During the period January 2026 through December 2027, SCE forecasts:

- $715 million in ISO non-incentive network transmission projected to go into rate base (including $352 million in ISO Blanket-Specifics),
- $90 million in FERC incentive rate qualified CWIP expenditures, and
- $125 million of CWIP Expenditures projected to go into rate base.

In addition to the numerous but relatively small transmission projects, there are 37 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 2026 through December 2027 – 18 Blanket-Specifics (items 1 through 18 below), 16 Specific non-incentive projects (items 19 through 34), and three Specific incentive projects (items 35 through 37 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 2026 and 2027
(Nominal $Thousands)

No.	PIN	Project	FERC CWIP	FERC Non-CWIP	Total
1	3138	Sylmar Convertor Station: Miscellaneous Capital Maintenance		9,176	9,176
2	3363	Substation Planned Maintenance Replacements		11,925	11,925
3	3363	Substation Unplanned Maintenance Replacements		14,974	14,974
4	3364	Transmission Deteriorated Pole Replacement & Restoration		12,880	12,880
5	3364	Transmission Grid-Based Maintenance		8,200	8,200
6	3364	Transmission Small Civil		13,676	13,676
7	3364	Transmission Tower Corrosion Program		38,857	38,857
8	3367	Transmission - Storm		7,901	7,901
9	4651	Palo Verde Switchrack: Miscellaneous Capital Maintenance		6,385	6,385
10	4756	Substation Miscellaneous Equipment Additions & Betterment		11,552	11,552
11	4837	Substation Automation System Infrastructure Replacements		6,010	6,010
12	5210	Substation Transformer Bank Replacement Program		5,085	5,085
13	7298	Transmission Line Rating Remediation (Exempt from Licensing)		112,330	112,330
14	7392	Seismic Program - Transmission Substations		18,242	18,242
15	7637	Substation Facility Capital Maintenance		9,049	9,049
16	7713	Substation Switchrack Rebuilds (FERC)		9,692	9,692

17	7716	Substation Battery & Charger Replacement		5,230	5,230
18	7949	Protection of Grid Infrastructure Assets		32,031	32,031
19	7924	Substation Reliability Upgrades - Antelope		17,476	17,476
20	7956	Substation Reliability Upgrades - Pardee		11,576	11,576
21	8029	Lugo-Victorville 500kV Transmission Line Upgrade		10,978	10,978
22	8042	Physical Security Enhancement Projects (Tiers 2 & 3)		30,438	30,438
23	8326	Arida Solar Farm (TOT880)		5,296	5,296
24	8342	Sanborn Hybrid 3		16,350	16,350
25	8393	Kestrel Storage Project (TOT907/Q1616)		6,154	6,154
26	8448	Laguna Bell-Mesa No. 1 230 kV Line Rating Increase Project		13,177	13,177
27	8473	Devers 230 kV Reconfiguration Project		9,454	9,454
28	8474	Antelope 66 kV Circuit Breaker Upgrade		18,049	18,049
29	8519	Barre 230 kV Switchrack Conversion to Breaker-And-A-Half Project		7,647	7,647
30	8547	Bolt Substation: Colorado River Substation-(IRNU-Shared) - TOT1013 (Q1757) Cobalt Project		5,067	5,067
31	8563	Windhub 220 kV - TOT985 - Q1791 - Sanborn 5 Hybrid		6,059	6,059
32	8577	Tortilla 115/33 kV Upgrade Project		5,590	5,590
33	8616	Mesa - Mira Loma 500 kV UG Third Cable		70,004	70,004
34	8617	Vista-Etiwanda 230 kV 1 Line Upgrade		41,026	41,026
35	6420	West of Devers	7,787		7,787
36	7546	Eldorado-Lugo-Mohave (ELM) Upgrade	53,804	2,934	56,738
37	8631	Lugo-Victor 230 kV Line Reconductor	60,221	6,971	67,192
38	Various	Less than $5m each	3,371	97,663	101,034
		Total	**125,183**	**715,102**	**840,285**

1. Sylmar Convertor 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 ±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 the City of 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 for paying for its 50% share of PDCI'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 expenditure that is projected to go into rate base during this period is $9.176 million.

2. Substation Planned Maintenance Replacements (PIN: 3363)

Substation Planned Capital Maintenance captures the labor, equipment, and other material costs to remove and replace assets not identified in other replacement programs. This is a programmatic approach that allows SCE to proactively plan work over a controlled schedule, perform any necessary engineering design activity, and allocate and manage resources effectively. Activities are predominantly like-for-like replacements and maintenance which are identified and planned for in advance. Examples of such work include replacement of power and current transformers, as well as Circuit Breakers, B-Banks and Disconnects that are not covered under another capital program.

The estimated ISO-related direct capital expenditure that is projected to go into rate base during this period is $11.925 million.

