

During the period January 2022 through December 2023, SCE forecasts:

- \$622 million in ISO non-incentive network transmission projected to go into rate base (including \$374 million in ISO Blanket-Specifics),
- \$301 million in FERC incentive rate qualified CWIP expenditures, and
- \$1,031 million of CWIP Expenditures projected to go into rate base.

In addition to the numerous but relatively small transmission projects, there are 32 significant transmission projects (each \$5 million or greater in ISO-related costs) that are projected to go into rate base during the forecast period January 2022 through December 2023 – 16 Blanket-Specifics (items 1 through 16 below), twelve Specific non-incentive projects (items 17, 18, 19, 22, and 25 through 32 below), and four Specific incentive projects (items 20, 21, 23 and 24 below). These projects will increase the reliability of the ISO transmission grid, increase access to new generation resources to serve the ISO market, and/or provide congestion relief. SCE’s Formula Protocols, Section 3(a) specifies that SCE will provide work papers detailing specific information regarding its capital forecast.

**Table 1**  
**Forecast Direct Capital Expenditures Projected to Go into Rate Base between 2022 and 2023**  
*(Nominal \$Millions)*

<b>No.</b>	<b>PIN</b>	<b>Project</b>	<b>FERC CWIP</b>	<b>FERC Non-CWIP</b>	<b>Total</b>
1	3138	Sylmar Convertor Station: Miscellaneous Capital Maintenance	-	8.466	8.466
2	3362	Critical Infra Spare - FERC Spare Transformer Equipment Program (STEP)/ Emergency Spares	-	10.416	10.416
3	3364	Transmission Tower Corrosion Program	-	18.290	18.290
4	3364	Transmission Grid-Based Maintenance	-	18.664	18.664
5	3364	Transmission Deteriorated Pole Replacement & Restoration	-	10.927	10.927
6	4211	Replace Bulk Power Circuit Breakers	-	11.052	11.052
7	4756	Substation Miscellaneous Equipment Additions & Betterment	-	35.463	35.463
8	5089	Bulk Power 500 kV & 230 kV Line Relay Replacement	-	19.090	19.090
9	6446	Phasor Measurement System Installations	-	8.978	8.978

10	7298	Transmission Line Rating Remediation	-	130.091	130.091
11	7392	Seismic Assessment and Mitigation Program for Transmission Assets	-	32.622	32.622
12	7573	Substation Fence/Gate (Cu Theft)	-	6.804	6.804
13	7949	Protection of Grid Infrastructure Assets	-	18.335	18.335
14	7637	Substation Facility Capital Maintenance	-	10.692	10.692
15	4343	Non-Bulk Relay Replacement Program ("SRRP")	-	6.245	6.245
16	5210	Substation Transformer Bank Replacement Program (AA-Bank & A-Bank)	-	8.041	8.041
17	7957	Devers: Substation Maintenance and Test Building Improvements program	-	8.951	8.951
18	8284	West of Colorado River CRAS Inland/Devers Extension	-	6.426	6.426
19	4057	September Wildfires CEMA Transmission Restoration and Erosion Control	-	7.482	7.482
20	5450	Riverside Transmission Reliability Project	224.978	-	224.978
21	6420	West of Devers Upgrade Project (WODUP)	371.472	-	371.472
22	7227	Casa Diablo IV Project Interconnection	-	6.237	6.237
23	7546	Eldorado-Lugo-Mohave (ELM) Upgrade	215.537	2.359	217.896
24	7555	Mesa Substation	217.354	0.498	217.852
25	7558	Magunden-Springville No.1 & 2 Tower Replacement ("Lake Success Towers in Water")	-	13.124	13.124
26	7763	Lugo-Victorville 500 kV T/L SPS	-	12.460	12.460
27	8042	Physical Security Enhancement Projects (Tiers 2 & 3)	-	30.453	30.453
28	8077	Annual Transmission Reliability Assessment 2016 - Protection Upgrades (ATRA)	-	37.290	37.290
29	8104	Moorpark-Pardee 230 kV No. 4 Circuit	-	41.798	41.798
30	8163	Red Bluff 2nd 500/230 kV AA Bank (Reliability Network Upgrades)	-	20.971	20.971
31	8220	Athos Power Plant Project Reliability Network Upgrades	-	5.346	5.346
32	8294	Pardee-Sylmar No. 1 and No. 2 230kV Line Rating Increase Project	-	18.773	18.773
33	Various	Less than \$5m each	1.560	56.527	58.087
		<b>Total</b>	<b>1,030.90</b>	<b>622.870</b>	<b>1,653.77</b>

## 1. Sylmar Converter Station: Miscellaneous Capital Maintenance (PIN: 3138)

The Sylmar Converter Station is the southern converter station of the Pacific DC Intertie (PDCI), an electric power transmission line which transmits electricity from the Celilo Converter Station outside The Dalles, Oregon to Sylmar in the northeastern San Fernando Valley region of Los Angeles, California. The station converts the  $\pm 500$  kV high voltage direct current (HVDC) coming from the northern converter station Celilo to alternating current (AC) at 60 Hz and 230 kV

synchronized with the Los Angeles power grid. The station capacity is 3,100 megawatts and it is jointly owned by Southern California Edison (SCE) and Los Angeles Department of Water and Power (LADWP).

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. The forecasted capital expenditures are for miscellaneous maintenance capital work activities, which include, but not limited to polymer insulators, removal of old electrodes, and bowed towers.

The estimated ISO-related direct capital expenditures that are projected to go into rate base during this period are \$8.466 million.

## **2. Critical Infrastructure Spares (PIN: 3362)**

The Spare Transformer Equipment Program (STEP), which is maintained within the FERC Emergency Equipment Program (EEP), is a voluntary transformer sharing program put together to help mitigate the impact of a terrorist event that targets key substation equipment. The 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. To avoid or mitigate potential reductions in reliability, SCE maintains a reserve inventory of such equipment. Inventory levels are prioritized based on in-serviced equipment counts to ensure grid reliability. The STEP focuses on large transformers, as the lead times are well over a year. Any investor-owned, government-owned, or rural electric cooperative electric company in the United States or Canada may participate in the program.

