Application No.:	A.24-09-008
Exhibit No.:	SCE-0001
Witnesses:	A. Bahen
	G. Chen
	S. Cheng
	M. Childs
	C. Fanous
	A. Li
	M. Ostendorf
	J. von Almen

SOUTHERN CALIFORNIA EDISON®

(U 338-E)

Testimony of Southern California Edison Company (U 338-E) in Support of Its Application for Approval Under Public Utilities Code Section 851 To Sell Certain Hydroelectric Power Plants to Fontana Union Water Company

Before the

Public Utilities Commission of the State of California

Rosemead, California
September 17, 2024

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I.

INTRODUCTION

Southern California Edison Company (SCE) respectfully requests that the California Public Utilities Commission (Commission or CPUC) authorize the sale by SCE of its Fontana and Lytle Creek hydroelectric power plants and associated electric generating facilities (each a Project, collectively the Projects) to Fontana Union Water Company (FUWC or Buyer). The details of the asset sales are set forth in the Asset Purchase Agreement (APA) dated August 12, 2024, which is included as Appendix A. SCE also requests that the Commission approve the requested ratemaking treatment detailed in Chapter V. As described below, SCE is offering the Projects for sale because they are non-core assets which SCE no longer needs to provide its customers with economical and reliable electric power. The sale of the Projects to Buyer is in the best interest of SCE's customers, as it is the least-cost outcome compared to the alternatives of retaining and repairing the assets for continued operation and/or decommissioning the assets. This Application is made pursuant to California Public Utilities Code Section 851 and Articles 2, 3, and 7 of the Commission's Rules of Practice and Procedure.

A. Background

SCE operates 25 hydroelectric (Hydro) projects that include powerhouses and generating units, dams, stream diversions, and water conveyance systems consisting of tunnels, conduits, flumes, and flow lines.[1] Cumulatively, SCE's Hydro facilities have 1,164 megawatts (MW) of nameplate generating capacity. SCE's Big Creek system accounts for 1,015 MW of the SCE generating capacity and includes six large reservoirs with appreciable storage that provides significant economic benefits for SCE's customers. The Big Creek system continues to be economic and is not being considered for divestment. Additionally, the Kern River No. 1 and Kern River No. 3 projects account for approximately 66 MW of the 150 MW of generating assets outside of Big Creek. While the two Kern Projects do not have

[1] SCE has executed an asset purchase agreement with San Bernardino Valley Municipal Water District (SBVMWD) for the sale of seven of SCE's Hydro projects. SCE is currently seeking approval of the transaction with SBVMWD in Application (A.)24-08-012.

reservoir storage, their capacity factors have historically averaged 51%, and their size provides reasonable economies of scale, so they are not under consideration for divestment.

SCE's small Hydro assets (16 Hydro projects) make up the remaining 95 MW in SCE's Hydro portfolio. The average capacity of SCE's small Hydro projects is 4.3 MW, with the largest rated at less than 13 MW. The locations of SCE's East End small Hydro facilities, which include the Lytle Creek and Fontana Projects, are shown below in Figure I-1.

Figure I-1
SCE's Small Hydro East End Portfolio

Until recently, divestment of SCE's small Hydro assets seemed unlikely because of their renewable energy benefits. However, due to the age of the existing infrastructure, much of which exceeds 100 years, and increasing costs to license and operate the facilities, some of SCE's small Hydro

projects are being retired or divested. Some of the small Hydro projects in SCE's portfolio have limited reservoir storage, but most are run-of-the-river systems, meaning power is only generated when water is flowing. The limited reservoir storage and run-of-the-river nature of the small Hydro projects decrease their ability to be optimized for market revenue, resulting in a reduced benefit to customers.