3. Substation Unplanned Maintenance Replacements (PIN: 3363)

Substation Unplanned Capital Maintenance captures the labor, equipment, and other material costs to remove and replace assets not identified in other replacement programs, on a reactive basis. Activities are predominantly like-for-like replacements and maintenance. Reactive equipment replacements must be completed in a timely manner because substation equipment failures may lead to prolonged outages, unsafe operating conditions, or more costly reactive solutions. Examples of such work include unplanned replacement of failed power and current transformers, as well as Circuit Breakers, B-Banks and Disconnects.

The estimated ISO-related direct capital expenditure that is projected to go into rate base during this period is $14.974 million.

4. Transmission Deteriorated Pole Replacement & Restoration (PIN 3364)

Transmission deteriorated pole replacements are identified through Intrusive Pole Inspections (IPI), non-programmatic activities, and by pole loading calculations (PLC) performed by planners during the normal course of work. For replacements driven by IPI, the poles identified as needing replacement are prioritized based on the extent of deterioration and are assigned a Remediation Action Code (RAC), which specifies compliance timeframes. Pole replacements identified through non-programmatic activities may be submitted to the Deteriorated Pole Program for replacement based on their external condition. If these poles meet the criteria for external decay outlined in the program standard, they are prioritized according to the standard for replacement in the Deteriorated Pole Program. PLCs performed during design work may identify poles that do not meet GO 95 requirements. Planners perform pole loading calculations as part of day-to-day work when they plan to add new equipment to the pole, such as a transformer, capacitor, bank, conductor wire, etc. The planner may perform a pole loading calculation on the pole "as-is" in its current state, assuming only the currently attached equipment is in place. If the pole does not satisfy compliance requirements "as-is," the cost of its replacement is included in the Deteriorated Pole Program.

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. Most pole replacements 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 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 are charged to Transmission work.

The estimated ISO-related direct capital expenditure that is projected to go into rate base during this period is $12.880 million.

5. 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 rights 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 conductor 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 expenditure that is projected to go into rate base during this period is $8.200 million.

6. Transmission Small Civil (PIN: 3364)

Small Civil Capital Program (SCCP) is the deployment of non-electrical capital assets that support Transmission facilities. The program is comprised of projects that are either new construction or improvement of existing field conditions. Activities under the SCCP include:

- Installation/Improvement of new and existing Access Roads
- Installation/Improvement of Wet Crossings (Bridges) and Drainage
- Implementation/Improvement of Laydown/Material Yards
- Implementation/Replacement of Retaining Walls

The estimated ISO-related direct capital expenditure that is projected to go into rate base during this period is $13.676 million.

7. Transmission Tower Corrosion Program (PIN: 3364)

In 2020, more than 90% of SCE's transmission towers were at least 30 years old, which is generally the age at which the first signs of corrosion – ranging from minor surface deterioration to more severe steel degradation – begin to appear. These all-steel structures are among SCE's most critical assets, and without timely identification and mitigation, corrosion can accelerate, leading to steel loss, structural impairment, or potential failure. Corrosion is often more pronounced where protective coatings have deteriorated, making proactive inspection and evaluation essential to maintaining asset integrity and reliability. Consistent with SCE's Transmission Corrosion Program approach, asset management involves an assessment phase followed by a mitigation phase, with mitigation activities determined based on the severity and specific condition of each structure. Based on inspection results and engineering analyses, SCE performs targeted remedies such as footing repair or replacement, sandblasting, tower coating application, replacement of corroded lattice members, cathodic protection, or full structure replacement. While coating is generally the least costly mitigation, the selected solution varies by location and condition to effectively address corrosion risks and extend the service life of each tower.

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 latest Wildfire Mitigation Plan (WMP).

The estimated ISO-related direct capital expenditure that is projected to go into rate base during this period is $38.857 million.

8. Transmission – Storm (PIN: 3367)

This activity includes costs associated with replacing transmission electrical facilities, structures, or equipment damaged during storm events. Storm events are driven by weather and other environmental factors outside of SCE's control.

The estimated ISO-related direct capital expenditure that is projected to go into rate base during this period is $7.901 million.

9. Palo Verde Switchrack: Miscellaneous Capital Maintenance (PIN: 4651)

The Salt River Project (SRP) serves as the Operating Agent for the Arizona Nuclear Power Project (ANPP) High Voltage Switchyard (PIN 4651). As the Operating

Agent, SRP bills for capital project costs, with Southern California Edison (SCE) responsible for its proportional share.

Several capital projects are currently underway at the ANPP High Voltage Switchyard. These include, but are not limited to, disconnect switch replacements, cable trench replacements, fire protection enhancements, and other capital maintenance-related services.

The estimated ISO-related direct capital expenditure that is projected to go into rate base during this period is $6.385 million.

