Cost Allocation Study in Support of Proposed Adjustments to SRP's Standard Electric Price Plans Effective with the May 2019 Billing Cycle

Salt River Project Agricultural Improvement and Power District

December 20, 2018

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Executive Summary

The Cost Allocation Study (CAS) allocates expenses and revenues to customer classes and functions and relates these to the level of investment in electric plant. This relationship yields a return on net plant less construction work in progress (CWIP). These returns are used as the basis to determine the allocation of the proposed revenues by function and customer class.

SRP management ("Management") is proposing an overall 2.2% net price decrease effective with the May 2019 billing cycle (the beginning of SRP's Fiscal Year 2020). The proposal incorporates and adds to the overall annual 1.5% decrease that SRP initially implemented on a temporary basis for Fiscal Year 2019 (May 2018 through April 2019) and includes a 1.7% increase to base prices. Management also proposes eliminating the Environmental Programs Cost Adjustment Factor (EPCAF) and moving those dollars to the base and FPPAM components as appropriate. These proposed changes are projected to increase SRP's return from 3.4% to 3.8% in FY20. This price proposal is reflected, on an annualized basis, in the proposed revenues and the functional and class returns on net plant less CWIP in this study. The effect of these proposals improves returns inter-class from their current levels.

Background

The Cost Allocation Study utilizes SRP's functional budget for Fiscal Year 2020 as the basis for evaluating returns by function and establishing revenue targets by function and customer class. Where functional budgets provide insufficient detail, historical financial data and data from the *Derivation of Proposed Changes to SRP's Transmission and Ancillary Services Prices Effective May 1, 2019* are utilized.

Operating expenses and net plant less CWIP are allocated to customer classes based on factors derived from an analysis of usage, number of customers, expenses and investment. Revenue targets are based on the operating expenses, the functional return target on net plant less CWIP, and the overall revenue adjustments for each customer class associated with each unbundled function for Fiscal Year 2020.

Functional Budget for Fiscal Year 2020 – The functional budget used in this study is for Fiscal Year 2020, which was developed in the spring of 2018. This functional budget is from the financial plan that was reviewed by the SRP Board on March 13, 2018. This budget is used as the basis for establishing unbundled revenue targets in this price process for two primary reasons:

- As SRP continues to align its resources with business functions, budgeting information is better aligned with the functional components of the price plans than historical cost data.
- The first full fiscal year that the plans will be in effect will be for Fiscal Year 2020.

Operating expenses and net plant are identified in SRP's functional budget for Fiscal Year 2020. The following operating expenses are identified in the functional budget: operations and maintenance (O&M)

and staff (Administrative and General, or A&G); fuel and purchased power; depreciation; contributions in lieu of property tax; and out-of-state ad valorem taxes (property taxes). Additional items are transferred or credited among functions for consistency with transmission and ancillary service rate design in the *Derivation of Proposed Changes to SRP's Transmission and Ancillary Services Prices Effective May 1, 2019*. Similar transfers are made with net plant less CWIP.

Pricing Components

SRP's proposed price plans contain the following functions: fuel and purchased power; generation; ancillary services; transmission; distribution (delivery, facilities and dedicated); meter, billing and customer service; and system benefits for provision of retail electric sales. The discussion below provides greater detail on each function.

Generation

Formerly referred to as the "Energy (Generation)" component. Generation expenses are those expenses incurred directly in the production of power, less the Fuel and Purchased Power and Ancillary Services expenses. Operating expenses associated with Generation include related depreciation expense, taxes, O&M and A&G. Plant reflects net plant less CWIP and includes step-up transformers transferred from transmission.

Fuel and Purchased Power Adjustment Mechanism (FPPAM)

This component includes fuel, associated fuel, water for power, and purchased power expenses. The FPPAM price is determined for two seasons (summer and winter), thereby providing a better reflection of the underlying costs of providing service. This helps to ensure that customers who impose the costs of providing energy will pay for those costs through these seasonal prices. The overall seasonal prices in this study are based on the fuel and purchased power prices projected for Fiscal Year 2020. Part of Management's proposal is to move expenses associated with renewable resources, currently collected through EPCAF, to the FPPAM.

Total Fuel and Purchased Power prices are adjusted for losses. Because certain customers require less transformation to lower voltage levels, they have less energy losses. Less fuel is consumed to provide a kilowatt-hour (kWh) of energy. Therefore, customers with less energy loss will pay a slightly smaller proportion of fuel and purchased power expenses.

The projected expenses of providing wholesale sales (fuel and related variable O&M) are excluded from total operating expenses to determine the retail Fuel and Purchased Power expenses associated with retail customers under SRP's standard price plans.

Pricing Components

Transmission

Formerly referred to as the "Transmission Delivery" component. Transmission expenses are consistent with the *Derivation of Proposed Changes to SRP's Transmission and Ancillary Services Prices Effective May 1, 2019*. This document will be updated concurrent with SRP's price adjustment process. The Transmission function includes expenses from the 500-kilovolt (kV) to the 69 kV transmission system, excluding generator step-up transformers. Transmission operating expenses include related depreciation expense, taxes, O&M and A&G.

In prior price processes, SRP included must-run generation expenses in the Transmission component. Must-run generation expenses were those expenses associated with SRP generation units that were called upon to alleviate transmission constraints in SRP's system or to provide power when transmission constraints prevented the use of any other resources. SRP's current Simultaneous Import Limit and the economic dispatch of Valley generation is sufficient for load requirements up to SRP's peak load. Therefore, Management proposes that all capacity-related generation costs be collected in the Generation component.

Ancillary Services

Ancillary service expenses and net plant less CWIP are consistent with the *Derivation of Proposed Changes to SRP's Transmission and Ancillary Services Prices Effective May 1, 2019*. Ancillary Services include the following:

1. Scheduling, System Control and Dispatch Service
2. Reactive Supply and Voltage Control from Generation Sources Service
3. Regulation and Frequency Response Service
4. Energy Imbalance Service
5. Operating Reserve – Spinning Reserve Service
6. Operating Reserve – Supplemental Reserve Service

Only the costs of these services applicable to SRP customers taking service under SRP's Standard Price Plans are included.

Pricing Components

Billing and Customer Service

Formerly split into two components: “Billing, Collections” and the “Competitive Customer Service” charges. Competitive Customer Service was partitioned as part of the December 2001 Price Process because it was deemed competitive under SRP’s First Amended Code of Conduct. Direct access for retail electric customers is currently inactive in Arizona and if it were to become available, SRP would need to readdress internal organization to accurately identify competitive expenses. Management proposes combining these components into one component because the cost driver for both Billing and Customer Services is customer-related.

Billing and Customer Service expenses reflect the cost to support customer applications, contracts, orders and bills for delivery and collection. Costs also include receiving, preparing, recording, and handling customer billing data, customer account records, routine orders for service, disconnections and transfers, and providing assistance and communicating with customers.

Dedicated Distribution

Dedicated Distribution comprises customer Dedicated Substation and other customer dedicated equipment such as redundant multiple feeds and switches at the request of a customer. Dedicated Substation expenses include distribution expenses associated with providing dedicated substation service to customers taking service on the E-65, E-66 or the proposed E-67 Standard Price Plan.

Distribution Delivery

Distribution Delivery and Distribution Facilities were formerly combined into one Distribution category. Based on an internal distribution study, the Distribution component has been divided into Distribution Delivery (substation and primary costs), which are expenses that vary with demand, and Distribution Facilities (secondary costs), which are customer-related and do not vary with the customer’s usage. In some rate plans, part of the Distributed Facilities costs may be collected in the Distribution Delivery component.

Distribution Delivery costs include depreciation expense, taxes, O&M, and A&G related to equipment such as substations, switches, primary conductors, conduits and other primary appurtenances.

Distribution Facilities

Distribution Facilities expenses include secondary costs comprising secondary transformers, conductors, conduits, switches and other secondary appurtenances, and some directly assigned customer enhancement-related expenses. Distribution Facilities operating expenses include related depreciation expense, taxes, O&M and A&G. Distribution Facilities plant reflects net plant less CWIP for secondary.

Pricing Components

Environmental Programs Cost Adjustment Factor (EPCAF)

The EPCAF component collects costs associated with environmental programs and transactions such as renewable power purchase agreements and energy efficiency programs adopted to meet SRP's sustainability objectives. As sustainability has increasingly become a core part of SRP's operations, Management proposes that these expenses no longer be segregated and tracked separately. As such, the EPCAF will be eliminated and expenses recovered instead under the Systems Benefit Charge, the Generation charge, and the FPPAM as appropriate.

Meter

Meter expenses reflect the costs of installing and maintaining metering equipment at the customer's site. Meter plant is found in Federal Energy Regulatory Commission (FERC) Account 370.

System Benefits

The System Benefits Charge (SBC) that applies to SRP's standard price plans was established in 1998. SRP determined at that time that the expenses included in the SBC benefit all SRP customers. Examples of system benefits expenses include decommissioning the Palo Verde Nuclear Generating Station (PVNGS), disposing of nuclear fuel at PVNGS, and providing programs that aid SRP customers (e.g., limited-income customers receiving discounts under the Economy Discount Rider). Part of Management's proposal is to move energy efficiency costs which were collected in the SBC prior to the development of the EPCAF, back to the SBC. The derivation of this charge is calculated on Schedule SBC.

Class Definitions

For cost allocation purposes, SRP partitions customers into a distinct class when customers are easily identifiable and when they have usage patterns similar to each other and distinct from other classes.

The following main classes have been identified in this study. They include:

- Residential
- General Service
- Large General Service

In addition, each of the three main classes are broken down into several distinct sub-classes for cost allocation purposes.

Residential

EZ-3: Primarily consists of customers on the Residential Super Peak Time-of-Use Service (E-21) but also includes customers on the Experimental Price Plans for Residential Super Peak Time-of-Use Service (E-22 and E-25). These customers have average load characteristics similar to other residential classes but have a distinct dip in their load during on-peak hours.

E-23: Consists of customers served on the Standard Price Plan for Residential Service (E-23).

E-24: Consists of customers served on the M-Power Price Plan for Pre-Pay Residential Service (E-24). Customers in the E-24 class have distinct costs associated with prepay equipment dedicated to them.

E-26: Primarily consists of customers served on the Standard Price Plan for Residential Time-Of-Use Service (E-26) but also includes the small number of customers on the Pilot Price Plan for Residential Demand Rate Service (E-27 P) and the Experimental Price Plan for Time-of-Use Service with Super Off-Peak for Electric Vehicles (E-29) rates.

E-27: Consists of customers served on the Customer Generation Price Plan for Residential Service. As part of the 2015 Price Process, Management committed to include these customers as their own class in the cost study.

Class Definitions

General Service

E-32: Primarily consists of customers served on the Standard Price Plan for Time-Of-Use General Service (E-32) but also includes the small number of customers on the Experimental Price Plan for Super Peak Time-of-Use General Service (E-33).

E-36: Consists of customers served on the Standard Price Plan for General Service (E-36).

E-40: Consists of customers served on the Standard Price Plan for Pumping Service (E-47) and the Standard Price Plan for Time-Of-Week Pumping Service (E-48).

E-50: Consists of customers served on the Standard Price Plan for Traffic Signal Lighting (E-54), the Standard Price Plan for Public Lighting Service (E-56), and the Standard Price Plan for Private Security Lighting Service (E-57).

Large General Service

E-61: Consists of customers served under the Standard Price Plan for Secondary Large General Service (E-61).

E-63: Consists of customers served under the Standard Price Plan for Primary Large General Service (E-63).

E-65: Primarily consists of customers served under the Standard Price Plan for Substation Large General Service (E-65) but also includes customers on the Standard Price Plan for Substation Large General Service with Instantaneous Interruptible Load (E-66).

Schedule 1: Functional Expenses and Plant

Schedule: 1 & 1b

Purpose: Schedule 1 summarizes functional expenses and plant for Fiscal Year 2020 and shows Management's proposed method of separately functionalizing EPCAF expenses. Schedule 1b summarizes functional expenses under the current EPCAF cost recovery method.

Methodology: Operating expenses and net plant less CWIP are incorporated directly from SRP's functional budget for Fiscal Year 2020 with the exception of dedicated distribution and lighting equipment which are estimated from historical data.

Expenses and net plant associated with ancillary services are identified in the *Derivation of Proposed Changes to SRP's Transmission and Ancillary Services Rates Effective May 1, 2019*.

SRP currently provides lighting services, such as installing and maintaining poles, fixtures, etc., for security lighting. The customer has the option to install the equipment themselves or use other providers as the equipment does not pertain to the delivery of electricity. In past studies, the cost of providing these services was included in the distribution component. Management proposes removing these expenses and plant and pricing them separately from the retail sale of electricity.

Management proposes eliminating the EPCAF mechanism. Schedule 1 reflects changes to the functional expenses in accordance with the elimination of EPCAF. $151 million in Purchased Power was moved from EPCAF to Fuel. $1.5 million in plant O&M was moved from EPCAF to Generation. $54 million in Systems Benefits Programs (specifically, the Energy Efficiency program expenses and some distribution generation program expenses) was moved from EPCAF to the Systems Benefits. Schedule 1b shows functional expenses if SRP maintained its current EPCAF cost recovery method.

