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Decision 20-12-035 December 17, 2020

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Application of Southern California Edison Company (U338E) For Approval of Its Forecast 2021 ERRA Proceeding Revenue Requirement.	Application 20-07-004
And Related Matter.	Application 20-10-007

DECISION ADOPTING SOUTHERN CALIFORNIA EDISON COMPANY'S 2021 ELECTRIC PROCUREMENT COST REVENUE REQUIREMENT FORECAST, 2021 FORECAST OF GREENHOUSE GAS-RELATED COSTS, AND POWER CHARGE INDIFFERENCE ADJUSTMENT TRIGGER MECHANISM SURCHARGE

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Summary

This decision approves Southern California Edison Company's (SCE) total 2021 Energy Resource Recovery Account (ERRA) electric procurement cost revenue requirement forecast of $4,454.131 million,[1] consisting of both a generation service and a delivery service component. Within SCE's generation service requirement of $3,980.401 million, SCE is authorized to recover a total of $3,560.837 million in fuel and purchased power costs and transfer the following account balances: -$75.026 million from the ERRA Balancing Account (BA), $493.886 million from the Portfolio Allocation Balancing Account (PABA), and $0.704 million from the Energy Settlements Memorandum Account. Based on this forecast, SCE's total average rates will increase by 2.2% to 18.922¢/kWh in 2021.

Within SCE's delivery service revenue requirement of $473.729 million, SCE is authorized to recover the following: 1) $710.233 million for the New System Generation and System Reliability contracts, 2) $4.532 million in spent nuclear fuel costs and $27.696 million for economic demand response programs, 3) -$330.882 million for customer returns of greenhouse gas (GHG) allowance proceeds, and 4) $83.782 million for both the Tree-Mortality Non-Bypassable Charge and the SCE's Preferred Resources Pilot #2. SCE is also authorized to transfer the following account balances: 1) -$32.819 million for the New System

[1] Includes Franchise Fees and Uncollectibles (FF&U).

Generation BA and 2) $11.187 million for the Tree Mortality Non-Bypassable Charge BA.

This decision approves SCE's forecast GHG costs, including $302.970 million in GHG Cap-and-Trade costs and $402.139 million in net 2021 GHG forecast auction proceeds. SCE is directed to return $330.882 million in GHG auction proceeds to SCE's customers, after setting aside $71.004 million in funding for clean energy and energy efficiency programs and $252.902 thousand in outreach and administrative expenses. This decision also authorizes the forecast amount of $29 per household for the residential California Climate Credit program, to be returned to residential customers beginning in 2021 on a semi-annual basis.

In addition, this decision approves SCE's Power Charge Indifference Adjustment (PCIA) Trigger Mechanism application and adopts Cost Responsibility Surcharge rates. In addition to 2021 PCIA rates, SCE is directed to assess a PCIA Trigger Mechanism Surcharge on departed load customers which amortizes the 2020 year-end undercollection in the PCIA Undercollection Balancing Account (PUBA) over three years, with one-third of the balance amortized each year in 2021, 2022, and 2023. For 2021, the PCIA Trigger Mechanism Surcharge shall also include all of the 2021 forecast PCIA revenue requirement for departed load customers which exceeds the amount recoverable under capped PCIA rates. The Settlement Agreement resolving PCIA Trigger Mechanism Surcharge rates for departed load customers is denied.

SCE's revenue requirements will be consolidated with the revenue requirement changes under other Commission decisions in the Annual Electric

True-up process. The rate changes are effective upon approval of the Tier 1 advice letter filed in conformance with this Decision.

SCE is directed to include additional volumetric data and bill impact information in future ERRA forecast proceedings. Consolidated Applications (A.) 20-07-004 and A.20-10-007 are closed.

1. Factual Background

In Decision (D.) 02-10-062, the Commission established the Energy Resource Recovery Account (ERRA), the power procurement balancing account required by Public Utilities (Pub. Util.) Code § 454.5(d)(3). Pursuant to D.02-10-062 and D.02-12-074, the purpose of the ERRA is to provide recovery of energy procurement costs, including expenses associated with fuel and purchased power, utility retained generation, California Independent System Operator (CAISO) related costs, and costs associated with the residual net short procurement requirements to Southern California Edison's (SCE) bundled electric service customers.

The ERRA regulatory process includes: (1) an annual forecast proceeding to adopt a forecast of the utility's electric procurement cost revenue requirement and electricity sales for the upcoming year, (2) an annual compliance proceeding to review the utility's compliance in the preceding year regarding energy resource contract administration, least cost dispatch, prudent maintenance of Utility Owned Generation and the ERRA balancing account, and (3) the quarterly compliance report where Energy Division reviews procurement transactions "to ensure the prices, types of products, and quantities of each product conform to the approved plan."[2]

[2] D.02-10-062 at 47, 50.

The Commission adopted the Cost Responsibility Surcharge in D.02-11-022 (as modified by D.03-07-030), which consisted of the Competition Transition Charge (CTC). The CTC is used to recover the above-market costs of resources procured prior to market restructuring after the 2000-01 Energy Crisis.

In D.06-07-030 (as modified by D.07-01-030 and subsequently refined in D.11-12-018, D.14-10-045, D.18-10-019, D.19-10-001, D.20-01-030, D.20-03-019, and D.20-08-004), the Commission adopted the Power Charge Indifference Adjustment (PCIA) for determining the above-market costs associated with the utility/California Department of Water Resources (CDWR) Power Charge as an element of the Costs Responsibility Surcharge. The PCIA applies to departing load customers who are responsible for a share of the CDWR power contracts or new generation resource commitments. The PCIA is intended to ensure that departing load customers pay their share of the above-market portion of the CDWR contract and generation resource costs incurred on their behalf, and that bundled customers remain indifferent to customer departures.

The electric utilities are also required to incorporate GHG costs into the generation component of electricity rates through the ERRA process.[3] Incorporating the costs of GHG emissions into rates results in a carbon price signal intended to incent an overall decrease in energy consumption and reduction in GHG emissions.[4] Finally, the electric utilities are required to report and return annual GHG allowance revenues to eligible customers. Pursuant to Pub. Util. Code § 748.5(c), the Commission can allocate up to 15 percent (%) of

[3] D.12-12-033; D.14-10-033.

[4] D.14-10-033.

GHG allowance revenues for clean energy and energy efficiency (EE) projects which are approved by the Commission, but not funded by another source.

2. Procedural Background for Application 20-07-004

On July 1, 2020, Southern California Edison Company (SCE) filed Application (A.) 20-07-004, requesting approval of its 2021 Energy Resource Recovery Account (ERRA) forecast application (Forecast Application). On August 5, 2020, the following parties filed protests to the Application: 1) Public Advocates Office of the California Public Utilities Commission (Cal Advocates), 2) California Community Choice Association (Cal CCA), and 3) Clean Power Alliance of Southern California (CPA) and California Choice Energy Authority (CCEA) (collectively the "SoCal CCAs"), jointly. Direct Access Customer Coalition (DACC) also filed a response to the Application on August 5, 2020. SCE filed a reply to the protests and response on August 17, 2020.

A prehearing conference (PHC) was held on September 3, 2020, to discuss the issues of law and fact, and to determine the need for hearing and schedule for resolving the matter. A scoping memo was issued on September 10, 2020. On September 21, 2020, Sunrun Incorporated's (Sunrun) motion to become a party to the Forecast Application proceeding was granted by ruling.

On September 24, 2020, SoCal CCAs and Sunrun served opening testimony. On October 5, 2020, SCE served rebuttal testimony. On October 9, 2020, the parties to the Forecast Application filed a joint case management statement indicating no evidentiary hearings were needed. On October 12, 2020, evidentiary hearings were taken off-calendar by ruling.

On October 26, 2020, SCE, SoCal CCAs and Sunrun filed opening briefs. On November 2, 2020, SCE and SoCal CCAs filed reply briefs.

SCE served its November Update testimony on November 9, 2020. SoCal CCAs; Cal CCA; and DACC and AREM, jointly, filed opening comments to SCE's November Update testimony on November 16, 2020. SCE and Cal Advocates filed reply comments to SCE's November Update testimony on November 20, 2020. SCE also filed a motion for approval of a settlement agreement on November 20, 2020, which also addresses certain issues in A.20-10-007.

Exhibits related to the ERRA Forecast Application were admitted into evidence and granted confidential treatment, as applicable, by rulings dated November 16, 2020, and November 24, 2020. This matter was submitted on November 24, 2020.

3. Procedural Background for Application 20-10-007

On October 9, 2020, SCE filed A.20-10-007, requesting approval of its PCIA trigger mechanism application, which addressed an undercollection in the PCIA Undercollection Balancing Account (PUBA) that exceeded the PCIA trigger point and was not expected to self-correct within 120 days (PCIA Trigger Application).

On October 23, 2020, a PHC was set by Chief Administrative Law Judge (ALJ) ruling and served concurrently on the service list for A.20-07-004. The Chief ALJ ruling stated the Commission's intent to discuss consolidation of this proceeding with A.20-07-004 at the PHC.

On October 29, 2020, the following parties filed protests to the Trigger Application: 1) AREM and DACC, jointly; 2) Cal Advocates, and 3) SoCal CCAs and Cal CCA, jointly. SCE filed a reply to the protests on November 3, 2020.

A telephonic PHC was held on November 5, 2020. The Forecast Application was consolidated with the PCIA Trigger Application through the assigned Commissioner's scoping memo pursuant to Rule 7.4,[5] issued November 12, 2020. Parties were directed to file comments on the Trigger Application as part of their comments and reply comments to the November Update testimony, as discussed in Section 2 above.

On November 20, 2020, SCE filed a motion to admit its PCIA Trigger Application-related exhibit and another motion to give confidential treatment to portions of its workpapers. The exhibit and associated workpapers were accepted into evidence and granted confidential treatment by ruling dated November 24, 2020. This matter was submitted on November 24, 2020.

4. Issues Before the Commission

The issues to be determined in this decision are:

1. Whether SCE's requested 2021 ERRA forecast revenue requirement of $4.115 billion is reasonable, including but not limited to consideration of the following:
    a. SCE's forecast of electric sales and electric load;
    b. fuel and purchased power expenses;
    c. SCE's forecast Greenhouse Gas (GHG) costs; and
    d. Annual true-ups for balancing accounts such as the Portfolio Allocation Balancing Account (PABA), New System Generation Balancing Account, Energy Settlements Memorandum Account, ERRA Balancing Account and Green Tariff Shared Renewables Balancing Account;
2. Whether SCE's forecast of GHG allowance revenue return allocations for energy-intensive trade-exposed customers, small business customers and the residential customer California Climate Credit is reasonable;

[5] All references to "Rule" or "Rules" hereinafter shall refer to the Commission's Rules of Practice and Procedure.

3. Whether SCE's forecast of GHG revenues and expenses set aside for 1) clean energy and energy efficiency programs and GHG administration, and 2) customer education and outreach plan costs are reasonable;
4. Whether the Cost Allocation Mechanism rates are reasonable;
5. Whether SCE's calculation of the PCIA and Competition Transmission Charge rates are reasonable; including discussion of the following;
    a. Treatment of Resource Adequacy resources and associated costs in the PCIA;
    b. Treatment of Renewable Portfolio Standard (RPS) resources with excess RPS value and allocation of RPS sales across vintages;
    c. Calculation of the indifference amount;
    d. Calculation of the year-end PABA balance; and
    e. Allocation of indifference charges among vintages and customer classes;
6. Whether SCE's request and methods used to determine the items above comply with all applicable rules, regulations, resolutions and decisions for all customer categories; and
7. Whether there are any safety concerns.
8. Whether SCE's Trigger Application complied with the law and Commission orders, including Decision (D.) 18-10-019;
9. Whether SCE's PUBA balance exceeded the PCIA trigger and threshold, and whether it was likely that the balance would self-correct within 120 days of the threshold balance exceedance;
10. The causes of the PUBA undercollection (excluding reasonableness review or compliance with SCE's bundled procurement plan);
11. The appropriate amortization period of the PUBA balance;
12. The impact on rates of the undercollection recovery;

13. Whether the proposed allocation of the undercollection among customers for the rate adjustment is reasonable; and
14. Whether the Trigger Application should adjust the PCIA rate such that they may exceed current PCIA rate caps for 2021. If so, whether SCE's PCIA rates should be set at levels consistent with full recovery of SCE's forecast PCIA in 2021.