10. 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 replacements 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 expenditure that is projected to go into rate base during this period is $11.552 million.

11. Substation Automation System Infrastructure Replacements (PIN: 4837)

The Substation Automation System (SAS) Replacement Program focuses on modernizing SCE's substation control and monitoring infrastructure by replacing obsolete first-generation automation systems (SA1). The Program converts Remote Terminal Unit (RTU) systems to SCE's latest Substation Automation System, 3rd Generation (SA3) standard. Additionally, in instances where no automatic reclosing is required, this program replaces a limited number of failing RTUs with new RTUs to provide remote SCADA monitoring and remote control only.

Through this program, SCE maintains and improves system monitoring and control capabilities and enables advanced functionality such as arc flash energy reduction, remote configuration, fault recording, high-speed control, and standardized communications (IEC-61850). This is accomplished by retrofitting entire substations with advanced equipment such as relays, controllers, and Human Machine Interfaces (HMI) providing for increased system-level capabilities.

The program is needed primarily due to ageing and obsolete equipment. Much of SCE's existing automation infrastructure dates to the 1980s and has exceeded its useful life, with some devices lacking vendor support, upgrade paths, or availability of spare parts. Among the major limitations associated with this system are basic functionality of electromechanical relays and their inability to support multiple protection schemes and other advanced functionalities. Additionally, older electromechanical relays present safety risks, including inadequate response to arc flash hazards, and reliability risks, such as delayed fault clearing and longer outage restoration times due to the inability to remotely control or automatically restore substations. Without replacement, failures in these systems could result in extended outages, reduced situational awareness at control centers, and increased operational inefficiencies.

SCE developed a comprehensive remediation plan to replace SA1 and RTU systems due to their associated safety and reliability risks. The scope of work includes (1) converting SA1 systems to SA3, (2) converting RTU systems to SA3 systems, and (3) replacing failing RTUs with new RTUs. The program prioritizes replacements based on

asset age, failure risk, and relay vintage, with particular focus on older installations known to have higher failure rates.

The estimated ISO-related direct capital expenditure that is projected to go into rate base during this period is $6.010 million.

12. 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 into 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 expenditure that is projected to go into rate base during this period is $5.085 million.

13. 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,[1] 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.

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, with the focus 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.

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

- 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 these 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 expenditure that is projected to go into rate base during this period is $112.330 million.

14. 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 portion of SCE's funding 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 local 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 which are all FERC-jurisdictional 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 sites 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 (employees, contractors and citizens) 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 expenditure that is projected to go into rate base during this period is $18.242 million.

15. 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. A low FCI score is more desirable than a high score. 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. Continued ongoing capital maintenance is required for additional and sustained improvement into the next score category. It would not be prudent or possible to replace all aged facilities, for a variety of reasons including excessive cost and disruptions to personnel. FCI is one of several indicators 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 senior leadership from across various organizational units to rank SCE's facilities by the business units that utilize them. A site is prioritized by its importance and criticality to delivering safe and reliable services to SCE's customers. A lower API ranking (i.e., number) indicates a higher priority. For example, an API ranking of 3 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 of its expected need to the Company, and the ability for the facility, to best support the change in need.

- 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 to advance work initiatives in customers' best interests.

The forecast for substation capital maintenance is a combination of historical expenditures and a zero-based budget, considering fluctuations in maintenance activity. The forecasted level of spending 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 expenditure that is projected to go into rate base during this period is $9.049 million.

16. Substation Switchrack Rebuilds (PIN: 7713)

Substation Switchrack Rebuilds activity captures the capital expenditures related to rebuilding existing substation racks based on conditions found in the field, as well as through various analyses including structural and seismic analysis. A substation switchrack is the skeletal/structural system used to support substation assets such as circuit breakers, disconnects, and conductors. Substation structures degrade over time and need to be replaced and/or upgraded. The switchracks/structure needs are initially identified at the scoping job walk, typically driven by the circuit breaker and transformer replacement, and in some cases disconnect switch replacements.

At the scoping job walk the field personnel (operations, construction, maintenance, and others as necessary) and engineering personnel evaluate and determine the project scope. These workers evaluate the condition of foundations, equipment, structures, and working areas/to identify the need to potentially perform a switchrack rebuild project. Prior to pursuing a rebuild project, SCE also considers other potential solutions including, but not limited to, deferring a project, modifying a switchrack (i.e., structural modification in place or additional grading beneath a switchrack structure), and/or increasing maintenance activity for the circuit breakers and/or transformers.