Additionally, the Federal Energy Regulatory Commission (FERC) relicensing process has the potential to further challenge small Hydro economics by requiring increased capital expenditures for relicensing and continued operation. Almost all of these small Hydro assets entered service between 1899 and 1929 and, while appreciable capital refurbishment and improvement has been made over their lives, much of this infrastructure is original equipment that requires significant additional refurbishment if operations are to safely and reliably continue for several more decades. Many of these small hydro assets are located in remote mountainous locations that are difficult to access which further increases refurbishment costs. The general trend of continued degradation of small Hydro economics has led to the outcome that, in some cases, divestment or decommissioning is the least-cost option for customers. In this case, the sale of the Projects to FUWC is the best option for customers.

The decision to retire a small Hydro project, either by divestment or decommissioning, is a complex one, as multiple variables can influence the economic viability of a project. These include the need to refurbish aging assets, renew FERC operating licenses through relicensing, implement new license requirements, complete environmental permitting and mitigation requirements, comply with contractual water rights requirements, and address concerns with numerous stakeholders and/or public advocacy groups. SCE's decision to divest a small Hydro project or to continue operations into the future will be made on a case-by-case basis and will typically be linked to the FERC license renewal process.[2] Once a decision is made to retire an asset, the next decision is to determine if divestiture or decommissioning would provide a better cost-benefit to customers. Costs to decommission projects are extremely high since all the components of the Hydro facilities (i.e., powerhouses, dams, stream diversion structures, and water conveyance systems) must be removed and the project lands may need to

[2] FERC license expiration dates for SCE's small Hydro plants span from 2021 through 2033.

be restored to pre-project conditions. Even if only a small number of SCE's small Hydro projects are decommissioned, costs could easily exceed $100 million dollars or more, none of which have been collected from SCE's customers to date for the projects in this Application. As such, SCE determined that divestment of a Hydro project, provided the project can be sold, generally yields a greater benefit to customers compared to the cost of decommissioning and began the process to pursue the sale of several small Hydro facilities in 2020.

1. Small Hydro is No Longer a "Forever Asset"

There are many considerations that must be evaluated by SCE when determining whether to decommission or divest a project, including FERC rules which do not allow SCE to cease operations of FERC-licensed small Hydro facilities, such as the Lytle Creek Project, without a plan to decommission or divest. As stated above, most of these projects have been in service for approximately 100 years and much of the infrastructure is original equipment that may require significant refurbishment for continued operation. With respect to continuing operations, the FERC licensing and other facility needs can require substantial capital investments that would inherently make the projects uneconomic and only delay, but do not eliminate, future decommissioning. For example, new license terms and/or conditions that require infrastructure modifications, such as coring a dam to put in a new valve to provide required flow releases, could be very expensive. As a result, FERC relicensing costs can range from $3.5 to $7 million[3] per project. Even for non-FERC licensed projects, there are significant ongoing and future operations and maintenance (O&M), capital recovery, and decommissioning costs to customers. As further discussed in Chapter IV, SCE evaluated the net customer cost to continue operations, the net customer cost to decommission, and potential interest from third parties to purchase the Projects. Using its Present Value of Revenue Requirement (PVRR) model, SCE determined that sales at the agreed upon purchase prices would be the least-cost path forward for customers.

[3] Estimated relicensing costs are based on historical spend incurred by SCE, which is approximately $5 million per relicensing proceeding. The relicensing cost will vary by project due the complexity of the project and the potential effect of the Hydro operations on environmental and cultural resources.

B. Overview of Asset Purchase Agreement

As described above, SCE began formally exploring the possibility of divesting many of its smaller and less-economic Hydro facilities in 2020, and in 2022 initiated a divestment process with potential bidders to sell ten small Hydro projects. The process resulted in SCE executing the APA with FUWC on August 12, 2024 for the two Projects. The project assets are being transferred to FUWC in "as-is and where-is" condition. At closing, SCE shall make a payment (Transfer Payment) to FUWC consisting of the following: $5.516 million for the Lytle Creek Project and $1.788 million for the Fontana Project. Closing of the transaction is subject to CPUC approval of this Application, including SCE's proposed ratemaking treatment. Closing is also subject to the concurrent FERC license transfer approvals process described in Chapter VI. Additional terms and conditions of the APA are described in Section III.C.2 below.