The sharing agreement is triggered by an act of sabotage on a utility substation. The impacted utility must use up its own available resources to

mitigate the damage prior to calling on the sharing agreement. Thus, work within this program is reactive and prioritized according to criticality.

The estimated ISO-related direct capital expenditures that are projected to go into rate base during this period are \$10.416 million.

### **3. Transmission Tower Corrosion Program (PIN: 3364)**

By 2020, more than 90% of SCE's transmission towers will be at least thirty years old. Thirty years is the average age at which the first signs of tower corrosion, from minor to severe, generally begin to appear. If not identified and addressed, steel loss due to corrosion could lead to structure failure. Based on the severity of corrosion and the particular tower location, SCE can perform the following remedies: footing repair, footing replacement/rebuild, sandblasting, tower coating application, corroded steel lattice member replacement, or entire structure replacement.

SCE's forecast for this activity is based on unit costs and scope estimates from SCE's prior engineering efforts as well as from an internal pilot program, both for assessments of SCE's transmission towers and for planned remediation. Assessment and testing practices will take place on all of SCE's towers to identify further remediation needs. Assessment costs are for bore scope, ultrasonic, and engineering assessments. Bore scope and engineering assessments are performed on transmission towers, while ultrasonic testing is used for tubular steel poles (TSPs). For remediations, SCE has known project scope and anticipated scope that will arise from its forthcoming assessments and testing that are performed on each of its transmission towers.

SCE will also target high risk structures within SCE's High Fire Risk Areas (HFRA) to assess and remediate any transmission towers located in areas that pose the highest wildfire risk. To do this, SCE will leverage the various wildfire risk analysis tools SCE has developed in support of its broader wildfire mitigation

efforts. Additional information on these tools and models can be found in SCE's 2020 Wildfire Mitigation Plan (WMP), as well as the annual WMP's, and other updates, that have been submitted subsequent to the 2020 WMP.

The estimated ISO-related direct capital expenditures that are projected to go into rate base during this period are \$18.290 million.

#### **4. Transmission Grid-Based Maintenance (PIN: 3364)**

SCE has a robust transmission inspection and maintenance program wherein circuits and equipment are inspected on a programmatic basis. Pursuant to CPUC requirements for inspection and maintenance programs, SCE inspects right of ways, conductors, structures, and hardware components for "break/fix" items. Based on these inspections, capital replacements are then identified. Capital replacements may include pole replacement, tower replacement, switch replacement, overhead and underground conduct replacement, underground structures/conduit replacement and pothead/arrestor replacement.

Within this program, SCE workers review the identified equipment issue and classify the resulting work based on a prioritization scale: P1, P2 and P3. The first level of prioritization (P1) requires immediate remediation within 72 hours. The second level (P2) has two classifications: (1) Tier 3: remediation within six months and (2) Tier 2: remediation in 12 months. Additionally, within non-high fire risk areas with a (P2) classification, there can be a 12-month to three-year time frame depending on observations made by field personnel. The third level of prioritization (P3) requires remediation within five years from the date the issue is identified.

The estimated ISO-related direct capital expenditures that are projected to go into rate base during this period are \$18.664 million.

## **5. Transmission Deteriorated Pole Replacement & Restoration (PIN: 3364)**

Pole replacements are identified through a variety of sources. Regardless of the way in which the pole is identified, the process for replacement is generally the same. The steps to design and construct a pole replacement are described here. The vast majority of pole replacements discussed in this exhibit are designed by contract planners. Prior to replacing a pole, SCE must perform a land rights check to ensure it has the right to install a pole or a down guy in the designated location. Environmental clearances must be obtained and any special execution requirements in order to protect the environment must be identified and fulfilled. If the pole is jointly owned, SCE coordinates with the joint owners on the design and construction. Permits must be obtained from various agencies such as city or county governments, railroads, or CalTrans.

When a pole supports both Transmission and Distribution equipment, SCE refers to it as a “combo” pole. When a combo pole is replaced, the cost to set the new pole and transfer the Transmission equipment is charged to Transmission. The cost associated with the Distribution equipment is charged to Distribution. This Distribution work is called “Underbuild”. The Underbuild work is in a separate work order from the Transmission pole replacement to make sure that no costs associated with Distribution work is charged to Transmission work. After an intrusive pole inspection, the poles identified as needing replacement are prioritized based on the extent of deterioration and are assigned a Remediation Action Code (RAC). The cost of these replacements is included in the Deteriorated Pole Replacements activity.

The estimated ISO-related direct capital expenditures that are projected to go into rate base during this period are \$10.927 million.

## **6. Bulk Power Circuit Breaker Replacement (PIN: 4211)**

Bulk power circuit breakers interrupt the flow of electricity through transmission lines, typically at the 500 kV or 230 kV voltage level. Circuit breakers are essential in preventing equipment damage and public injury when faults occur in their downstream circuits.

The Bulk Power Circuit Breaker Replacement program identifies and replaces bulk power circuit breakers approaching the end of their service lives that contain parts known to be: (1) problematic, (2) no longer available, or (3) that can no longer be cost-effectively maintained. Circuit Breaker replacements are identified similarly to transformers using Weibull analysis and the Health Index. The Health Index aides in prioritizing and replacing the correct asset population with the highest risk and consequence of failure. The replacement of bulk power circuit breakers is under FERC jurisdiction and is necessary to proactively replace aging 500 kV and 230 kV circuit breakers at substations to enhance transmission system safety and to improve system reliability. This program also increases the reliability of the ISO transmission grid.

To derive the circuit breakers' health index, SCE utilizes 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.

The estimated ISO-related direct capital expenditures that are projected to go into rate base during this period are \$11.052 million.