Switchrack rebuild projects often result from the need to replace substation circuit breakers. SCE estimates the costs for each project based on the unique characteristics of each project, and not by using an average cost per project approach. This is because, unlike like-for-like replacements of circuit breakers and transformers, switchrack rebuild projects can vary and have unique site-specific challenges, including voltage class, geographic location, property size and footprint, non-SCE original construction, modification of construction standards, local city regulations, space constraints for construction, maintaining service during construction, and geologic circumstances. As a result, using an average cost per project forecast is not meaningful and representative to the costs of such projects.

The estimated ISO-related direct capital expenditure that is projected to go into rate base during this period is $9.692 million.

17. Substation Battery & Charger Replacement (PIN: 7716)

The Substation Battery & Charger Replacement Program is part of SCE's broader Substation Infrastructure Replacement (Sub IR) portfolio, which focuses on proactively replacing aging, obsolete, and at-risk substation equipment to maintain system safety and reliability. Sub IR encompasses a range of equipment categories, including protection, control, and other supporting substation components – such as batteries, battery racks, chargers, monitoring equipment, and related components – that is necessary for safe and reliable station operations. SCE undertakes these replacements based on asset conditions, age, and risk of in-service failure, with the objective of mitigating safety risks and preventing outages.

The estimated ISO-related direct capital expenditure that is projected to go into rate base during this period is $5.230 million.

18. 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, SCE's Corporate Security organization reviews emerging threats and security vulnerabilities to develop a prioritized list of electrical facilities designated for security system installations or security systems refreshments, upgrades 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 of these assets, lower and standardize maintenance costs, and provide consistent refresh cycles of security technology components across SCE's territory.

To maintain the operation of existing alarms, access controls, and security systems at SCE, Corporate Security experts 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 their current operations, how the site is being utilized, types of assets requiring protection, access controls for the existing and expected population and types of individuals that are or will be present at the site, and the required protections associated with the security refresh/enhancement.

Since the completion of NERC CIP-014 Tier 1, the focus has shifted towards the subsequent Tiers starting with Tier 2 & 3 sites concurrently. The Tier Program supports the efforts of providing safe and reliable service to our customers by improving the protection of critical assets, buildings, and people around electric facilities. Performing security enhancements based on risk such as perimeter intrusion detection, integrated access control, alarm management, video surveillance, and radar. The Tier Program is an ongoing program where electric facilities are assessed yearly.

The estimated ISO-related direct capital expenditure that is projected to go into rate base during this period is $32.031 million.

19. Substation Reliability Upgrades - Antelope (PIN: 7924)

The Substation Maintenance and Test Building program is designed to replace temporary and outdated facilities that are in need of a significant upgrade. Substation maintenance and test facilities co-locate electricians that perform maintenance and inspections on assets (e.g., circuit breakers, relays, transformers, etc.) critical to grid reliability. Initially, crews worked in buildings that were not constructed to adequately support this type of specialized work, and in trailers that were provided as temporary solutions. The updated or new buildings will improve crew productivity by providing adequate space for personnel and equipment, as well as for crucial maintenance and test activities.

The Antelope substation's Maintenance building is too small to support this level of maintenance and test staff operations, and a 1955 Test trailer that previously housed test staff has been removed. For the last four years, maintenance and test crews have been working in a double-wide trailer where space is limited, which impedes operations and reduces possible productivity of these personnel. SCE will construct a new Maintenance and Test building (11,600 square feet) at this site and retain the existing Maintenance building for future equipment storage needs.

For this project, SCE will:

- Complete design and obtain permits and approvals;
- Remove existing double-wide trailer;
- Prepare the site (e.g., excavation and grading) for circulation, runoff and water management, and utilities;
- Add 480 kW, 3-phase electrical power services, concrete pad, transformer, and switchgear;
- Construct a Maintenance and Test building (approximately 11,600 square feet), to include maintenance shops, staff work areas, meeting areas, restrooms, and a break room;
- Repurpose the existing Maintenance building for equipment storage;
- Construct covered parking with solar panels for SCE trucks;

- Construct staff parking areas;
- Construct communication closets with data infrastructure, racks, cable and fiber trays; and,
- Install audio visual equipment and telecom.

The estimated ISO-related direct capital expenditure that is projected to go into rate base during this period is $17.476 million.

20. Substation Reliability Upgrades - Pardee (PIN: 7956)

The Substation Maintenance and Test Building program is designed to replace temporary and outdated facilities. Substation maintenance and test facilities co-locate electricians that perform maintenance and inspections on assets (such as circuit breakers, relays and transformers) critical to grid reliability. Initially, crews worked in buildings that were not constructed to adequately support current work, and in trailers that were provided as temporary solutions. The updated or new buildings will improve crew productivity by providing adequate space for personnel and their equipment, as well as adequate space for the expected maintenance and test activities.

The Pardee test crew currently operates in the Operations building. However, future plans for equipment installation to support grid operations in this building will require the test crew to relocate. The maintenance crew currently occupies the Maintenance building. SCE will construct a new Maintenance and Test building and install additional power infrastructure to support it. Thereafter, operations will use the vacated space in the Maintenance building.