Schedule 1: Functional Expenses and Plant

Operating Expenses	FPPAM	Generation	Transmission	Ancillary Services 1-2	Ancillary Services 3-6	Billing and Customer Service	Distribution Delivery	Distribution Facilities	Dedicated Distribution	Meter	System Benefits	Total Retail Electric	Wholesale	Excluded	Total
Fuel/Purchased Power	$ 1,036,599,248										$ 1,923,058	$ 1,038,522,306			$ 1,038,522,306
Falling Water	$ 6,584,595											$ 6,584,595			$ 6,584,595
Operations & Maintenance		$ 507,353,193	$ 108,021,867			$ 226,111,288	$ 116,628,853	$ 75,467,341	$ 930,398	$ 1,273,468	$ 16,140,807	$ 1,051,927,214			$ 1,051,927,214
Depreciation		$ 351,147,175	$ 57,593,449			$ 4,176,291	$ 125,199,028	$ 81,012,866	$ 2,325,224	$ 28,050,407		$ 649,504,440			$ 649,504,440
In Lieu Tax		$ 66,480,424	$ 16,657,566			$ 727,916	$ 30,263,426	$ 19,582,635	$ 585,152			$ 134,297,119			$ 134,297,119
Bond Defeasance												$ -			$ -
Credit for Wholesale Energy	$ (210,354,500)											$ (210,354,500)	$ 210,354,500		$ -
Transfer Ancillary Services		$ (29,516,589)	$ (22,250,909)	$ 31,619,188	$ 20,148,310							$ -			$ -
Transfer Step Up		$ 1,928,207	$ (1,928,207)									$ -			$ -
Excluded From Retail												$ -		$ 8,067,300	$ 8,067,300
Transfer Wholesale Transmission			$ (26,917,822)									$ (26,917,822)	$ 26,917,822		$ -
Lighting Equipment								$ (6,117,889)				$ (6,117,889)		$ 6,117,889	$ -
Non-E-65 Dedicated Distribution								$ (2,367,681)	$ 2,367,681			$ -			$ -
Energy Efficiency Programs											$ 50,115,410	$ 50,115,410			$ 50,115,410
Customer Assistance Programs											$ 19,262,147	$ 19,262,147			$ 19,262,147
Total - Operating Expenses	$ 832,829,343	$ 897,392,411	$ 131,175,943	$ 31,619,188	$ 20,148,310	$ 231,015,495	$ 272,091,306	$ 167,577,272	$ 6,208,454	$ 29,323,875	$ 87,441,422	$ 2,706,823,020	$ 237,272,322	$ 14,185,189	$ 2,958,280,532

Net Plant Less CWIP	FPPAM	Generation	Transmission	Ancillary Services 1-2	Ancillary Services 3-6	Billing and Customer Service	Distribution Delivery	Distribution Facilities	Dedicated Distribution	Meter	System Benefits	Total Retail	Wholesale	Excluded	Total
Net Plant Less CWIP		$ 3,665,576,312	$ 1,475,728,646			$ 17,486,092	$ 1,426,225,423	$ 922,871,460	$ 44,275,048	$ 197,446,908		$ 7,749,609,890			$ 7,749,609,890
Transfer Ancillary Services		$ (203,245,916)		$ 65,195,605	$ 138,050,312							$ -			$ -
Transfer from RMR		$ -										$ -			$ -
Transfer to Meters												$ -			$ -
Lighting Equipment								$ (28,221,475)				$ (28,221,475)		$ 28,221,475	$ -
Transfer Step Up		$ 17,782,001	$ (17,782,001)									$ -			$ -
Transfer Wholesale Transmission			$ (248,237,168)									$ (248,237,168)	$ 248,237,168		$ -
Total - Net Plant Less CWIP		$ 3,480,112,397	$ 1,209,709,477	$ 65,195,605	$ 138,050,312	$ 17,486,092	$ 1,426,225,423	$ 894,649,985	$ 44,275,048	$ 197,446,908		$ 7,473,151,247	$ 248,237,168	$ 28,221,475	$ 7,749,609,890

Schedule 1b: Functional Expenses and Plant, with Current EPCAF Methodology

Operating Expenses	FPPAM	Generation	Transmission	Ancillary Services 1-2	Ancillary Services 3-6	Billing and Customer Service	Distribution Delivery	Distribution Facilities	Dedicated Distribution	Meter	EPCAF	System Benefits	Total Retail Electric	Wholesale	Excluded	Total
Fuel/Purchased Power	$ 885,260,533										$ 151,338,714	$ 1,923,058	$ 1,038,522,306			$ 1,038,522,306
Falling Water	$ 6,584,595												$ 6,584,595			$ 6,584,595
Operations & Maintenance		$ 505,791,131	$ 108,021,867			$ 225,698,689	$ 116,628,853	$ 75,467,341	$ 930,398	$ 1,273,468	$ 6,134,661	$ 11,980,807	$ 1,051,927,214			$ 1,051,927,214
Depreciation		$ 351,147,175	$ 57,593,449			$ 4,176,291	$ 125,199,028	$ 81,012,866	$ 2,325,224	$ 28,050,407			$ 649,504,440			$ 649,504,440
In Lieu Tax		$ 66,480,424	$ 16,657,566			$ 727,916	$ 30,263,426	$ 19,582,635	$ 585,152				$ 134,297,119			$ 134,297,119
Bond Defeasance													$ -			$ -
Credit for Wholesale Energy	$ (210,354,500)												$ (210,354,500)	$ 210,354,500		$ -
Transfer Ancillary Services		$ (29,516,589)	$ (22,250,909)	$ 31,619,188	$ 20,148,310								$ -			$ -
Transfer Step Up		$ 1,928,207	$ (1,928,207)										$ -			$ -
Excluded From Retail													$ -		$ 8,067,300	$ 8,067,300
Transfer Wholesale Transmission			$ (26,917,822)										$ (26,917,822)	$ 26,917,822		$ -
Lighting Equipment								$ (6,117,889)					$ (6,117,889)		$ 6,117,889	$ -
Non-E-65 Dedicated Distribution								$ (2,367,681)	$ 2,367,681				$ -			$ -
Energy Efficiency Programs											$ 50,115,410		$ 50,115,410			$ 50,115,410
Customer Assistance Programs												$ 19,262,147	$ 19,262,147			$ 19,262,147
Total - Operating Expenses	$ 681,490,629	$ 895,830,349	$ 131,175,943	$ 31,619,188	$ 20,148,310	$ 230,602,896	$ 272,091,306	$ 167,577,272	$ 6,208,454	$ 29,323,875	$ 207,588,786	$ 33,166,012	$ 2,706,823,020	$ 237,272,322	$ 14,185,189	$ 2,958,280,532

Net Plant Less CWIP	FPPAM	Generation	Transmission	Ancillary Services 1-2	Ancillary Services 3-6	Billing and Customer Service	Distribution Delivery	Distribution Facilities	Dedicated Distribution	Meter	EPCAF	System Benefits	Total Retail	Wholesale	Excluded	Total
Net Plant Less CWIP		$ 3,665,576,312	$ 1,475,728,646			$ 17,486,092	$ 1,426,225,423	$ 922,871,460	$ 44,275,048	$ 197,446,908			$ 7,749,609,890			$ 7,749,609,890
Transfer Ancillary Services		$ (203,245,916)		$ 65,195,605	$ 138,050,312								$ -			$ -
Transfer from RMR		$ -											$ -			$ -
Transfer to Meters													$ -			$ -
Lighting Equipment								$ (28,221,475)					$ (28,221,475)		$ 28,221,475	$ -
Transfer Step Up		$ 17,782,001	$ (17,782,001)										$ -			$ -
Transfer Wholesale Transmission			$ (248,237,168)										$ (248,237,168)	$ 248,237,168		$ -
Total - Net Plant Less CWIP	$ -	$ 3,480,112,397	$ 1,209,709,477	$ 65,195,605	$ 138,050,312	$ 17,486,092	$ 1,426,225,423	$ 894,649,985	$ 44,275,048	$ 197,446,908		$ -	$ 7,473,151,247	$ 248,237,168	$ 28,221,475	$ 7,749,609,890

Schedule 2: Functional Current Revenue by Class

Schedule: 2

Purpose: This schedule summarizes revenue by function for Fiscal Year 2020.

Methodology: Revenue by class is derived from applying current (April 2015) prices to forecasted customer usage by class.

The FPPAM revenue was adjusted to match the fuel prices effective during FY19 because of two separate temporary fuel decreases amounting to $43 million, or a 1.5% annual decrease. The summer fuel prices are prices effective with the May 2018–October 2018 billing cycles and the winter fuel prices are prices effective with the November 2018–April 2019 billing cycles.

For comparison purposes, Management opted to use current temporary lower fuel prices rather than the higher fuel prices that were in effect at the last price process of 2015 and would be in effect beginning with the May 2019 billing cycle without further SRP pricing activity. See Figure 1 and accompanying discussion in *Proposed adjustments to SRP's Standard Electric Price Plans effective with the May 2019 Billing Cycle.*

Schedule 2: Functional Current Revenue by Class

Current Revenues	EZ-3	E-23	E-24	E-26	E-27	E-32	E-36	E-40	E-50	E-61	E-63	E-65	Totals
Billings, Collections	$ 6,892,030	$ 15,068,256	$ 5,118,844	$ 4,082,331	$ 182,277	$ 476,288	$ 3,254,142	$ 21,487	$ -	$ 518,725	$ 54,475	$ 59,317	$ 35,728,171
Meter	$ 5,380,395	$ 11,763,322	$ 3,996,124	$ 3,186,950	$ 142,298	$ 1,735,152	$ 8,553,200	$ 173,607	$ -	$ 131,327	$ 17,604	$ 190,512	$ 35,270,490
Distribution Delivery	$ 72,743,309	$ 117,424,432	$ 43,707,953	$ 49,086,393	$ 957,669	$ 44,550,601	$ 127,462,808	$ 4,254,302	$ 3,789,699	$ 14,395,450	$ 3,358,359	$ -	$ 481,730,975
Distribution Facilities	$ 10,760,791	$ 23,526,644	$ 7,992,247	$ 6,373,899	$ 1,193,949	$ -	$ -	$ -	$ 9,108,924	$ 9,979,850	$ 2,162,384	$ -	$ 71,098,689
Dedicated Distribution	$ -	$ -	$ -	$ -	$ -	$ 58,512	$ 252,288	$ 95,448	$ -	$ 1,824,322	$ 2,409,900	$ 7,565,679	$ 12,206,149
Transmission	$ 37,115,805	$ 87,477,252	$ 27,667,802	$ 29,607,538	$ 967,210	$ 23,097,446	$ 71,242,260	$ 560,777	$ 20,064	$ 14,107,006	$ 3,265,480	$ 33,220,593	$ 328,349,234
Transmission Cost Adjustment (TCA)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Ancillary Services 1 - 2	$ 2,008,901	$ 4,720,140	$ 1,483,978	$ 1,633,751	$ 53,851	$ 1,184,357	$ 3,791,114	$ 39,484	$ 20,064	$ 772,754	$ 182,344	$ 1,786,795	$ 17,677,534
Ancillary Services 3 - 6	$ 2,320,125	$ 4,450,120	$ 1,534,503	$ 1,736,031	$ 28,028	$ 1,630,041	$ 5,029,842	$ 89,510	$ 80,257	$ 1,447,778	$ 357,837	$ 3,635,801	$ 22,339,874
System Benefits	$ 2,244,260	$ 4,211,059	$ 1,381,908	$ 1,691,840	$ 57,798	$ 1,529,281	$ 4,458,834	$ 93,183	$ 140,450	$ 1,320,656	$ 329,473	$ 3,374,587	$ 20,833,327
Competitive Customer Services	$ 28,208,644	$ 61,673,418	$ 20,951,105	$ 16,708,721	$ 746,049	$ 3,932,436	$ 11,624,493	$ 885,951	$ 1,705,466	$ 3,548,446	$ 568,197	$ 2,165,833	$ 152,718,759
Energy (Generation)	$ 94,621,525	$ 203,461,960	$ 69,797,644	$ 73,532,884	$ 1,839,729	$ 62,795,669	$ 191,070,337	$ 2,410,490	$ 1,745,594	$ 47,266,707	$ 11,219,358	$ 113,012,050	$ 872,773,947
Aggregation	$ -	$ -	$ -	$ -	$ -	$ (378,187)	$ (841,918)	$ (21,177)	$ -	$ (560,877)	$ (140,720)	$ (1,446,251)	$ (3,389,131)
EPCAF	$ 17,633,473	$ 33,086,889	$ 10,857,847	$ 13,293,028	$ 455,999	$ 12,015,776	$ 35,033,699	$ 732,155	$ 1,103,537	$ 10,376,581	$ 2,588,713	$ 26,514,609	$ 163,692,305
FPPAM	$ 80,825,042	$ 151,615,574	$ 49,896,568	$ 61,238,143	$ 1,018,773	$ 54,312,490	$ 157,112,954	$ 3,210,712	$ 4,834,711	$ 46,386,397	$ 11,406,309	$ 115,535,087	$ 737,392,759
Total	**360,754,300**	**718,479,066**	**244,386,525**	**262,171,509**	**7,643,629**	**206,939,862**	**618,044,053**	**12,545,929**	**22,548,766**	**151,515,121**	**37,779,712**	**305,614,612**	**2,948,423,082**
Other Electric Revenue	$ 4,652,043	$ 10,170,904	$ 3,455,162	$ 2,755,527	$ 123,035	$ 158,028	$ 1,070,598						$ 22,385,298

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Schedule 3: Class Characteristics

Schedule: 3

Purpose: This schedule summarizes the number of customers per class as well as key usage information.

Methodology: The number of customers and usage characteristics are derived from the FY20 forecast.

An hourly 8760 forecast by class is used to determine the class Coincident Peak (CP) and class Non-Coincident Peaks (NCP). The 4CP is the average class contribution to each of the monthly system coincident peaks in June through September. The overall system peak has always occurred in one of these four months and the system peak is a major cost driver for transmission and capacity-related costs. The NCP is the average usage for each class during the hour when that class is peaking. The Sum of the Non-Coincident Peaks (SNCP) for each class was determined by analyzing the relationship between NCP and SNCP in historic data.

This study makes a distinction between the net kWh and delivered kWh of each customer class. For non-Distributed Generation (DG) customers, net kWh and delivered kWh are identical. For DG customers, the delivered and net kWh differ. The net kWh is the difference between the amount of kWh a customer uses from the grid and exports to the grid. The Delivered kWh @ Meter (w/o losses), rows 18–20, are based on the net kWh but adjusted by class using historic interval data to account for the difference between net and delivered kWh.

Losses by rate and season were calculated in the 2017 Loss Study.