5. 2021 Forecast Overview and Methodology

SCE's forecast fuel and purchased power (F&PP) costs are associated with its Utility Owned Generation (UOG) resources, purchased power contracts, financing and various carrying costs. SCE forecasts its 2021 total estimated F&PP revenue requirement at $4,454.131 million.[6] F&PP costs make up the bulk of SCE's total $4,454.131 million revenue requirement. SCE forecasts $4,244 million in total purchased power for 2021.[7] SCE also forecasts $88.192 million in total fuel costs, which includes $53.607 million for Franchise Fees and Uncollectibles (FF&U) and municipal surcharges.[8]

SCE bases its revenue requirement on a forecast of total electricity sales and customers for its service territory in 2021, which it adjusts to account for the bundled customer portion of load. SCE forecasts total electricity sales in 2020 and 2021 will be lower than the recorded total retail electricity sales volume of 82,935 Gigawatt hours (GWh) in 2019, forecasting 80,119 GWh in 2020 and 79,270 GWh in 2021.[9] This represents a total reduction in annual total retail sales

[6] Exhibit SCE-04 at 8.

[7] *Id*. at 81.

[8] *Id*. at 80.

[9] *Id*. at 14.

by 3.4% from 2019 to 2020 and further 1.1% reduction from 2020 to 2021. At the same time, SCE forecasts an increase of 0.7% in total electricity customers in its service territory from 5,183,295 in 2020 to 5,217,585 in 2021.[10]

SCE considers the Coronavirus Disease 2019 (COVID-19)-related impacts of California's various shelter-in-place orders to be a primary driver of decreased retail sales in 2020 and 2021.[11] Its retail sales forecast is also influenced by historical trends in employment growth, residential housing starts, the economic outlook, weather assumptions and other factors (*e.g.,* energy efficiency savings, spending on wildfire mitigation, grid safety and resiliency).[12]

SCE calculates the revenue requirement necessary for procuring bundled customer energy in 2021 using energy need at the CAISO interface, which allows SCE to account for line losses inherent in transporting energy from the CAISO interface to bundled service customers' meters.[13] SCE also adjusts the sales forecast downward 2.8% to adjust for the difference between billed and delivered energy for its bundled service Net Energy Metering (NEM) customers.[14]

Finally, SCE's forecast of total bundled service customers accounts for the statewide increase in the DA load cap expected to start in 2021.[15] It also includes Energy Service Providers and Community Choice Aggregations (CCA)[16] that

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[10] *Id.* at 16.

[11] Exhibit SCE-01 at 10.

[12] *Id.* at 12-17.

[13] *Id.* at 11.

[14] Exhibit SCE-04 at 15.

[15] Exhibit SCE-01 at 19.

[16] SCE included the following CCAs in its 2021 ERRA forecast: 1) Lancaster Choice Energy, 2) Apple Valley Choice Energy, 3) Pico Rivera Innovative Municipal Energy, 4) CPA

Footnote continued on next page.

meet the following criteria: 1) file a binding notice of intent to begin CCA service, 2) file an initial Resource Adequacy (RA) filing, 3) start CCA service or 4) formally submit an April RA forecast pursuant to Pub. Util. Code § 380.[17]

6. SCE's Portfolio of Resources

SCE's portfolio of resources includes a variety of utility owned and contracted resources, as discussed in Sections 6.1 through 6.13 below.

6.1. UOG and Purchased Power Contracts – Hydroelectric, Combined Heat and Power (CHP), Solar Photovoltaic Program, Renewables, Natural Gas

SCE's UOG and purchased power contract resources consist of hydroelectric, fuel cells, CHP and renewable generation resources, nuclear, natural gas and battery storage. SCE's hydroelectric resources consist of 33 powerhouses with a 1,176 Megawatts (MW) nameplate capacity, which are organized into the Western[18] and Eastern[19] Divisions.[20] SCE forecasts a slightly-below-normal hydrological year for 2021 and incorporates planned outages for hydroelectric units.[21]

(Phases 1-5), 5) San Jacinto Power, 6) Rancho Mirage Energy Authority, 7) Western Community Energy, 8) Desert Communities Energy, 9) Monterey Bay Community Power, 10) Pomona, 11) Baldwin Park, and 12) City of Santa Barbara.

[17] Exhibit SCE-01 at 19-20; Exhibit SCE-04 at 14 (reflecting City of Palmdale's delay of CCA implementation beyond 2021).

[18] The Western Division, known as the Big Creek and Southwest Production areas, consist of nine powerhouses in the western Sierra Nevada Mountains.

[19] The Eastern Division consists of 24 powerhouses in the eastern and southern Sierra Nevada Mountain, the San Bernardino Mountains and San Gabriel Mountains.

[20] Exhibit SCE-01 at 30.

[21] *Id*. at 31.

SCE's solar photovoltaic resources consist of the Solar Photovoltaic Program, which allows SCE to install, own, and operate up to 91 MW of direct current solar photovoltaic projects in SCE's service territory.[22]

SCE's CHP and renewables projects resources consist of projects delivering 10,620 MW of contract capacity, which include 796 MW of CHP capacity and 9,824 MW of renewable capacity.[23] In addition, SCE contracted for 53.5 MW of additional dispatchable capacity through the CHP Program Settlement requests for offers.[24] SCE's CHP and renewables projects include biomass, cogeneration, geothermal, small hydroelectric, solar and wind resources.[25]

SCE's natural gas resources consist of five black-start capable peakers owned by SCE and the Mountainview Generating Station. The five black-start capable peaker units have with a total capacity of 245 MW.[26] Natural gas costs incurred by the five peakers are included in the ERRA forecast, while the capacity and non-fuel variable costs associated with these peakers are included in SCE's General Rate Case revenue requirement.[27]

6.2. Interagency Contracts

SCE is a party to two inter-utility contracts with dispatchability, which affects forecast F&PP costs. For 2021, SCE has an entitlement of 280.245 MW of contingent capacity and 238.16 Gigawatts (GW) of firm energy through a contract with the Western Area Power Administration (WAPA) and the Bureau

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[22] *Ibid*.

[23] *Id*. at 32.

[24] *Ibid*.

[25] *Id*. at 33.

[26] *Id*. at 35.

[27] *Ibid*.

of Reclamation from power generated by the Hoover Dam.[28] However, SCE forecasts monthly capacity and firm energy delivery as low as 135 MW and 10 GWh due to the lowered surface elevation of Lake Mead, the forebay of the Hoover Dam.[29]

SCE also purchases power from the City of Pasadena from the 3 MW Azusa Powerhouse, which SCE transferred to the City of Pasadena through a Corporation Grant Deed. The Corporation Grant Deed requires the City of Pasadena to deliver the entire electrical output of the Azusa Powerhouse to SCE, and the City of Pasadena has 12 months from the time of delivery to request the same amount of energy.[30]

6.3. Resource Adequacy Contracts

In D.06-07-029, as modified by D.10-12-035 and Senate Bill 695, the Commission adopted a Cost-Allocation Mechanism (CAM) to allocate the costs electric utilities incur to meet RA requirements on behalf of customers in an electric utility's service territory. In D.10-12-035, the Commission also allowed SCE to allocate costs associated with CHP generation procured on behalf of direct access customers' Electric Service Providers and Community Choice Aggregators.

SCE forecasts 2021 F&PP costs associated with four types of RA generation resources: 1) New System Generation CAM contracts, 2) System Reliability Modified CAM contracts, 3) Generic and Bilateral contracts used to meet 2021 system capacity requirements, and 4) contracts used to meet local capacity

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[28] *Id*. at 36.

[29] *Ibid*.

[30] *Id*. at 37.

requirements. First, SCE forecasts costs from New System Generation CAM contracts procured pursuant to D.07-09-044, for which it plans to hold the dispatch rights in 2021.[31] SCE does not use the energy from these contracts to meet bundled load, and the net capacity costs[32] are allocated to benefitting customers through the CAM.[33]

Second, SCE forecasts costs associated with seven RA contracts for energy storage resources procured in accordance with D.19-11-016's order directing SCE to procure 1,184.7 MW of incremental system RA capacity.[34] Third, SCE forecasts RA purchase costs for generic RA using the RA market price benchmark and the revenue from sale of excess RA.[35] Finally, SCE forecasts costs for RA resources procured through Local Capacity Requirement (LCR) solicitations in the Western Los Angeles[36] and Moorpark[37] subareas.[38]

6.4. Public Purpose Program Charges - Preferred Resources Pilot (PRP) #2 and Tree Mortality Non-Bypassable Charge

SCE incurs procurement-related expenses for two programs recovered through the Public Purpose Programs charge. First, SCE incurs costs related to electrical energy, capacity, and renewable attributes contracted through its

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[31] *Id*. at 38.

[32] The net capacity costs are the net of estimated expected revenue and production costs.

[33] Exhibit SCE-01 at 38.

[34] *Id*. at 38-39.

[35] *Id*. at 39.

[36] D.15-11-041.

[37] D.16-05-050; D.19-12-055.

[38] Exhibit SCE-01 at 40.

PRP #2.[39] SCE incorporates forecast, monthly in-front-of the meter energy costs[40] from the PRP into the F&PP forecast.

Second, SCE incurs above-market costs associated with biomass contracts procured pursuant to D.18-12-003. The Tree Mortality Non-Bypassable Charge BA records the net costs of tree mortality-related biomass energy procurement mandated by Pub. Util. Code § 399.20.3(f).[41] The net costs include the costs of procurement, but exclude the value received from the utilities for 1) energy or ancillary services sales, 2) the value of renewable energy credits associated with the biomass contracts, and 3) the RA capacity value of the contracts.[42]

6.5. Green Tariff Shared Renewables Program

In 2015, the Commission established the Green Tariff Shared Renewables program pursuant to Pub. Util. Code §§ 2831 to 2833.[43] The Green Tariff Shared Renewables program provides customers with two options for obtaining a greater mix of renewable energy. Under the Green Tariff option, marketed as the Green Rate program at SCE, customers may choose either a 50% or 100% option for the mix of renewable energy with a corresponding increase in their generation rate. Under the enhanced community renewables option, customers may support local renewable energy project agreements with third-party developers.

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[39] *Id*. at 40-41.

[40] Behind-the-meter LCR resources from the PRP reduce the overall bundled load requirement and are not included in the F&PP forecast.

[41] D.18-12-003 at 2.

[42] *Id*. at 2, 25 (Ordering Paragraph (OP) 1).

[43] D.15-01-051.

SCE forecasts 2,122,257 kWh of participation through the Green Tariff Shared Renewables program in 2021.[44] The forecasted kWh to serve Green Tariff Shared Renewables customers is removed from the CHP and Renewables energy and shown separately, as the resources to generate the energy are now online and expected to produce power in 2021.[45]

6.6. Nuclear

SCE has ownership interests in the San Onofre Nuclear Generating Station (SONGS), a nuclear power facility which ceased operations in 2013, and the Palo Verde Nuclear Generating Station (PVNGS), a nuclear power facility in Phoenix operated by the Arizona Public Service.[46] SCE forecasts $4.4 million in costs for interim spent fuel storage costs at SONGS in 2020.[47] SCE forecasts $33.7 million in nuclear fuel expenses and approximately $0.1 million in net interim used fuel storage charges at PVNGS, accounting for a $1.8 million damages award payment from the United States Department of Energy from litigation to recover spent fuel storage costs.[48]

6.7. Catalina Fuel Costs

SCE forecasts a total fuel cost of $5.811 million to provide electricity service to Santa Catalina Island using six diesel generators and 23 propane-fired micro-turbines at the Pebbly Beach Generating Station.[49] This fuel cost forecast includes $5.414 million for diesel fuel based on a forecast use of 49,671 barrels of

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[44] Exhibit SCE-01 at 41.

[45] *Id*. at 41-42.

[46] *Id*. at 42.

[47] *Id*. at 45.

[48] *Id*. at 44-45.

[49] Exhibit SCE-04 at 41.

diesel at an average commodity costs of $108.83 per barrel.[50] It also includes a forecast of $0.398 million in propane costs to operate the microturbines in 2021.[51]

6.8. Demand Response

SCE forecasts a total cost of $27.734 million for 6 GW of energy reductions in 2021 provided by economic demand response programs, including the Summer Discount Plan, Capacity Bidding Program, Critical Peak Pricing, and Smart Energy Programs.[52] SCE does not include the costs associated with demand response programs that provide reliability, which are programs that require participants to reduce their load in response to a forecast or actual system emergency.[53] SCE records the cost of all demand response incentives in the Demand Response Program BA pursuant to D.17-12-003.[54]

6.9. California Independent System Operator (CAISO) Costs, Load Procurement and PABA Energy Revenue

The forecast CAISO cost is the net cost of the following: grid management charges, Federal Energy Regulatory Commission fees, Congestion Revenue Rights, auction-related CAISO costs, ancillary services, CAISO uplist costs, Standard Capacity Product costs, and other non-energy-related CAISO costs.[55] The forecast load procurement cost is the cost of procuring load, estimated by multiplying the hourly load by the south of path 15 zone of the CAISO control

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50 *Id*. at 39-40.