For this project, SCE will:

- Complete design and obtain required permits and approvals;
- Prepare the site (e.g., excavation and grading) for circulation, runoff and water management, and utilities;
- Relocate two 16-kilovolt lines underground;

- Construct a new Maintenance and Test building (approximately 11,600 square feet), with maintenance shops, test benches, staff work areas, meeting areas, restrooms, and a break room;
- Construct staff parking areas;
- Construct communication closets with data infrastructure, racks, cable and fiber trays; and,
- Install audio visual equipment and telecom.

The estimated ISO-related direct capital expenditure that is projected to go into rate base during this period is $11.576 million.

21. Lugo-Victorville 500kV Transmission Line Upgrade (PIN: 8029)

The Lugo-Victorville 500kV Transmission Line (T/L) Upgrade is a CAISO Approved Project developed to address reliability needs caused by thermal overload conditions impacting the Lugo-Victorville 500 kV T/L. The project is intended to mitigate overloads that occur under certain contingency scenarios (N-2 conditions), including the simultaneous loss of either Eldorado-Lugo 500 kV with Eldorado-Mohave 500 kV or Eldorado-Lugo 500kV with Lugo-Mohave 500 kV, which can cause the Lugo-Victorville line to exceed its thermal limits, creating reliability concerns that necessitate system upgrades to maintain acceptable operating ratings.

To resolve these constraints, the project includes both transmission line and substation upgrades designed to increase the T/L's thermal normal and emergency ratings. On the transmission line side, the scope includes remediating clearance discrepancies to achieve compliance with GO-95. In parallel, the project involves replacing high-voltage terminal equipment at the SCE Lugo Substation and the LADWP Victorville Substation which includes circuit breakers, disconnect switches, line drops, wave traps, and associated terminal equipment. These upgrades are intended to accommodate the increased transmission capacity of the Lugo-Victorville 500kV T/L.

The estimated ISO-related direct capital expenditure that is projected to go into rate base during this period is $10.978 million.

22. Physical Security Enhancement Projects (Tiers 2 & 3) (PIN: 8042)

The objective of this project 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 calendar year 2018, SCE was able to test several new and more cost-effective security systems after the filing of its 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 expenditure that is projected to go into rate base during this period is $30.438 million.

23. Arida Solar Farm (TOT880) (PIN: 8326)

The Arida Solar Farm (TOT880) Project is an interconnection project to enable the integration of a new large-scale renewable energy resource into SCE's transmission system. Specifically, the project supports the interconnection of a 370 MW Hybrid solar photovoltaic facility with a battery energy storage system (BESS) at the Mohave 500 kV Switching Station. The primary need for the project is to complete the required design, engineering, and infrastructure upgrades necessary to safely and reliably connect the new generation facility to the grid, while meeting targeted in-service and operational dates.

To meet this need, the project scope encompasses a broad set of interconnection facilities, network upgrades, and supporting infrastructure. Major elements include installation of a new 500 kV generation tie-line, equipping a new line position within the switchrack, and implementation of protection, relay, and control systems. The scope also includes telecommunications infrastructure (fiber optic cable, lightwave equipment, and RTUs) to enable monitoring, control, and protection requirements for the planned Remedial Action Scheme (RAS). Additional workstreams cover environmental compliance, permitting and licensing, real property acquisition (easements/land), and security enhancements required for regulatory compliance and interconnection standards.

The estimated ISO-related direct capital expenditure that is projected to go into rate base during this period is $5.296 million.

24. Sanborn Hybrid 3 (PIN: 8342)

The purpose of the project is to construct interconnection facilities needed to interconnect the Sanborn Hybrid 3 Project which is a 1,400 MW solar photovoltaic and battery energy storage system (BESS) Project into the Windhub 500 kV bus. The project scope includes constructing two new 500 kV Line positions, two new 500kV

transmission Lines approximately 2000 feet in total length, implement required environmental services, and pursue Tehachapi Centralized Remedial Action Scheme (CRAS) modifications.

The estimated ISO-related direct capital expenditure that is projected to go into rate base during this period is $16.350 million.

25. Kestrel Storage Project (TOT907/Q1616) (PIN: 8393)

The Kestrel Storage Project (TOT907/Q1616) is a customer-driven interconnection project that enables the integration of a 200 MW battery energy storage system (BESS) into SCE's transmission system at the Walnut 220 kV Substation. The project is needed to provide the required interconnection facilities and network upgrades to safely and reliably connect the new energy storage resource to the grid, consistent with interconnection agreement requirements and the planned in-service timeline. In addition to supporting the immediate interconnection request, the project helps facilitate broader grid reliability and operational flexibility by enabling large-scale energy storage integration into the transmission network.