Schedule 3: Class Characteristics

	Line Number	Source	EZ-3	E-23	E-24	E-26	E-27	E-32	E-36	E-40	E-50	E-61	E-63	E-65	Totals
# of Customers	[1]	FP19 FY20 Forecast	213,508	466,799	158,576	126,466	5,647	12,213	82,737	549	9,393	429	45	49	1,076,409
4CP Average per Customer	[2]	FP19 FY20 Forecast, Class 8760	4.2	4.7	3.7	5.9	3.0	35.5	16.2	30.8	0.1	719.6	1,537.1	11,160.3	
NCP Average per Customer	[3]	FP19 FY20 Forecast, Class 8760	5.8	5.0	3.9	6.4	4.7	48.4	19.5	46.0	4.8	830.0	1,666.0	12,368.1	
SNCP/NCP Ratio	[4]	Historic Interval data	176%	183%	183%	167%	171%	150%	140%	198%	100%	123%	130%	120%	
Net kWh @ Meter (w/o losses)	[5]	FP19 FY20 Forecast	3,206,086,027	6,015,798,066	1,974,154,000	2,416,914,218	39,770,000	2,184,686,610	6,369,763,451	133,119,000	200,643,000	1,886,651,000	470,675,000	4,820,838,000	29,719,098,372
Summer	[6]	FP19 FY20 Forecast	1,192,818,969	2,196,271,105	724,244,000	918,628,245	13,985,561	795,637,535	2,158,844,828	47,090,000	67,195,000	671,643,000	160,945,000	1,632,760,000	10,580,063,242
Peak	[7]	FP19 FY20 Forecast	795,671,682	1,529,873,237	515,457,000	617,069,212	12,606,418	479,330,306	1,412,291,746	24,650,000	33,033,000	380,981,000	90,494,000	844,900,000	6,736,357,600
Winter	[8]	FP19 FY20 Forecast	1,217,595,376	2,289,653,723	734,453,000	881,216,761	13,178,022	909,718,770	2,798,626,878	61,379,000	100,415,000	834,027,000	219,236,000	2,343,178,000	12,402,677,530
Load Factor	[9]	=[5] /([1] - [3] x 8760)	30%	29%	36%	34%	17%	42%	45%	60%	51%	61%	72%	91%	
Losses															
Summer	[10]	Loss Study	5.7	5.7	5.7	5.7	5.7	5.3	5.3	5.3	5.8	5.3	4.0	3.1	
Peak	[11]	Loss Study	6.0	6.0	6.0	6.0	5.9	5.5	5.5	5.4	5.9	5.4	4.3	3.1	
Winter	[12]	Loss Study	6.1	6.1	6.1	6.1	6.1	5.8	5.8	5.8	6.3	5.8	4.2	3.6	
Net kWh @ Generator (w/ losses)	[13]	=[14] + [15] + [16]	3,395,982,309	6,372,388,096	2,091,091,630	2,560,113,882	42,129,039	2,306,170,030	6,725,471,560	140,479,955	212,829,730	1,991,234,551	490,170,326	4,981,126,331	31,309,187,440
Summer	[14]	=[6] x (1 + [10] / 100)	1,260,932,254	2,321,640,989	765,604,007	971,093,199	14,786,977	837,995,200	2,273,991,957	49,568,822	71,102,901	707,160,758	167,322,340	1,682,892,540	11,124,091,944
Peak	[15]	=[7] x (1 + [11] / 100)	843,014,507	1,621,073,463	546,181,498	653,801,895	13,355,693	505,738,290	1,490,216,751	25,981,373	34,973,259	401,670,288	94,363,778	871,370,187	7,101,740,983
Winter	[16]	=[8] x (1 + [12] / 100)	1,292,035,547	2,429,673,644	779,306,126	935,218,789	13,986,369	962,436,541	2,961,262,852	64,929,759	106,753,570	882,403,505	228,484,208	2,426,863,603	13,083,354,513
Delivered kWh @ Meter (w/o losses)	[17]	=[18] + [19] + [20]	3,208,550,787	6,066,877,054	1,974,154,000	2,431,713,314	67,242,161	2,185,667,648	6,371,553,016	133,119,000	200,643,000	1,887,051,673	470,708,389	4,820,871,389	29,818,151,431
Summer	[18]	[6] Adjusted using Interval Data	1,193,667,485	2,214,205,300	724,244,000	923,696,585	21,218,555	795,910,090	2,159,507,572	47,090,000	67,195,000	671,767,996	160,955,416	1,632,770,416	10,612,228,415
Peak	[19]	[7] Adjusted using Interval Data	795,980,630	1,536,578,555	515,457,000	618,896,269	14,821,837	479,537,438	1,412,531,139	24,650,000	33,033,000	381,072,534	90,501,628	844,907,628	6,747,967,658
Winter	[20]	[8] Adjusted using Interval Data	1,218,902,672	2,316,093,199	734,453,000	889,120,461	31,201,769	910,220,119	2,799,514,305	61,379,000	100,415,000	834,211,142	219,251,345	2,343,193,345	12,457,955,357
Delivered kWh @ Generator (w/ losses)	[21]	=[22] + [23] + [24]	3,398,593,828	6,426,507,408	2,091,091,630	2,575,795,551	71,252,935	2,307,206,043	6,727,361,253	140,479,955	212,829,730	1,991,657,485	490,205,102	4,981,160,827	31,414,141,749
Summer	[22]	=[18] x (1 + [4] / 100)	1,261,829,223	2,340,598,923	765,604,007	976,451,003	22,434,444	838,282,266	2,274,690,050	49,568,822	71,102,901	707,292,365	167,333,169	1,682,903,277	11,158,090,448
Peak	[23]	=[19] x (1 + [] / 100)	843,341,838	1,628,178,505	546,181,498	655,737,712	15,702,789	505,956,834	1,490,469,353	25,981,373	34,973,259	401,766,793	94,371,732	871,378,054	7,114,039,740
Winter	[24]	=[20] x (1 + [5] / 100)	1,293,422,767	2,457,729,981	779,306,126	943,606,836	33,115,703	962,966,944	2,962,201,850	64,929,759	106,753,570	882,598,328	228,500,201	2,426,879,496	13,142,011,561

Schedule 4: Total Return with Current Revenue

Schedule:	4
Purpose:	This schedule calculates SRP’s total return under current prices.
Methodology:	SRP does not currently include revenues and expenses pertaining to FPPAM and EPCAF in its return calculation since these revenues and expenses are purely pass-through items recovered by means of adjustor mechanisms.

Schedule 4: Total Return with Current Revenue

	Line Number	Source	Total
Current Retail Electric Revenues	[1]	Sch 2	$ 2,948,423,082
Current EPCAF Revenues	[2]	Sch 2	$ 163,692,305
Current FPPAM Revenues	[3]	Sch 2	$ 737,392,759
Current Retail Electric Revenues w/o FPPAM & EPCAF	[4]	=[1] - [2] - [3]	$ 2,047,338,018
Total Retail Electric Expenses	[5]	Sch 1b	$ 2,706,823,020
FPPAM Expenses	[6]	Sch 1b	$ 681,490,629
EPCAF Expenses	[7]	Sch 1b	$ 207,588,786
Total Retail Electric Expenses w/o FPPAM & EPCAF	[8]	=[5] - [6] - [7]	$ 1,817,743,605
Current Operating Income w/o FPPAM & EPCAF	[9]	=[4] - [8]	$ 229,594,413
Other Electric Revenues	[10]	Sch 2	$ 22,385,298
Total Current Operating Income w/o FPPAM & EPCAF	[11]	=[9] + [10]	$ 251,979,710
Retail Net Plant Less CWIP	[12]	Sch 1b	$ 7,473,151,247
Current Return	[13]	=[11] / [12]	3.4%

Schedule 5: Allocation Factor Calculations

Schedules: 5: Allocation Factors Summary
5a: Allocator Calculation for 4CP, NCP & SNCP
5b: Allocator Calculation for Energy
5c: Allocator Calculation for Generation
5d: Allocator Calculation for Metering
5e: Allocator Calculation for Distribution

Purpose: This schedule calculates factors used to allocate expense and net plant across classes.

Methodology: **Schedule 5a** uses each class's forecasted 8760 load for FY20 to determine the class average 4CP and NCP. Class load data is insufficient to calculate the SNCP because the SNCP is the average of each customer in the class's maximum hourly demand. Therefore, historic interval data for each customer is used to understand the relationship between NCP and SNCP to create an SNCP/NCP ratio. SNCP for the class is calculated by multiplying that historic ratio with the NCP for each class.

Some customers do not include secondary distribution services. Row 13 ensures that customers that do not use secondary distribution services are not allocated a portion of those costs.

Schedule 5b uses each class's share of different energy measures to calculate allocation factors for energy.

Schedule 5c calculates the Peak and Average to allocate generation. SRP allocates fixed generation costs using a Peak and Average method (also referred to as Average and Peak) and has been using that method since 1985. In this approach, SRP uses the system load factor to weight the fixed generation costs between energy-related and demand-related components.

Schedule 5d uses actual metering costs for each class to allocate meter-related expenses and plant across classes. Meter cost data is obtained from the Marginal Cost Study.

Schedule 5e allocates distribution costs using a distribution study. NCP and SNCP were used to allocate distribution costs in the 2015 Price Process. Row 1 shows distribution costs directly assigned to classes in the Customer Systems Study; these include business segments such as Power Quality or Grid Modernization Services that support Customer Services but are related to the distribution system.

Because the primary cost driver for Distribution Delivery (Substation and Primary) and Distribution Facilities (Secondary) differ, SRP has separated them into two functions. The total distribution dollars are split into Distribution Delivery and Distribution Facilities using the ratio for those functions from the distribution study.

SRP uses each class's ratio of Distribution Delivery and Distribution Facilities dollars in the distribution study to allocate the distribution expenses. The one exception is the lighting class, which the distribution study did not calculate. Lighting customers use SRP's distribution system and so the Pricing Principle of equity suggests that the lighting class include some portion of those costs. Consequently, this study uses NCP to allocate

Distribution Delivery costs and SNCP to allocate the Distribution Facilities costs to the lighting class, with the rest of the dollars being allocated according to the distribution study results.

Schedule 5: Allocation Factor Summary

Allocator	Source	EZ-3	E-23	E-24	E-26	E-27	E-32	E-36	E-40	E-50	E-61	E-63	E-65	Totals
4CP	Sch 5a	12.5%	30.7%	8.1%	10.5%	0.2%	6.1%	18.8%	0.2%	0.0%	4.3%	1.0%	7.7%	100.0%
NCP	Sch 5a	14.7%	28.1%	7.5%	9.8%	0.3%	7.1%	19.3%	0.3%	0.5%	4.3%	0.9%	7.3%	100.0%
Net kWh @ Generator (w/ losses)	Sch 5b	10.8%	20.4%	6.7%	8.2%	0.1%	7.4%	21.5%	0.4%	0.7%	6.4%	1.6%	15.9%	100.0%
Delivered kWh @ Generator (w/ losses)	Sch 5b	10.8%	20.5%	6.7%	8.2%	0.2%	7.3%	21.4%	0.4%	0.7%	6.3%	1.6%	15.9%	100.0%
Delivered kWh @ Meter (w/o losses)	Sch 5b	10.8%	20.3%	6.6%	8.2%	0.2%	7.3%	21.4%	0.4%	0.7%	6.3%	1.6%	16.2%	100.0%
Peak and Average	Sch 5c	11.7%	25.7%	7.4%	9.4%	0.2%	6.7%	20.0%	0.3%	0.3%	5.3%	1.3%	11.6%	100.0%
Metering	Sch 5d	16.2%	35.4%	12.0%	9.6%	0.8%	6.9%	18.0%	0.3%	0.0%	0.3%	0.1%	0.4%	100.0%
Distribution Delivery (Study Results)	Sch 5e	17.1%	30.4%	9.1%	11.2%	0.4%	7.1%	17.1%	0.4%	0.5%	5.3%	1.4%	0.0%	100.0%
Distribution Facilities (Study Results)	Sch 5e	10.3%	19.7%	6.7%	7.0%	0.3%	12.6%	40.4%	0.3%	0.4%	2.1%	0.0%	0.2%	100.0%
Billing & Customer Service	Customer Systems Study	17.5%	38.3%	21.4%	10.4%	1.1%	1.0%	6.7%	0.1%	0.7%	1.6%	0.2%	1.1%	100.0%

Schedule 5a: Allocator Calculation for 4CP, NCP & SNCP

	Line Number	Source	EZ-3	E-23	E-24	E-26	E-27	E-32	E-36	E-40	E-50	E-61	E-63	E-65	Totals
Number of Customers	[1]	Sch 3	213,508	466,799	158,576	126,466	5,647	12,213	82,737	549	9,393	429	45	49	1,076,409
Average 4CP per Customer	[2]	Sch 3	4.2	4.7	3.7	5.9	3.0	35.5	16.2	30.8	0.1	719.6	1,537.1	11,160.3	
Class 4CP	[3]	=[1] x [2]	892,312	2,191,433	579,091	748,726	17,110	433,259	1,339,854	16,891	816	308,350	69,170	546,855	
System Average 4CP	[4]	=sum[3]													7,143,868
Class Allocation of 4CP	[5]	=[3] / [4]	12.5%	30.7%	8.1%	10.5%	0.2%	6.1%	18.8%	0.2%	0.0%	4.3%	1.0%	7.7%	100.0%
Average NCP per Customer	[6]	Sch 3	5.8	5.0	3.9	6.4	4.7	48.4	19.5	46.0	4.8	830.0	1,666.0	12,368.1	
Class NCP	[7]	=[1] x [6]	1,229,659	2,348,276	626,145	815,052	26,695	591,465	1,614,748	25,266	45,064	355,658	74,972	606,035	
Total of Class NCP	[8]	=sum[7]													8,359,034
Class Allocation of NCP	[9]	=[7] / [8]	14.7%	28.1%	7.5%	9.8%	0.3%	7.1%	19.3%	0.3%	0.5%	4.3%	0.9%	7.3%	100.0%
SNCP/NCP Ratio	[10]	Sch 3	176%	183%	183%	167%	171%	150%	140%	198%	100%	123%	130%	120%	
Average SNCP per Customer	[11]	=[6] x [10]	10.2	9.2	7.2	10.8	8.1	72.7	27.3	91.0	4.8	1,018.1	2,169.2	14,826.1	
Class SNCP	[12]	=[1] x [11]	2,167,128	4,288,972	1,143,612	1,364,579	45,745	887,877	2,259,436	49,991	45,064	436,247	97,613	726,479	
Adjustment for Accounts w/o Secondary	[13]	Billing Data	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	12.8%	0.0%	0.0%	100.0%	100.0%	
Adjustment for Accounts w/o Secondary	[14]	=[12] x [13]	-	-	-	-	-	-	-	6,403	-	-	97,613	726,479	
Total of Class SNCP w/ Adjustments	[15]	=[12] - [14]	2,167,128	4,288,972	1,143,612	1,364,579	45,745	887,877	2,259,436	43,589	45,064	436,247	-	-	
Total of Class SNCP	[16]	=sum[15]													12,682,249
Class Allocation of SNCP	[17]	=[15] / [16]	17.1%	33.8%	9.0%	10.8%	0.4%	7.0%	17.8%	0.3%	0.4%	3.4%	0.0%	0.0%	100.0%