## **7. Substation Miscellaneous Equipment Additions & Betterment (PIN: 4756)**

The Substation Miscellaneous Equipment Additions & Betterment program includes planned capital maintenance that is typically driven by substation inspection and maintenance programs. Activity within this program is driven by the imminent failure of equipment 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 required.

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, possible safety issues, or more expensive reactive solutions. This typically includes the installation and replacement of trench covers, potential transformers, current transformers, batteries, charges, as well as emergent circuit breakers, B-bank transformers and disconnect replacements that are not covered under a specific commodity capital program.

The estimated ISO-related direct capital expenditures that are projected to go into rate base during this period are \$35.463 million.

## **8. Bulk Power 500 kV & 230 kV Line Relay Replacement (PIN: 5089)**

The Bulk Power 500kV & 230 kV Line Relay Replacement Program and Non-Bulk Substation Relay Replacement Program (SRRP) identify and proactively replace substation protective relays, automation, and control equipment. These programs are driven by equipment obsolescence and compliance requirements (where applicable).

The prioritization of relay replacements is based on several 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. These are discussed further below:

- 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 helps 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 that the relay protects is taken into consideration. For example, SCE considers the impacts should a relay fail or have a mis-operation. In many cases, SCE will proactively replace an older relay in favor of reacting to an imminent failure.
- Current protection and compliance requirements: The current relay may not be capable of new compliance requirements or protection needs such as relay coordination parameters.

The estimated ISO-related direct capital expenditures that are projected to go into rate base during this period are \$19.090 million.

## **9. Phasor Measurement System Installations (Disturbance Monitoring) (PIN: 6446)**

North American Electric Reliability Corporation (NERC) requires each Transmission Owner (TO) to install Disturbance Monitoring Equipment (DME) and report on disturbance data to facilitate analysis of events and verify system models. Each TO 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. PMUs are installed within SCE's electric system in all 500kV substations, select 230 kV substations that have a high load flow capacity, and at the interfaces of some neighboring utilities and generation interties. PMUs capture real time power system data and DFRs capture the sequence of events on power system disturbances for post event analysis. The DFR or PMU projects are typically the same. PMU is an added capability in the DFR or these units may be separate devices.

TOs must be compliant with NERC Protection and Control (PRC) 002-2 by July 1, 2022. NERC PRC-002-2 provides requirements and measurements for TOs 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.

Replacement of an obsolete PMU is accomplished through a combination of infrastructure replacement work and bundled capital projects. SCE takes advantage of substation construction projects to upgrade PMUs when possible, as efficiencies can be realized by coupling the PMU installation with other capital work. PMU 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 coming from these devices.

The estimated ISO-related direct capital expenditures that are projected to go into rate base during this period are \$8.978 million.

#### **10. Transmission Line Rating Remediation (Exempt from Licensing) (PIN: 7298)**

SCE conducted a rating assessment of its CAISO controlled and 115 kV radial lines built before 2005 to identify spans potentially not meeting CPUC's General Order (GO) 95 clearance requirements under certain operating and atmospheric conditions. SCE committed to North American Electric Reliability Corporation (NERC) and Western Electricity Coordinating Council (WECC) to remediate all identified potential clearance issues for the CAISO-controlled facilities by 2025 and the 115 kV radial lines by 2030. While not its original intent, 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.

A Light Detection and Ranging (LiDAR) study was conducted to identify transmission lines potentially in violation of GO 95 Table 1,<sup>1</sup> which included building industry standard Power Line Systems-Computer Aided Design and Drafting (PLS-CADD) three-dimensional models to analyze each line for potential clearance discrepancies. Based on the results of the LiDAR study, SCE prioritized the transmission line discrepancies based on criteria such as line sag when operating at or above 130 degrees Fahrenheit and potential risk to public safety and system reliability based on location of span, terrain, encroachment type, and extent of deviation from standards.

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<sup>1</sup> Available at [http://www.cpuc.ca.gov/gos/GO95/go\\_95\\_table\\_1.html](http://www.cpuc.ca.gov/gos/GO95/go_95_table_1.html)

SCE has taken a programmatic approach to the remediation work by utilizing new technologies and construction methods to minimize overall project impacts. Aligning scope with other programs and initiatives minimizes redundant work, outage impacts, and resource constraints. Initially, the program prioritized discrepancies into six levels and the focus was to remediate in order of highest priority. A discrepancy is any condition found in the field requiring remediation to meet GO 95 requirements during peak loading conditions. Currently, all discrepancies are evaluated on an entire circuit basis to allow for a holistic and effective remediation strategy. There are two major categories of discrepancies SCE is mitigating: (1) Bulk Transmission – 500 kV and 230 kV; and (2) Non-Bulk or Sub-transmission – 161 kV, 115 kV, 66 kV, and 55 kV. The following factors are considered when reviewing the discrepancies:

- Geographic proximity and bundling of projects for construction efficiencies.
- Government land or land agency overlap.
- Permitting similarities and schedule impacts.
- Engineering design.
- Construction methods.
- Outage opportunities or restrictions with other TLRR and SCE projects.
- Material and procurement efficiency.
- Potential of remediating by working on a lower voltage; and
- Aligning scope with other programs and initiatives to minimize redundant work, outage impacts and resource constraints.

Each project is also reviewed under CPUC GO 131-D, which defines the rules relating to the planning and construction of electric facilities. Some projects fall under the exemptions listed in GO 131-D Section III.B.1, while others require full permitting and become licensing projects. The following corrective actions have been identified for majority of the discrepancies:

- Reconductor.
- Structure replacement.
- Structure raises.
- Retensioning.
- Reframing.
- Adding an interset structure.
- Lowering or relocating sub-transmission or distribution.
- Grading; or
- Lowering/removing object (such as a light pole).

The estimated ISO-related direct capital expenditures that are projected to go into rate base during this period are \$130.091 million.