51 *Id*. at 40-41.

52 *Id*. at 47-48.

53 *Ibid*.

54 *Id*. at 48.

55 *Id*. at 48-49.

area (SP15) price for the corresponding hour.[56] SCE calculates the forecast load procurement charges by multiplying the hourly load with the corresponding hourly SP15 price.[57] SCE calculates the forecast energy revenues by multiplying the forecast production of its CAM and PABA-eligible resources by the corresponding hourly SP15 price.[58]

6.10. Hedging Costs

SCE's forecast hedging costs include energy-related transaction fees and option premiums for hedging SCE's open energy position in 2021.[59]

6.11. Gas Transportation and Storage

SCE forecasts $1,200 of costs associated with natural gas delivery for 2021.[60] This includes the costs of a month-to-month contract to deliver natural gas to SCE's UOG fuel cells at University of California at Santa Barbara and California State University at San Bernardino.[61] It also includes SCE's forecast costs associated with a month-to-month contract with SoCalGas to transport natural gas to the Mountainview Generating Station along with delivery to SCE's Barre, Center, Grapeland, McGrath and Mira Loma peakers.[62]

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[56] *Ibid*.

[57] *Id*. at 49.

[58] *Ibid*.

[59] Exhibit SCE-01 at 50.

[60] *Id*. at 51.

[61] *Ibid*.

[62] *Ibid*.

6.12. Financing Costs

SCE has a $3 billion multi-year revolving credit facility, also called the "revolver," to serve short-term borrowing requirements.[63] SCE plans to extend its credit facility in 2021 in order to maintain a five-year term by exercising a one-year extension option. Forecast costs associated with extending the credit facility include 1) upfront costs and fees for the extension, 2) $20,000 administrative fee, 3) 17.5 basis point annual facility fee, 4) 107.5 basis point participation fee on any outstanding letters of credit, 5) 20 basis point issuer fee on any letters of credit, and 6) London Inter-Bank Offered Rate plus 107.5 basis points borrowing (loan) rate.[64] SCE forecasts using the revolver to provide capacity for collateral and supporting balancing accounts.[65]

SCE previously issued a $100 million bond to support financing the minimum balance of its fuel inventories, which is set to expire in March 2021.[66] SCE anticipates issuing another 3-year $100 million fixed-rate bond in March 2021 to pay for fuel inventories, which it forecasts will have $552,000 insurance costs and expenses, plus the cost of interest.[67]

In 2021, SCE proposes to use a $3 billion commercial paper program to finance fuel inventories in excess of the amount of the $100 million fixed rate bond.[68] In addition, SCE proposed to provide collateral to counterparties in the

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63 *Id*. at 53.

64 *Id*. at 54.

65 *Ibid*.

66 *Id*. at 55.

67 *Ibid*.

68 *Ibid*.

form of letters of credit rather than cash; fees associated with letters of credit will be charged to the ERRA-related balancing accounts.[69]

6.13. Carrying Costs - Fuel Inventory, GHG Compliance and Collateral

SCE forecasts fuel inventory carrying costs for nuclear, natural gas, diesel and propane.[70] SCE also forecasts GHG procurement compliance carrying costs for 2021, which SCE estimates using historical GHG inventory balances and the ERRA BA interest rates.[71] Finally, SCE forecasts the carrying costs associated with SCE's collateral requirements necessary to procure power.[72] SCE proposes to recover its carrying costs through the ERRA-related balancing accounts.[73]

7. SCE's Revenue Requirement and Ratemaking Proposal

SCE proposes to divide its ERRA revenue requirement between generation service, which applies to bundled customers, and delivery service, which applies to both bundled and unbundled customers. SCE's generation service revenue requirement is discussed in Section 7.1 while SCE's delivery service requirement is discussed in Section 7.2.

Based on SCE's forecast, SCE's total average rates will increase by 2.2% to 18.922¢/kWh in 2021.[74] SCE's proposed average rates by customer class are summarized in Table 7-1 below.

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[69] *Ibid*.

[70] *Id*. at 57-59.

[71] *Ibid*.

[72] *Ibid*.

[73] *Ibid*.

[74] Exhibit SCE-04 at 125 (The Rate increase percentage is relative to rates as of October 1, 2020, as implemented in SCE AL 4301-E).

Table 7-1. SCE's Proposed 2021 ERRA Forecast Average Rates by Customer Class.[75]

Rate Schedule by Customer Group	Total Delivery (¢/kWh)	Total Generation (¢/kWh)	Total (¢/kWh)
Domestic			
• D	14.744	9.509	24.253
• D-CARE	5.599	9.673	15.272
• D-APS	12.962	9.686	22.648
• DE	8.387	9.665	18.052
• DM	15.787	9.713	25.500
• DMS-1	15.020	9.713	24.733
• DMS-2	13.452	9.712	23.164
Lighting-Small, Med. Power			
• GS-1	11.003	9.640	20.643
• GS-2	12.049	9.015	21.064
• TC-1	15.247	7.277	22.524
• TOU-GS	10.748	7.985	18.732
Large Power			
• TOU-S	9.044	7.563	16.607
• TOU-P	7.856	7.069	14.925
• TOU-T	3.170	6.539	9.709
• TOU-8-S-S	9.149	7.420	16.569
• TOU-8-S-P	9.209	7.561	16.770
• TOU-8-S-T	4.192	6.186	10.378
Agricultural & Pumping			
• TOU-PA-2	9.608	8.035	17.643
• TOU-PA-3	8.087	6.735	14.822
Street & Area Lighting			
• LS-1	31.431	4.750	36.181
• LS-2	11.342	4.833	16.175
• LS-3	4.862	4.866	9.728
• DTL	28.069	4.861	32.930
• OL-1	24.595	4.861	29.456
Average Rate - All Groups	10.280	8.642	18.922

[75] *Id*. at 125.

SCE requests to remove its assessment of rate impacts from future ERRA forecast applications, arguing the rate impacts tables are burdensome to generate and are not an accurate reflection of rate changes, as they do not reflect other changes incorporated into SCE's first quarter 2021 consolidated revenue requirement.[76] However, SCE is not opposed to providing insight into the generation rates in a more simplified, less burdensome form.[77]

SoCal CCAs oppose the removal of rate impact information as the "rate comparison table is one of the few, if not the only, places where parties have visibility into current projections of bundled customers' generation rates for the forecast year."[78] Cal Advocates also opposes removal of the rate impact information.[79]

We agree with SoCal CCAs and Cal Advocates, and direct SCE to keep its assessment of rate impacts in future ERRA forecast applications. The rate impacts assessment informs the Commission's decision-making, even if it does not fully reflect SCE's final rates in the annual Electric True Up advice letter. Moreover, the True-Up advice letter consolidates rate changes approved in multiple proceedings, making it critical that SCE provide a clear assessment of the rate impacts specific to this proceeding in its ERRA Forecast testimony. In addition to the information already provided, we direct SCE to also provide the percent rate change relative to current rates and a summary of the bill impacts.

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[76] *Id*. at 124.

[77] SCE Reply Comments on SCE's November Update Testimony at 6.

[78] SoCal CCAs Opening Comments on SCE's November Update Testimony at 9.

[79] Cal Advocates Reply Comments on SCE's November Update Testimony at 1-4.

7.1. Generation Service Revenue Requirement

The generation service revenue requirement covers F&PP costs, along with the associated GHG costs of resources, recorded in the following accounts: 1) ERRA BA, 2) PABA, and 3) Green Tariff Shared Renewables BA, and 4) the Energy Settlements MA, as discussed in Sections 7.1.1 to 7.1.4 and summarized in Table 7-2 below. SCE forecasts a $271.949 million decrease in the forecast generation revenue requirement from its 2020 generation service revenue requirement.[80]

Table 7-2. Summary of SCE's Proposed Generation Service Revenue Requirement.[81]

Description	Forecast 2020 Revenue Requirement (millions)
2021 F&PP Costs (including GHG costs) • ERRA BA-related • PABA-related • Green Tariff Shared Renewables BA-related	 $2,424.828 $1,133.862 $2.148
2020 ERRA BA True-up	-$75.026
2020 PABA True-Up	$493.886
2020 Energy Settlements MA True-Up	$0.704
Total Generation Service	**$3,980.401**

7.1.1. ERRA BA

The ERRA BA records the difference between the ERRA-related revenue requirement and SCE's F&PP expenses for bundled service customers in the prior year. For 2021, SCE forecasts a total revenue requirement of $2,424.828 million for F&PP costs for wholesale short-term market purchases and

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[80] Exhibit SCE-04 at 11.

[81] *Id*. at 11.

fuel and purchased power contracts costs for resources not eligible for recovery through the PABA.[82] This includes $0.304 million in F&PP-related subscription fees.[83]

In its November Update testimony, SCE forecasts a $75.026 million overcollection in the ERRA BA by December 31, 2020, which SCE proposes to return to bundled service customers in 2021.[84] Upon consideration, we find SCE's forecasted ERRA BA revenue requirement and 2020 ERRA BA overcollection true-up proposal reasonable and in compliance with applicable rules, orders and Commission decisions.

7.1.2. PABA

The PABA records the costs of long-term, fixed-price contract costs and utility-owned generation costs for bundled and departed load customers (see Section 6 above for specific resource types). SCE forecasts $1,133.862 million in F&PP costs in the PABA for bundled service customers in 2021 through the generation service component of its revenue requirement.[85]

SCE also forecasts a $493.886 million total undercollection in its 2020 PABA balance by December 31, 2020. The forecast undercollection for 2021 is similar to the $543.608 million undercollection forecasted in the November Update testimony of SCE's 2020 Forecast Application, A.19-06-002.[86]

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[82] *Id*. at 83.

[83] *Id*. at 83; Subscription fees (totaling $0.304 million in 2021) are used to "perform key market functions including monitoring independent market data, risk reports, power prices, natural gas prices, emissions prices, and industry news." (Exhibit SCE-04 at 45.)

[84] *Id*. at 84.

[85] *Id*. at 11.

[86] *Ibid*.

In comments, SoCal CCAs point out that SCE incorrectly assigned one of the 2015 PRP contracts to the 2020 vintage rather than the 2016 vintage. SCE agrees to make this modification to the PABA through the annual electric true-up process, and SoCal CCAs agree with this means of correction is agreeable as the resulting change to the PABA is minor.[87] Other than correcting for the PRP contract vintage, we find SCE's proposed 2021 forecast PABA and 2020 PABA year end true-up reasonable and in compliance with applicable rules, orders and Commission decisions.

7.1.3. Green Tariff Shared Renewables BA

The Green Tariff Shared Renewables BA records the difference between the costs and revenues collected for Green Tariff Shared Renewables-commodity resources, used for both the Green Tariff option[88] and the Enhanced Community Renewables option[89] of the Green Shared Tariff Renewables program.

SCE forecasts Green Tariff participation at 2,122,257 kWh in 2021[90] and forecast revenue requirement of $2.148 million for F&PP costs related to three projects procured on behalf of Green Tariff Shared Renewables program customers.[91]

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[87] SoCal CCAs Opening Comments on the SCE November Update Testimony at 8, SCE Reply Comments on November Update Testimony at 5.

[88] Under the Green Tariff option, customers can choose to allocate either 50% or 100% of their electricity bill to renewable energy.

[89] Under the Enhanced Community Renewables option, customers can support local renewables projects through agreements with third-party energy developers. The specific projects SCE contracted to serve customers with this option are not yet in commercial operation. (Exhibit SCE-04 at 38, fn. 48.)

[90] Exhibit SCE-04 at 38.

[91] *Id*. at 11.

No parties opposed or commented on this matter. Upon consideration, the Commission finds SCE's proposed 2021 Green Tariff Shared Renewable BA amount reasonable and in compliance with applicable rules, orders and Commission decisions.

7.1.4. Energy Settlements MA

The Energy Settlements MA tracks refunds from generators who overcharged SCE for electricity during the 2000-01 California Energy Crisis. The Litigation Costs Tracking Account (TA) is a subaccount in the Energy Settlements MA which tracks litigation costs "set-aside" in Federal Energy Regulatory Commission investigation settlement agreements and actual litigation costs incurred by SCE.

