Substation Assets	2021-2023	COS-00-SP-BR-000000, COS-00-SP-TD-000000, COS-00-SP-TD-000001, COS-00-SP-TD-000002	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	CET-ET-IR-ME-782008, CET-ET-IR-ME-782001, CET-ET-IR-ME-782002, CET-ET-IR-ME-782005, CET-ET-IR-ME-782009, CET-ET-IR-ME-804201, CET-ET-IR-ME-804200, CET-ET-IR-ME-804202, CET-ET-IR-ME-804205, CET-ET-IR-ME-804203, CET-ET-IR-ME-804206, CET-ET-IR-ME-804204, CET-ET-IR-ME-804207, CET-ET-IR-ME-757301, COS-00-CS-CS-745400, COS-00-CS-CS-782000	22,835,758	24,487,523	12,568,171	$ 59,891,452	
	Total Physical Security Enhancement Programs			$ 22,835,758	$ 24,487,523	$ 12,568,171	$ 59,891,452	
Total				$ 208,427,312	$ 268,895,638	$ 262,526,262	$ 739,849,213	

Appendix C – Response to Stakeholder Comments on Draft 2019 TMCR Report

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Response to Stakeholder Comments on Draft 2019 Transmission Maintenance and Compliance Review (TMCR) Report

On May 15, SCE posted on its website its Draft 2019 TMCR Report. On May 29, 2019 SCE held a public meeting to review the Draft 2019 TMCR Report. On June 26, 2019 the California Public Utilities Commission (CPUC), Six Cities, and Northern California Power Agency (NCPA) provided comments on the Draft 2019 TMCR Report and the related stakeholder meeting. SCE appreciates comments submitted by stakeholders on the Draft 2019 TMCR Report. The 2019 TMCR process was SCE's first and stakeholder comments include recommendations that SCE can use to improve the TMCR stakeholder process going forward. Below are responses to stakeholders' comments on various aspects of the Draft 2019 TMCR Report. Stakeholders have an opportunity to submit comments on SCE's Final 2019 TMCR Report within ten business days after it being posted.

I. General Stakeholder Comments on the Draft 2019 TMCR Report

SCE responds to parties' comments on the actual information contained in the Draft 2019 TMCR Report and presented during the May 29 stakeholder meeting as follows:

- NCPA states that it "would like to better understand how projects are chosen and the prioritization process. More information is needed, for example: project start date, purpose of the project, alternatives considered, types of analysis/inspections performed including results, PUC fire threat zone, ISO planning area, age of the asset, and the how the budget was determined."[5]
    - SCE Response: Typically, the specific projects are not selected and prioritized when the five-year forecast is developed. Various methods are used to determine the proposed budget (e.g., unit costs, historical average, etc) and then as the annual operational plans are developed the projects are identified.

- CPUC states "the TMCR should break out the data on an individual project basis, rather than on the basis of PINs, or programmatic categories."[6]
    - SCE Response: Categories with known individual projects are provided in this Final 2019 TMCR Report when available. (e.g., circuit breakers, TLRR).

- Six Cities states that "many of the projected annual costs are shown aggregated into certain categories (*see, e.g.,* the costs for the Transmission Line Remediation program on page 10), but there is no breakdown of or description for how the various estimates were derived apart from the listing of 'PINs' for projects in Appendix B. Nor is there significant detail regarding how SCE is organizing or prioritizing projects within the identified categories. If there is more granular data regarding specific projects and their costs, that information would enhance the transparency of SCE's projections. … Providing cost information for the two listed PINs broken down by, for example, substation location, would be informative. Further, to the extent that the aggregated projections include costs that are expected to

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5 NCPA Comments, p. 1.

6 CPUC Comments, p. 3.

be recovered via the Transmission Revenue Requirement and through wholesale distribution charges, those costs should be separately designated."[7]

- SCE Response: Per Appendix XI of SCE's TO Tariff, the TMCR Report covers proposed SCE transmission facilities and projects that will have their capital costs included in SCE's wholesale transmission rate base. The TMCR does not include any costs subject to recovery through SCE's WDAT.