C. CPUC Should Approve the Sale and SCE's Ratemaking Proposal as Reasonable

As mentioned above, FERC will not allow SCE to cease operations without a plan to divest or decommission FERC-licensed Hydro facilities. SCE has met this obligation through its auction and the resulting APA described in detail below for the FERC-licensed Lytle Creek Project. Additionally, SCE's PVRR analysis demonstrates that the sale of the small Hydro facilities to FUWC at the agreed upon purchase price is the best economic outcome for customers when compared to the alternatives of decommissioning the facilities or making significant capital investments to renew the FERC license, repair, and continue operations. Moreover, SCE's customers must fund the ongoing operations of the Projects since the electricity they produce doesn't generate sufficient revenue to offset their operating costs.

SCE's transaction with FUWC complies with all applicable Commission requirements and is in the public interest, consistent with Public Utilities Code Section 851. SCE's proposed ratemaking treatment is consistent with the Commission's gain/loss on sale of utility assets and follows the "percentage allocation rule." As a result of the transaction, SCE is proposing a rate base reduction of approximately $0.8 million upon the close of sale. SCE's full ratemaking proposal is discussed in Chapter V.

II.

DESCRIPTION OF SMALL HYDRO ASSETS TO BE SOLD

The Projects to be sold consist of two powerhouses with an aggregate capacity of 3.45 MW. An overview of each Project is provided in Table II-1, and the description of each Project's facilities is provided in the following section.

Table II-1
Fontana Union Water Company Portfolio

Projects	**MW, Operating Status** **SCE-Owned Land** **FERC License # and Expiration** **Water Diversion and Conveyance Beneficiaries**
Portfolio Total 3.45 MW	
Fontana	2.95 MW, operating 5.21 acres Non-FERC project Fontana Union Water Company
Lytle Creek	0.5 MW, operating 12.05 acres FERC Project No. 1932 License expires: 5/31/2033 Fontana Union Water Company

A. Description of the Facilities and Current Operating Status

1. Fontana

Beginning operations in 1917, the Fontana Project is located approximately two miles north of Highland Avenue in the City of Fontana, CA. It is a non-FERC licensed project and is currently operating. The Fontana Project consists of the following components: (1) a 15-foot-long by 10-foot-wide by 10-foot-deep concrete forebay; (2) a 22,567-foot-long, 36-inch to 42-inch diameter steel penstock; (3) a 60-foot by 50-foot concrete powerhouse with two Pelton turbines (Unit 1 is rated at 1,355 HP and Unit 2 at 1,400 HP) that are both direct connected to Westinghouse rated at 1,475 kW each (however the

effective capacity for the plant is 1,370 kW due to the water flow limitations); (4) a 25-foot long distribution line tying the powerhouse to Seller's distribution system; and (5) a switchyard.

2. Lytle Creek

Beginning operations in 1904, the Lytle Creek is located in the San Gabriel mountains, above Highway 15 and the Cities of Nealeys Corner, Fontana, and San Bernardino, CA. Its FERC licensing number is 1932, which expires on June 25, 2033. The Lytle Creek project is currently operating. The Lytle Creek Project consists of the following components: (1) a 3-foot-high, 200-foot-long rubble masonry gravity dam; (2) a concrete intake structure with automatic traveling debris screen; (3) a concrete-lined sandbox with 4 automatic fish screens; (4) a 4.3-mile-long flowline system consisting of 13 tunnels, a concrete pipeline, 5 siphons, and 28 concrete and steel manways; (5) a 750-cubic-foot concrete forebay; (6) a 1,546-foot-long, 30 to 26 inch-diameter steel penstock; (7) a powerhouse containing two generating units with a combined installed capacity of 500 kilowatt (kW); (8) a 904-foot-long tailrace siphon; (9) a 0.25-mile-long,12-kilovolt (kV) transmission line tap; and (10) related appurtenant facilities.