SCE has a $0 balance in the Energy Settlements MA through 2020, and a forecast year-end balance of $0.704 million in the Litigation Costs TA for litigation costs related to the FERC investigation settlement agreements and actual litigation costs.[92]

No parties opposed or commented on SCE's Energy Settlements MA true-up in the November Update. Upon consideration, the Commission finds SCE's proposed 2021 Energy Settlements MA true-up reasonable and in compliance with applicable rules, orders and Commission decisions.

7.2. Delivery Service Revenue Requirement

SCE forecasts a total delivery service revenue requirement of $473.729 million in 2021. This forecast includes F&PP and GHG costs of resources associated with the following: 1) New System Generation BA and 2021 System Reliability BA, *see* Section 7.2.1, 2) Spent Nuclear Fuel Costs, *see*

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[92] *Id*. at 85.

Section 7.2.2, 3) the distribution sub-account of the Base Revenue Requirement BA, *see* Section 7.2.3, 4) GHG Allowance revenue, *see* Section 7.2.4, and 5) the Public Purpose Programs, *see* Section 7.2.5.

The delivery service revenue requirement is recovered from all bundled and departing load SCE customers through allocation mechanisms other than the CTC and PCIA. SCE forecasts a $45.108 million decrease in the forecast delivery revenue requirement from the 2020 revenue requirement.[93]

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93 *Id*. at 11.

Table 7-3. Summary of SCE's Proposed Delivery Service Revenue Requirement.[94]

Description	2021 Revenue Requirement (millions)
New System Generation • New System Generation F&PP 2021 Forecast[95] and 2021 System Reliability F&PP • New System Generation BA 2020 True-Up	 $710.233 -$32.819
Spent Nuclear Fuel	$4.532
Distribution Rate Component • Base Revenue Requirement BA-D F&PP 2021 Forecast • GHG Allowance Revenues 2021 Forecast	 $27.696 -$330.882
Public Purpose Programs Charge • Public Purpose Program Charge F&PP 2021 Forecast • Tree Mortality Non-Bypassable Charge BA (2020 True-Up)	 $83.782 $11.187
Total Delivery Service	**$473.729**

7.2.1. New System Generation and System Reliability F&PP

The New System Generation BA records the benefits and costs of power purchase agreements associated with new generation resources (*see* Section 6.3 for a discussion of applicable contracts). SCE estimates the 2020 year-end balance of the New System Generation BA is an under-collection of $32.819 million.[96]

No parties opposed or commented on this matter. Upon consideration, we find SCE's total requested revenue requirement for New System Generation and System Reliability contracts, along with SCE's request to true-up the New System

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94 *Id*. at 11.

95 Estimate includes GHG costs.

96 Exhibit SCE-04C at 11.

Generation BA, reasonable and in compliance with applicable rules, orders and Commission decisions.

7.2.2. Spent Nuclear Fuel

SCE forecasts $4.532 million in costs for interim spent fuel storage costs at SONGS and PVNGS in 2021, as discussed in Section 6.6 above.[97]

No parties opposed or commented on this matter. We find SCE's 2021 forecast of $4.532 million for interim spent nuclear fuel storage costs reasonable and in compliance with applicable rules, orders and Commission decisions.

7.2.3. Base Revenue Requirement BA

The distribution subaccount of the Base Revenue Requirement BA records the costs associated with SCE's demand response programs, as discussed in Section 6.8 above.

No parties opposed or commented on this matter. Upon consideration, we find SCE's 2021 forecast of $23.734 million for demand response programs costs reasonable and in compliance with applicable rules, orders and Commission decisions.

7.2.4. GHG Allowance Revenue Return

SCE requests the GHG allowance revenue return for the, Emissions-Intensive and Trade Exposed (EITE) customer return, the small business return and the residential California Climate Credit as a sum total of -$330.882 million through its delivery service revenue requirement. These charges are considered in Sections 8.5 to 8.7 below.

[97] Exhibit SCE-01 at 45.

7.2.5. Public Purpose Program Charges

SCE forecasts a total 2021 revenue requirement of $83.782 million for the Tree Mortality Non-Bypassable Charge and the Preferred Resources Pilot, as discussed in Section 6.4 above.[98]

No parties opposed or commented on SCE's set-aside for Public Purpose Program charges. After considering the matter, we find SCE's request to recover the $83.782 million for PPP programs through its 2021 revenue requirement in this ERRA forecast decision reasonable and in compliance with applicable rules, orders and Commission decisions.

8. Greenhouse Gas Forecast Costs, Revenues and Reconciliation

The Commission adopted standard procedures for electric utilities to request greenhouse gas forecast revenue and reconciliation requirements filed after 2013 in D.14-10-033. The decision also adopted Confidentiality Protocols for Cap-and-Trade-related data and required the utilities to use a proxy price in their forecasts. Finally, the decision required the utilities to file GHG Forecast Revenue and Reconciliation Applications annually as part of their ERRA forecast applications. We use the standards adopted in D.14-10-033 to review SCE's current Forecast Application to determine the reasonableness of both the recorded and forecasted variables.[99]

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98 *Id.* at 109.

99 Previously, the variables included Recorded and Forecast Volumetric Residential Return. However, in D.15-07-001, the Commission concluded that "The IOUs 2016 ERRA Forecast Filings should reflect that the residential volumetric GHG rate offset will be eliminated in 2016."

SCE's total GHG Cap-and-Trade costs are $302.970 million.[100] SCE calculates the total net GHG revenues at $451.842 million.[101] SCE's net GHG revenues consist of the following: 1) recorded and forecast GHG auction allowance revenues, 2) administrative and customer outreach expenses, and 3) expenses for approved incremental clean energy and EE projects.

SCE requests to distribute the $330,881.545 million to 1) EITE customers, 2) eligible small business customers, and 3) residential customers through the California Climate Credit. Finally, SCE proposes to return a biannual residential California Climate Credit of $29.00 per eligible household.

A summary of SCE's proposed GHG allowance revenues and expenses are provided in Table 8-1 below:

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[100] Exhibit SCE-04 at 55.

[101] *Id*. at 77.

Table 8-1. Summary of GHG Allowance Auction Revenues and Expenses.[102]

Program	Amount
GHG auction revenues	
1. 2020 GHG Auction revenue true-up	$49,703,087
2. 2021 Forecast GHG auction allowance revenue	-$446,757,000
3. 2021 Forecast FF&U	-$5,085,030
GHG Revenue Subtotal	-$402,138,943
Administrative Expenses	
1. 2021 Outreach and Administrative Expenses	$250,000
2. 2021 Forecast FF&U	$2,902
Subtotal	$252,902
Clean Energy and Energy Efficiency Programs	
1. 2020 Solar on Multifamily Affordable Housing (SOMAH)	$44,675,700
2. 2019/2020 SOMAH True-Up	$19,197,913
3. 2021 Disadvantaged Communities – Single-Family Solar Homes (DAC-SASH)	$4,600,000
4. 2021 Disadvantaged Communities – Green Tariff (DAC-GT) and Community Solar Green Tariff (CSGT)	$2,530,884
5. Clean Energy Optimization Pilot (CEOP)	$0
Total Clean Energy and EE Program Set-Asides	$71,004,497
Volumetric Returns	
1. Emissions-Intensive and Trade-Exposed (EITE) Customer Return	$39,901,149
2. Small Business Returns	$19,658,135
3. California Climate Credit	$271,322,261

8.1. Greenhouse Gas Costs

GHG emissions costs are incurred directly or indirectly by a utility as a result of the GHG Cap-and-Trade program. Direct costs include, generally, the

102 *Ibid.*

costs incurred to purchase compliance instruments for plants run by the utility or the costs of providing physical or financial settlements specifically for GHG emissions from plants not owned or operated by the utility. Indirect costs generally reflect GHG costs embedded in the price of power purchased on the market or through contracts that do not include GHG settlement terms.

SCE's November Update forecasts $302.970 million, including FF&U, for direct GHG costs in 2021. SCE calculates direct GHG costs by multiplying the 2021 forecast price of $17.74/metric ton (MT), which is the Intercontinental Exchange settlement price as of August 24, 2020, by the forecasted GHG emissions volume for non-imported power.[103] SCE forecasts GHG emissions costs associated with imported power by multiplying the volume of imports by the California Air Resource Board's (CARB) default emissions factor for unspecified power.[104]

SCE's Forecast Application proposes to allocate direct GHG costs to the customers who receive a benefit from the resources to which the GHG costs are attributable. SCE includes the direct cost of the GHG compliance instruments in its proposed generation service though the ERRA BA, PABA and the Energy Settlement MA, as shown on Table 7-2. SCE also proposes to include direct GHG costs for the New System Generation BA through its delivery service, as shown on Table 7-3. In addition, SCE forecasts additional indirect GHG costs embedded in the price of resources it will procure through the CAISO market to meet bundled customer load.

[103] *Id*. at 55, 57.

[104] *Id*. at 55.

No parties opposed or commented on SCE's GHG costs. Upon review, the Commission finds SCE's 2021 forecast GHG costs reasonable and in compliance with applicable rules, orders and Commission decisions.

8.2. Greenhouse Gas Allowance Proceeds

GHG allowance revenue comes from the sale of GHG allowances allocated by the State for the benefit of ratepayers, which SCE sells on behalf of ratepayers at quarterly GHG allowance auctions. SCE forecasts its GHG allowance revenue by multiplying a proxy GHG allowance price of $17.74/MT by the total volume of allowances the CARB allocated to SCE (25,183,597 allowances) in 2021.[105] SCE's total forecast GHG allowance revenue in 2021 is $446.757 million. SCE adjusts this forecast to reflect a $49.703 million undercollection in 2020 and a $5.085 million refund in FF&U in 2021 for a final 2021 GHG allowance revenue forecast of $402.139 million.[106]

No parties opposed or commented on SCE's GHG proceeds calculations. Upon consideration, the Commission finds SCE's net 2021 forecast allowance proceed amount reasonable and in compliance with applicable rules, orders and Commission decisions.

8.3. Administrative and Customer Outreach Expenses

The recorded and forecast administrative and customer outreach expenses are the costs incurred by a utility for administrative and customer outreach expenditures that relate to the GHG allowance proceeds return program.

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[105] *Id*. at 67.

[106] *Id*. at 72.

SCE's 2020 recorded administrative and customer outreach costs were $278,660.[107] SCE's 2021 forecast of administrative and customer outreach expenses is $250,000, consisting primarily of "marketing, education and outreach costs associated with the April and October (May/June in 2020) climate credits."[108] SCE also forecasts $2,902 in FF&U, for a total cost of $252,902 for administrative and customer outreach costs.[109]

No parties opposed or commented on SCE's 2021 forecast of administrative and customer outreach expenses as proposed in the November Update. Upon consideration, the Commission finds SCE's 2021 forecast administrative and customer outreach expense costs reasonable and in compliance with applicable rules, orders and Commission decisions.

8.4. Clean Energy and EE Projects

Under Pub. Util. Code § 748.5(c), the Commission may allocate up to 15% of the revenue received by an electric corporation from its sales of allocated GHG allowances to specific clean energy and EE projects that are not funded by another source and are already approved by the Commission. SCE's allowance for clean energy and EE projects for 2021 is $67.0 million.[110] A summary of SCE's proposed Clean Energy and EE programs is provided in Table 8-1 above and discussed in Sections 8.4.1 (SOMAH), 8.4.2 (DAC-SASH, DAC-GT and CSGT) and 8.4.3 (CEOP).

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[107] *Id*. at 63.

[108] *Ibid*.

[109] *Id*. at 72.

[110] *Id*. at 68, fn. 68.

8.4.1. SOMAH

Assembly Bill (AB) 693 (Eggman), Stat. 2015 ch. 582, created the SOMAH program, allocating up to $100 million annually for fiscal years 2016 through 2020 in funding from Pacific Gas and Electric Company, San Diego Gas & Electric Company, SCE, Liberty Utilities (CalPeco Electric) LLC and PacifiCorp d/b/a Pacific Power's share of greenhouse gas allowance auction proceeds to install solar photovoltaic energy systems on multifamily affordable housing properties throughout California.[111] SCE set aside funding for SOMAH starting in 2017 and the SOMAH program began operating on July 1, 2019. In D.20-01-022, the Commission clarified that prior-year GHG revenue allocations should be trued-up based on 10% allocation of actual GHG revenues received.