- CPUC states that "as part of the TMCR Report, SCE should provide the 5-year forecast of the Health Index Tool for each set of assets, showing the priority of each project and expected date of replacement."[8]
  - SCE Response: SCE will look to include more detail in these areas in the 2020 TMCR Report.

- Six Cities states that "relatedly, it is almost incomprehensible that the Draft TMCR Report includes no information relating to projects that may be needed for purposes of expected wildfire-related equipment repair or risk mitigation for the Years 3-5 period."[9]
  - SCE Response: SCE's wildfire mitigation plans are currently under development and projects associated with such plans will be included in the 2020 TMCR Report.

- CPUC states "other stakeholders should have the opportunity through a transparent process to be able to ask written questions and expect good faith answers. Additional time is also needed for a robust discovery process."[10]
  - SCE Response: Although discovery is not part of the TMCR process, SCE encourages parties to provide suggested topic areas that they would like to see discussed during the stakeholder meeting, to make that meeting more useful. To provide parties additional time to review the 2020 Draft TMCR Report and submit suggested topics for discussion during the stakeholder meeting, SCE will hold the stakeholder meeting twenty business days (increased from ten business days) after posting its 2020 Draft TMCR Report.

II. Stakeholder Comments on the Scope of the TMCR Process

A number of issues identified in stakeholder comments are beyond the scope of Appendix XI of Southern California Edison's (SCE's) Transmission Owner Tariff. As provided in that Appendix, the scope of the TMCR includes:

1. The TMCR will describe proposed, in-scope High Voltage Transmission Facilities, Low Voltage Transmission Facilities, or other transmission solutions to address identified needs in the second year (X+2) after the year of its designation as well as for the two additional years thereafter (years X+3 and X+4). (*TOT – Appendix XI*, *Section II*)
   - Projects or facilities outside the scope of the TMCR include facilities or projects that require an in-service date less than two years after their need being identified. (*TOT – Appendix XI*, *Section*

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7 Six Cities Comments, p. 2.
8 CPUC Comments, p. 6-7.
9 Six Cities Comments, p. 2.
10 CPUC Comments, p. 4.

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2. The TMCR will identify proposed projects and provide their estimated costs, their projected in-service date, and the need that they are addressing. (*TOT – Appendix XI*, *Section II*)

3. The TMCR will provide the basic methodology, criteria, and processes used for its development. (*TOT – Appendix XI*, *Section II*)
    - During the May 1, 2018, Technical Conference, the Participating Transmission Owners (PTOs), including SCE, discussed that "asset management refers to the activities necessary to maintain a safe, reliable, and compliant grid, based on existing grid topology.[11]" Further, "with respect to the definition of asset management, the PTOs explained that they use <u>inspection-based</u> maintenance programs that identify repairs and replacements <u>based on observed asset conditions</u>."[12]

4. The TMCR will also provide the annual estimated aggregate cost of projects addressing the physical and cyber security needs of the transmission system identified in the second calendar year (year X+2) after the calendar year of its designation as well as for the two additional years thereafter (X+3 and X+4). (*TOT – Appendix XI, Section II)*

5. SCE shall review and consider all stakeholder comments it receives by the due date specified in Section III.e. (*TOT – Appendix XI*, *Section III.f*)

Based upon the above-described scope, SCE believes the following comments raise issues that are outside of the above-described scope:

- NCPA states "[p]rojects that require an in-service date of less than two years after their need has been identified should not be exempt from the TMCR process."[13]
    - <u>SCE Response</u>: Per item No. 1 above, Projects or facilities outside the scope of the TMCR include facilities or projects that require an in-service date less than two years after their need being identified.

- The CPUC states "SCE should consolidate the Years 1-2 Projects in the TO rate filings with the Years 3-5 forecasts into a single document or platform."[14]
    - <u>SCE Response</u>: This request is outside the scope of the TMCR process.

- The CPUC states "[s]eeing what is planned in the next year or two when the Draft TMCR Report is released would help stakeholders anticipate what is planned. Simply claiming projects are emergent, and then not having to disclose information because only years 3-5 are discussed, does not help stakeholders to fully participate in the TMCR process."[15]

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[11] FERC Order on Tariff Filing, Docket No. ER18-370-00 (issued August 31, 2018), par. 14.
[12] Id, par. 15.
[13] NCPA Comments, p. 1.
[14] CPUC Comments, pgs. 2.
[15] CPUC Comments, p. 7.