Schedule 5b: Allocation Calculation for Energy

	Line Number	Source	EZ-3	E-23	E-24	E-26	E-27	E-32	E-36	E-40	E-50	E-61	E-63	E-65	Totals
Net kWh @ Generator (w/ losses)	[1]	Sch 3	3,395,982,309	6,372,388,096	2,091,091,630	2,560,113,882	42,129,039	2,306,170,030	6,725,471,560	140,479,955	212,829,730	1,991,234,551	490,170,326	4,981,126,331	
Total Net kWh @ Generator (w/ losses)	[2]	=sum[1]													31,309,187,440
Class Allocation of Net kWh @ Generator (w/ losses)	[3]	=[1] / [2]	10.8%	20.4%	6.7%	8.2%	0.1%	7.4%	21.5%	0.4%	0.7%	6.4%	1.6%	15.9%	100.0%
Delivered kWh @ Generator (w/ losses)	[4]	Sch 3	3,398,593,828	6,426,507,408	2,091,091,630	2,575,795,551	71,252,935	2,307,206,043	6,727,361,253	140,479,955	212,829,730	1,991,657,485	490,205,102	4,981,160,827	
Total Delivered kWh @ Generator (w/ losses)	[5]	=sum[4]													31,414,141,749
Class Allocation of Delivered kWh @ Generator (w/ losses)	[6]	=[4] / [5]	10.8%	20.5%	6.7%	8.2%	0.2%	7.3%	21.4%	0.4%	0.7%	6.3%	1.6%	15.9%	100.0%
Delivered kWh @ Meter (w/o losses)	[7]	Sch 3	3,208,550,787	6,066,877,054	1,974,154,000	2,431,713,314	67,242,161	2,185,667,648	6,371,553,016	133,119,000	200,643,000	1,887,051,673	470,708,389	4,820,871,389	
Total Delivered kWh @ Meter (w/o losses)	[8]	=sum[7]													29,818,151,431
Class Allocation of Delivered kWh @ Meter (w/o losses)	[9]	=[7] / [8]	10.8%	20.3%	6.6%	8.2%	0.2%	7.3%	21.4%	0.4%	0.7%	6.3%	1.6%	16.2%	100.0%

Schedule 5c: Allocator Calculation for Generation

	Line Number	Source	EZ-3	E-23	E-24	E-26	E-27	E-32	E-36	E-40	E-50	E-61	E-63	E-65	Totals
System Load Factor	[1]	FP19 FY20 Forecast													48.3%
Class Allocation of Delivered kWh @ Generator (w/ losses)	[2]	Sch 5b	10.8%	20.5%	6.7%	8.2%	0.2%	7.3%	21.4%	0.4%	0.7%	6.3%	1.6%	15.9%	100.0%
Class Allocation of 4CP	[3]	Sch 5a	12.5%	30.7%	8.1%	10.5%	0.2%	6.1%	18.8%	0.2%	0.0%	4.3%	1.0%	7.7%	100.0%
Peak and Average	[4]	=[2] x [1] + [3] x (1 - [1])	11.7%	25.7%	7.4%	9.4%	0.2%	6.7%	20.0%	0.3%	0.3%	5.3%	1.3%	11.6%	100.0%

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Schedule 5d: Allocator Calculation for Metering

	Line Number	Source	EZ-3	E-23	E-24	E-26	E-27	E-32	E-36	E-40	E-50	E-61	E-63	E-65	Totals
Meter Cost (Marginal)	[1]	Marginal Cost Study Sch 5 B	251.24	251.24	251.24	251.24	481.21	1,877.13	721.95	1,877.13	-	2,415.86	7,067.32	26,601.46	
Number of Customers	[2]	Sch 3	213,508	466,799	158,576	126,466	5,647	12,213	82,737	549	9,393	429	45	49	
Class Meter Cost (Marginal)	[3]	=[1] x [2]	$ 53,642,483	$ 117,280,195	$ 39,841,309	$ 31,773,852	$ 2,717,291	$ 22,924,469	$ 59,731,315	$ 1,031,015	$ -	$ 1,035,197	$ 318,029	$ 1,303,471	
Total Meter Cost (Marginal)	[4]	=sum[3]													$ 331,598,626
Class Allocation of Metering	[5]	=[3] / [4]	16.2%	35.4%	12.0%	9.6%	0.8%	6.9%	18.0%	0.3%	0.0%	0.3%	0.1%	0.4%	100.0%

Schedule 5e: Allocator Calculation for Distribution

	Line Number	Source	EZ-3	E-23	E-24	E-26	E-27	E-32	E-36	E-40	E-50	E-61	E-63	E-65	Totals
Assigned Distribution	[1]	Customer Systems Study	$ 393,205	$ 896,145	$ 374,452	$ 265,666	$ 39,327	$ 112,225	$ 917,743	$ 37,859	$ 38,502	$ 739,486	$ 82,558	$ 383,189	
Total Assigned Distribution	[2]	=sum[1]													$ 4,280,356
Total Distribution Facilities	[3]	Sch 1													$ 167,577,272
Total Distribution Facilities, Less Assigned Distribution	[4]	=[3] - [2]													$ 163,296,915
Substation Plus Getaway (Marginal)	[5]	Special Distribution Study	$ 13,093,754	$ 23,229,009	$ 6,944,209	$ 8,633,245	$ 317,809	$ 6,837,799	$ 17,170,881	$ 313,378		$ 4,129,785	$ 979,088		
Primary (Marginal)	[6]	Special Distribution Study	$ 33,233,743	$ 59,187,832	$ 17,693,939	$ 21,738,179	$ 801,531	$ 12,303,569	$ 29,214,904	$ 789,458		$ 10,342,752	$ 2,753,593		
Distribution Delivery (Marginal)	[7]	=[5] + [6]	$ 46,327,497	$ 82,416,841	$ 24,638,147	$ 30,371,424	$ 1,119,340	$ 19,141,368	$ 46,385,785	$ 1,102,836		$ 14,472,537	$ 3,732,681		
Total Distribution Delivery (Marginal)	[8]	=sum[7]													$ 269,708,457
Class Allocation of Distribution Delivery (Study Results), w/o Lighting	[9]	=[7] / [8]	17.2%	30.6%	9.1%	11.3%	0.4%	7.1%	17.2%	0.4%	0.0%	5.4%	1.4%		100.0%
Lighting Allocation of NCP	[10]	Sch 5a									0.5%				
Non-Lighting Class Allocation, Less Lighting Allocation	[11]	=[9] x (1- [10])	17.1%	30.4%	9.1%	11.2%	0.4%	7.1%	17.1%	0.4%		5.3%	1.4%		
Class Allocation of Distribution Delivery (Study Results)	[12]	=[10] + [11]	17.1%	30.4%	9.1%	11.2%	0.4%	7.1%	17.1%	0.4%	0.5%	5.3%	1.4%		100.0%
Secondary (Marginal)	[13]	Special Distribution Study	$ 18,905,164	$ 35,951,959	$ 12,213,257	$ 12,782,522	$ 527,563	$ 23,457,760	$ 74,712,445	$ 503,403		$ 3,149,698			
Total Secondary (Marginal)	[14]	=sum[13]													$ 182,203,770
Class Allocation of Distribution Facilities (Study Results), w/o Lighting	[15]	=[13] / [14]	10.4%	19.7%	6.7%	7.0%	0.3%	12.9%	41.0%	0.3%		1.7%			
Lighting Allocation of SNCP	[16]	Sch 5a									0.4%				
	[17]	=[15] x (1- [16])	10.3%	19.7%	6.7%	7.0%	0.3%	12.8%	40.9%	0.3%	0.0%	1.7%	0.0%	0.0%	
Class Allocation of Distribution Facilities (Study Results)	[18]	=[16] + [17]	10.3%	19.7%	6.7%	7.0%	0.3%	12.8%	40.9%	0.3%	0.4%	1.7%	0.0%	0.0%	100.0%
Allocated Distribution Facilities Dollars	[19]	=[4] x [18]	$ 16,883,215	$ 32,106,818	$ 10,907,022	$ 11,415,403	$ 471,139	$ 20,948,900	$ 66,721,784	$ 449,563	$ 580,241	$ 2,812,831	$ -	$ -	
Plus Assigned Distribution Facilities Dollars	[20]	=[1] + [19]	$ 17,276,420	$ 33,002,963	$ 11,281,474	$ 11,681,069	$ 510,466	$ 21,061,126	$ 67,639,527	$ 487,422	$ 618,743	$ 3,552,317	$ 82,558	$ 383,189	
Class Allocation of Distribution Facilities (Study Results)	[21]	=[20] / [3]	10.3%	19.7%	6.7%	7.0%	0.3%	12.6%	40.4%	0.3%	0.4%	2.1%	0.0%	0.2%	100.0%

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Schedule 6: Expense Allocation Factors

Schedule:	6 and 6b
Purpose:	These schedules summarize the operating expenses and the factors used to allocate these expenses to customer classes without EPCAF (Schedule 6) and with EPCAF (Schedule 6b).
Methodology:	Total expenses by function from Schedule 1 are allocated based on the allocation factors calculated in Schedule 5, with the exception of Dedicated Distribution which is directly assigned to classes based on billing data.

Billing and Customer Service, Meter, Distribution Delivery, and Distribution Facilities expenses are all allocated based on the factors calculated for those functions in Schedule 5.

Transmission expenses are allocated based on 4CP because the cost driver for transmission planning is SRP's expected peak, which will occur in one of the four months June–September. Ancillary Services 1-2 are associated with transmission and so are also allocated based on 4CP.

Ancillary Services 3-6 are associated with the amount of energy that SRP must generate and so is allocated based on Delivered kWh @ Meter (w/o losses). Delivered kWh is used instead of net kWh because the costs are driven by energy delivered, not net energy deliveries.

Systems Benefits costs are allocated based on Net kWh @ Generator (w/ losses) because the SBC is a surcharge on energy as stated in the 1998 Price Process where it was implemented, "it will be levied on energy consumption of all retail customers."

Generation is allocated based on the Peak and Average allocator. Management believes it appropriately balances the Pricing Principles of Equity and Cost Relation (or efficiency).

Fuel and Purchased Power (FPPAM) is allocated based on Net kWh @ Generator (w/ losses) because the cost driver for those expenses is the amount of fuel used at the generator or power purchased at the exchange and the losses incurred while transporting the power to the customer. Net kWh is used instead of Delivered kWh because (under the assumption of a constant market price) excess power exported to SRP directly offsets the fuel or purchased power expense SRP incurs when delivering an equal amount of power later (net kWh is defined as the difference between exported and delivered kWh).

Schedule 6: Expense Allocation Factors

Function	Line Number	Allocator	Source	EZ-3	E-23	E-24	E-26	E-27	E-32	E-36	E-40	E-50	E-61	E-63	E-65	Totals[1]
Billing and Customer Service	[1]	Billing & Customer Service	Schedule 5	17.5%	38.3%	21.4%	10.4%	1.1%	1.0%	6.7%	0.1%	0.7%	1.6%	0.2%	1.1%	$ 231,015,495
Meter	[2]	Metering	Schedule 5	16.2%	35.4%	12.0%	9.6%	0.8%	6.9%	18.0%	0.3%	0.0%	0.3%	0.1%	0.4%	$ 29,323,875
Distribution Delivery	[3]	Distribution Delivery (Study Results)	Schedule 5	17.1%	30.4%	9.1%	11.2%	0.4%	7.1%	17.1%	0.4%	0.5%	5.3%	1.4%	0.0%	$ 272,091,306
Distribution Facilities	[4]	Distribution Facilities (Study Results)	Schedule 5	10.3%	19.7%	6.7%	7.0%	0.3%	12.6%	40.4%	0.3%	0.4%	2.1%	0.0%	0.2%	$ 167,577,272
Dedicated Distribution	[5]	Class actual share of Dedicated Distribution	Billing Data	0.0%	0.0%	0.0%	0.0%	0.0%	0.5%	2.1%	0.8%	0.0%	14.9%	19.7%	62.0%	$ 6,208,454
Transmission	[6]	4CP	Schedule 5	12.5%	30.7%	8.1%	10.5%	0.2%	6.1%	18.8%	0.2%	0.0%	4.3%	1.0%	7.7%	$ 131,175,943
Transmission Cost Adjustment (TCA)	[7]															
Ancillary Services 1 - 2	[8]	4CP	Schedule 5	12.5%	30.7%	8.1%	10.5%	0.2%	6.1%	18.8%	0.2%	0.0%	4.3%	1.0%	7.7%	$ 31,619,188
Ancillary Services 3 - 6	[9]	Delivered kWh @ Meter (w/o losses)	Schedule 5	10.8%	20.3%	6.6%	8.2%	0.2%	7.3%	21.4%	0.4%	0.7%	6.3%	1.6%	16.2%	$ 20,148,310
System Benefits	[10]	Net kWh @ Generator (w/losses)	Schedule 5	10.8%	20.4%	6.7%	8.2%	0.1%	7.4%	21.5%	0.4%	0.7%	6.4%	1.6%	15.9%	$ 87,441,422
Generation	[11]	Peak and Average	Schedule 5	11.7%	25.7%	7.4%	9.4%	0.2%	6.7%	20.0%	0.3%	0.3%	5.3%	1.3%	11.6%	$ 897,392,411
FPPAM	[12]	Net kWh @ Generator (w/losses)	Schedule 5	10.8%	20.4%	6.7%	8.2%	0.1%	7.4%	21.5%	0.4%	0.7%	6.4%	1.6%	15.9%	$ 832,829,343