SOMAH was extended through 2026 by the Commission in D.20-04-012, which also directed SCE to set aside the quarter (Q)1/Q2 2020-2021 Fiscal Year (FY) allocations for SOMAH in the 2021 forecast.[112]

SCE proposes to set aside $44,675,700 in GHG revenue allocation for SOMAH in 2021. SCE also proposes to set aside $19,197,913 to true-up the Q1/Q2 FY 2020-2021 SOMAH budget, as authorized in D.20-04-012; and includes a nominal true up of the 2019 and 2020 SOMAH budget based on the difference between forecast and actual GHG allowance revenue during those two years.

Sunrun requests the Commission order additional reporting and accounting changes related to the administration of the SOMAH program in this decision. Specifically, Sunrun asks for a Commission order requiring "reports

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[111] D.17-12-022.

[112] The SOMAH program funding is allocated on a fiscal year basis while the Forecast revenue requirement is set for the calendar year, in this case 2021.

showing GHG auctions received, set-asides for the SOMAH Program, current SOMAH [BA] balances, transfer of funds to the public no less often than quarterly, but, preferably on a real-time basis."[113] Sunrun also requests a Commission order requiring SCE to include actual forecast funding in the SOMAH BA as soon as the forecasts are adopted.[114]

In response, SCE argues Sunrun's requests are outside the scope of this proceeding and suggests Sunrun make its discovery requests directly to the SOMAH program administrator prior to seeking a Commission order.[115]

We decline to make any methodology changes to the SOMAH program administration in this proceeding in response to Sunrun's request, as this issue is more appropriately addressed on an industry-wide basis in Rulemaking (R.) 20-08-020, the open NEM rulemaking proceeding. Otherwise, the Commission finds SCE's set aside for SOMAH reasonable and in compliance with applicable rules, orders and Commission decisions.

8.4.2. DAC Programs

In D.18-06-027, the Commission created the DAC-SASH, DAC-GT, and CSGT programs to increase access to solar generation in low income households. D.18-06-027 set an annual $10 million budget for the DAC-SASH program. SCE proposes to set-aside $4.600 million, its share of the annual $10 million budget, for the DAC-SASH program in 2021.

D.18-06-027 set no budget for the DAC-GT or CSGT programs, but authorized utilities to fund both programs first through available GHG

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[113] Sunrun Opening Brief at 2.

[114] *Ibid*.

[115] SCE Reply Brief at 10-11.

allowance proceeds, and then through public purpose program funds if the GHG allowance funds were exhausted. It also authorized CCAs to access these same program funding sources for their own DAC programs. On November 9, 2020, the Commission issued Resolution E-5102, which approved CPA's request for DAC-GT and CSGT program funding in Advice Letter (AL) 4-E/E-A. SCE set aside $2.531 million in clean energy and EE program funding for 2021 for CPA's budget request.[116]

CPA agreed with the DAC-GT and CSGT set-aside in comments.[117] Upon consideration, the Commission finds SCE's set aside for DAC-SASH, DAC-GT and CSGT reasonable and in compliance with D.18-06-027.

8.4.3. CEOP

In D.20-11-030, the Commission approved suspension of the CEOP due to energy use impacts resulting from California's COVID-19 shelter in place orders. As a result of the pilot's suspension, SCE no longer requests an additional set-aside in this Forecast Application.[118] This Decision does not approve any funding for CEOP.

8.5. Emissions-Intensive and Trade Exposed (EITE) Emissions Customer Return

A portion of the GHG allowance proceeds are returned to customers who qualify as EITE. The EITE customer return is set by formula and made to EITE customers once per year.

SCE's 2020 recorded EITE customer return was $39.189 million and SCE's 2021 forecast EITE customer return is $39.901 million. No parties opposed or

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[116] Exhibit SCE-04 at 69-70; Resolution E-5102.

[117] Opening Comments on SCE's November Update Testimony at 10.

[118] Exhibit SCE-04 at 69.

commented on SCE's 2020 forecast EITE customer return as proposed in the November Update. Upon consideration, the Commission finds SCE's forecast 2021 EITE customer return reasonable and in compliance with applicable rules, orders and Commission decisions.

8.6. Small Business Return

A portion of allowance proceeds are returned to customers who meet the definition of a small business. The forecast Small Business Return is volumetric; it is calculated using the forecast GHG Cost (*see* Section 7.1 above) and the volume of electricity used by the customer, and is returned as a credit to the delivery component of the applicable customers' monthly bills.

To set the credit amount for small business volumetric returns for 2021, SCE uses $312.598 million as the total cost of GHG for small businesses, which includes the total 2021 forecast Cap-and-Trade costs of $306.418 million and a $6.110 million cost adjustment for 2020.[119]

SCE's 2020 recorded Small Business Volumetric Return is $39.189 million and its 2021 forecast Small Business Volumetric Return is $39.901 million.

No parties opposed or commented on SCE's 2021 Small Business Volumetric Return in the November Update. Upon consideration, the Commission finds SCE's forecast 2021 Small Business Volumetric Return is reasonable for the purpose of calculating the proceeds available to customers.

The exact credit per customer will be determined by multiplying the Cap-and-Trade unit cost for the customer's rate schedule by the customer's monthly usage and then adjusting it 50%, which is the Industry Assistance Factor for 2021 as determined in D.20-10-002.

[119] Exhibit SCE-04 at 73.

8.7. Residential California Climate Credit

The California Climate Credit is distributed to residential households after all applicable GHG-related expenses and customer returns have been made. It appears as a credit on applicable residential customers' bills twice a year. The California Climate Credit is not related to the volume of electricity used by the household; each household within a utility's territory receives the same California Climate Credit.

In 2020, the total recorded GHG allowance revenue was approximately $49.703 million less than forecast for 2020.[120] SCE proposes to recover the 2020 shortfall through a reduction in total 2021 GHG allowance revenue available for distribution through the California Climate Credit.

SCE's 2021 forecast of the total number of households eligible for the residential California Climate Credit is 4,635,512 and the proposed total revenue available for the residential Climate Credit is $271.322 million.[121] SCE proposes a residential California Climate Credit of $29, to be distributed as a credit on residential customers' bills in April and October of 2021.

No parties opposed or commented on SCE's residential California Climate Credit in the November Update. Upon consideration, we find SCE's proposed residential climate credit return of $29 biannually reasonable and in compliance with applicable rules, orders and Commission decisions.

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[120] 2020 GHG revenues of $380.488 million and 2020 actual recorded revenues of $345.008 million. Exhibit SCE-04 at 72.

[121] *Ibid*.

9. Cost Responsibility Surcharges

The Cost Responsibility Surcharge Indifference Amount[122] is the difference between the total portfolio cost and the forecast value of the portfolio; it includes the CTC and the PCIA charges. The CTC charge is discussed in Section 9.1. PCIA charges are discussed in Section 9.2.

9.1. CTC Surcharge

The CTC recovers the "above-market" charges for pre-restructuring resources and is the same for all customers regardless of their departure date. For 2021, SCE forecasts a total CTC cost is $0.00001/kWh per customer for all vintages.

9.2. 2021 PCIA Surcharge

The PCIA recovers the above-market costs of all non-CTC eligible resources and varies by the generation resources in that vintage, except for the DWRBC Costs. The DWRBC is a surcharge to collect the "above-market" costs associated with the utility/California Department of Water Resources contracts entered into during the 2000-01 California Energy Crisis. For 2021, SCE forecasts a DWRBC cost of $0.00500/kWh for all vintages.

All other PCIA costs are assigned by customer vintage year. A customer's vintage year is determined by the date of a customer's departure from bundled customer service. Customers who depart in the first half of each year are assigned to the prior year's vintage and customers who depart in the second half of each year are assigned to the current year's vintage.[123] For example, 2019

[122] The Commission adopted the Cost Responsibility Surcharge Indifference Charge in D.02-11-022, as modified by D.03-07-030, D.06-07-030, D.08-09-012, D.11-12-018, Resolution E-4475, D.18-10-019 and D.19-10-001.

[123] D.08-09-012 at 108 (OP 9).

vintage departing load customers are those who departed SCE's bundled customer service between July 1, 2019 and June 30, 2020. SCE's vintages include 2001-2003, 2004-2008, and annually starting in 2009.

In order to calculate its PCIA requirement, SCE first calculates the "above market" or "below market" costs of its portfolio, also called the Indifference Amount. Accounting for true-ups and adjustments, SCE calculates a total 2021 PCIA revenue requirement of $1,446.275 million, $1,462.737 million including FF&U. SCE's forecast of its 2021 PCIA requirement is summarized in Table 9-1.

Table 9-1. Summary of 2021 Portfolio Costs, Portfolio Market Value, Balancing Account True-Ups, and Total PCIA Revenue Requirement Based in November Update Testimony[124]

PCIA Revenue Requirement	Amount (millions)
Portfolio Cost	$3,180.969
Market Value	$2,090.959
• Energy Value	$1,164.689
• RPS Value	$262.049
• RA Value	$664.220
Total 2021 Indifference Amount	$1,090.011
Balancing Account True-Ups (no FF&U)	
• 2020 YE PABA Balance	$488.327[125]
• 2020 YE PUBA Bundled Service Financing (BSF) Balance	-$56.421[126]

124 Exhibit SCE-04 at 95.

125 $493.886 million with FF&U.

126 The PUBA BSF Subaccount has a total balance of $67.111 million with interest and FF&U. This is slightly more than the $66.356 million undercollection recovered though the PCIA Trigger for the balance in the "PUBA DL Shortfall Subaccount." (Exhibit SCE-04 at A-6.)

• 2020 YE ERRA Balance	-$74.182[127]
• 2018 ERRA Review Decision	-$1.460
2021 PCIA Revenue Requirement	$1,446.275
2021 PCIA Revenue Requirement with FF&U	$1,462.737

For 2021, SCE forecasts a total Indifference Amount of $1,090.011 million, which is the Total Portfolio Cost[128] of $3,180.969 million less the $2,090.959 million Market Value[129] of SCE's portfolio. The positive Indifference Amount of $1,090.011 million indicates that SCE's generation portfolio is "above market" for 2021, which requires a PCIA surcharge on departed load customers' bills and higher electricity rates for SCE's bundled service customers.

After calculating the Indifference Amount, SCE calculates the total PCIA revenue requirement by accounting for applicable balancing account true-ups and one-time adjustments, including: 1) annual true-ups in the ERRA BA and PABA, 2) the one-time 2018 ERRA compliance decision disallowance adjustment, and 3) the PUBA trigger application.

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[127] -$75.026 million with FF&U.

[128] The Total Portfolio Cost is based on fixed and variable costs of generation resources SCE forecasts it will use to meet bundled customer needs for the year. (Exhibit SCE-04 at 96.) These include the base generation revenue requirement determined in the General Rate Case Phase I, fuel costs, direct GHG costs of eligible UOG, RPS-eligible contract costs, QF and non-CAM-eligible CPH contract costs, all bilateral and RFO contract costs (including fuel costs and direct GHG costs as applicable), one-time refunds or adjustments. (Exhibit SCE-04 at, 96-97.) "The Total Portfolio Cost does not include any costs associated with CAM or LCR-eligible resources, ISO-load related costs, or Residual Net Position spot market (*i.e.*, "short term") purchases." (Exhibit SCE-04 at 97.)

[129] The Market Value of SCE's portfolio is calculated as a sum of the energy value, the RPS value, and the RA value of the portfolio. For each variable, a market price benchmark is multiplied by the applicable volume of the value calculated.

In D.18-10-009, the Commission adopted a cap that limits the year-over-year change in PCIA rates. Beginning in forecast year 2020, "the cap level of the PCIA rate is set at 0.5 cents (¢)/kWh more than the prior year's PCIA, differentiated by vintage." As a result, if the system average PCIA rate by customer vintage is forecast to increase by more than 0.5 ¢/kWh, then all PCIA rates for that customer vintage would be capped. In accordance with D.18-10-019, the rates adopted in the decision are capped for departed load customer vintages 2011 through 2019, with just the 2014 through 2017 vintages impacted by the cap in the 2021 ERRA forecast. These rates are summarized in the table below.

Table 9-2. Summary of Adopted 2021 System Average PCIA Rates.

PCIA Vintage Year	2021 Capped PCIA Rates (System Average)
2001	$0.00015/kWh
2004	$0.00016/kWh
2009	$0.01017/kWh
2010	$0.01245/kWh
2011	$0.01528/kWh
2012	$0.01608/kWh
2013	$0.01766/kWh
2014	$0.02241/kWh
2015	$0.01770/kWh
2016	$0.02085/kWh
2017	$0.02010/kWh
2018	$0.02422/kWh
2019	$0.02436/kWh
2020	$0.02154/kWh
2021	$0.02108/kWh

We also adopted a PCIA Trigger Mechanism surcharge for departed load customers to recover the indifference costs above the PCIA cap for vintages 2014 through 2017 forecast for 2021 as well as to recover the 2020 undercollection in the PUBA, as discussed in Sections 9.5 below.