#### **11. Seismic Mitigations for Transmission Assets (PIN: 7392)**

The Seismic Assessment and Mitigation Program, consolidated under SCE's Business Resiliency activities, is part of a larger, mostly CPUC-funded effort beyond just the FERC dollar request. The broader seismic program centralizes and coordinates across organizational units to assess and perform mitigations as identified to increase safety, infrastructure reliability and maintain regulatory requirements surrounding the occurrence of earthquakes. 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, generation, and telecom infrastructure and identify what seismic mitigations are needed, and (2) mitigate risks by making the necessary retrofits and improvements in order to increase reliability and reduce the risk of harm to workers, customers and communities due to a moderate or major earthquake in SCE's service territory.

Within this Formula Rate Annual Update, SCE addresses the seismic mitigation activities pertaining to SCE's transmission system assets, which include

both transmission line infrastructure and substation assets. Examples of mitigations for these assets include bracing and anchoring electrical equipment in substations, improving conductor slack, structural work to reinforce building wall to roof connections, and replacing aged equipment with modern equipment designed to withstand greater levels of seismic activity. Other work includes more detailed assessments of significant transmission tower corridors along the earthquake faults to determine possible landslide risk and mitigate said risk accordingly to ensure system reliability.

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 existing electrical 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.

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 populated buildings as well as transmission, distribution, generation, and telecom infrastructure critical to maintaining business continuity and operational reliability. As mentioned in the criteria above, reviewing the data against the United States Geological Survey's probabilistic scenarios informs the prioritization of transmission infrastructure in terms of imminent failure should moderate to high seismic activity occur. In addition to the prioritization method used, some projects may be escalated to bundle work for cost efficiency purposes and to minimize outages. Projects related to high-hazards dams with pending FERC reviews will be prioritized accordingly.

The estimated ISO-related direct capital expenditures that are projected to go into rate base during this period are \$32.622 million.

## **12. Substation Fence/Gate (Cu Theft) (PIN: 7573)**

Substation Fence/Gate (also known as Security Fence and Lights Upgrade) program is focused on deployment of physical security improvements at substations to mitigate the impact on service to customers resulting from theft, vandalism, and other intrusions by upgrading security fence and lights to latest security standards.

The need for ongoing improvement of physical security at SCE substations is driven by their varying levels of impact on electrical systems if a security breach occurs, and by reported incidents of theft, vandalism, and other intrusions. The security monitoring and deterrence deficiencies, and the remote location of many of the 230/66 kV A-Bank substations, increase the potential for unauthorized entry and malicious activity. Improving the physical protection systems at SCE substations continues to be an important initiative to safeguard key systems, information, and facilities, mitigate threats to worker safety, and support reliable delivery of electricity and continuity of business operations.

The estimated ISO-related direct capital expenditures that are projected to go into rate base during this period are \$6.804 million.

## **13. Protection of Grid Infrastructure Assets (PIN: 7949)**

The Protection of Grid Infrastructure Assets program (previously known as the Physical Security Systems – Electric Facilities Blanket) deploys and standardizes new security systems at SCE and corrects identified deficiencies with access control and monitoring of SCE entry/exit points, critical areas, and critical assets. Each year, Corporate Security reviews emerging threats and security vulnerabilities to develop a prioritized list of electrical facilities designated for security system installations or security systems refresh and enhancements for the next year. Electrical facilities requiring a new security system or security system component will undergo a structured process to identify specific physical security

needs and to develop a system design incorporating SCE security standards, installation and integration with the Edison Security Operations Center (ESOC), and personnel training and awareness. Each deployed security system will be standardized to improve management of replacement assets, lower and standardize maintenance costs, and provide for consistent refresh cycles of security technology components.

To maintain the operation of existing alarms, access controls, and security systems at SCE, Corporate Security will first identify which facilities have security systems that are operating at a less than optional performance level. Corporate Security will evaluate each security system to be enhanced or refreshed considering current operations, how the site is being utilized, types of assets requiring protection, access controls for population and types of persons at the site, and the required protections associated with the refresh/enhancement.

Completing work needed for NERC CIP-014 Tier 1 substation and associated command centers/switching centers critical asset protection is a priority for 2019 and 2020. NERC CIP-014 work requires many of the same resources as the Protection of Grid Infrastructure Assets program. Consequently, a low level of work for this program was scheduled for prior years. From 2019 to 2023, the focus will be on making security enhancements to control/command centers, major/medium/minor substation enhancement projects, and system replacements and renewals.

The estimated ISO-related direct capital expenditures that are projected to go into rate base during this period are \$18.335 million.



#### **14. Substation Facility Capital Maintenance (PIN: 7637)**

SCE's Substation Capital Maintenance Program seeks to preserve the value of SCE's substation buildings, equipment, and grounds, making them as safe and productive as reasonably possible and proper asset management 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.

SCE uses Asset Management Methodology, to prioritize capital projects and program expenditures to support SCE's objectives to provide safe, reliable, and affordable electricity to its customers. One of the three main influencing factors under Asset Management Methodology is Facility Condition Index (FCI) that assesses conditions (e.g., age and wear of the building and its systems) and compares the cost to improve them against the cost to replace the building or site. The FCI score, expressed as a percentage, is the ratio of the cost of correcting identified deficiencies to the replacement cost for the facility in whole. A low FCI score is more desirable than a high one. To be more specific, the FCI Score of 0-5.0% translates into Good; 5.1%-10.0% into Fair; 10.1%-29.9% into Poor; and >30% into Critical overall condition characterization. SCE's portfolio FCI score has improved from 23% (Poor condition) in 2013 to 16% in 2016 - improved, but still in overall Poor condition and, therefore require ongoing capital maintenance. It would not be prudent to replace all aged facilities, for a variety of reasons. FCI is one indicator used by SCE in prioritizing investments. Other conditions and influencing factors must also be considered, as discussed below.