The scope of work encompasses upgrades and installations across transmission, substation, communication, and support systems centered at Walnut Substation, with related work at Lewis Substation. Major components include the installation of a new 220 kV substation position and associated generation tie-line to connect the BESS, as well as the relocation of the existing Walnut-Creek Generation 220 kV transmission line to a new TSP within the substation. Additional transmission work includes constructing new 220 kV structures and conductor spans to integrate the reconfigured line and tie-line facilities. Substation upgrades involve installing circuit breakers, disconnect switches, voltage transformers, and protective relaying systems, along with expanding control systems to incorporate new monitoring and protection points. Ground grid studies are conducted at both Walnut and Lewis substations to ensure system safety and proper grounding design.

Supporting infrastructure is also a key component of the project scope. This includes implementation of a remote terminal unit (RTU) to transmit operational data to

the grid control center and deployment of telecommunications equipment such as fiber optic cables and associated communication systems to support protection and control requirements.

The estimated ISO-related direct capital expenditure that is projected to go into rate base during this period is $6.154 million.

26. Laguna Bell-Mesa No. 1 230 kV Line Rating Increase Project (PIN 8448)

Reconductor Laguna Bell-Mesa 230 kV No. 1 Line to Aluminum Conductor Composite Core Fort Worth, or equivalent High Temperature Low Sag conductor. Upgrade the Laguna Bell-Mesa No. 1 230 kV Line terminal equipment in Position 11 and upgrade the 230 kV Bus at Laguna Bell Substation to achieve rating increase to 3250/4760 Amps SN/SE.

The estimated ISO-related direct capital expenditure that is projected to go into rate base during this period is $13.177 million.

27. Devers 230 kV Reconfiguration Project (PIN: 8473)

The purpose of the project is to upgrade the Devers 220 kV Bus configuration to improve operational flexibility and reduce the financial impact during a Devers 220 kV Bus outage. The project scope involves installing one (1) 220kV, 4000A, 63kA, SP6 gas type CB 5012; installing a dead-end structure for the 1AA bank conductor; replacing CB 4012 BCT with 5000/5 BCT; installing three (3) CCVT; installing two (2) 4000A line disconnects; install one (1) C60 for LBFB; install two (2) test relays; reconnect 1AA bank relay protection; remove two (2) 220kV, 4000A, 63kA, SP6 gas type CB 41X2 & 61X2; and remove SBC 99 relay, SEL 351 test relays and associated equipment.

The estimated ISO-related direct capital expenditure that is projected to go into rate base during this period is $9.454 million.

28. Antelope 66 kV Circuit Breaker Upgrade (PIN: 8474)

The purpose of the project is to upgrade 41 Antelope 66 kV Circuit Breakers and associated equipment from 40 kA to 50 kA Circuit Breakers. The scope of work also includes replacing 101 66 kV disconnect switches & 45 66 kV PTs, as well as removing 15 steel lattice structures and installing 15 dead-end structures. Project will also require relay upgrades at Antelope Substation as well as 5 other satellite substations.

The estimated ISO-related direct capital expenditure that is projected to go into rate base during this period is $18.049 million.

29. Barre 230 kV Switchrack Conversion to Breaker-And-A-Half Project (PIN: 8519)

The purpose of the project is to convert the existing Barre 230 kV switchrack from a double-breaker-double-bus (DBDB) to a breaker-and-a-half (BAAH) configuration. The scope of work includes relocating the south bus, adding a third Circuit breaker to 4 bay positions, adding sectionalizing circuit breakers and split Barre 230 kV to lower short circuit duty, and relocating lines/towers/other facilities within the current fence line.

The estimated ISO-related direct capital expenditure that is projected to go into rate base during this period is $7.647 million.

30. Bolt Substation: Colorado River Substation-(IRNU-Shared) - TOT1013 (Q1757) Cobalt Project (PIN: 8547)

The Bolt Substation: Colorado River Substation (IRNU-Shared) – TOT1013 (Q1757) Cobalt Project is driven by an interconnection request from RE Cobalt LLC to integrate a proposed 250 MW hybrid generating facility, consisting of solar photovoltaic and battery energy storage systems, into the CAISO-controlled transmission grid at the Colorado River 220 kV bus. The project addresses the need to accommodate new large-scale renewable generation while maintaining system reliability, enabling power delivery from the generating facility to the bulk transmission network. This requires both interconnection facilities and associated reliability network upgrades to ensure that the

existing system can support the additional capacity without compromising operational performance or compliance requirements.