[1]From Schedule 1

	Line Number	Source	EZ-3	E-23	E-24	E-26	E-27	E-32	E-36	E-40	E-50	E-61	E-63	E-65	Totals
Billing and Customer Service	[13]	=[1] x [1] Total	$ 40,449,584	$ 88,436,159	$ 49,426,801	$ 23,959,352	$ 2,569,098	$ 2,270,186	$ 15,379,918	$ 180,275	$ 1,704,397	$ 3,738,574	$ 393,940	$ 2,507,212	$ 231,015,495
Meter	[14]	=[2] x [2] Total	$ 4,743,703	$ 10,371,303	$ 3,523,240	$ 2,809,820	$ 240,295	$ 2,027,253	$ 5,282,150	$ 91,175	$ -	$ 91,544	$ 28,124	$ 115,268	$ 29,323,875
Distribution Delivery	[15]	=[3] x [3] Total	$ 46,484,837	$ 82,696,750	$ 24,721,825	$ 30,474,573	$ 1,123,142	$ 19,206,377	$ 46,543,323	$ 1,106,582	$ 1,466,849	$ 14,521,690	$ 3,745,358	$ -	$ 272,091,306
Distribution Facilities	[16]	=[4] x [4] Total	$ 17,276,420	$ 33,002,963	$ 11,281,474	$ 11,681,069	$ 510,466	$ 21,061,126	$ 67,639,527	$ 487,422	$ 618,743	$ 3,552,317	$ 82,558	$ 383,189	$ 167,577,272
Dedicated Distribution	[17]	=[5] x [5] Total	$ -	$ -	$ -	$ -	$ -	$ 29,761	$ 128,322	$ 48,548	$ -	$ 927,911	$ 1,225,755	$ 3,848,157	$ 6,208,454
Transmission	[18]	=[6] x [6] Total	$ 16,384,658	$ 40,239,166	$ 10,633,283	$ 13,748,134	$ 314,181	$ 7,955,517	$ 24,602,449	$ 310,153	$ 14,977	$ 5,661,941	$ 1,270,107	$ 10,041,378	$ 131,175,943
Transmission Cost Adjustment (TCA)	[19]	=[7] x [7] Total	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Ancillary Services 1 - 2	[20]	=[8] x [8] Total	$ 3,949,425	$ 9,699,414	$ 2,563,090	$ 3,313,907	$ 75,732	$ 1,917,630	$ 5,930,275	$ 74,761	$ 3,610	$ 1,364,777	$ 306,152	$ 2,420,415	$ 31,619,188
Ancillary Services 3 - 6	[21]	=[9] x [9] Total	$ 2,168,038	$ 4,099,426	$ 1,333,948	$ 1,643,124	$ 45,436	$ 1,476,869	$ 4,305,298	$ 89,949	$ 135,576	$ 1,275,093	$ 318,061	$ 3,257,493	$ 20,148,310
System Benefits	[22]	=[10] x [10] Total	$ 9,484,421	$ 17,797,034	$ 5,840,076	$ 7,149,978	$ 117,659	$ 6,440,754	$ 18,783,138	$ 392,337	$ 594,399	$ 5,561,191	$ 1,368,965	$ 13,911,468	$ 87,441,422
Generation	[23]	=[11] x [11] Total	$ 104,845,067	$ 231,004,483	$ 66,462,501	$ 84,168,166	$ 2,094,356	$ 59,969,894	$ 179,833,720	$ 3,034,984	$ 2,988,644	$ 47,503,026	$ 11,255,091	$ 104,232,479	$ 897,392,411
FPPAM	[24]	=[12] x [12] Total	$ 90,333,667	$ 169,506,532	$ 55,623,368	$ 68,099,435	$ 1,120,639	$ 61,344,488	$ 178,898,608	$ 3,736,789	$ 5,661,305	$ 52,967,154	$ 13,038,608	$ 132,498,749	$ 832,829,343
															$ -
Total Expense	[25]	=sum(of [13]-[24])	$ 336,119,821	$ 686,853,231	$ 231,409,606	$ 247,047,556	$ 8,211,004	$ 183,699,856	$ 547,326,729	$ 9,552,974	$ 13,188,498	$ 137,165,219	$ 33,032,719	$ 273,215,808	$ 2,706,823,020
Total Expense, Less FPPAM	[26]	=[25] - [24]	$ 245,786,154	$ 517,346,699	$ 175,786,237	$ 178,948,121	$ 7,090,365	$ 122,355,368	$ 368,428,121	$ 5,816,185	$ 7,527,193	$ 84,198,064	$ 19,994,110	$ 140,717,059	$ 1,873,993,677

Schedule 6b: Expense

Function	Line Number	Allocator	Source	EZ-3	E-23	E-24	E-26	E-27	E-32	E-36	E-40	E-50	E-61	E-63	E-65	Totals[1]
Billing and Customer Service	[1]	Billing & Customer Service	Schedule 5	17.5%	38.3%	21.4%	10.4%	1.1%	1.0%	6.7%	0.1%	0.7%	1.6%	0.2%	1.1%	$ 230,602,896
Meter	[2]	Metering	Schedule 5	16.2%	35.4%	12.0%	9.6%	0.8%	6.9%	18.0%	0.3%	0.0%	0.3%	0.1%	0.4%	$ 29,323,875
Distribution Delivery	[3]	Distribution Delivery (Study Results)	Schedule 5	17.1%	30.4%	9.1%	11.2%	0.4%	7.1%	17.1%	0.4%	0.5%	5.3%	1.4%	0.0%	$ 272,091,306
Distribution Facilities	[4]	Distribution Facilities (Study Results)	Schedule 5	10.3%	19.7%	6.7%	7.0%	0.3%	12.6%	40.4%	0.3%	0.4%	2.1%	0.0%	0.2%	$ 167,577,272
Dedicated Distribution	[5]	Class actual share of Dedicated Distribution	Billing Data	0.0%	0.0%	0.0%	0.0%	0.0%	0.5%	2.1%	0.8%	0.0%	14.9%	19.7%	62.0%	$ 6,208,454
Transmission	[6]	4CP	Schedule 5	12.5%	30.7%	8.1%	10.5%	0.2%	6.1%	18.8%	0.2%	0.0%	4.3%	1.0%	7.7%	$ 131,175,943
Transmission Cost Adjustment (TCA)	[7]															
Ancillary Services 1 - 2	[8]	4CP	Schedule 5	12.5%	30.7%	8.1%	10.5%	0.2%	6.1%	18.8%	0.2%	0.0%	4.3%	1.0%	7.7%	$ 31,619,188
Ancillary Services 3 - 6	[9]	Delivered kWh @ Meter (w/o losses)	Schedule 5	10.8%	20.3%	6.6%	8.2%	0.2%	7.3%	21.4%	0.4%	0.7%	6.3%	1.6%	16.2%	$ 20,148,310
System Benefits	[10]	Net kWh @ Generator (w/ losses)	Schedule 5	10.8%	20.4%	6.7%	8.2%	0.1%	7.4%	21.5%	0.4%	0.7%	6.4%	1.6%	15.9%	$ 33,166,012
Generation	[11]	Peak and Average	Schedule 5	11.7%	25.7%	7.4%	9.4%	0.2%	6.7%	20.0%	0.3%	0.3%	5.3%	1.3%	11.6%	$ 895,830,349
EPCAF	[12]	Delivered kWh @ Generator (w/ losses)	Schedule 5	10.8%	20.5%	6.7%	8.2%	0.2%	7.3%	21.4%	0.4%	0.7%	6.3%	1.6%	15.9%	$ 207,588,786
FPPAM	[13]	Net kWh @ Generator (w/ losses)	Schedule 5	10.8%	20.4%	6.7%	8.2%	0.1%	7.4%	21.5%	0.4%	0.7%	6.4%	1.6%	15.9%	$ 681,490,629

[1]From Schedule 1b

	Line Number	Source	EZ-3	E-23	E-24	E-26	E-27	E-32	E-36	E-40	E-50	E-61	E-63	E-65	Totals
Billing and Customer Service	[14]	=[1] x [1] Total	$ 40,377,340	$ 88,278,210	$ 49,338,524	$ 23,916,560	$ 2,564,510	$ 2,266,131	$ 15,352,449	$ 179,953	$ 1,701,353	$ 3,731,897	$ 393,236	$ 2,502,734	$ 230,602,896
Meter	[15]	=[2] x [2] Total	$ 4,743,703	$ 10,371,303	$ 3,523,240	$ 2,809,820	$ 240,295	$ 2,027,253	$ 5,282,150	$ 91,175	$ -	$ 91,544	$ 28,124	$ 115,268	$ 29,323,875
Distribution Delivery	[16]	=[3] x [3] Total	$ 46,484,837	$ 82,696,750	$ 24,721,825	$ 30,474,573	$ 1,123,142	$ 19,206,377	$ 46,543,323	$ 1,106,582	$ 1,466,849	$ 14,521,690	$ 3,745,358	$ -	$ 272,091,306
Distribution Facilities	[17]	=[4] x [4] Total	$ 17,276,420	$ 33,002,963	$ 11,281,474	$ 11,681,069	$ 510,466	$ 21,061,126	$ 67,639,527	$ 487,422	$ 618,743	$ 3,552,317	$ 82,558	$ 383,189	$ 167,577,272
Dedicated Distribution	[18]	=[5] x [5] Total	$ -	$ -	$ -	$ -	$ -	$ 29,761	$ 128,322	$ 48,548	$ -	$ 927,911	$ 1,225,755	$ 3,848,157	$ 6,208,454
Transmission	[19]	=[6] x [6] Total	$ 16,384,658	$ 40,239,166	$ 10,633,283	$ 13,748,134	$ 314,181	$ 7,955,517	$ 24,602,449	$ 310,153	$ 14,977	$ 5,661,941	$ 1,270,107	$ 10,041,378	$ 131,175,943
Transmission Cost Adjustment (TCA)	[20]	=[7] x [7] Total	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Ancillary Services 1 - 2	[21]	=[8] x [8] Total	$ 3,949,425	$ 9,699,414	$ 2,563,090	$ 3,313,907	$ 75,732	$ 1,917,630	$ 5,930,275	$ 74,761	$ 3,610	$ 1,364,777	$ 306,152	$ 2,420,415	$ 31,619,188
Ancillary Services 3 - 6	[22]	=[9] x [9] Total	$ 2,168,038	$ 4,099,426	$ 1,333,948	$ 1,643,124	$ 45,436	$ 1,476,869	$ 4,305,298	$ 89,949	$ 135,576	$ 1,275,093	$ 318,061	$ 3,257,493	$ 20,148,310
System Benefits	[23]	=[10] x [10] Total	$ 3,597,385	$ 6,750,309	$ 2,215,106	$ 2,711,944	$ 44,628	$ 2,442,940	$ 7,124,333	$ 148,811	$ 225,452	$ 2,109,327	$ 519,240	$ 5,276,537	$ 33,166,012
Generation	[24]	=[11] x [11] Total	$ 104,662,567	$ 230,602,381	$ 66,346,812	$ 84,021,657	$ 2,090,710	$ 59,865,507	$ 179,520,689	$ 3,029,701	$ 2,983,442	$ 47,420,339	$ 11,235,499	$ 104,051,044	$ 895,830,349
EPCAF	[25]	=[12] x [12] Total	$ 22,458,356	$ 42,467,207	$ 13,818,209	$ 17,021,196	$ 470,849	$ 15,246,321	$ 44,455,289	$ 928,310	$ 1,406,407	$ 13,161,135	$ 3,239,340	$ 32,916,167	$ 207,588,786
FPPAM	[26]	=[13] x [13] Total	$ 73,918,562	$ 138,704,423	$ 45,515,693	$ 55,724,653	$ 917,001	$ 50,197,191	$ 146,389,805	$ 3,057,753	$ 4,632,553	$ 43,342,156	$ 10,669,280	$ 108,421,559	$ 681,490,629
															$ -
Total Expense	[27]	=sum(of [14]-[26])	$ 336,021,291	$ 686,911,553	$ 231,291,203	$ 247,066,636	$ 8,396,948	$ 183,692,623	$ 547,273,910	$ 9,553,117	$ 13,188,960	$ 137,160,127	$ 33,032,710	$ 273,233,941	$ 2,706,823,020
Total Expense, Less FPPAM & EPCAF	[28]	=[27] - [26] - [25]	$ 239,644,373	$ 505,739,923	$ 171,957,301	$ 174,320,787	$ 7,009,099	$ 118,249,111	$ 356,428,815	$ 5,567,054	$ 7,150,000	$ 80,656,836	$ 19,124,091	$ 131,896,216	$ 1,817,743,605

Schedule 7: Plant less CWIP Allocation

Schedule: 7

Purpose: This schedule summarizes the capital costs and the factors used to allocate capital to the customer classes.

Methodology: Plant less CWIP Allocation factors are identical to the expense allocation factors shown in Schedule 6.

Schedule 7: Plant less CWIP Allocation

Function	Line Number	Allocator	Source	EZ-3	E-23	E-24	E-26	E-27	E-32	E-36	E-40	E-50	E-61	E-63	E-65	Totals[1]
Billing and Customer Service	[1]	Billing & Customer Service	Schedule 5	17.5%	38.3%	21.4%	10.4%	1.1%	1.0%	6.7%	0.1%	0.7%	1.6%	0.2%	1.1%	$ 17,486,092
Meter	[2]	Metering	Schedule 5	16.2%	35.4%	12.0%	9.6%	0.8%	6.9%	18.0%	0.3%	0.0%	0.3%	0.1%	0.4%	$ 197,446,908
Distribution Delivery	[3]	Distribution Delivery (Study Results)	Schedule 5	17.1%	30.4%	9.1%	11.2%	0.4%	7.1%	17.1%	0.4%	0.5%	5.3%	1.4%	0.0%	$ 1,426,225,423
Distribution Facilities	[4]	Distribution Facilities (Study Results)	Schedule 5	10.3%	19.7%	6.7%	7.0%	0.3%	12.6%	40.4%	0.3%	0.4%	2.1%	0.0%	0.2%	$ 894,649,985
Dedicated Distribution	[5]	Dedicated Distribution	Billing Data	0.0%	0.0%	0.0%	0.0%	0.0%	0.5%	2.1%	0.8%	0.0%	14.9%	19.7%	62.0%	$ 44,275,048
Transmission	[6]	4CP	Schedule 5	12.5%	30.7%	8.1%	10.5%	0.2%	6.1%	18.8%	0.2%	0.0%	4.3%	1.0%	7.7%	$ 1,209,709,477
Transmission Cost Adjustment (TCA)	[7]															
Ancillary Services 1 - 2	[8]	4CP	Schedule 5	12.5%	30.7%	8.1%	10.5%	0.2%	6.1%	18.8%	0.2%	0.0%	4.3%	1.0%	7.7%	$ 65,195,605
Ancillary Services 3 - 6	[9]	Delivered kWh @ Meter (w/o losses)	Schedule 5	10.8%	20.3%	6.6%	8.2%	0.2%	7.3%	21.4%	0.4%	0.7%	6.3%	1.6%	16.2%	$ 138,050,312
System Benefits	[10]	Delivered kWh @ Meter (w/o losses)	Schedule 5	10.8%	20.3%	6.6%	8.2%	0.2%	7.3%	21.4%	0.4%	0.7%	6.3%	1.6%	16.2%	$ -
Generation	[11]	Peak and Average	Schedule 5	11.7%	25.7%	7.4%	9.4%	0.2%	6.7%	20.0%	0.3%	0.3%	5.3%	1.3%	11.6%	$ 3,480,112,397