9.3. PCIA Trigger Application

We now consider recovery of the 2020 PUBA undercollection proposed in SCE's PCIA Trigger Application. SCE's compliance with PCIA Trigger Application requirements are discussed in Section 9.3.1. The components of SCE's PCIA Trigger Application are discussed in Section 9.3.2. The joint Settlement Agreement is discussed in Section 9.4.

9.3.1. SCE's Compliance with PCIA Trigger Application Requirements

SCE must file an expedited PCIA trigger application within 60 days if there is an undercollection or overcollection of the PCIA revenue requirement for departed load customers which exceeds the 7% trigger point and SCE expects the departed load PCIA to exceed the 10% trigger threshold.[130] On October 9, 2020, SCE filed an expedited application notifying the Commission that it exceeded its 7% PCIA trigger point as of August 31, 2020, and had no reasonable expectation the PUBA BSF subaccount balance would self-correction within 120 days.

SCE's PCIA trigger point for 2020 is $29.060 million and its PCIA threshold amount is $41.514 million.[131] SCE has an undercollection of $35.366 million as of August 31, 2020, which exceeds its trigger point, as shown in Table 10-1 below. At the time, SCE forecast its balance for the remainder of the year, which showed that its PCIA trigger-related balance would not self-correct within 120 days.

Since SCE filed an expedited trigger mechanism application within 60-days of exceeding the PCIA trigger point, the Commission finds SCE

[130] D.18-10-019 at 86-87; 162 (OP 10).

[131] D.20-01-022.

complied with the trigger mechanism's reporting requirement in D.18-10-019 OP 10(b).

9.3.2. PCIA Trigger Application Components

A PCIA trigger application must include "a projected account balance as of 60 days or more from the date of filing depending on when the balance will reach the 10% threshold."[132] It must also "propose a revised PCIA rate that will bring the projected account balance below 7% and maintain the balance below that level until January 1 of the following year, when the PCIA rate adopted in that utility's ERRA forecast proceeding will take effect."[133]

When reviewing a trigger application, the Commission must confirm the accuracy of SCE's estimates and confirm that those estimates meet the PCIA threshold amount within the timeframes established by D.18-10-019 in order to approve the application. Where a rate increase is required to correct an undercollected revenue requirement, the Commission conducts a step-by-step review of the request in order to benefit SCE, its ratepayers and the protestants. The step-by-step review of SCE's PCIA Trigger Application includes the following: 1) the accuracy of the PCIA trigger-related balance request and requirement to meet the PCIA threshold amount, 2) causes of the undercollection, 3) the rate impact of including the undercollection in SCE's PCIA rates, 4) allocation of the overcollection amongst SCE's customers; and 5) the amortization period of the overcollection.

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[132] D.18-10-019 at 162 (OP 10(c)).

[133] *Id*. at 162-163 (OP 10(d)).

9.3.2.1. Accuracy of the PCIA Trigger Application and Requirement to Meet the PCIA Trigger Point and PCIA Threshold Amount

The PCIA trigger application "shall include a projected account balance as of 60 days or more from the date of filing depending on when the balance will reach the 10% threshold."[134]

SCE provided a table that itemized the components of the projected $66.356 million year-end undercollection, as shown in the tables below.

Table 9-3. SCE's Recorded 2020 PUBA Balance[135]

2020 Month	PUBA Balance w/o FF&U (millions)	Trigger as % of 2020 PCIA Revenue Requirement
April	$1.323	0.32%
May	$8.544	2.06%
June	$18.238	4.39%
July	$27.891	6.72%
August	$35.366	8.52%
September	$42.595	10.26%

Table 9-4. SCE's Forecast 2020 PUBA Balance

2020 Month	PUBA Balance (millions)	Trigger as % of 2020 PCIA Revenue Requirement
October	$50.968	12.28%
November	$58.519	14.10%
December	$66.356	15.98%

The Commission is satisfied that parties were provided sufficient time to review the PUBA balance for inaccuracies. While the shortened timeframes imposed by statutes (combined with the uncertainties generally inherent in energy forecasting) create challenges for all parties in the ERRA process, parties

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[134] D.18-10-019 at 87.

[135] Exhibit SCE-04 at A-6.

have had the opportunity to review the PUBA balances. Therefore, the Commission finds that SCE first exceeded the 7% PCIA trigger point as of August 31, 2020.

9.3.2.2. Causes of the PCIA Trigger-Related Undercollection

According to SCE, the main cause of the revenue shortfall is the Commission's adoption of capped PCIA rates for 2011 through 2019 vintage departed load customers in the 2020 ERRA Forecast Decision (D.20-01-022).[136] SCE also argues that "using forecast PCIA rates for the year-to-year PCIA Rate cap comparison rather than trued-up or reset PCIA rates," results in a flawed PCIA rate which also drives the PUBA undercollection.[137] SCE proposes to address this PCIA true-up methodology change through the PCIA Trigger Application.

We deny SCE's request to change the current PCIA methodology for calculating the PCIA rate cap by interpreting the language of D.18-10-019 OP 9. PCIA methodology changes are more appropriately addressed in the open PCIA rulemaking proceeding, R.17-06-026. Otherwise, we find SCE's explanation for the causes of the PUBA undercollection reasonable and in compliance with D.18-10-019's PCIA trigger mechanism requirements.

9.3.2.3. PCIA Rate Impact, Allocation, and Amortization Period of PUBA BSF Subaccount Undercollection – SCE Proposal 1 and 2

A PCIA trigger application "shall propose a revised PCIA rate that will bring the projected account balance below 7% and maintain the balance below

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[136] Exhibit SCE-PCIA-01 at 14.

[137] *Id*. at 7, 14.

that level until January 1 of the following year, when the PCIA rate adopted in that utility's ERRA forecast proceeding will take effect."[138] In its PCIA Trigger Application, SCE requests the Commission adopt one of two proposals to change its 2021 forecast PCIA rates. Subsequently, parties to the PCIA Trigger Application reached a settlement and now propose the Commission adopt this third option. The settlement agreement is discussed in Section 9.4.

SCE's first proposal in the PCIA Trigger Application is to recover 100% of the forecast 2020 year-end PCIA Trigger Balance, or $66.356 million, as a surcharge on applicable departing load customers over a 12-month amortization period coincident with amortization of the 2021 ERRA Forecast Revenue Requirement (Proposal 1). [139] Under this proposal, SCE's 2021 PCIA rate is capped at a half-cent increase over the capped 2020 PCIA rates.

SCE argues that this approach is consistent with historical cost-recovery principles. SCE expects to incur a PCIA rate recovery shortfall of $3,562,814 in 2021 as it amortizes the PUBA BSF DL Subaccount balance under Proposal 1, as shown in Table 9-4.

SCE's second proposal is to recover a 80% of the 2020 PUBA undercollection and the full "uncapped" 2021 forecast PCIA revenue requirement in 2021 (Proposal 2).[140] Under Proposal 2, the remaining 20% of the 2020 PUBA undercollection is amortized in 2022. Bundled service customers, on the other hand, are credited 100% of the PUBA balance in 2021. Both proposals

[138] D.18-10-019 at 87.

[139] PCIA Trigger Application at 4.

[140] *Id*. at 4.

result in similar increases to 2021 PCIA rates. We deny both proposals in favor of the PCIA Trigger Mechanism Surcharge approach discussed in Section 9.5.

9.4. Settlement Agreement

This decision denies approval of the settlement agreement, dated November 20, 2020, which addresses the PUBA undercollection and proposes PCIA rates for 2021 (Settlement Agreement). The Settlement Agreement is entered into by SCE, CPA, Cal CCA, and SoCal CCAs (collectively the "Settling Parties.") Sunrun, AReM, DACC, and Cal Advocates, are not parties to this Settlement Agreement.

SCE noticed a settlement conference pursuant to Rule 12.1 on November 4, 2020. The Settling Parties held an initial meeting on November 13, 2020, where they agreed on a term sheet addressing 2021 PCIA rates and amortization of the PUBA undercollection. The Settlement Agreement was finalized on November 19, 2020, and the Settling Parties filed a joint motion for approval of the Settlement Agreement on November 20, 2020.

In reviewing the Settlement Agreement, we look at whether it is reasonable in light of the record, consistent with the law, and in the public interest, as the Commission historically favored such settlements.

In this instance, we review whether the Settlement Agreement is consistent with the law first, as the rest of our analysis revolves around addressing legal concerns with the terms of the Settling Parties' agreement. In order for the Commission to approve a Settlement Agreement, it must not contravene any statutory provisions or prior Commission decisions, and provide sufficient information for the Commission to discharge future regulatory obligations.

First, we address Term 3 of the Settlement Agreement, wherein the Settling Parties agree to waive the PCIA rate cap for 2021. The PCIA rate cap is set by

Commission order in D.18-10-019 and parties cannot waive the Commission's orders by agreement. We have already found that changes to the PCIA rate cap are properly addressed in the open PCIA rulemaking. Accordingly, Term 3 is not consistent with the Commission's orders in D.18-10-019.

Now we review Terms 5 and 6 of the Settlement Agreement. These terms not only obligate the Settling Parties to support a petition for modification (PFM) of D.18-10-019 to remove the PCIA cap from consideration but also obligate the Commission to approve the termination of the PCIA cap through approval of the PFM. While we note the Settling Parties' unanimous opposition to the PCIA rate cap in this proceeding, we neither obligate the Settling Parties to take a position on the PCIA cap in a future PFM to D.18-10-019 nor prejudge the outcome the Commission's consideration of any such PFM in the PCIA rulemaking. Accordingly, Terms 5 and 6 of the Settlement Agreement are denied as outside the scope of this proceeding.

Finally, Term 9 requires that "if the Commission rejects the Settlement Agreement or a Party withdraws from the Settlement Agreement, the Parties agree that SCE shall be entitled to collect the entire remaining two-thirds (2/3) amortization of the 2020 PCIA Trigger Balance in 2020."[141] Requiring PCIA rate obligations predicated on the Commission's rejection of the Settlement Agreement undermines the orders in this decision, and is denied as inconsistent with the Commission's authority to regulate SCE pursuant to Pub. Util. § 701.

As we find terms of the Settlement Agreement are not consistent with the law, this decision denies the parties' Settlement Agreement.

[141] Settlement Agreement at 8.

9.5. PCIA Trigger Mechanism Surcharge

We now consider the proper surcharge to apply to departed load customers in response to the PCIA Trigger Mechanism Application. It is worth noting first that the term "undercollection" with regards to the PUBA is a misnomer. While the PCIA amount that exceeds the cap (and which therefore cannot be collected from departed load customers and is tracked in the PUBA) is referred to as an "undercollection," SCE has collected this amount in 2020 rates as a "loan" from bundled service customers to departed load customers. The PCIA Trigger amount at issue has already been (or, by the end of 2020, will be) paid by bundled service customers.

In setting the PCIA Trigger Mechanism Surcharge, we balance multiple goals, including: 1) minimizing rate shock for departed load customers, 2) providing fair returns to bundled service customers, 3) revising the PCIA rate to bring the PUBA balance below the PCIA trigger point, and 4) maintaining the PUBA balance below the trigger point until January 1 of the following year.

The parties' proposals, along with the Commission's adopted surcharge, are summarized in Table 9-5, below.

Table 9-5. Summary of PCIA Departed Load Surcharge under PCIA Rate Proposals.

Year	Balance	Proposal 1	Proposal 2	Settlement Proposal	Adopted Trigger Surcharge
2021	2020 PUBA	$66,355,658 (100%)	$51,990,946 (80%)	$22,118,553 (33%)	$22,118,553 (33%)
	2021 PCIA above cap	NA	$3,562,814 (100%)	$3,562,814 (100%)	$3,562,814 (100%)
2022	2020 PUBA	NA	$13,271,132 (20%)	$22,118,553 (33%)	$22,118,553 (33%)
2023	2020 PUBA	NA	NA	$22,118,553 (33%)	$22,118,553 (33%)

To reduce the PUBA balance below the trigger point, we adopt a PCIA Trigger Mechanism Surcharge which amortizes the $66.356 million year-end 2020 forecast PUBA undercollection over three years, with one-third of the balance amortized each year for 2021, 2022, and 2023. This is consistent with the terms of the Settlement Agreement. We find a three-year amortization period for the 2020 year-end PUBA balance reasonably reduces rate shock for departing load customers while balancing the needs of bundled service customers for a fair return of the amount they have paid.