To meet this need, the scope of work includes transmission, substation, and communication upgrades centered on the Colorado River Substation and associated facilities. This includes expansion of the existing 220 kV switchrack to add new positions, installation of circuit breakers, disconnect switches, dead-end structures, and protection relays to accommodate new line terminations and sectionalizing capability, as well as the addition of a new 220 kV line position and generation tie-line connections. The project also includes installation of metering, RTU, SCADA, and telecommunications infrastructure, such as fiber optic cable and lightwave equipment, to support monitoring, control, and system protection functions. Additional work encompasses environmental permitting and compliance activities, acquisition of real property rights, and installation of security measures.

The estimated ISO-related direct capital expenditure that is projected to go into rate base during this period is $5.067 million.

31. Windhub 220 kV - TOT985 - Q1791 - Sanborn 5 Hybrid (PIN: 8563)

The Windhub 220 kV – TOT985 – Q1791 – Sanborn 5 Hybrid Project (PIN: 8563) is an interconnection project designed to enable the integration of a new 550 MW generating facility into the existing transmission network at Windhub 220 kV. The project is driven by the required interconnection facilities and supporting network upgrades to reliably connect the new generation resource into a newly established 220 kV line position at the Windhub Substation. This effort supports system reliability, operational visibility, and compliance with interconnection requirements by ensuring that the generating facility can be effectively monitored, controlled, and protected within the broader transmission system.

To meet this need, the project includes work spanning multiple substations and system components, including installation of a new 220 kV tie circuit breaker within an existing position at Windhub Substation to terminate the generation tie-line, along with

associated high-voltage equipment such as disconnect switches, and coupling capacitor voltage transformers. The scope also involves construction of 220kV transmission line facilities to connect the generating facility, including new structures, conductor spans, underground ducts and structures, and fiber optic cable. In addition, the project incorporates protection, control, and telecommunications upgrades, such as installation of relays, RTUs, SCADA and communication systems, and centralized RAS/CRAS infrastructure across substations including Lugo, Mesa, Vincent, and others. Environmental permitting, real property acquisition, and corporate security measures are also required to support installation of the interconnection facilities.

The estimated ISO-related direct capital expenditure that is projected to go into rate base during this period is $6.059 million.

32. Tortilla 115/33 kV Upgrade Project (PIN: 8577)

The Tortilla 115/33 kV Project is a capacity-driven reinforcement effort designed to address growing load demand in the Rurals (Kramer 220/115) area, driven primarily by a customer request for approximately 66.3 MW associated with a railyard facility and surrounding warehouse development. Existing 33 kV infrastructure in the area does not have sufficient capacity to reliably serve this level of demand, prompting the need for system expansion. The project is intended to enable long-term service to this load while maintaining operational flexibility, improving reliability, and mitigating identified system constraints, including contingency concerns within the substation and surrounding network.

To meet this need, the project encompasses line expansion and substation upgrades at Tortilla 115/33 kV, including the construction of three new 33 kV line positions to increase feeder capacity, installation of a new 33 kV capacitor bank to support voltage and reactive power requirements, and upgrades to existing conductors and relay systems on transformer and bus tie positions. A major component of the work involves reconfiguring and rebuilding the 33 kV switchrack from an operating/transfer bus arrangement to a double operating bus with a transfer bus configuration, allowing for

increased switching flexibility and future capacity expansion. Additionally, the project replaces the existing 115 kV bank-on-bus configuration for transformer banks No. 3 and No. 4 with two dedicated 115 kV transformer positions, along with associated switching and protection equipment.

The substation scope is being implemented in phases to align construction sequencing with system needs and while minimizing operational impacts. Initial work includes upgrading transformer bank positions 5 and 7 to double-breaker double-bus configurations, installing additional 115 kV circuit breakers, disconnect switches, and lightning arresters, and modernizing protection and control infrastructure within the existing equipment building. Subsequent phases focus on site modifications, including substation fencing and drainage improvements, and a rebuild and expansion of the 33 kV switchrack to accommodate new and existing line positions, transformer connections, and capacitor banks. The final phase completes the installation of new 33 kV infrastructure, including capacitor additions.

The estimated ISO-related direct capital expenditure that is projected to go into rate base during this period is $5.590 million.

33. Mesa - Mira Loma 500 kV UG Third Cable (PIN: 8616)

The Mesa-Mira Loma 500 kV Underground Third Cable project is a transmission investment project developed in alignment with the California Independent System Operator (CAISO) 2022-2023 Transmission Planning Process (TPP), which prioritized infrastructure necessary to support the integration of new renewable resources and to enhance overall grid reliability. The project was approved as a policy-driven project to address identified deliverability constraints on the existing Mesa-Mira Loma 500 kV underground segment and to facilitate increased power delivery capability to load centers, particularly within the Los Angeles Basin.