[1] From Schedule 1

	Line Number	Source	EZ-3	E-23	E-24	E-26	E-27	E-32	E-36	E-40	E-50	E-61	E-63	E-65	Totals
Billing and Customer Service	[12]	=[1] x [1] Total	$ 3,061,722	$ 6,693,935	$ 3,741,228	$ 1,813,538	$ 194,461	$ 171,836	$ 1,164,141	$ 13,645	$ 129,010	$ 282,981	$ 29,818	$ 189,777	$ 17,486,092
Meter	[13]	=[2] x [2] Total	$ 31,940,851	$ 69,833,256	$ 23,723,088	$ 18,919,405	$ 1,617,982	$ 13,650,134	$ 35,566,382	$ 613,907	$ -	$ 616,397	$ 189,367	$ 776,138	$ 197,446,908
Distribution Delivery	[14]	=[3] x [3] Total	$ 243,660,328	$ 433,472,900	$ 129,584,791	$ 159,739,065	$ 5,887,192	$ 100,674,377	$ 243,966,895	$ 5,800,388	$ 7,688,804	$ 76,118,579	$ 19,632,105	$ -	$ 1,426,225,423
Distribution Facilities	[15]	=[4] x [4] Total	$ 92,234,158	$ 176,193,943	$ 60,228,756	$ 62,362,084	$ 2,725,238	$ 112,439,686	$ 361,109,245	$ 2,602,213	$ 3,303,300	$ 18,964,864	$ 440,756	$ 2,045,743	$ 894,649,985
Dedicated Distribution	[16]	=[5] x [5] Total	$ -	$ -	$ -	$ -	$ -	$ 212,239	$ 915,118	$ 346,216	$ -	$ 6,617,316	$ 8,741,368	$ 27,442,792	$ 44,275,048
Transmission	[17]	=[6] x [6] Total	$ 151,099,934	$ 371,087,100	$ 98,060,532	$ 126,785,807	$ 2,897,393	$ 73,366,075	$ 226,884,712	$ 2,860,242	$ 138,116	$ 52,214,628	$ 11,712,974	$ 92,601,964	$ 1,209,709,477
Transmission Cost Adjustment (TCA)	[18]	=[7] x [7] Total	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Ancillary Services 1 - 2	[19]	=[8] x [8] Total	$ 8,143,320	$ 19,999,222	$ 5,284,836	$ 6,832,944	$ 156,151	$ 3,953,962	$ 12,227,635	$ 154,149	$ 7,444	$ 2,814,035	$ 631,254	$ 4,990,654	$ 65,195,605
Ancillary Services 3 - 6	[20]	=[9] x [9] Total	$ 14,854,758	$ 28,088,068	$ 9,139,821	$ 11,258,202	$ 311,314	$ 10,119,075	$ 29,498,639	$ 616,306	$ 928,925	$ 8,736,560	$ 2,179,258	$ 22,319,385	$ 138,050,312
System Benefits	[21]	=[10] x [10] Total	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Generation	[22]	=[11] x [11] Total	$ 406,592,048	$ 895,841,727	$ 257,743,402	$ 326,406,457	$ 8,121,970	$ 232,564,897	$ 697,400,100	$ 11,769,750	$ 11,590,044	$ 184,218,040	$ 43,647,551	$ 404,216,412	$ 3,480,112,397
Total Plant Less CWIP	[23]	=sum(of [12]-[22])	$ 951,587,120	$ 2,001,210,152	$ 587,506,453	$ 714,117,503	$ 21,911,700	$ 547,152,280	$ 1,608,732,867	$ 24,776,816	$ 23,785,643	$ 350,583,400	$ 87,204,450	$ 554,582,864	$ 7,473,151,247

Schedule 8: Current Return by Class

Schedule: 8

Purpose: Schedule 8 calculates current returns by class.

Methodology: Return is calculated by dividing Operating Income by Total Plant less CWIP.

Schedule 8: Current Return by Class

	Line Number	Source	EZ-3	E-23	E-24	E-26	E-27	E-32	E-36	E-40	E-50	E-61	E-63	E-65	Totals
Current Retail Electric Revenue	[1]	Sch 2	$ 360,754,300	$ 718,479,066	$ 244,386,525	$ 262,171,509	$ 7,643,629	$ 206,939,862	$ 618,044,053	$ 12,545,929	$ 22,548,766	$ 151,515,121	$ 37,779,712	$ 305,614,612	$ 2,948,423,082
Current FPPAM Revenue	[2]	Sch 2	$ 80,825,042	$ 151,615,574	$ 49,896,568	$ 61,238,143	$ 1,018,773	$ 54,312,490	$ 157,112,954	$ 3,210,712	$ 4,834,711	$ 46,386,397	$ 11,406,309	$ 115,535,087	$ 737,392,759
Current EPCAF Revenue	[3]	Sch 2	$ 17,633,473	$ 33,086,889	$ 10,857,847	$ 13,293,028	$ 455,999	$ 12,015,776	$ 35,033,699	$ 732,155	$ 1,103,537	$ 10,376,581	$ 2,588,713	$ 26,514,609	$ 163,692,305
Other Electric Revenue	[4]	Sch 2	$ 4,652,043	$ 10,170,904	$ 3,455,162	$ 2,755,527	$ 123,035	$ 158,028	$ 1,070,598	$ -	$ -	$ -	$ -	$ -	$ 22,385,298
Current Retail Electric Revenue w/o FPPAM and EPCAF	[5]	=[1] - [2] - [3] + [4]	$ 266,947,828	$ 543,947,507	$ 187,087,272	$ 190,395,865	$ 6,291,892	$ 140,769,623	$ 426,967,998	$ 8,603,062	$ 16,610,519	$ 94,752,144	$ 23,784,691	$ 163,564,916	$ 2,069,723,316
Total Retail Electric Expenses	[6]	Sch 6b	$ 336,021,291	$ 686,911,553	$ 231,291,203	$ 247,066,636	$ 8,396,948	$ 183,692,623	$ 547,273,910	$ 9,553,117	$ 13,188,960	$ 137,160,127	$ 33,032,710	$ 273,233,941	$ 2,706,823,020
FPPAM Expenses	[7]	Sch 6b	$ 73,918,562	$ 138,704,423	$ 45,515,693	$ 55,724,653	$ 917,001	$ 50,197,191	$ 146,389,805	$ 3,057,753	$ 4,632,553	$ 43,342,156	$ 10,669,280	$ 108,421,559	$ 681,490,629
EPCAF Expenses	[8]	Sch 6b	$ 22,458,356	$ 42,467,207	$ 13,818,209	$ 17,021,196	$ 470,849	$ 15,246,321	$ 44,455,289	$ 928,310	$ 1,406,407	$ 13,161,135	$ 3,239,340	$ 32,916,167	$ 207,588,786
Total Retail Electric Expenses w/o FPPAM & EPCAF	[9]	=[6] - [7] - [8]	$ 239,644,373	$ 505,739,923	$ 171,957,301	$ 174,320,787	$ 7,009,099	$ 118,249,111	$ 356,428,815	$ 5,567,054	$ 7,150,000	$ 80,656,836	$ 19,124,091	$ 131,896,216	$ 1,817,743,605
Total Current Operating Income w/o FPPAM & EPCAF	[10]	=[5] - [9]	$ 27,303,455	$ 38,207,585	$ 15,129,971	$ 16,075,078	$ (717,207)	$ 22,520,512	$ 70,539,183	$ 3,036,008	$ 9,460,518	$ 14,095,308	$ 4,660,600	$ 31,668,701	$ 251,979,710
Total Plant Less CWIP	[11]	Sch 7	$ 951,587,120	$ 2,001,210,152	$ 587,506,453	$ 714,117,503	$ 21,911,700	$ 547,152,280	$ 1,608,732,867	$ 24,776,816	$ 23,785,643	$ 350,583,400	$ 87,204,450	$ 554,582,864	$ 7,473,151,247
Current Return, Including EPCAF	[12]	=[10] / [11]	2.9%	1.9%	2.6%	2.3%	-3.3%	4.1%	4.4%	12.3%	39.8%	4.0%	5.3%	5.7%	3.4%

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Schedule EPCAF: Summary of EPCAF Changes

Schedule: EPCAF

Purpose: This schedule illustrates how the changes to EPCAF affect base and fuel revenues.

Methodology: With the proposed elimination of EPCAF, this schedule details the revenue recovery of those costs from the EPCAF to FPPAM and base rates. Per the FPPAM budget, $121.8 million of EPCAF revenues is moving to FPPAM. Those revenue recoveries are allocated among the classes by net energy with losses because FPPAM is allocated by net energy with losses. The remaining EPCAF revenues move to base rates.

Schedule EPCAF: Summary of EPCAF Changes

	Line Number	Source	EZ-3	E-23	E-24	E-26	E-27	E-32	E-36	E-40	E-50	E-61	E-63	E-65	Totals
Current EPCAF Revenue Collected	[1]	Sch 2	$ 17,633,473	$ 33,086,889	$ 10,857,847	$ 13,293,028	$ 455,999	$ 12,015,776	$ 35,033,699	$ 732,155	$ 1,103,537	$ 10,376,581	$ 2,588,713	$ 26,514,609	
Total EPCAF Revenue Collected	[2]	=sum[1]													$ 163,692,305
EPCAF Dollars to FPPAM	[3]	FPPAM Budget													$ 121,838,273
EPCAF Dollars to BASE	[4]	=[2] - [3]													$ 41,854,032
Class Allocation of Net kWh @ Generator (w/ losses)	[5]	Sch 5b	10.8%	20.4%	6.7%	8.2%	0.1%	7.4%	21.5%	0.4%	0.7%	6.4%	1.6%	15.9%	
EPCAF Dollars to FPPAM by Class	[6]	=[3] x [5]	$ 13,215,310	$ 24,797,857	$ 8,137,388	$ 9,962,566	$ 163,943	$ 8,974,355	$ 26,171,865	$ 546,671	$ 828,217	$ 7,748,798	$ 1,907,475	$ 19,383,826	
EPCAF Dollars to Base by Class	[7]	=[1] - [6]	$ 4,418,163	$ 8,289,032	$ 2,720,459	$ 3,330,462	$ 292,056	$ 3,041,421	$ 8,861,834	$ 185,483	$ 275,319	$ 2,627,782	$ 681,237	$ 7,130,783	
Total Change in EPCAF Rates	[8]	=-([6] - [7])	$ (17,633,473)	$ (33,086,889)	$ (10,857,847)	$ (13,293,028)	$ (455,999)	$ (12,015,776)	$ (35,033,699)	$ (732,155)	$ (1,103,537)	$ (10,376,581)	$ (2,588,713)	$ (26,514,609)	

Schedule FPPAM: Derivation of Proposed FPPAM Charge

Schedule:	FPPAM
Purpose:	This schedule illustrates the detailed calculation used to derive the Fuel and Purchased Power Adjustment Mechanism (FPPAM) cost recovery by class.
Methodology:	This schedule allocates the FPPAM recovery by season and by class using net kWh adjusted for losses. Once class FPPAM recovery allocations are determined, the schedule then calculates the FPPAM by season by rate by dividing the allocations by the respective classes' net kWh excluding losses. The FPPAM rate is then applied to each class's seasonal energy to calculate the proposed FPPAM revenue recovery by class which is then compared to current fuel revenues for each class which determines the net change in fuel recovery.