To maintain the PUBA balance below the trigger point in 2021, we adopt a PCIA Trigger Mechanism Surcharge that includes the portion of the 2021 indifference amount which is above the 2021 capped PCIA rates (a total forecast value of $3.563 million). While Proposal 2 and the Settlement Agreement both sought to recover these "above cap" costs, our adopted proposal recovers this amount as part of the PCIA Trigger Mechanism Surcharge rather than waive or alter the PCIA rate cap requirement in D.18-10-019 for setting the 2021 forecast PCIA rates.

10. Data Access

Given the importance of an expedited process to review and adopt SCE's ERRA-related revenue requirement prior to the annual electric true-up, we recognize the need for certain market participants, such as CCAs, to have more detailed information on a routine basis ahead of the annual November Update testimony.

Throughout this proceeding, SoCal CCAs requested the Commission direct SCE to provide certain information in confidential workpapers and routine reports, including:

1. Confidential versions of the monthly ERRA/PABA/PUBA reports;
2. Additional detail supporting the monthly PABA reports, including subcategories for summarized line items such as UOG costs and Contracts (*e.g.* provide by resource type, and whether RPS or non-RPS eligible);
3. Actual volumetric quantities underlying each relevant dollar figure in PABA report; such categories include UOG generation, power purchases and sales, CAISO market sales, and retail customer sales;
4. Monthly volumes of Actual Sold, Retained, and Unsold Resource Adequacy; and
5. Monthly volumes of Actual Sold, Retained, and Unsold RPS.[142]

As part of the discovery process, SCE provided substantial verifiable data to the SoCal CCA's reviewing representatives through data requests, including:

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[142] SoCal CCAs Opening Brief at 13-16; SoCal CCAs Comments on the SCE November Update Testimony at 2.

1. Confidential versions of its monthly activity reports to the Commission's Energy Division regarding its ERRA Balancing Account, PABA, and PUBA reports;
2. Existing monthly reports providing underlying volumetric data for power purchase contracts, UOG; retained, sold and unsold RECs associated with Renewable Portfolio Standards Resources; and retain, sold, and unsold Resource Adequacy Reports.[143]

Delaying access to the ERRA/PABA/PUBA and other reports concerning the validity of SCE's ERRA forecast application until the November Update, and requiring extensive discovery requests to obtain this information, creates additional administrative burdens for the parties to the proceeding as well as Commission staff. While we acknowledge SCE's substantial discussion of the PABA in testimony, we also see the need for streamlining the ERRA review process moving forward. Accordingly, SCE must provide the following information in confidential workpapers for future ERRA forecast proceedings and in monthly ERRA compliance reports, beginning in January 2021:

1. Confidential version of monthly ERRA/PABA/PUBA activity reports;
2. Additional detail supporting the monthly PABA reports, including subcategories for summarized line items such as UOG costs and contracts (*e.g.*, provide by resource type, and whether RPS or non-RPS eligible)
3. Actual or accrued volumetric quantities underlying each relevant dollar figure; such categories include UOG generation, power purchases and sales, CAISO market sales, and retail customer sales;
4. Monthly accrued volumes of Actual Sold, Retained, and Unsold Resource Adequacy capacity; and

[143] SCE Reply Brief at 2-6.

5. Monthly accrued volumes of Actual Sold, Retained, and Unsold RPS eligible energy.

Due to the sensitivity of much of the information contained in these reports, we only direct SCE to distribute these reports to independent reviewing representatives or consultants, appointed by market participants, who have signed appropriate nondisclosure agreements. This does not alter our current confidentiality protocols or implicitly alter the sufficiency of current nondisclosure agreement language.

As discussed in Section 7, SCE is also directed to provide the following information in ERRA forecast proceeding workpapers, starting January 2021:

a. Percent rate change relative to current rates by customer class; and
b. Bill impact by customer class.

11. Safety Considerations

The health and safety impacts of GHGs are among the reasons that the Legislature enacted AB 32. Specifically, the Legislature found and declared that global warming caused by GHGs "poses a serious threat to the economic well-being, public health, natural resources, and the environment of California." Potential adverse impacts include "the exacerbation of air quality problems, a reduction in the quality and supply of water to the state from the Sierra snowpack, a rise in sea levels resulting in the displacement of thousands of coastal businesses and residences, damage to marine ecosystems and the natural environment, and an increase in the incidences of infectious disease, asthma, and other human health-related problems."[144]

[144] AB 32 § 38501(a).

This decision approves SCE's forecast of GHG costs and allocation of GHG allowance proceeds to maintain a key aspect of the GHG reduction program envisioned by AB 32 and Pub. Util. Code § 748.5 and, as a result, will improve the health and safety of California residents.

12. Compliance with the Authority Granted Herein

SCE must submit a Tier 1 advice letter to the Commission's Energy Division within 30 days of the date of issuance date of this decision in order to implement the rate changes authorized by this decision. The tariff sheets filed in this advice letter shall be effective on or after the date filed, subject to the Commission's Energy Division determining that SCE's advice letter complies with this decision.

13. Reduction of Comment Period and Party Comments

Pursuant to Rule 14.6(b), all parties stipulated to reduce the 30-day public review and comment period required by Pub. Util. Code § 311 to 10 days for opening comments and five days for reply comments DACC and AReM, jointly; SCE; and SoCalCCAs filed opening comments on December 10, 2020. SCE and SoCalCCAs filed reply comments on December 15, 2020.

This decision reflects revisions in response to comments as noted throughout. Where the comments were merely repeated contentions made earlier in the proceeding, those comments are not addressed further.

14. Assignment of Proceeding

Martha Guzman Aceves is the assigned Commissioner and Zita Kline is the assigned ALJ.

Findings of Fact

1. SCE's total forecast ERRA revenue requirement for 2021 is $4,454.131 million.

2. SCE predicts a 1.1% decrease in total retail electricity sales from 2020 to 2021, from a total retail sales forecast of 80,119 GWh in 2020 to 79,270 GWh in 2021.

3. SCE forecasts an increase of 0.7% increase in total electricity customers from 5,183.295 million in 2020 to 5,217.585 million in 2021.

4. SCE's preliminary forecast includes the statewide increase in the DA load expected to start in 2021 and CCAs that meet the following criteria 1) filed a binding notice of intent to begin CCA service, 2) filed an initial RA filing, 3) started CCA service and 4) formally submitted an April RA forecast pursuant to Pub. Util. Code § 380.

5. SCE's UOG and Purchased Power contracts in 2021 consist of 1,176 MW nameplate capacity of hydroelectric power, 91 MW of solar photovoltaic resources, 10,620 MW of CHP and renewables projects resources and 245 MW of natural gas resources.

6. SCE executed two inter-utility contracts for 2021, consisting of 1) an entitlement of 280.245 MW of contingent capacity and 238.16 GW of firm energy through a contract with WAPA and 2) 3 MW of energy from the Azusa Powerhouse through a corporate grant deed.

7. SCE forecast F&PP costs associated with four types of contracts for new generation resources in 2021, including 1) New System Generation CAM contracts, 2) System Reliability Modified CAM contracts, 3) Generic and Bilateral contracts used to meet 2021 system capacity requirements, and 4) contracts used to meet local capacity requirements.

8. SCE's procurement-related Public Purpose Programs charges fund behind the meter resources procured through the Preferred Resources Pilot #2 and recover the net costs associated with biomass generation associated with the Tree Mortality Non-Bypassable Charge.

9. SCE forecasts 2,122,257 kWh of participation through the Green Tariff Shared Renewables program in 2021.

10. SCE forecasts $4.4 million in interim spent nuclear fuel costs at SONGS in 2021.

11. SCE forecasts $33.7 million in costs for nuclear fuel expenses and $0.1 million net interim spent nuclear fuel expenses at PVNGS in 2021.

12. SCE forecasts a cost of $5.811 million to provide electricity service to Catalina Island, which includes the $5.414 million in diesel fuel and $0.398 million for propane in 2021.

13. SCE forecasts costs for 6 GW of energy reductions in 2021 to provide economic demand response programs, including the Summer Discount Plan, Capacity Bidding Program, Critical Peak Pricing, and Smart Energy Programs.

14. SCE forecasts F&PP costs in 2021 associated with the net CAISO costs of grid management charges, Federal Energy Regulatory Commission fees, congestion fees, Congestion Revenue Rights actions-related CAISO costs, ancillary services, CAISO uplist costs, Standard Capacity Product costs, and other non-energy related CAISO costs.

15. SCE forecasts 2021 hedging costs for energy-related transaction fees and option premiums for hedging SCE's open energy position in workpapers for 2020.

16. SCE forecasts $1,200 in 2021 costs associated with natural gas delivery to SCE's UOG fuel cells at UC Santa Barbara and California State University at San Bernardino.

17. SCE has a $3 billion multi-year revolving credit facility, also called the "revolver," to serve short-term borrowing requirements.

18. SCE forecasts costs associated with the revolving credit facility in workpapers for 2021, including 1) upfront costs and fees for the extension, 2) $20,000 administrative fee, 3) 17.5 basis point annual facility fee, 4) 107.5 basis point participation fee on any outstanding letters of credit, 5) 20 basis point issuer fee on any letters of credit, and 6) London Inter-Bank Offered Rate plus 107.5 basis points borrowing (loan) rate.

19. SCE forecasts fuel inventory carrying costs for nuclear, natural gas, diesel and propane in workpapers for 2021.

20. SCE forecasts GHG procurement compliance carrying costs for 2021, which SCE estimates using historical GHG inventory balances and the ERRA balancing account interest rates in workpapers for 2021.

21. SCE forecasts the carrying costs associated with SCE's collateral requirements necessary to procure power in workpapers for 2021.

22. SCE's 2021 forecast bundled service customer rates are as follows:

Rate Schedule by Customer Group	Total Delivery (¢/kWh)	Total Generation (¢/kWh)	Total (¢/kWh)
Domestic			
• D	14.744	9.509	24.253
• D-CARE	5.599	9.673	15.272
• D-APS	12.962	9.686	22.648
• DE	8.387	9.665	18.052
• DM	15.787	9.713	25.500
• DMS-1	15.020	9.713	24.733
• DMS-2	13.452	9.712	23.164
Lighting-Small, Med. Power			
• GS-1	11.003	9.640	20.643
• GS-2	12.049	9.015	21.064
• TC-1	15.247	7.277	22.524
• TOU-GS	10.748	7.985	18.732
Large Power			
• TOU-S	9.044	7.563	16.607
• TOU-P	7.856	7.069	14.925
• TOU-T	3.170	6.539	9.709
• TOU-8-S-S	9.149	7.420	16.569
• TOU-8-S-P	9.209	7.561	16.770
• TOU-8-S-T	4.192	6.186	10.378
Agricultural & Pumping			
• TOU-PA-2	9.608	8.035	17.643
• TOU-PA-3	8.087	6.735	14.822
Street & Area Lighting			
• LS-1	31.431	4.750	36.181
• LS-2	11.342	4.833	16.175
• LS-3	4.862	4.866	9.728
• DTL	28.069	4.861	32.930
• OL-1	24.595	4.861	29.456
Average Rate - All Groups	10.280	8.642	18.922

23. SCE's 2021 forecast Generation Service revenue requirement is $3,980.401 million, which will be allocated in balancing accounts as follows:

Description	Forecast 2020 Revenue Requirement (millions)
Fuel and Purchased Power Costs (including GHG costs) • ERRA BA-related • PABA-related • Green Tariff Shares Renewables BA-related	 $2,424.828 $1,133.862 $2.148
2020 ERRA BA True-up	-$75.026
2020 PABA True-Up	$493.886
2020 Energy Settlements MA True-Up	$0.704
Total Generation Service	**$3,980.401**

24. SCE's 2021 forecast Delivery Service revenue requirement is $473.729 million, which will be allocated as follows:

Description	2021 Revenue Requirement (millions)
New System Generation • New System Generation Fuel and Purchased Power 2021 Forecast[145] and 2021 System Reliability F&PP • New System Generation BA 2020 True-Up	 $710.233 -$32.819
Spent Nuclear Fuel	$4.532
Distribution Rate Component • Base Revenue Requirement BA-D F&PP 2020 Forecast • GHG Allowance Revenues 2020 Forecast	 $27.696 -$330.882
Public Purpose Programs Charge • Public Purpose Program Charge F&PP • Tree Mortality Non-Bypassable Charge BA (2020 True-Up)	 $83.782 $11.187
Total Delivery Service	**$473.729**

[145] Estimate includes GHG costs.