III.

REASONABLESS OF TRANSACTION

A. SCE's Small Hydro Auction Process

SCE hired Bodington & Company (B&Co) in 2021 to advise on the sale and to assist with bid evaluation, including testing the assumptions in SCE's PVRR analysis. B&Co is an investment banking firm that specializes in power generation and has a wide range of experience assisting clients with power project transactions in the state of California, including six completed hydroelectric transactions for Pacific Gas and Electric Company (PG&E), and elsewhere including hydroelectric project sales for Xcel Energy. B&Co analyzed the Projects and advised SCE in advance of an auction that, like the PG&E Kern and Tule transactions, buyers would be unlikely to bid positive purchase prices. B&Co also prepared a detailed information memorandum[4] and an operation and financial model for the Projects and set up a virtual data room. SCE launched an auction process on March 3, 2022. The first phase of the auction was to contact potential buyers and make announcements requesting submission of indicative proposals. B&Co contacted over 60 potential buyers and called each one every week until interest was declined or affirmed by a proposal. The initial marketing list for potential buyers included six water beneficiaries; seven water infrastructure funds; 24 independent power producers (IPPs); and 26 investment, consultant, and other companies. Additionally, B&Co also advertised the opportunity in various industry news outlets including Hydro Review and California Energy Markets. The outreach resulted in SCE executing 26 non-disclosure agreements with potential buyers. A total of six parties submitted indicative proposals.

SCE then reviewed and evaluated the indicative proposals submitted by interested parties to 1) determine whether the bidder met mandatory requirements, such as operating experience, ability to meet FERC requirement to hold a license, and no contingency for a power offtake agreement; 2) preliminarily assess the bidder's credibility, ownership portfolio of projects, and financial ability to consummate the transaction; and then 3) assess potential adders/subtractors to purchase price.

[4] *See* Appendix B in SCE-0002.

All six parties that submitted indicative proposals met the Phase 1 screening criteria and were moved to Phase 2 of the auction. Two parties were from a consortium of water agencies that had previously submitted an unsolicited expression of interest for East End assets; three parties were developers, owners, and operators of hydroelectric projects; and one party intended to use the power to produce and sell green hydrogen. SCE and B&Co invited finalists to site visits, conducted interviews and responded to their questions, and requested submission of final bid offers in the form of letters of intent with final pricing and terms, including a purchase agreement term sheet. Phase 2 of the auction concluded on September 2, 2023 with five parties submitting final bids.

SCE reviewed all offers submitted by the potential buyers and selected the final buyers that best met the objectives of the sale. This was done by comparing the PVRR inclusive of the final offered prices against the PVRRs of the continued ownership scenarios. In addition to the PVRR of each offer, other factors were considered and evaluated with the objective of achieving the highest value for SCE customers, including the highest confidence in completing the sale.

Adders, both quantitative and qualitative, considered included:

- Inclusion of all or large amount of the portfolio including high-risk assets in the offer, and
- Whether buyers were natural buyers, such as consumptive water rights holders or owners of other hydro assets adjacent to the SCE project(s) they are acquiring.

Subtractors, both quantitative and qualitative, considered included:

- Inclusion of single, small group or only most attractive assets in the offer
- Existence of post-sale risk exposures,
- Contingencies,
- Carve-outs and purchasing requirements set by bidders,
- Concerns over CPUC/FERC approvals,
- Extended timelines to close, and
- Questionable financial wherewithal to complete transaction and operate assets.