Schedule FPPAM: Derivation of Proposed FPPAM Charge

FY19 Prices

	Line Number	Source	EZ-3	E-23	E-24	E-26	E-27	E-32	E-36	E-40	E-50	E-61	E-63	E-65	Totals
Total Summer FPPAM Dollars (Proposed)	[1]	FPPAM Budget													$ 447,540,265
Total Winter FPPAM Dollars (Proposed)	[2]	FPPAM Budget													$ 297,402,390
Net kWh @ Generator (w/ losses)															
Summer	[3]	Sch 3	1,260,932,254	2,321,640,989	765,604,007	971,093,199	14,786,977	837,995,200	2,273,991,957	49,568,822	71,102,901	707,160,758	167,322,340	1,682,892,540	
Peak	[4]	Sch 3	843,014,507	1,621,073,463	546,181,498	653,801,895	13,355,693	505,738,290	1,490,216,751	25,981,373	34,973,259	401,670,288	94,363,778	871,370,187	
6-Month Summer	[5]	=[3] + [4]	2,103,946,762	3,942,714,452	1,311,785,504	1,624,895,094	28,142,670	1,343,733,489	3,764,208,708	75,550,196	106,076,160	1,108,831,046	261,686,118	2,554,262,728	
Winter	[6]	Sch 3	1,292,035,547	2,429,673,644	779,306,126	935,218,789	13,986,369	962,436,541	2,961,262,852	64,929,759	106,753,570	882,403,505	228,484,208	2,426,863,603	
Total 6-Month Summer Net kWh @ Generator (w/ losses)	[7]	=sum[5]													18,225,832,927
Total Winter Net kWh @ Generator (w/ losses)	[8]	=sum[6]													13,083,354,513
Allocator: 6-Month Summer Net kWh @ Generator (w/ losses)	[9]	=[5] / [7]	11.5%	21.6%	7.2%	8.9%	0.2%	7.4%	20.7%	0.4%	0.6%	6.1%	1.4%	14.0%	
Allocator: Winter Net kWh @ Generator (w/ losses)	[10]	=[6] / [8]	9.9%	18.6%	6.0%	7.1%	0.1%	7.4%	22.6%	0.5%	0.8%	6.7%	1.7%	18.5%	
Allocated Summer FPPAM Dollars	[11]	=[1] x [9]	$ 51,662,983	$ 96,814,421	$ 32,211,248	$ 39,899,739	$ 691,051	$ 32,995,740	$ 92,431,165	$ 1,855,156	$ 2,604,729	$ 27,227,647	$ 6,425,774	$ 62,720,613	
Allocated Winter FPPAM Dollars	[12]	=[2] x [10]	$ 29,369,720	$ 55,229,777	$ 17,714,685	$ 21,258,791	$ 317,929	$ 21,877,488	$ 67,313,520	$ 1,475,941	$ 2,426,653	$ 20,058,228	$ 5,193,756	$ 55,165,901	
Net kWh @ Meter (w/o losses)															
Summer	[13]	Sch 3	1,192,818,969	2,196,271,105	724,244,000	918,628,245	13,985,561	795,637,535	2,158,844,828	47,090,000	67,195,000	671,643,000	160,945,000	1,632,760,000	
Peak	[14]	Sch 3	795,671,682	1,529,873,237	515,457,000	617,069,212	12,606,418	479,330,306	1,412,291,746	24,650,000	33,033,000	380,981,000	90,494,000	844,900,000	
6-Month Summer	[15]	=[13] + [14]	1,988,490,651	3,726,144,342	1,239,701,000	1,535,697,457	26,591,979	1,274,967,840	3,571,136,573	71,740,000	100,228,000	1,052,624,000	251,439,000	2,477,660,000	
Winter	[16]	Sch 3	1,217,595,376	2,289,653,723	734,453,000	881,216,761	13,178,022	909,718,770	2,798,626,878	61,379,000	100,415,000	834,027,000	219,236,000	2,343,178,000	
Calculated Summer FPPAM Prices	[17]	=round([11] / [15],4)	$ 0.0260	$ 0.0260	$ 0.0260	$ 0.0260	$ 0.0260	$ 0.0259	$ 0.0259	$ 0.0259	$ 0.0260	$ 0.0259	$ 0.0256	$ 0.0253	
Calculated Winter FPPAM Prices	[18]	=round([12] / [16],4)	$ 0.0241	$ 0.0241	$ 0.0241	$ 0.0241	$ 0.0241	$ 0.0240	$ 0.0241	$ 0.0240	$ 0.0242	$ 0.0240	$ 0.0237	$ 0.0235	
Adjustment to Summer Price to keep Consistent Class Rounding	[19]														
Adjustment to Winter Price to keep Consistent Class Rounding	[20]							$ 0.0001							
Proposed Summer FPPAM Prices	[21]	=[17] + [19]	$ 0.0260	$ 0.0260	$ 0.0260	$ 0.0260	$ 0.0260	$ 0.0259	$ 0.0259	$ 0.0259	$ 0.0260	$ 0.0259	$ 0.0256	$ 0.0253	
Proposed Winter FPPAM Prices	[22]	=[18] + [20]	$ 0.0241	$ 0.0241	$ 0.0241	$ 0.0241	$ 0.0241	$ 0.0241	$ 0.0241	$ 0.0240	$ 0.0242	$ 0.0240	$ 0.0237	$ 0.0235	
Proposed Summer FPPAM Revenues	[23]	=[15] x [21]	$ 51,700,757	$ 96,879,753	$ 32,232,226	$ 39,928,134	$ 691,391	$ 33,021,667	$ 92,492,437	$ 1,858,066	$ 2,605,928	$ 27,262,962	$ 6,436,838	$ 62,684,798	
Proposed Winter FPPAM Revenues	[24]	=[16] x [22]	$ 29,344,049	$ 55,180,655	$ 17,700,317	$ 21,237,324	$ 317,590	$ 21,924,222	$ 67,446,908	$ 1,473,096	$ 2,430,043	$ 20,016,648	$ 5,195,893	$ 55,064,683	
Proposed FPPAM Revenue	[25]	=[23] + [24]	$ 81,044,805	$ 152,060,408	$ 49,932,543	$ 61,165,458	$ 1,008,982	$ 54,945,889	$ 159,939,345	$ 3,331,162	$ 5,035,971	$ 47,279,610	$ 11,632,732	$ 117,749,481	
EPCAF dollars moved to FPPAM	[26]	Sch EPCAF	$ 13,215,310	$ 24,797,857	$ 8,137,388	$ 9,962,566	$ 163,943	$ 8,974,355	$ 26,171,865	$ 546,671	$ 828,217	$ 7,748,798	$ 1,907,475	$ 19,383,826	
Proposed FPPAM Revenue, Less EPCAF Change	[27]	=[25] - [26]	$ 67,829,495	$ 127,262,550	$ 41,795,156	$ 51,202,892	$ 845,039	$ 45,971,534	$ 133,767,480	$ 2,784,491	$ 4,207,754	$ 39,530,811	$ 9,725,256	$ 98,365,655	
Current FPPAM Revenue	[28]	Sch 2	$ 80,825,042	$ 151,615,574	$ 49,896,568	$ 61,238,143	$ 1,018,773	$ 54,312,490	$ 157,112,954	$ 3,210,712	$ 4,834,711	$ 46,386,397	$ 11,406,309	$ 115,535,087	
Change in FPPAM Rates	[29]	=[27] - [28]	$ (12,995,547)	$ (24,353,023)	$ (8,101,413)	$ (10,035,251)	$ (173,734)	$ (8,340,956)	$ (23,345,474)	$ (426,222)	$ (626,957)	$ (6,855,585)	$ (1,681,053)	$ (17,169,431)	
Change in FPPAM Rates, Including EPCAF	[30]	=[25] - [28]	$ 219,763	$ 444,834	$ 35,975	$ (72,685)	$ (9,791)	$ 633,399	$ 2,826,391	$ 120,450	$ 201,260	$ 893,213	$ 226,423	$ 2,214,394	

Schedule SBC: Derivation of System Benefits Charge

Schedule:	SBC
Purpose:	Schedule SBC shows the summarized derivation of the System Benefits Charge (SBC).
Methodology:	The SBC includes $32 million of nuclear decommissioning and spent fuel storage expenses, distributed generation programs, and customer assistance programs, such as the economy discount rider for low-income customers and the medical life support equipment discount rider.

As discussed in Schedule 1, Management proposes eliminating the EPCAF mechanism. Schedule 1 reflects changes to the functional expenses in accordance with the elimination of EPCAF. $50 million associated with the energy efficiency programs is moving from EPCAF to the SBC.

Management proposes that a single customer's maximum contribution to energy efficiency programs be capped at $300,000 (see *Proposed adjustments to SRP's Standard Electric Price Plans effective with the May 2019 Billing Cycle* write-up for a detail of this proposal). Rows [4] and [10] represent the kWh and dollars that will not be eligible for the energy efficiency portion of the SBC charge under that proposed cap.

The proposed SBC charge is $0.0029/kWh based on the projected Fiscal Year 2020 test year SBC budget.

Schedule SBC: Derivation of System Benefits Charge

	Line Number	Source		
Energy Efficiency Programs, Total Dollars	[1]	Sch 1	$	50,115,410
Other SBC Programs, Total Dollars	[2]	Corp Accounting Services	$	32,326,012
Total Billed kWh	[3]	Sch 3		29,719,098,372
Estimated kWh Not Applicable for Energy Efficiency Programs	[4]	Billing Data		2,230,023,203
Applicable kWh for Energy Efficiency Programs	[5]	=[3] - [4]		27,489,075,169
$ per kWh for Energy Efficiency Programs	[6]	=round([1] / [5],4)	$	0.0018
$ per kWh for Other SBC Programs	[7]	=round([2] / [3],4)	$	0.0011
$ per kWh for Systems Benefits Charge	[8]	=[6] + [7]	$	0.0029
SBC Total Collected	[9]	=[3] x [8]	$	86,185,385
Estimated Refunded Revenue in Excess of Energy Efficiency Cap	[10]	=[4] x [6]	$	4,014,042
SBC Target Revenues	[11]	=[9] - [10]	$	82,171,344

Schedule 9: Target Revenues by Class

Schedule:	9
Purpose:	This schedule calculates by function and by class the current, proposed change in revenue, and target revenues to be recovered in prices.
Methodology:	This schedule summarizes current revenue by function and by class from Schedule 2 and adds Management's proposed changes in revenues by function and by class in order to provide revenue targets by function and class.

Schedule 9: Target Revenues by Class

Current Revenues	Line Number	Source	EZ-3	E-23	E-24	E-26	E-27	E-32	E-36	E-40	E-50	E-61	E-63	E-65	Totals
Billings, Collections	[1]	Sch 2	$ 6,892,030	$ 15,068,256	$ 5,118,844	$ 4,082,331	$ 182,277	$ 476,288	$ 3,254,142	$ 21,487	$ -	$ 518,725	$ 54,475	$ 59,317	$ 35,728,171
Meter	[2]	Sch 2	$ 5,380,395	$ 11,763,322	$ 3,996,124	$ 3,186,950	$ 142,298	$ 1,735,152	$ 8,553,200	$ 173,607	$ -	$ 131,327	$ 17,604	$ 190,512	$ 35,270,490
Distribution Delivery	[3]	Sch 2	$ 72,743,309	$ 117,424,432	$ 43,707,953	$ 49,086,393	$ 957,669	$ 44,550,601	$ 127,462,808	$ 4,254,302	$ 3,789,699	$ 14,395,450	$ 3,358,359	$ -	$ 481,730,975
Distribution Facilities	[4]	Sch 2	$ 10,760,791	$ 23,526,644	$ 7,992,247	$ 6,373,899	$ 1,193,949	$ -	$ -	$ -	$ 9,108,924	$ 9,979,850	$ 2,162,384	$ -	$ 71,098,689
Dedicated Distribution	[5]	Sch 2	$ -	$ -	$ -	$ -	$ -	$ 58,512	$ 252,288	$ 95,448	$ -	$ 1,824,322	$ 2,409,900	$ 7,565,679	$ 12,206,149
Transmission	[6]	Sch 2	$ 37,115,805	$ 87,477,252	$ 27,667,802	$ 29,607,538	$ 967,210	$ 23,097,446	$ 71,242,260	$ 560,777	$ 20,064	$ 14,107,006	$ 3,265,480	$ 33,220,593	$ 328,349,234
Transmission Cost Adjustment (TCA)	[7]	Sch 2	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Ancillary Services 1 - 2	[8]	Sch 2	$ 2,008,901	$ 4,720,140	$ 1,483,978	$ 1,633,751	$ 53,851	$ 1,184,357	$ 3,791,114	$ 39,484	$ 20,064	$ 772,754	$ 182,344	$ 1,786,795	$ 17,677,534
Ancillary Services 3 - 6	[9]	Sch 2	$ 2,320,125	$ 4,450,120	$ 1,534,503	$ 1,736,031	$ 28,028	$ 1,630,041	$ 5,029,842	$ 89,510	$ 80,257	$ 1,447,778	$ 357,837	$ 3,635,801	$ 22,339,874
System Benefits	[10]	Sch 2	$ 2,244,260	$ 4,211,059	$ 1,381,908	$ 1,691,840	$ 57,798	$ 1,529,281	$ 4,458,834	$ 93,183	$ 140,450	$ 1,320,656	$ 329,473	$ 3,374,587	$ 20,833,327
Competitive Customer Services	[11]	Sch 2	$ 28,208,644	$ 61,673,418	$ 20,951,105	$ 16,708,721	$ 746,049	$ 3,932,436	$ 11,624,493	$ 885,951	$ 1,705,466	$ 3,548,446	$ 568,197	$ 2,165,833	$ 152,718,759
Generation	[12]	Sch 2	$ 94,621,525	$ 203,461,960	$ 69,797,644	$ 73,532,884	$ 1,839,729	$ 62,795,669	$ 191,070,337	$ 2,410,490	$ 1,745,594	$ 47,266,707	$ 11,219,358	$ 113,012,050	$ 872,773,947
Aggregation	[13]	Sch 2	$ -	$ -	$ -	$ -	$ -	$ (378,187)	$ (841,918)	$ (21,177)	$ -	$ (560,877)	$ (140,720)	$ (1,446,251)	$ (3,389,131)
EPCAF	[14]	Sch 2	$ 17,633,473	$ 33,086,889	$ 10,857,847	$ 13,293,028	$ 455,999	$ 12,015,776	$ 35,033,699	$ 732,155	$ 1,103,537	$ 10,376,581	$ 2,588,713	$ 26,514,609	$ 163,692,305
FPPAM	[15]	Sch 2	$ 80,825,042	$ 151,615,574	$ 49,896,568	$ 61,238,143	$ 1,018,773	$ 54,312,490	$ 157,112,954	$ 3,210,712	$ 4,834,711	$ 46,386,397	$ 11,406,309	$ 115,535,087	$ 737,392,759
Total	[16]	Sch 2	$ 360,754,300	$ 718,479,066	$ 244,386,525	$ 262,171,509	$ 7,643,629	$ 206,939,862	$ 618,044,053	$ 12,545,929	$ 22,548,766	$ 151,515,121	$ 37,779,712	$ 305,614,612	$ 2,948,423,082

Revenue Deltas	Line Number	Source	EZ-3	E-23	E-24	E-26	E-27	E-32	E-36	E-40	E-50	E-61	E-63	E-65	Totals
Billing and Customer Service	[17]	Mgmt. Proposal	$ 10,009,206	$ 21,745,526	$ 7,502,513	$ 5,914,769	$ 266,923	$ (2,130,497)	$ 553,895	$ (725,049)	$ 53,794	$ (315,351)	$ (226,825)	$ 295,212	$ 42,944,116
Meter	[18]	Mgmt. Proposal	$ 3,535	$ (1,284,274)	$ 644,217	$ (128,564)	$ 169,979	$ 930,843	$ (1,663,664)	$ 12,656	$ -	$ (10,929)	$ 22,638	$ (21,460)	$ (1,325,024)
Distribution Delivery	[19]	Mgmt. Proposal	$ (21,727,877)	$ (28,302,063)	$ (14,316,538)	$ (16,566,162)	$ 272,618	$ (22,672,642)	$ (70,211,729)	$ (2,544,827)	$ 946,868	$ 2,074,738	$ 691,808	$ -	$ (172,355,807)
Distribution Facilities	[20]	Mgmt. Proposal	$ 8,364,385	$ 9,748,167	$ 6,125,349	$ 6,126,490	$ (562,241)	$ 26,322,609	$ 83,959,493	$ 890,479	$ (7,085,430)	$ (5,539,812)	$ (2,051,620)	$ -	$ 126,297,869
Dedicated Distribution	[21]	Mgmt. Proposal													
Transmission	[22]	Mgmt. Proposal	$ (11,753,680)	$ (25,190,279)	$ (11,208,341)	$ (8,326,539)	$ (480,883)	$ (10,782,950)	$ (33,159,659)	$ (80,685)	$ 3,118	$ (5,342,780)	$ (1,299,457)	$ (17,152,403)	$ (124,774,536)
Transmission Cost Adjustment (TCA)	[23]	Mgmt. Proposal													
Ancillary Services 1 - 2	[24]	Mgmt. Proposal	$ 2,429,938	$ 6,181,227	$ 1,396,730	$ 2,090,816	$ 31,266	$ 970,906	$ 2,874,042	$ 44,541	$ (16,007)	$ 761,146	$ 161,746	$ 933,558	$ 17,859,910
Ancillary Services 3 - 6	[25]	Mgmt. Proposal	$ 740,937	$ 1,335,929	$ 348,972	$ 583,311	$ 35,676	$ 455,300	$ 1,048,958	$ 37,494	$ 111,170	$ 352,624	$ 91,253	$ 963,636	$ 6,105,260
System Benefits	[26]	Mgmt. Proposal	$ 7,053,389	$ 13,234,756	$ 4,343,139	$ 5,317,211	$ 57,535	$ 4,782,507	$ 13,820,067	$ 278,636	$ 404,768	$ 3,905,667	$ 990,667	$ 7,149,674	$ 61,338,016
Generation	[27]	Mgmt. Proposal	$ 18,377,527	$ 28,902,194	$ 8,805,829	$ 14,917,268	$ 608,194	$ 8,062,503	$ 20,293,047	$ 2,447,882	$ 6,172,721	$ 8,863,691	$ 2,829,943	$ 19,241,171	$ 139,521,970
Aggregation	[28]	Mgmt. Proposal													
EPCAF	[29]	Mgmt. Proposal	$ (17,633,473)	$ (33,086,889)	$ (10,857,847)	$ (13,293,028)	$ (455,999)	$ (12,015,776)	$ (35,033,699)	$ (732,155)	$ (1,103,537)	$ (10,376,581)	$ (2,588,713)	$ (26,514,609)	$ (163,692,305)
FPPAM	[30]	Mgmt. Proposal	$ 219,763	$ 444,834	$ 35,975	$ (72,685)	$ (9,791)	$ 633,399	$ 2,826,391	$ 120,450	$ 201,260	$ 893,213	$ 226,423	$ 2,214,394	$ 7,733,627
Total	[31]	=sum(of[17] - [30])	$ (3,916,349)	$ (6,270,873)	$ (7,180,001)	$ (3,437,113)	$ (66,723)	$ (5,443,798)	$ (14,692,857)	$ (250,579)	$ (311,274)	$ (4,734,374)	$ (1,152,137)	$ (12,890,827)	$ (60,346,904)