Asset Priority Index (API) rates the relative importance of a facility among the network of facilities required to serve SCE's customer base. A facility's API is used to define a facility's importance in meeting SCE's strategic business intent and operational performance. Periodically, SCE's Corporate Real Estate (CRE) department consults with SCE leadership from across OUs to rank SCE's

facilities. A site is prioritized by its importance and criticality to delivering safe and reliable services. A lower API ranking (i.e., number) indicates a higher priority. An API ranking of three shows a highly needed and important facility, as compared to an API ranking of 98, which would be a non-essential asset. SCE deprioritizes investments in non-essential buildings, such as a general non-electric tool shed, with a Poor FCI condition and a high API ranking. Conversely, investments are prioritized for the most significant facilities, which have comparatively high operational purpose and, therefore, a low API rank. Last, where the FCI and API focus on the condition and criticality of a facility, SCE considers a facility's fitness for purpose, as a way to integrate evolving business conditions, and the ability of a facility to support these changes, into portfolio planning and capital prioritization. This factor considers the unique conditions of a facility and its ability to support current and future operations, such as:

- Changing work methods or equipment (e.g., T&D vehicles or IT data processing machines) and limitations or deficiencies of the current building infrastructure, building design, and site design, which can cause overburdened building systems, non-compliance with current building codes, or poor service reliability conditions.
- Regulations, such as building codes that cannot be achieved in old building or site designs, that pre-dated such regulations, and which conditions have become an increasing concern for safety and operational reliability.
- The current capacity and utilization of buildings or sites (e.g., of parking, office spaces, etc.) versus the forecast growth or contraction and the ability for the facility, to best support the change.
- The ability to consolidate or co-locate functions or uses, to continue to use facilities to their highest and best use or to promote better collaborative work environments.

The forecast for substation capital maintenance is a combination of historical expenditures and a zero-based budget, considering fluctuations in the maintenance activity. The forecasted level of spend is needed for proper preventative maintenance to mitigate negative impacts from any deferred maintenance, including costly repairs and replacements.

The estimated ISO-related direct capital expenditures that are projected to go into rate base during this period are \$10.692 million.

#### **15. Non-Bulk Relay Replacement Program ("SRRP") (PIN: 4343)**

Modern microprocessor relays allow for comprehensive fault data, flexibility in operation, lower maintenance cost (due to being fully monitored), and multi-function capabilities. SCE is standardizing its sub-transmission protection schemes to include at least one high-speed communication aided differential protection scheme utilizing modern microprocessor relays and digital communication channel components. The standardization reduces the need to maintain multiple standards and creates efficiencies due to not having to train SCE's staff on commissioning and maintaining different protection schemes. This conversion is achieved through the Non-Bulk Relay Replacement Program.

The estimated ISO-related direct capital expenditures that are projected to go into rate base during this period are \$6.245 million.

#### **16. Substation Transformer Bank Replacement Program (PIN: 5210)**

Substation transformers are major pieces of equipment used to either (1) increase electricity voltage to reduce energy losses during its transmission over long distances, or (2) reduce electricity voltage to make it more practical for the customer.

AA-Bank transformers are in major substations where they take electricity at the 500kV transmission level and transform it to the 220kV level. This program

identifies and replaces AA-Bank transformers approaching the end of their service lives, which contain parts known to be problematic or are no longer available.

A-Bank transformers are in major substations where electricity at the 220kV transmission level is transformed to a subtransmission voltage, either 115kV or 66kv. The Sub IR program identifies and replaces A-Bank transformers approaching the end of their service lives, which contain parts known to be problematic or are no longer available.

The estimated ISO-related direct capital expenditures that are projected to go into rate base during this period are \$8.041 million.

**17. Devers: Substation Maintenance and Test Building Improvements Program (PIN: 7957)**

This substation facility was in need of updating as it had a low FCI score, and needed certain expansions to fit SCE's current business needs. The project involves the addition of maintenance shops, test benches, employee work areas, meeting areas, improved IT infrastructure, covered parking, as well as employee assembly location, restroom and break rooms for the employee crews operating out of this facility. The estimated ISO-related direct capital expenditures that are projected to go into rate base during this period are \$8.951 million.

**18. West of Colorado River CRAS Inland/Devers Extension (PIN: 8284)**

As part of the Queue Cluster (QC) 10 studies, generation projects (Q1402 Atlas Solar, Q1403 Harquahala Flats, Q1405 Athos Power Plant, Q1406 Mesaville Solar and Q1407 Mountainview Generating Station Pmax Increase) seeking interconnection to the Eastern Area triggered the need for the West of Colorado River CRAS Inland/Devers Extension. This CRAS monitors multiple 230 kV and 500 kV lines in the West of Devers Area.

The estimated ISO-related direct capital expenditures that are projected to go into rate base during this period are \$6.426 million.

**19. September Wildfires CEMA Transmission Restoration and Erosion Control (PIN: 4057)**

The Creek fire started on September 4, 2020 in Fresno County and burned more than 379 thousand acres. Once it was safe to do so, SCE personnel inspected the area to assess the damage and began restoration efforts. The Creek fire destroyed several of SCE's 230 kV Transmission structures and lines that are under CAISO control. SCE activated the Incident Support Team on September 14, 2020 in response to fire restoration activity within its service territory. Damage Assessment Teams identified 3 Transmission towers that needed to be replaced and 16 Transmission towers that needed repairs. The teams also identified 5 miles of overhead (OH) conductors to be replaced and approximately 10 spans of OH conductor needing repairs. There were approximately 30 towers that needed aerial washing as a result of the fire and smoke.

The Creek fire impacted SCE's Transmission, Distribution, Telecom, and Hydro facilities in the area, including the critical Big Creek generation facility. It was necessary for SCE to begin restoration and quickly restore power to impacted customers and the grid. The decision was made to rebuild 5 miles of Transmission OH conductor spans, replace 3 towers, and perform repairs to several towers as well as other essential material in-line with SCE's updated standards for High Fire Risk Areas for transmission assets that were damaged from the Creek fire. In replacing the damaged OH conductor spans, SCE also had to replace the adjoining OH conductor too, which resulted in slightly more miles of OH conductor spans.