B. Bid Evaluation

SCE conducted a quantitative evaluation comparing bids against the PVRRs of continued operations and decommissioning of the associated hydro projects to confirm if the bids were the least cost path for customers. SCE then compared the bids against each other from a quantitative perspective, also taking qualitative factors into consideration. All bids during the Phase 2 auction would have effectively resulted in negative transfer prices for the assets but offered better economics to customers when compared to both continued operations and decommissioning. B&Co also prepared its own analysis and comparison of the proposals considering quantitative and qualitative factors and submitted that analysis to SCE for consideration. After consideration of the SCE and B&Co analyses, SCE entered into exclusive negotiations with FUWC for the sale of the Projects.

C. Selection of Fontana Union Water Company

1. Buyer Description

Fontana Union Water Company was formed on April 26, 1912. The principal shareholders of Fontana Union Water Company are San Gabriel Valley Water Company and Cucamonga Valley Water District. San Gabriel Valley Water Company is the Operating Agent for Fontana Union Water Company, and its two operating divisions, Los Angeles County and Fontana Water Company, collectively provide water utility service to a population of over 481,000. Additionally, San Gabriel Valley Water Company owns and operates two hydroelectric facilities. Cucamonga Valley Water District is a public corporation special district water agency and serves a population of 195,000 in the cities of Rancho Cucamonga, Fontana and Ontario.

2. Portfolio Sale Price, Terms and Conditions

The proposed transaction is beneficial for both SCE customers and Buyer, and the Transfer Payment is a fair valuation based upon the interest of both parties. The parties agreed to a Transfer Payment from SCE to Buyer of $5.516 million for the Lytle Creek Project and $1.788 million for the Fontana Project upon closing of the transaction. The Transfer Payment will be adjusted by any changes to the Final Cost-of-Ownership Charges from the Estimated Cost-of-Ownership Charges as reflected in Generator Interconnection Agreement (GIA) for each Project. The Transfer Payment does

not include the cost estimate for the interconnection facilities and upgrades, which is a separate cost to be incurred by SCE on behalf of the Buyer.[5] Additional details on the GIA are provided in section III.C.2.a below.

The assets being transferred to FUWC pursuant to the Transaction are described in Chapter II above and in the APA. SCE will pay the Buyer the Transfer Payment at closing. The APA also contains mutual representations, warranties, and indemnities. In the APA, the parties agree to cooperate in obtaining all approvals, permits and consents required to consummate the sale. SCE is selling each Project in its "as-is and where-is" condition, with the Buyer assuming all obligations and liabilities for repairing, restoring and operating the facilities after the close of the sale, thereby eliminating such risk for customers. As stated in the APA, the Buyer will also fund an escrow account in the amount of $605,272, which may be drawn by SCE in the event the Buyer fails to satisfy its payment obligations to SCE related to reimbursement of interconnection costs spent by SCE prior to closing if the transaction is terminated under certain circumstances. The sale of the Projects will close upon the satisfaction of the following closing conditions:

- Project permits required to operate the Projects are transferred to Buyer,
- Generator interconnection agreements for the Projects are finalized and executed,
- CPUC approval of this Application, and
- FERC license transfer approvals are obtained.

a) <u>Generator Interconnection Agreements</u>

A condition precedent to the closing of this transaction is execution of a generator interconnection agreement for each Project. As discussed above, almost all of SCE's small Hydro assets entered service between 1899 and 1929. SCE has been the sole owner and operator of the Hydro facilities since construction and they are connected directly to its own distribution system. Now that the Hydro facilities are being transferred to SBVMWD, SCE must ensure the proper protections and equipment are installed to separate the third-party-owned facilities from SCE's distribution system.

[5] This is consistent with D.20-09-027, which approved PG&E's sale of its Kern Canyon Hydro project and permitted recovery of interconnection costs. *Id.* at 5.