The primary need for the project is to mitigate thermal and deliverability constraints on the existing underground transmission segment under planning scenarios that incorporate increased renewable generation interconnections and load growth

drivers. The project increases the transmission capacity of the existing 500 kV underground line segment by raising its rating from 1,992/3,204 MVA (normal/emergency) to 2,536/3,442 MVA, thereby enhancing system reliability and operational flexibility. In addition, the project provides secondary system benefits by mitigating constraints in the broader SCE Eastern interconnection area, including the Serrano-Alberhill-Valley 500 kV path, and by increasing the overall supply capability at both 500 kV and 230 kV levels into the LA Basin.

The scope of work consists of installing a third set of 5000 kcmil cross-linked polyethylene (XLPE) underground cable within the existing underground duct bank of the Mesa-Mira Loma 500 kV circuit between the East and West Transition Stations, utilizing previously constructed spare conduits associated with the original system design. This addition effectively completes the originally engineered three-cable-per-phase configuration by adding a third subcircuit in parallel with the two existing underground circuits. The project also includes installation of associated line drops, bushings, instrument transformers (current and voltage transformers), and termination equipment at both transition stations to integrate the new cable segment into the existing 500 kV bus configuration.

In support of the new cable installation, the project includes substation and system upgrades necessary to accommodate the modified configuration, including protection system enhancements at the Mesa and Mira Loma Substations and related telecommunications and control system modifications to ensure proper operation and monitoring of the expanded transmission asset.

The estimated ISO-related direct capital expenditure that is projected to go into rate base during this period is $70.004 million.

34. Vista-Etiwanda 230 kV 1 Line Upgrade (PIN: 8617)

The Vista–Etiwanda 230 kV Line Upgrade Project is a transmission reinforcement initiative designed to increase the capacity and operational performance of the existing 230 kV line segment connecting the Vista and Etiwanda substations. The project was

identified through the 2022–2023 Transmission Planning Process (TPP) as a policy-driven reliability and deliverability upgrade needed to support the integration of new renewable generation resources and to facilitate compliance with California's clean energy objectives. The project also addresses a modeled deliverability constraint on the Valley-Alberhill-Serrano 500 kV transmission corridor under certain contingency conditions, thereby improving system capability to transmit energy from new generation sources while alleviating congestion on the existing grid.

The scope of work consists primarily of increasing the thermal rating of the existing Vista–Etiwanda 230 kV No. 1 Line from approximately 797/876 MVA or 2,000/2,200 amps (normal/emergency) to 988/1331 MVA or 2,480/3,340 amps (normal/emergency). To achieve this upgrade, the project will address current ground clearance limitations by raising two to five (2-5) existing transmission structures within 2.1 circuit miles and reconductoring the rest of the 13.2 circuit miles to HTLS wire (High Temperature Low Sag – ACCC) , thereby enabling operation with increased conductor rating. These modifications are intended to eliminate existing capacity constraints and enhance the line's ability to reliably carry higher power flows under both normal and contingency conditions. The project improvements will enhance transmission system reliability, increase deliverability of renewable energy resources, and support long-term grid modernization objectives within the region.

The estimated ISO-related direct capital expenditure that is projected to go into rate base during this period is $41.026 million.

35. 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 to increase the power transfer capabilities in this area of SCE's system. 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 WODUP. As a result of the delay in receipt of 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, CPUC issued a decision denying ORA's September 2016 Application for Rehearing. This action confirmed SCE's proposed project. In December 2017, SCE was awarded the competitive bid for transmission construction, which resulted in a decrease to the expected cost of WODUP from $1.075 billion to $848 million. As a result of SCE's diligent efforts of working closely with this contractor, and CAISO's availability of outages, the project resulted in $751 million in recorded amounts and was completed ahead of schedule.

The estimated ISO-related direct capital expenditure that is projected to go into rate base during this period is $7,787 million.

36. 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 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 in 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 on at CPUC's at its August 27th Business Meeting, approving the project to move forward. BLM Nevada authorized SCE to proceed with construction under O&M conditions 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 expenditure that is projected to go into rate base during this period is $56.738 million.

37. Lugo-Victor 230 kV Line Reconductor (PIN: 8631)

CAISO approved the Lugo-Victor 230kV upgrade in its 2022-2023 Transmission Planning Process (TPP) as a policy-driven upgrade 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 in the North of Lugo System and will provide renewable integration, improved deliverability, and enhanced reliability benefits. CAISO identified reliability benefits of the project in that it relieves overloads on adjacent 220kV facilities.

The Lugo-Victor 230kV Upgrade project would increase the power flow through the existing Lugo-Victor Nos. 1-4 230 kV transmission lines for the purpose of increasing the amount of power delivered in the North of Lugo Area, to mitigate base case overloads on all four circuits and category P1 overloads on the remaining three circuits under the loss of one circuit as identified in the sensitivity scenarios.

The estimated ISO-related direct capital expenditure that is projected to go into rate base during this period is $67.192 million.