The estimated ISO-related direct capital expenditures that are projected to go into rate base during this period are \$7.482 million.

## **20. Riverside Transmission Reliability Project (PIN: 5450)**

The Riverside Transmission Reliability Project (“RTRP”) is a joint project between SCE and Riverside Public Utilities (“RPU”), the municipal utility department of the City of Riverside. While RPU would be responsible for constructing some of the project's facilities within Riverside, SCE's portion of the project consists of constructing upgrades to its system, including a new 230-kV Substation; certain interconnection and telecommunication facilities and transmission lines in the cities of Riverside, Jurupa Valley and Norco as well as in portions of unincorporated Riverside County. The purpose of the project is to provide RPU and its customers with adequate transmission capacity to serve existing and projected load, to provide for long-term system capacity for load growth, and to provide needed system reliability.

In October 2018, the CPUC issued an environmental report that identified a new route alternative, as the environmentally preferred project, and proposed an additional underground section of the proposed 230-kV power line. In March 2020, the alternative project with revised scope and an updated cost of \$584 million was approved by CPUC. The scheduled in-service date of the project has been extended from 2024 to 2026.

In June 2020, SCE filed a petition with the FERC seeking authorization to recover SCE's prudently incurred costs if the project is cancelled or abandoned for reasons beyond SCE's control, and inclusion of 100% of the project's network transmission Construction Work In Progress in transmission rate base during the construction period. In September 2020, the FERC issued orders granting SCE's requests. SCE is allowed to seek recovery of 100% of all prudently incurred costs after September 17, 2020 and 50% of prudently incurred costs prior to that date.

The estimated ISO-related direct capital expenditures that are projected to go into rate base during this period are \$224.978 million.

## **21. West of Devers Upgrade Project (PIN: 6420)**

The West of Devers Upgrade Project (WODUP) consists of upgrading and reconfiguring approximately 48 miles of four existing 230 kV transmission lines between the Devers, El Casco, Vista, and San Bernardino substations in order to increase the power transfer capabilities in this area of SCE's system. The WODUP is needed to integrate planned renewable generation resources, comply with executed Large Generator Interconnection Agreements (LGIAs) and signed Power Purchase Agreements (PPAs), comply with NERC and WECC transmission reliability planning criteria and facilitate compliance with California's renewable portfolio standards (RPS) goals.

In August 2016, the CPUC approved the construction of the WODUP. As a result of the delay in receipt of the WODUP's approval from the CPUC, SCE deferred the forecasted timing of project capital expenditures. Office of Ratepayer Advocates (ORA) filed an Application for Rehearing in September 2016 stating that the August 2016 decision failed to follow the California Environmental Quality Act (CEQA) when it approved the WODUP and should have approved an alternative project with an amended scope. In March 2017, the CPUC issued a decision denying ORA's September 2016 Application for Rehearing. This action confirmed SCE's proposed project. In December 2017, SCE awarded the competitive bid for transmission construction, which resulted in a decrease to the expected cost of the WODUP from \$1.075 billion to \$848 million.

The estimated ISO-related direct capital expenditures that are projected to go into rate base during this period are \$371.472 million.

## **22. Casa Diablo IV Project Interconnection (PIN: 7227)**

This project is needed to interconnect the Casa Diablo IV generation Project to SCE's Casa Diablo 115/33 kV Substation. The scope of the project includes the Casa Diablo IV interconnection in the Bishop Special Protection System (SPS)

under the single outage of the Control-Coso-Haiwee-Inyokern 115 kV transmission line, the single outage of the Control-Haiwee-Inyokern 115 kV line, and the simultaneous outage of the Control-Coso-Haiwee-Inyokern and Control-Haiwee-Inyokern 115 kV lines. Two N60 relays will be also installed at Control 115/55 kV Substation as part of project scope.

The estimated ISO-related direct capital expenditures that are projected to go into rate base during this period are \$6.237 million.

### **23. Eldorado-Lugo-Mohave (ELM) Upgrade (PIN: 7546)**

CAISO approved the Lugo-Eldorado series capacitor and terminal equipment upgrade in its 2012-2013 Transmission Planning Process (TPP) and the Lugo-Mohave series capacitor and terminal equipment upgrade in its 2013-2014 TPP as policy-driven upgrades to relieve deliverability constraints in order to support achievement of California's renewable energy goals. This project will increase power flow through SCE's existing transmission lines from Nevada to Southern California and will provide renewable integration, improved deliverability, and enhanced reliability benefits. CAISO identified reliability benefits of the project in that it relieves overloads on certain 500kV facilities in the neighboring LADWP's transmission system.

The ELM project would modify SCE's existing Eldorado, Lugo, and Mohave electrical substations to accommodate the increased current flow from Nevada to Southern California; increase the power flow through the existing Eldorado-Lugo, Eldorado-Mohave, and Lugo-Mohave 500 kV transmission lines for the purpose of increasing the amount of power delivered from California's Ivanpah Valley, as well as power delivered from Nevada, and Arizona to the Electrical Needs Area (ENA) through the SCE system in an effort to meet requirements associated with the California Renewables Portfolio Standard (RPS) by constructing two new 500 kV mid-line series capacitors (i.e., the proposed



Newberry Springs Series Capacitor and Ludlow Series Capacitor) and associated equipment; raise transmission tower heights to meet ground clearance requirements; and install communication wire on SCE's transmission lines to allow for communication between existing SCE substations.

SCE has proposed an expedited schedule and a non-standard review process with the regulatory permitting agencies to meet the current in-service date. During September 2017, SCE awarded the competitive bid for the project which resulted in a decrease to the expected capital forecast for the project.