Accordingly, SCE's Transmission and Distribution (T&D) Grid Interconnection and Contract Development team worked with T&D Engineering to perform a Facilities Study Technical Assessment of the Projects. The Report, issued on June 30, 2021, contained the results of the evaluation to identify additional facilities and upgrades required to enable compliance with T&D's current standards for Interconnection Service under the Rule 21 Tariff[6] for these Small Hydro Facilities.

b) Interconnection Facilities Installation

The APA requires SCE to complete the design and engineering, procurement and installation of certain interconnection facilities for the Fontana Project and the Lytle Creek Project prior to closing. SCE anticipates the pre-closing interconnection facilities work to be completed by approximately October of 2025.

[6] The FERC open access tariff, which is a set of regulations that require public utilities to provide non-discriminatory access to their transmission networks, was first established in 1996. This required utilities to offer the same transmission services to others as they do to themselves, ensuring fair competition in the electricity market.

IV.

ALTERNATIVES TO SALE

To ensure the sale of the Projects is in the best interest of its customers, SCE evaluated the alternatives of (a) continuing to relicense and operate the Projects or (b) decommissioning the Projects. SCE's PVRR methodology described in the section below examines these two alternatives and how they compare to the sale.

A. PVRR Analysis of Alternatives Considered

SCE identified and evaluated three alternatives for the Projects:

1) Continued operation of the Projects and renewal of FERC licenses when current licenses expire (for FERC-licensed Lytle Creek Project)
2) Decommission the Projects in 10 years (or next FERC relicensing cycle if earlier)
3) Sell the Projects to third party

The comparison of the cost to customers in each of the scenarios is presented in the PVRR analysis below in Table IV-2. This analysis shows that selling the Projects is estimated to save customers an aggregate of $10.0 million in terms of PVRR due to the avoided costs of continued operations and or decommissioning.

Table IV-2
Total Cost to Customers
PVRR Alternative Scenarios $ in Millions

Project	Relicense / Ongoing Operation (a)	Decommission (b)	Sale (c)	Lower of (a) or (b) = (d)*	Savings (d) - (c)
Fontana	$7.6	$9.7	$3.3	$7.6	$4.3
Lytle Creek	$12.3	$19.9	$6.6	$12.3	$5.7
FUWC	**$19.9**	**$29.6**	**$9.9**	**$19.9**	**$10.0**

*This column represents the lower of either (a) the relicense and continue operation column or (b) the decommission column. The sale option (c) is the least cost alternative to customers for both Projects, which results in the customer savings.

1) Continued Operations

This scenario assumes continued recovery of capital previously invested in the Projects. Depreciation rate for Hydro assets is based on the shorter of the remaining FERC license term or the composite asset life. This scenario reflects the revenue requirement associated with future O&M, capital expenditures, repair costs to re-operationalize currently inactive plants, and decommissioning costs, net of forecasted market revenues (including value of energy, capacity and renewable energy credits). Because SCE has not collected decommissioning funds for these Projects, the analysis assumes recovery of future decommissioning costs starting in base year (2024) until physical decommissioning starts in 2073 (at the end of the next FERC license term).

2) Decommission

This scenario assumes continued recovery of capital previously invested in the Projects and future O&M and capital costs net of forecasted market revenues in the same manner as Continued Operation scenario until the decommissioning of the Projects. However, this scenario assumes recovery of future decommissioning costs starting in base year (2024) until physical decommissioning starts in 2033.

3) Sell to Third Party

SCE is proposing to recover the unrecovered capital previously invested in the Projects, comprised of the undepreciated plant in service in the year the sale closes if the sale is approved by the Commission. Those costs are added to the Transfer Payment, interconnection costs, and transaction costs. This scenario reflects revenue requirement associated with future costs until the closing date that include O&M, net of forecasted market revenues. Future capital expenditures and decommissioning costs are not incorporated.

The Decommission and Continued Operation scenarios both result in higher costs to customers than the Sell scenario for each Project. By selling the Projects, customers would avoid: (1) the cost and risk of capital repairs or upgrades; (2) the costs of future relicensing or other regulatory proceedings including costs associated with implementing license conditions; (3) future O&M costs; and (4) future decommissioning costs.