25. SCE forecast its 2020 GHG allowance revenue using a forecast proxy price of $17.74/MT.

26. SCE was allocated 25,183,597 allowances by CARB in 2021.

27. SCE's net forecast revenue proceeds from GHG allowances granted by CARB in 2021 is $402.139 million, which includes a $5.085 million refund in 2020 for FF&U, $49.703 million reduction due to lower than expected GHG allowance revenue in 2020, and $446.575 million in 2021 forecast GHG auction proceeds.

28. SCE's 2021 forecast administrative and customer outreach expenses to be set aside is $252,902.

29. GHG allowance revenue to be set aside for SOMAH program funding in 2021 is $44.676 million.

30. GHG allowance revenue to be set aside for the 2019/2020 true-up of the SOMAH program is $19.198 million.

31. GHG allowance revenue to be set aside for SCE's 2020 DAC-SASH program in 2021 is $4.6 million.

32. GHG allowance revenue to be set aside to be set aside for CPA's DAC-GT and CSGT program in 2021 is $2.531 million.

33. SCE's 2021 forecast EITE customer return is $39.901 million.

34. SCE's 2021 forecast Small Business Volumetric Return is $19.658 million.

35. SCE's 2021 forecast semi-annual Residential California Climate Credit is $29 per household, based on a forecast of 4,635,512 eligible households.

36. Challenges to facts supporting SCE's proposed 2021 forecast of fuel and purchased power prices; natural gas prices; electricity prices; GHG costs and proceeds; demand response costs; bundled customer electric sales and year-end

balancing accounts are waived by parties in this proceeding by virtue of stipulation to waive evidentiary hearing.

37. Setting a PCIA surcharge for departed load customers that amortizes the PUBA undercollection equally over three years (2021, 2022, and 2023) and includes the "above PCIA rate cap" amounts of the 2021 PCIA Revenue Requirement in the 2021 PCIA surcharge rate is consistent with the Settlement Agreement.

38. Certain market participants, including CCAs, require timely access to SCE's ERRA/PABA/PUBA reporting as well as precise volume of RA, RPS and other metrics in order to meet their evidentiary burden in the ERRA forecast proceeding.

39. SCE already provides certain data regarding its ERRA/ PABA/PUBA balances and other metrics associated with its ERRA forecast to the Commission on a monthly basis.

40. Delaying access to the ERRA/PABA/PUBA and other reports concerning the validity of SCE's ERRA forecast application until the November Update creates additional administrative burdens for the parties to the proceeding as well as Commission staff.

Conclusions of Law

1. SCE's forecast of fuel and purchased power prices; natural gas prices; electricity prices; GHG costs and proceeds; demand response costs; bundled customer electric sales and year-end balancing account balances are reasonable.
2. The Settlement Agreement is not consistent with the law.
3. The Settlement Agreement should be denied.

4. SCE's request to change the current PCIA methodology for calculating the PCIA rate cap is more appropriately addressed in the open PCIA rulemaking proceeding, R.17-06-026.

5. Granting independent consultants access to confidential market sensitive information, under appropriate non-disclosure agreements, is a reasonable means of allowing market participants to review confidential versions of ERRA/PABA/PUBA reports.

6. Advice Letters to implement changed tariff sheets in accordance with this Decision should be filed as Tier 1 Advice Letters.

7. These consolidated applications should be closed.

O R D E R

IT IS ORDERED that:

1. Southern California Edison Company (SCE) is authorized to recover a total 2021 Energy Resource Recovery Account (ERRA) electric procurement cost revenue requirement forecast of $4,454.131 million, consisting of both a generation service and a delivery service component.

Within SCE's generation service requirement of $3,980.401 million, SCE is authorized to recover a total of $3,560.837 million in fuel and purchased power costs and transfer the following account balances: 1) -$75.026 million from the ERRA Balancing Account (BA), 2) $493.886 million from the Portfolio Allocation BA, and 3) $0.704 million from the Energy Settlements Memorandum Account.

Within SCE's delivery service revenue requirement of $473.729 million, SCE is authorized to recover the following: 1) $710.233 million for the New System Generation and System Reliability contracts, 2) $4.532 million in spent nuclear fuel costs, 3) $27.696 million for economic demand response programs, 4) -$330.882 million customer return of greenhouse gas allowance proceeds, and

5) $83.782 million for both the Tree-Mortality Non-Bypassable Charge and the SCE's Preferred Resources Pilot #2. SCE is also authorized to transfer the following account balances: 1) -$32.819 million in the New System Generation BA and 2) $11.187 million in the Tree Mortality Non-Bypassable Charge BA.

SCEs is authorized to reconcile greenhouse gas (GHG) costs, revenues and requirements as follows: 1) recover a revenue requirement of -$302.970 million in GHG Cap-and-Trade costs, 2) distribute -$330.882 million in forecast 2021 GHG forecast auction proceeds (-$402.139 million net auction proceeds accounting for a $49.703 million undercollection in GHG auction revenue during 2020 and -$5.085 million in Franchise Fees and Uncollectibles during 2021), with $71.004 million set aside for clean energy and energy efficiency projects, and $252.902 thousand set aside for outreach and administrative expenses.

2. Southern California Edison Company's rate component for the Green Tariff Shared Renewables Program is approved.

3. This decision authorizes the forecast amount of $29 semi-annually per household for the California Climate Credit program to be returned to residential customers beginning in 2021.

4. Southern California Edison Company (SCE) must return $330.882 million in net Greenhouse Gas allowance proceeds to SCE's customers.

5. The November 20, 2020, Joint Motion for Commission adoption of a settlement agreement pursuant to Article 12.1 of the Commission's Rules of Practice and Procedure is denied and the Settlement Agreement is denied.

6. Southern California Edison Company (SCE) will apply a PCIA Trigger Mechanism Surcharge to departed load customers in 2021 which includes the following: 1) one-third of the 2020 year-end undercollection in the Power Charge

Indifference Adjustment (PCIA) Undercollection Balancing Account (PUBA) and 2) the portion of the 2021 forecast PCIA revenue requirement for departed load customers which exceeds the amount recoverable under capped PCIA rates. SCE will apply a PCIA Trigger Mechanism Surcharge to departed load customers in 2022 and 2023 which amortizes one-third of the remaining total 2020 year-end PUBA balance each year.

7. Southern California Edison Company must provide the following information in ERRA forecast proceeding workpapers, starting January 2021:

(a) Percent rate change relative to current rates by customer class; and

(b) Bill impact by customer class.

8. Southern California Edison Company must provide the following information in Energy Resource Recovery Account (ERRA) forecast proceeding workpapers and monthly ERRA compliance reports, starting January 2021:

(a) Confidential version of monthly ERRA/Portfolio Allocation Balancing Account (PABA)/ PABA Undercollection Balancing Account activity reports;

(b) Additional detail supporting the monthly PABA reports, including subcategories for summarized line items such as utility-owed generation (UOG) costs and contracts (*e.g.*, provide by resource type, and whether Renewables Portfolio Standard (RPS) or non-RPS eligible)

(c) Actual or accrued volumetric quantities underlying each relevant dollar figure; such categories include UOG generation, power purchases and sales, California Independent System Operator market sales, and retail customer sales;

(d) Monthly accrued volumes of Actual Sold, Retained, and Unsold Resource Adequacy capacity; and

(e) Monthly accrued volumes of Actual Sold, Retained, and Unsold RPS-eligible energy.

9. Southern California Edison Company shall file a Tier 1 Advice Letter (AL) and revised tariff sheets within 30 days of the issuance of this decision to implement this decision. The AL shall include changed tariff sheets and supporting documentation for:

(a) Residential rate schedules (including master-metered rate schedules) to include the authorized 2021 Climate Credit amount;

(b) Small business rate schedules to include the volumetric dollars per kilowatt hour greenhouse gas rate offset for small business customers; and

(c) The amount approved in Ordering Paragraph 1.

10. All rulings issued by the assigned Commissioner and Administrative Law Judge (ALJ) are affirmed herein; and all motions not specifically addressed herein or previously addressed by the assigned Commissioner or ALJ, are denied.

11. Consolidated Applications 20-07-004 and 20-10-007 are closed.

This order is effective today.

Dated December 17, 2020, at San Francisco, California.

MARYBEL BATJER
President
LIANE M. RANDOLPH
MARTHA GUZMAN ACEVES
CLIFFORD RECHTSCHAFFEN
GENEVIEVE SHIROMA
Commissioners

APPENDIX A

Acronym List

APPENDIX A

Acronym List

Acronym	Description
AB	Assembly Bill
AL	Advice Letter
ALJ	Administrative Law Judge
BA	Balancing Account
BRRBA - D	Base Revenue Requirement Balancing Account - Distribution
CA	Community Aggregation
CAISO	California Independent System Operator
Cal Advocates	The Public Advocates Office of the Public Utilities Commission
Cal CCA	California Community Choice Association
CAM	Cost-Allocation Mechanism
CARB	California Air Resources Board
CCA	Community Choice Aggregation
CCEA	California Choice Energy Authority
CDWR	California Department of Water and Resources
CEOP	Clean Energy Optimization Pilot
CHP	Combined Heat and Power
CPA	Clean Power Alliance of Southern California
CSGT	Community Solar Green Tariff
CTC	Competition Transition Charge
D	Domestic Service
DA	Direct Access
DACC	Direct Access Customer Coalition
DAC-GT	Disadvantaged Communities – Green Tariff
DAC-SASH	Disadvantaged Communities – Solar Affordable Housing
D-APS	Domestic Automatic Powershift Withdrawn 2809-E 12/9/12
D-CARE	Domestic Service – California Alternate Rates for Energy

DE	Domestic Service to Utility Employees
DM	Domestic Service Multifamily Accommodation
DMS -1	Domestic Service, Multifamily Accommodation - Submetered
DMS -2	Domestic Service, Mobilehome Park Multifamily Accommodation, Submetered
DWL	Residential Walkway Lighting
ED	Energy Division
EE	Energy Efficiency
EITE	Emissions Intensive and Trade Exposed
ERRA	Energy Resource Recovery Account
F&PP	Fuel and Purchased Power
FF&U	Franchise Fees and Uncollectibles
FY	Fiscal Years
GHG	Greenhouse Gas
GS-1	General Service 1
GS-2	General Service 2
GW	Gigawatt
GWh	Gigawatt Hours
LCR	Local Capacity Requirement
LCR – PPP	Local Capacity Requirement – Public Purpose Program
LS-1	Lighting – Street and Highway 1
LS-2	Lighting – Street and Highway 2
LS-3	Lighting – Street and Highway 3
MA	Memorandum Account
MT	Metric Ton
MW	Megawatts
MWh	Megawatt Hours
OL-1	Outdoor Lighting 1
OP	Ordering Paragraph

PABA	Portfolio Allocation Balancing Account
PCIA	Power Charge Indifference Adjustment
PHC	Pre-Hearing Conference
PRP	Preferred Resources Pilot
PVNGS	Palo Verde Nuclear Generating Station
PUBA	Portfolio Allocation Balancing Account Undercollection Balancing Account
PUBA- BSF Subaccount	Portfolio Allocation Balancing Account Undercollection Balancing Account - Bundled Service Financing Subaccount
RA	Resource Adequacy
RPS	Renewable Portfolio Standard
SCE	Southern California Edison
SoCal CCAs	CPA and CCEA, collectively
SOMAH	Solar on Multifamily Affordable Housing
SONGS	San Onofre Generating Station
SP15	South of Path 15
TA	Tracking Account
TC-1	Traffic Control 1
TOU-8-P	Time-of-Use, General Service – Primary Distribution
TOU-8-S	Time-of-Use, General Service – Large Standby
TOU-8-S-P	Time-of-Use, General Service – Large Standby – Primary Distribution
TOU-8-S-S	Time-of-Use, General Service – Large Standby – Secondary Distribution
TOU-8-S-T	Time-of-Use, General Service – Large – Standby - Tiered
TOU-8-T	Time-of-Use, General Service – Large – Tiered
TOU-GS	Time-of-Use General Service
TOU-PA-2	Time-of-Use Agricultural & Pumping 2
TOU-PA-3	Time-of-Use Agricultural & Pumping 3
UOG	Utility-Owned Generation

WAPA	Western Area Power Administration

(END OF APPENDIX A)