On May 2, 2018, SCE filed an application for a Permit to Construct (PTC) authorizing SCE to construct electrical facilities known as the Eldorado-Lugo-Mohave Series Capacitor Project.

On January 9, 2019, the CPUC directed SCE to file an amended application for a Certificate of Public Convenience and Necessity (CPCN). SCE submitted its amended application for a CPCN on April 19, 2019. The licensing process to file CPCN delayed the projected construction start date to third quarter of 2020.

A protest by the Public Advocates Office (PAO) resulted in CPUC ruling for an amended CPCN application to be filed (note SCE filed a PTC in May 2018, and then the amended CPCN application April 2019) and this licensing delay deferred construction start date to Q4 2020. Final Decision was voted at CPUC's at its August 27<sup>th</sup> Business Meeting, approving the project to move forward. BLM Nevada authorized SCE to proceed with construction under O&M condition until ROW Grant is renewed. Eldorado and Mohave construction started on November 2, 2020. CPUC issued Notice to Proceed (NTP) #1 authorizing work to start at Lugo Substation on Jan 4, 2021. The 60-Day Department of Interior Temporary Suspension of Delegated Authority (SO3395) has been lifted for BLM CA and NPS. BLM CA issued an NTP allowing construction at Newberry Springs to commence. BLM Nevada issued ROW Grant Renewal for the 500kV Transmission Line.

The estimated ISO-related direct capital expenditures that are projected to go into rate base during this period are \$217.896 million.

#### **24. Mesa Substation (PIN: 7555)**

The Mesa Substation Project consists of replacing the existing 230/66/16 kV Mesa Substation with a new 500/230/66/16 kV substation. The Mesa Substation Project addresses reliability concerns by providing additional transmission import capability, allowing greater flexibility in the siting of new generation, and reducing the total amount of new generation required to meet local reliability needs in the Western Los Angeles Basin area. In February 2017, the CPUC issued a final decision approving the Project largely consistent with SCE's proposal and rejected alternative project configurations proposed by CPUC staff members.

In October 2017, SCE was awarded the competitive bid for the new 230 kV portion of substation construction. SCE updated the expected cost of the Project from \$608 million to \$646 million due to schedule delays and scope changes. Construction of the new 500/230/66/16 kV substation and demolition of the existing 230/66/16 kV substation would occur in phases. Phase 1 would consist of grading and initial site development on the western portion of the project site. Phase 2 would consist of construction of the first half of the new Mesa Substation. During Phase 1 and 2, the existing substation on the eastern portion of the site would remain operational to maintain electrical service to customers during construction. Phase 3 would consist of demolition of the existing 220/66/16 kV substation and construction of the second half of the new substation on the eastern portion of the site. Phase 4 (500 kV substation construction) Request for Proposal (RFP) was issued December 2019 and bids were received February 28, 2020. A winning bid was awarded in May 2020 and SCE's project team is working to determine the logical start date for Phase 4 construction.

The estimated ISO-related direct capital expenditures that are projected to go into rate base during this period are \$217.852 million.

**25. Magunden-Springville No.1 & 2 Tower Replacement ("Lake Success Towers in Water") (PIN: 7558)**

The purpose of Lake Success Project is to develop a long-term solution to reroute Magunden-Springville 230kV No. 1 and 2 lines and to construct over 200 new submergible transmission towers that cross Lake Success and the surrounding local wetland areas which will address the following issues:

- Tower structure integrity –Since 1963, US Army Core of Engineers (USACE) has had the right to inundate the reservoir and SCE’s T/L ROW with water at or below elevation 660 feet.
- Lake’s water level increase –Lower Tule River Irrigation District (LTRID) & USACE’s current plan to increase the water level at Lake Success to 662.5 feet would cause additional area of SCE’s current right-of-way to become submerged.
- GO 95 clearance discrepancies – GO 95 compliance challenges regarding phase to water clearance. SCE Conductor clearance for transmission structures now requires 49 feet over water.
- Public safety –Lake Success visitors have historically been observed anchoring boats to, and diving from, SCE’s transmission towers.

The estimated ISO-related direct capital expenditures that are projected to go into rate base during this period are \$13.124 million.

**26. Lugo-Victorville 500 kV T/L Special Protection System (“SPS”) (PIN: 7763)**

The purpose of this project is to prevent overload conditions on the jointly owned Lugo-Victorville 500 kV transmission line. This SPS trips the Transition Cluster

(“TC”) generation projects for the N-1 loss of the Eldorado-Lugo 500 kV line and the N-2 loss of the Eldorado-Lugo and Lugo-Mohave 500 kV transmission lines.

This project was approved by the CAISO in an executed LGIA.

The estimated ISO-related direct capital expenditures that are projected to go into rate base during this period are \$12.460 million.

## **27. Physical Security Enhancement Projects (Tiers 2 & 3) (PIN: 8042)**

Project objective is to provide the most useful, and increased level of, security measures at SCE’s most critical facilities based on the criticality of need and the potential impact of a security breach. The Tier Program supports the efforts of providing safe and reliable service to SCE’s customers by improving the protection of critical assets, buildings, and people around SCE’s electric facilities. Deployment of security systems at these facilities is prioritized based on operational need and evolving area threats which can include incidences of theft, vandalism, or security breaches. Security enhancements include perimeter intrusion detection, integrated access control systems, alarm management with the Edison Security Operations Center and video surveillance systems. This program implements a set of standards to ensure that SCE undertakes a fiscally responsible decision-making process that is directly tied to risk mitigation efforts.

Although work associated with the Tier Program was scheduled to begin in 2018, SCE was able to test several new and more cost-effective security systems after the filing of the 2018 General Rate Case (GRC), prompting the rescheduling of implementation to 2019. The substation tiers are:

- Tier 1 – Substations identified in CIP-014 Risk Assessment (including Pre-CIP-014 Pilot Sites).
- Tier 2 – 500 kV with five or more Network Connections or load > 1,000 MW or Generation > 1,200 MW.