  - SCE Response: Per item No. 1 above, the TMCR describes proposed transmission solutions to identified needs in the second year (X+2) after the year of its designation as well as for the two additional years thereafter (years X+3 and X+4).

- CPUC states "SCE should adopt a walk-through exercise with stakeholders at the Stakeholder meeting, walking them through the process by which it considers, analyzes, and decides to pursue or not pursue individual capital projects. . . . For example, SCE subject matter expert should provide a walk-through on select projects in each PIN and demonstrate the modeling/analysis (e.g. PSLF, short circuit analysis, etc.) and model validation process that was conducted to justify the project, including input data and identification of the data sources."[16]
  - SCE Response: Per item No. 3 above, the TMCR will provide the basic methodology, criteria, and processes used for its development. As noted in FERC's Order accepting the TMCR filing, SCE uses "inspection-based maintenance programs that identify repairs and replacements based on observed asset conditions." [17] Projects included in the TMCR process typically are not identified through the types of modeling or analysis that is utilized for projects which increase system capacity and are evaluated under the CAISO's Transmission Planning Process.

- CPUC states "SCE indicated at the meeting that there were about 80 [projects that would fall into this (i.e. Physical/Cyber Security) category] that are represented in the TMCR forecasts. While still maintaining necessary restrictions on [CEII] and other justifiable and supported claims of confidentiality, this is not a long list of projects forecasted to be worked on in the next five years, and the complete list should be included in Appendix B."[18]
  - SCE Response: Per item No. 4 above, the TMCR will provide the annual estimated aggregate cost of projects addressing the physical and cyber security needs of the transmission system identified in the second calendar year (year X+2) after the calendar year of its designation as well as for the two additional years thereafter (X+3 and X+4).

- CPUC states "[f]or the physical/cyber security projects, it would be helpful to know the amounts of ratepayer funds spent on categories such physical deterrents (walls, fencing, equipment hardening, etc.), digital defenses (cameras, alarms, firewalls, etc.), and other forms of defense. (Partially provided in response to TMCR CPUC-SCE-001-36)."[19]
  - SCE Response: Per item No. 4 above, the TMCR will provide the annual estimated aggregate cost of projects addressing the physical and cyber security needs of the transmission system identified in the second calendar year (year X+2) after the calendar year of its designation as well as for the two additional years thereafter (X+3 and X+4).

III. Stakeholder Comments on Specific Project Categories

Compliance – Transmission Line Rating Remediation

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[16] CPUC Comments, pgs. 4-5.
[17] FERC Order on Tariff Filing, Docket No. ER18-370-00 (issued August 31, 2018), P 15.
[18] CPUC Comments, p. 8.
[19] CPUC Comments, p. 8.

- CPUC states "the TMCR Report should identify and describe the discrepancies for each project listed."[20]
    - SCE Response: The Transmission Line Rating Remediation program identified over 11,000 potential discrepancies. SCE does not envision this level of detail being appropriate in the context of TMCR. SCE believes this request is beyond the scope of Appendix XI's requirements to provide (1) a description of proposed, in-scope projects, including "their estimated cost, projected in-service date, and the need that they are addressing" and the "basic methodology, criteria and processes used for [the TMCR Report's] development. *Appendix XI, at Section II*.

- CPUC states "the TMCR report, knowing what the issues are, should also identify and describe the methodologies for determining and prioritizing the work, and how and when the discrepancies are to be addressed is necessary for a transparent stakeholder process."[21]
    - SCE Response: The team developed a long-range schedule that prioritized based on severity of discrepancy and considered outage restrictions, permitting and agency approvals, and resource constraints to balance the scope for the duration of the program. The scope will vary on all projects and will dictate how the discrepancies will be addressed. Based on the nature of the discrepancy, remediation can include vegetation clearance, cross arm adjustments, modifications to the structure, interests, or pole replacements.