V.

RATEMAKING PROPOSAL

This chapter presents SCE's calculations of the gain/loss on the sale of the Projects, SCE's request to apply the Commission's percentage application rule to the transaction, and SCE's proposed ratemaking treatment for the transaction.

A. Original Cost, Book Value, and Purchase Price & Tax Effect

The total historical cost (Original Cost) of the Projects is approximately $2.8 million. The historical cost less accrued and forecasted allocated reserve (accumulated depreciation) of $1.7 million value of the Projects results in an aggregate Net Book Value of approximately $1.1 million at closing in 2025. The aggregate negotiated Transfer Payment from SCE to Buyer will be $7.3 million.

The aggregate pre-tax loss-on-sale is estimated to be $9.5 million, $3.1 million for the Fontana project and $6.5 million for the Lytle Creek project. A table showing sales price, expenses, tax effects, and the resulting gain/loss calculation for customers and ratepayers for each of the Projects is shown below in Table V-3. The amounts cited and shown in this Application are estimated values at closing in 2025. The actual amounts will be based on the book values as of the actual closing date.

Table V-3
Sales Price and Gain/(Loss) Impact by Project ($ in Millions)

Category	Fontana	Lytle Creek	FUWD Total
Sale Price	(1.79)	(5.52)	(7.31)
Interconnection Cost	(0.40)	(0.22)	(0.62)
NBV: Depreciable Property	(0.54)	(0.55)	(1.09)
NBV: Non-Depreciable Property	(0.00)	(0.00)	(0.00)
Transaction Cost	(0.34)	(0.18)	(0.52)
Gain/(Loss) before Income Taxes	(3.07)	(6.47)	(9.54)
Total Tax Liability (Benefit)	(0.80)	(1.78)	(2.58)
Total After Tax Gain/(Loss)	(2.27)	(4.70)	(6.97)
Customers' After Tax Gain/(Loss)	(2.27)	(4.70)	(6.97)
Shareholders' Total After Tax Gain/(Loss)[+]	0.00	0.00	0.00
Tax Gross-Up	1.39	1.39	1.39
Revenue Requirement*	3.15	6.53	9.68

[+] Consistent with the "percentage allocation rule" in OP4 of D.06-05-041 (100% of depreciable assets to customers; 67% of non-depreciable assets to customers and 33% of non-depreciable assets to shareholders), the shareholders' total after tax gain/(loss) on the portfolio is ($467), comprised of ($426) for Fontana and ($41) for Lytle Creek, all of which round to $0.00M in the table above.
* The revenue requirement tax gross-up can be expressed formulaically: Revenue Requirement x 1/(1-Current Composite Tax Rate). The Composite Tax Rate is comprised of the highest federal and California marginal rates in effect, currently 21% for federal and 8.84% California. The state rate is effectively reduced to 6.98% to reflect the federal benefit of a deduction for state taxes.

B. Ratemaking and Gain (Loss) on Sale Decision

SCE proposes the following ratemaking for the sale transaction, which was not reflected in SCE's 2025 GRC forecast. Rate base will be reduced by the amount of the historical costs less (1) depreciated value of the assets and (2) deferred income taxes (discussed below), when the sale closes.

SCE proposes to recover the pre-tax loss on sale[7], inclusive of the interconnection costs and transaction costs (totaling approximately $0.6 million and $0.5 million, respectively), by recording a debit in the Legacy Utility Owned Generation (UOG) subaccount within the Portfolio Allocation

[7] The after-tax loss on sale SCE proposes to recover from customers is less the $467 loss on non-depreciable assets allocated to shareholders, consistent with the "percentage allocation rule."

Balancing Account (PABA).[8] Amounts recorded in PABA are recovered from bundled and non-exempt departing load customers through generation and vintaged Power Charge Indifference Adjustment (PCIA) rates.