- Tier 3 – 500 kV with five or more Network Connections OR 220 kV with eight Network Connections, OR 220 kV and load > 1,000 MW or Generation > 1,200 MW.
- Tier 4 – Additional A & AA-bank substations identified by SCE AND Substations not identified in Tiers 1-3.

The estimated ISO-related direct capital expenditures that are projected to go into rate base during this period are \$30.453 million.

## **28. Annual Transmission Reliability Assessment 2016 - Protection Upgrades**

**(PIN: 8077)**

Install protection upgrades to comply with NERC TPL 001-4 (Transmission System Planning Performance Requirements), which went into effect January 1, 2016. NERC Transmission Planning Standards 001-4 requires mitigations for the TPL violations and persistent faults identified as part of Annual Transmission Reliability Assessment (ATRA) 2016.

In coordination with CAISO's TPP, SCE performs an ATRA for its portion of the CAISO-controlled grid. This assessment is designed to:

- Evaluate the performance of the SCE transmission system under peak and off-peak conditions for near-term and long-term planning horizons.
- Determine transmission constraints under stressed system conditions.
- Identify upgrades needed to maintain the reliability of the transmission system and comply with the NERC Reliability Standards, the WECC Regional Business Practices, the CAISO Planning Standards, and SCE's transmission planning criteria.

SCE's ATRA is performed in parallel with the CAISO TPP under the CAISO's FERC jurisdictional tariff. SCE's Grid Reliability Projects are identified in the CAISO TPP and subject to review and approval by the CAISO's

Board of Directors and cost recovery is conducted through the CAISO's Transmission Access Charge (TAC).

The estimated ISO-related direct capital expenditures that are projected to go into rate base during this period are \$37.290 million.

**29. Moorpark-Pardee 230 kV No.4 Circuit (PIN: 8104)**

This project addresses a generation capacity deficiency that can cause a voltage collapse in the Moorpark local capacity subarea. The project involves stringing a fourth Moorpark-Pardee 230 kV circuit approximately 26 miles on existing transmission structures in SCE's current transmission right-of-way. This includes installing terminal equipment at the Moorpark and Pardee Substations and relocating existing circuit terminations in the 230 kV switchrack at the Moorpark Substation.

The estimated ISO-related direct capital expenditures that are projected to go into rate base during this period are \$41.798 million.

**30. Red Bluff 2nd 500/230 kV AA Bank (Deliverability Network Upgrade) (PIN: 8163)**

Proposed project scope will include installation of a second 500/230 kV 'AA' transformer bank at Red Bluff Substation. This will also require the need to modify the existing Special Protection System (SPS) to trip generation under an N-1 of one transformer bank. Upgrade was identified in the Q643AE/TOT486 executed Generator Interconnection Agreement (GIA) for full deliverability of Desert Harvest's 150 MW solar photovoltaic renewable generation.

The estimated ISO-related direct capital expenditures that are projected to go into rate base during this period are \$20.971 million.

### **31. Athos Power Plant Project Reliability Network Upgrades (PIN: 8220)**

SCE executed an Interconnection Agreement (IA) to interconnect the Athos Power Plant (450MW) generating facility, located in Desert Center, California, to SCE's electric system. This IA was executed in 2018 and was subsequently amended in April 2021. SCE entered into a Letter Agreement on March of 2022 with the customer to add 450MW of Battery Energy Storage at the existing Athos Power Plant location.

SCE's forecasted work is to complete the required reliability network upgrades by adding relays for transmission line outage detection as well as adding points to the Remote Terminal Units at four surrounding substations.

The estimated ISO-related direct capital expenditures that are projected to go into rate base during this period are \$5.346 million.

### **32. Pardee-Sylmar No. 1 and No. 2 230kV Line Rating Increase Project (PIN: 8294)**

The Pardee-Sylmar No.1 and No. 2 230 kV Line Rating Increase Project is a project that is intended to mitigate thermal overloads on the Pardee-Sylmar No. 1 and Pardee-Sylmar No.2 230 kV transmission lines under P1 and P3 contingency conditions.\* The project involves increasing the rating of the line from 3000 Amps to 4000 Amps by replacing circuit breakers and other terminal equipment at both SCE's Pardee Substation and LADWP's Sylmar Substation. This would serve to increase the emergency rating of both Pardee-Sylmar No. 1 and Pardee-Sylmar No.2 230 kV lines, to their full conductor capability. The project would also provide mitigation of GO 95 line clearance issues on both lines. The project is scheduled to be in-service by 2025.

The CAISO's 2019-2020 TPP showed thermal violations in year 2029 (Summer Peak) for the loss of either of these two Pardee-Sylmar 230 kV lines

(NERC P1\*), the loss of Lugo-Victorville 500 kV line (NERC P1\*) and/or the loss of a generator and either of these two Pardee-Sylmar 230 kV lines (NERC P3\*). The thermal violations are driven by shifts in future peak conditions, including generation retirement that is located in PG&E's system, combined with south-to-north flows on WECC Path 26 (Midway-Vincent No.1 and Midway-Vincent No.2, and Midway-Whirlwind 500 kV lines).

This project will increase the line rating of the Pardee-Sylmar Line Nos. 1 and 2 which are located in the Pardee – Sylmar areas of SCE's service territory in California through the successful execution of this project. The project scope involves upgrading 6 circuit breakers at two 220kV positions in the Pardee Substation, and the raising of four transmission towers to mitigate clearance issues, as well as the lowering of one distribution line crossing. This project was approved by the CAISO Board of Governors in March of 2022.

The estimated ISO-related direct capital expenditures that are projected to go into rate base during this period October 2022 through December 2025 are \$18.773 million.

\*A NERC P1 contingency is a single contingency (N-1);

\*A NERC P3 is a multiple contingency such as loss of generation unit followed by a loss of transmission line.