- CPUC states "as part of the stakeholder meeting, the SCE subject matter expert(s) should provide a walk-through on select projects in each PIN and demonstrate the modeling/analysis (e.g. PSLF, short circuit analysis, etc.) and model validation process that was conducted to identify the discrepancies and justify the remediation including the input data and identification of the data sources."[22]
    - SCE Response: The TMCR process does not include modeling/analysis through technical studies, which are common for projects which increase system capacity and are evaluated under the CAISO's Transmission Planning Process.

- CPUC states "WP-Schedule 10&16 of SCE's TO2018 Filing (FERC Docket No. ER18-169) at page 8 of 20 notes that based on the study performed on SCE's CAISO-controlled facilities, SCE 'prioritized the transmission line discrepancies that will require line clearance remediation.' This prioritized list of discrepancies should be provided, along with the reasons for the prioritizations, explanations of whether the discrepancies have been completed, or expected completion dates of each discrepancy."[23]
    - SCE Response: The request for SCE to provide additional detail on workpapers submitted to FERC as part of SCE's transmission rate case may be more appropriately addressed through the rate case proceeding.

- CPUC states "all compliance projects that are combined with distribution work must be noted and delineated."[24]

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[20] CPUC Comments, p. 5.
[21] CPUC Comments, p. 5.
[22] CPUC Comments, p. 5.
[23] CPUC Comments, p. 5.
[24] CPUC Comments, p. 5.

- SCE Response: TLRR does not address GO95 infractions on SCE's distribution system. SCE will lower or relocate distribution on occasion if it is the cause of the discrepancy with the transmission line if it is determined to be the correct and prudent solution.

- CPUC states "SCE also mentioned that like-for-like replacement projects are often performed to avoid triggering GO 131-D. While the CPUC appreciates the candor of this statement, it begs the conclusion that this approach is a deterrent to incorporating new or advanced technology in an increasingly modernizing grid and could inhibit innovative approaches to reducing costs and promoting safety and reliability. Defaulting to like-for-like replacement of decades-old assets may not provide the greatest benefits to the grid or ratepayers."[25]
  - SCE Response: In addressing discrepancies, the TLRR team first identifies cost-effective remediation that minimizes disturbance where possible, such as vegetation clearing, replacing cross-arms, and other methods to avoid pole replacement when feasible. In the interest of additionally minimizing cost and impacts, the TLRR team works with environmental subject matter experts and then determines the regulatory path forward. Projects may be consistent with a variety of GO 131-D exemptions, including like-for-like replacements, minor relocations, intersetting poles, or work occurring on facilities located in existing franchise. The use of a variety of exemptions provides the TLRR team with the flexibility to incorporate innovative solutions to addressing discrepancies while remaining exempt from GO 131-D, reducing the timeframe and cost to complete the project. TLRR has a track record of implementing new and advanced technologies to provide cost-effective solutions to these projects. TLRR was the first SCE program to utilize Ampjack Tower raising technology and the first to utilize High Temperature Low Sag (HTLS) conductors on our bulk electric system. The team will continue looking for innovative ways to cost-effectively and safely put our system into compliance.

- CPUC states "SCE should also provide information regarding compliance projects that may be needed for SCE's Wildfire Mitigation Plan."[26]
  - SCE Response: SCE is continuing to develop its plan to identify transmission projects to support the mitigation of risks associated with potential wildfires. Any projects resulting from this effort that fall within the TMCR criteria will be included in the 2020 TMCR Report.

Infrastructure Replacement – Substation

- CPUC states "SCE should provide the 5-year forecast of the Health Index Tool for each set of assets, showing the priority of each project and expected date of replacement."[27]
  - SCE Response: Currently SCE only prepares Health Indices for both Substation Power Transformers and Substation Circuit Breakers. Prioritization and justification of forecast work for both assets is managed by the Substation Infrastructure Replacement program which combines engineering analysis (Weibull analysis evaluation of historical removals and failures), an assessment of physical asset condition or "Health Index." From this algorithm-derived replacement prioritization, a five-year replacement schedule is drafted. Two adjustments are then made to this draft replacement schedule. The draft schedule is adjusted as necessary by a

[25] CPCU Comments, p. 5.
[26] CPUC Comments, p. 5.
[27] CPUC Comments, p. 6.

team of technical experts to ensure that factors difficult to quantify are incorporated into the prioritization process such that high-risk items are prioritized. Second, if equipment conditions allow, the draft schedule is adjusted to optimize the construction aspects of the replacements.