SCE proposes to recover any remaining regulatory tax assets related to the Projects by recording a debit in the Legacy UOG subaccount of PABA. Additionally, due to differences in timing between when revenue recovered from customers is taxable and when the tax loss on the Projects is deductible, an Accumulated Deferred Income Tax balance will be created on this transaction and included in rate base until the book-tax timing differences unwind.

SCE also proposes to reduce the revenue requirement associated with the Projects' retired rate base and maintenance costs requested in the 2025 GRC upon close of the sale by recording a credit of approximately $0.3 million per annum in PABA. This revenue reduction will be applied to the remaining periods in the 2025 GRC cycle from the closing of the sale.

In sum, SCE's proposed ratemaking treatment results in a substantial net benefit to customers compared to continued operations and or decommissioning.

Lastly, SCE proposes that the updated calculation of the loss-on-sale and tax information be provided to the Commission in a Tier 1 advice letter submittal following closing. Such a process is consistent with procedures that have been followed in sales of PG&E hydroelectric facilities such as the Merced Falls Hydroelectric Project Sale approved in D.16-10-026, Narrows Hydroelectric Project Sale approved in D.19-10-010, Deer Creek Hydroelectric Project Sale approved in D.19-10-011, Chili Bar Hydroelectric Project sale approved in D.20-11-024, the Kern Canyon Hydroelectric Project sale approved in D.20-09-027, and the Tule River Hydroelectric Project sale approved in D.22-11-002. SCE requests that the Commission approve the process discussed above for calculating and allocating the estimated loss on the sales in its decision in this Application and specific amounts to be so allocated upon review of a compliance advice letter to be filed by SCE within 60 days following the closing. To

[8] *See* p.3 of Advice 3914-E "Establishment of the Portfolio Allocation Balancing Account in Compliance with Decision 18-10-019" that describes how the Legacy UOG subaccount will be used to record the costs, realized market revenues, and imputed revenues of SCE's utility-owned generation that was installed before 2002.

the extent that SCE incurs costs following the closing, SCE proposes to file a subsequent Tier 1 advice letter upon completion of the work.

1. Application of Loss on Sale by Facility

SCE requests that the accounting loss from the sale of the Projects be recovered in accordance with Ordering Paragraphs 4 of the Commission's Gain on Sale of Utility Assets decision, D.06-05-041, as modified by D.06-12-043. Specifically, Ordering Paragraph 4 of D.06-05-041 states that the "percentage allocation rule" (100% of depreciable assets to customers; 67% of non-depreciable assets to customers and 33% of non-depreciable assets to shareholders) applies to routine asset sales where the sale price is $50 million or less and the after-tax gain or loss from the sale is $10 million or less. Accordingly, SCE seeks allocation per the "percentage allocation rule" for the Fontana and Lytle Creek Projects consistent with Ordering Paragraph 4, based upon their respective sale prices and after-tax loss amounts shown in Table V-3. SCE's request to apply the percentage allocation rule is consistent with other utility asset sales, notably, PG&E's Kern Canyon sale approved in D.20-09-027, and Tule River Hydro sale approved in D.22-11-002.

VI.

RELATED PROCEEDINGS

Section 8 of the Federal Power Act[9] provides that FERC licenses may be transferred only with the written approval of FERC. SCE, as the licensee, and FUWC, as the license transferee, must file a joint application with FERC that seeks FERC's approval to transfer the Lytle Creek Project's FERC license to FUWC and sets forth the qualifications of FUWC to hold the license and to operate the Project. Therefore, SCE and FUWC will be jointly filing a license transfer application with FERC in October 2024 for the Lytle Creek Project. SCE expects FERC to approve the transfer application because it is in the public's interest and because FUWC has the capability to operate the Project. SCE expects approval from FERC in approximately 12 months.

[9] 16 U.S.C. § 801.