- CPUC states "if certain projects are not based on the Health Index Tool, SCE should provide information describing how the project was identified (e.g., if transformers need to be replaced and SCE decides to rebuild a switchrack structure, maintenance records, inspections, etc.)."[28]
    - SCE Response: Projects that are not scored by means of Health Index formulation are identified as a result of scoping job walk to identify additional or required scope. Once identified, the scope is reviewed and approved by the Substation Infrastructure Replacement technical team.

IR – Transmission

- CPUC states "the information from the ODRM should be provided in order to support the projects included in these programs."[29]
    - SCE Response: Outage statistics are outside the scope of the TMCR. As discussed in the "Stakeholder Comments on the TMCR Process" section, above, the TMCR requires a description of proposed, in-scope projects, including "their estimated cost, projected in-service date, and the need that they are addressing". Further, outage statistics are central for replacement identification. The specific projects identified in the TMCR Report were identified for replacement due to the number of splices and age of the circuit.

- CPUC states "as for Tower Corrosion projects, SCE should provide data from the inspections and ranking of towers that need to be mitigated, and the type of mitigation (e.g. repair, protective coating, or replacement)."[30]
    - SCE Response: SCE appreciates the suggestion and will consider ways it can incorporate additional detail regarding tower corrosion projects in a future TMCR.

- CPUC states "as part of the stakeholder meeting, the SCE subject matter expert(s) should provide a walk-through on select projects in each PIN under Infrastructure Replacement and demonstrate the modeling/analysis process conducted to identify the need and justify the replacement activity including the input data used and identification of the data sources. Demonstrations of the analytical tools used (e.g. Health Index Tool, ORDM tracking system, etc.) should also be conducted." [31]
    - SCE Response: The TMCR process does not include modeling/analysis through technical studies, which are common for projects which increase system capacity and are evaluated under the CAISO's Transmission Planning Process.

Operation Support – Substation Capital Maintenance

- CPUC states "while many of the projects may be emergent to the point that they would not be known in years 3-5, there must be some work here that is known in advance."[32]

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28 CPUC Comments, p. 6.
29 CPUC Comments, p. 6.
30 CPUC Comments, p. 6.
31 CPUC Comments, p. 7.
32 CPUC Comments, p. 7.

- SCE Response: Forecast for Substation Capital Maintenance is based on an escalated historical spend. Projects in this realm are investments under a two-years horizon, and therefore are not identified in the years 3-5 window.

Operation Support – Seismic Activity

- CPUC states "of SCE's 70 transmission substations, only 3 are included in the 2019 TMCR Draft Report. Specific information on these 3 substations and the priority corridors and how methodologies were applied to prioritize this work is needed."[33]
    - SCE Response*:* A point of clarification, the three substations identified for 2021-2023 are based on the continuation of the ongoing work on the transmission system. Between 2018-2020, SCE estimates 30 substation projects will have been completed. The 3 substation projects in the 2021-2023 calendar years were selected based on evaluating the performance of these substations against various faults and the overall impact to the system, as well as feasibility of execution. The priority of the Cajon Pass and Tejon Pass transmission towers was based on existing DHS studies that suggest these corridors have vulnerable lifeline systems such as transmission lines. In addition, their close proximity to the San Andreas Fault provided reason to start work there. If additional details can be developed on the methodology and process, SCE will consider including such information in the 2020 TMCR Report.

- CPUC states "SCE discussed a 2016 study that identified the areas needing detailed assessments. This study, as well as any studies based upon the detailed assessments and prioritization thereof, should be provided for any transmission assets."[34]
    - SCE Response: SCE has provided the process and methodologies used to determine the scope, schedule, and justification of work.

[33] CPUC Comments, p. 8.
[34] CPUC Comments, p. 8.