Proposed Revenues	Line Number	Source	EZ-3	E-23	E-24	E-26	E-27	E-32	E-36	E-40	E-50	E-61	E-63	E-65	Totals
Billing and Customer Service	[32]	=[1] + [11] + [17]	$ 45,109,880	$ 98,487,199	$ 33,572,462	$ 26,705,821	$ 1,195,248	$ 2,278,227	$ 15,432,530	$ 182,389	$ 1,759,259	$ 3,751,820	$ 395,848	$ 2,520,363	$ 231,391,046
Meter	[33]	=[2] + [18]	$ 5,383,931	$ 10,479,048	$ 4,640,341	$ 3,058,385	$ 312,277	$ 2,665,995	$ 6,889,536	$ 186,263	$ -	$ 120,397	$ 40,242	$ 169,051	$ 33,945,466
Distribution Delivery	[34]	=[3] + [19]	$ 51,015,432	$ 89,122,369	$ 29,391,416	$ 32,520,231	$ 1,230,287	$ 21,877,958	$ 57,251,079	$ 1,709,474	$ 4,736,567	$ 16,470,188	$ 4,050,167	$ -	$ 309,375,168
Distribution Facilities	[35]	=[4] + [20]	$ 19,125,176	$ 33,274,811	$ 14,117,597	$ 12,500,389	$ 631,707	$ 26,322,609	$ 83,959,493	$ 890,479	$ 2,023,494	$ 4,440,039	$ 110,764	$ -	$ 197,396,557
Dedicated Distribution	[36]	=[5] + [21]	$ -	$ -	$ -	$ -	$ -	$ 58,512	$ 252,288	$ 95,448	$ -	$ 1,824,322	$ 2,409,900	$ 7,565,679	$ 12,206,149
Transmission	[37]	=[6] + [22]	$ 25,362,126	$ 62,286,974	$ 16,459,461	$ 21,280,999	$ 486,327	$ 12,314,496	$ 38,082,601	$ 480,092	$ 23,183	$ 8,764,226	$ 1,966,023	$ 16,068,190	$ 203,574,698
Transmission Cost Adjustment (TCA)	[38]	=[7] + [23]	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Ancillary Services 1 - 2	[39]	=[8] + [24]	$ 4,438,839	$ 10,901,367	$ 2,880,709	$ 3,724,567	$ 85,116	$ 2,155,264	$ 6,665,156	$ 84,025	$ 4,057	$ 1,533,901	$ 344,090	$ 2,720,353	$ 35,537,444
Ancillary Services 3 - 6	[40]	=[9] + [25]	$ 3,061,062	$ 5,786,049	$ 1,883,475	$ 2,319,343	$ 63,704	$ 2,085,341	$ 6,078,800	$ 127,004	$ 191,427	$ 1,800,401	$ 449,090	$ 4,599,436	$ 28,445,133
System Benefits	[41]	=[10] + [26]	$ 9,297,649	$ 17,445,814	$ 5,725,047	$ 7,009,051	$ 115,333	$ 6,311,787	$ 18,278,901	$ 371,820	$ 545,218	$ 5,226,323	$ 1,320,139	$ 10,524,260	$ 82,171,344
Generation	[42]	=[12] + [27]	$ 112,999,051	$ 232,364,154	$ 78,603,473	$ 88,450,152	$ 2,447,923	$ 70,858,172	$ 211,363,384	$ 4,858,372	$ 7,918,315	$ 56,130,398	$ 14,049,301	$ 132,253,221	$ 1,012,295,917
Aggregation	[43]	=[13] + [28]	$ -	$ -	$ -	$ -	$ -	$ (378,187)	$ (841,918)	$ (21,177)	$ -	$ (560,877)	$ (140,720)	$ (1,446,251)	$ (3,389,131)
EPCAF	[44]	=[14] + [29]	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
FPPAM	[45]	=[15] + [30]	$ 81,044,805	$ 152,060,408	$ 49,932,543	$ 61,165,458	$ 1,008,982	$ 54,945,889	$ 159,939,345	$ 3,331,162	$ 5,035,971	$ 47,279,610	$ 11,632,732	$ 117,749,481	$ 745,126,386
Total	[46]	=[16] + [31]	$ 356,837,951	$ 712,208,193	$ 237,206,523	$ 258,734,396	$ 7,576,905	$ 201,496,064	$ 603,351,196	$ 12,295,350	$ 22,237,492	$ 146,780,747	$ 36,627,575	$ 292,723,785	$ 2,888,076,178

Schedule 10: Overall Return with Proposed Revenue

Schedule: 10

Purpose: This schedule calculates return with current revenues under the current EPCAF methodology and also calculates the proposed return after Management's proposals.

Methodology: The schedule shows that with the current EPCAF methodology and without a base price increase, SRP's current return is 3.4%. The proposed EPCAF elimination and base rate changes would increase the return to 3.8%.

Proposed Total Revenues includes an adjustment associated with the proposed E-67 rate. E-67 was designed to generate the same level of revenues as E-65 if the rate was applied to all E-65 customers. However, some revenue loss is estimated due to eligible E-65 customers selecting the price plan optimal for them, which has been factored into the overall proposal.

Schedule 10: Overall Return with Proposed Revenue

	Line Number	Source	Total	
Current Retail Electric Revenues w/o FPPAM & EPCAF	[1]	Sch 4	$ 2,047,338,018	
Total Retail Electric Expenses w/o FPPAM & EPCAF	[2]	Sch 4	$ 1,817,743,605	
Current Operating Income w/o FPPAM & EPCAF	[3]	=[1] - [2]	$ 229,594,413	
Other Electric Revenues	[4]	Sch 2	$ 22,385,298	
Total Current Operating Income w/o FPPAM & EPCAF	[5]	=[3] + [4]	$ 251,979,710	
Retail Net Plant Less CWIP	[6]	Sch 4	$ 7,473,151,247	
Current Return	[7]	=[5] / [6]	3.4%	
Proposed Total Revenues	[8]	Sch 9, w/ Adjustment	$ 2,884,425,705	*
Proposed Total FPPAM Revenues	[9]	Sch 9	$ 745,126,386	
Proposed Total Revenues w/o FPPAM	[10]	=[8] - [9]	$ 2,139,299,319	
Total Expenses	[11]	Sch 1	$ 2,706,823,020	
FPPAM Expenses	[12]	Sch 1	$ 832,829,343	
Total Expenses w/o FPPAM	[13]	=[11] - [12]	$ 1,873,993,677	
Proposed Operating Income w/o FPPAM	[14]	=[10] - [13]	$ 265,305,642	
Total Proposed Operating Income w/o FPPAM	[15]	=[14] + [4]	$ 287,690,939	
Proposed Return	[16]	=[15] / [6]	3.8%	

*The total in row 8 includes an estimated revenue change from E-67 participation. E-67 was designed to generate the same level of revenues as E-65 if the rate was applied to all E-65 customers. However, some revenue loss is estimated due to eligible E-65 customers selecting the price plan optimal for them, which has been factored into the overall proposal.

Schedule 11: Current and Proposed Return by Class

Schedule:	11
Purpose:	This schedule contrasts the current and proposed returns by class under Management's proposal.
Methodology:	This schedule calculates the return by class by starting with current revenues adding the changes under Management's proposal to increase base rates, reduce FPPAM, eliminate EPCAF, and transfer revenue and the associated EPCAF recoveries to base and FPPAM.

Schedule 11: Current and Proposed Return by Class

	Line Number	Source	EZ-3	E-23	E-24	E-26	E-27	E-32	E-36	E-40	E-50	E-61	E-63	E-65	Totals
Current Retail Electric Revenues	[1]	Sch 2	$ 360,754,300	$ 718,479,066	$ 244,386,525	$ 262,171,509	$ 7,643,629	$ 206,939,862	$ 618,044,053	$ 12,545,929	$ 22,548,766	$ 151,515,121	$ 37,779,712	$ 305,614,612	$ 2,948,423,082
Current FPPAM Revenue	[2]	Sch 2	$ 80,825,042	$ 151,615,574	$ 49,896,568	$ 61,238,143	$ 1,018,773	$ 54,312,490	$ 157,112,954	$ 3,210,712	$ 4,834,711	$ 46,386,397	$ 11,406,309	$ 115,535,087	$ 737,392,759
Proposed EPCAF to FPPAM	[3]	Sch EPCAF	$ 13,215,310	$ 24,797,857	$ 8,137,388	$ 9,962,566	$ 163,943	$ 8,974,355	$ 26,171,865	$ 546,671	$ 828,217	$ 7,748,798	$ 1,907,475	$ 19,383,826	$ 121,838,273
Other Electric Revenue	[4]	Sch 2	$ 4,652,043	$ 10,170,904	$ 3,455,162	$ 2,755,527	$ 123,035	$ 158,028	$ 1,070,598	$ -	$ -	$ -	$ -	$ -	$ 22,385,298
Total Retail Electric Revenues w/ EPCAF Changes & w/o FPPAM	[5]	=[1] - [2] - [3] + [4]	$ 271,365,991	$ 552,236,539	$ 189,807,731	$ 193,726,327	$ 6,583,948	$ 143,811,044	$ 435,829,831	$ 8,788,545	$ 16,885,838	$ 97,379,926	$ 24,465,928	$ 170,695,700	$ 2,111,577,348
Total Expense	[6]	Sch 6	$ 336,119,821	$ 686,853,231	$ 231,409,606	$ 247,047,556	$ 8,211,004	$ 183,699,856	$ 547,326,729	$ 9,552,974	$ 13,188,498	$ 137,165,219	$ 33,032,719	$ 273,215,808	$ 2,706,823,020
FPPAM Expense	[7]	Sch 6	$ 90,333,667	$ 169,506,532	$ 55,623,368	$ 68,099,435	$ 1,120,639	$ 61,344,488	$ 178,898,608	$ 3,736,789	$ 5,661,305	$ 52,967,154	$ 13,038,608	$ 132,498,749	$ 832,829,343
Total Expense w/o FPPAM	[8]	=[6] - [7]	$ 245,786,154	$ 517,346,699	$ 175,786,237	$ 178,948,121	$ 7,090,365	$ 122,355,368	$ 368,428,121	$ 5,816,185	$ 7,527,193	$ 84,198,064	$ 19,994,110	$ 140,717,059	$ 1,873,993,677
Total Current Operating Income w/ EPCAF Changes & w/o FPPAM	[9]	=[5] - [8]	$ 25,579,837	$ 34,889,841	$ 14,021,494	$ 14,778,206	$ (506,417)	$ 21,455,677	$ 67,401,711	$ 2,972,360	$ 9,358,644	$ 13,181,862	$ 4,471,817	$ 29,978,641	$ 237,583,671
Change in Base Rates	[10]	Sum(of Sch 9 [17]-[28]) - Sch EPCAF [7]	$ 9,079,198	$ 18,082,150	$ 921,411	$ 6,598,139	$ 107,011	$ 2,897,158	$ 8,652,617	$ 175,643	$ 315,683	$ 2,121,212	$ 528,916	$ 4,278,605	$ 50,107,269 *
Change in FPPAM Rates	[11]	Sch FPPAM	$ (12,995,547)	$ (24,353,023)	$ (8,101,413)	$ (10,035,251)	$ (173,734)	$ (8,340,956)	$ (23,345,474)	$ (426,222)	$ (626,957)	$ (6,855,585)	$ (1,681,053)	$ (17,169,431)	$ (114,104,646)
Change in EPCAF Rates	[12]	Sch EPCAF	$ (17,633,473)	$ (33,086,889)	$ (10,857,847)	$ (13,293,028)	$ (455,999)	$ (12,015,776)	$ (35,033,699)	$ (732,155)	$ (1,103,537)	$ (10,376,581)	$ (2,588,713)	$ (26,514,609)	$ (163,692,305)
EPCAF to Base	[13]	Sch EPCAF	$ 4,418,163	$ 8,289,032	$ 2,720,459	$ 3,330,462	$ 292,056	$ 3,041,421	$ 8,861,834	$ 185,483	$ 275,319	$ 2,627,782	$ 681,237	$ 7,130,783	$ 41,854,032
EPCAF to FPPAM	[14]	Sch EPCAF	$ 13,215,310	$ 24,797,857	$ 8,137,388	$ 9,962,566	$ 163,943	$ 8,974,355	$ 26,171,865	$ 546,671	$ 828,217	$ 7,748,798	$ 1,907,475	$ 19,383,826	$ 121,838,273
Total Revenue Change	[15]	=[10] + [11] + [12] + [13] + [14]	$ (3,916,349)	$ (6,270,873)	$ (7,180,001)	$ (3,437,113)	$ (66,723)	$ (5,443,798)	$ (14,692,857)	$ (250,579)	$ (311,274)	$ (4,734,374)	$ (1,152,137)	$ (12,890,827)	$ (63,997,377)
Total Proposed Operating Income w/o FPPAM	[16]	=[9] + [10]	$ 34,659,034	$ 52,971,991	$ 14,942,905	$ 21,376,344	$ (399,406)	$ 24,352,835	$ 76,054,328	$ 3,148,003	$ 9,674,327	$ 15,303,073	$ 5,000,733	$ 34,257,245	$ 287,690,939
Total Plant Less CWIP	[17]	Sch 7	$ 951,587,120	$ 2,001,210,152	$ 587,506,453	$ 714,117,503	$ 21,911,700	$ 547,152,280	$ 1,608,732,867	$ 24,776,816	$ 23,785,643	$ 350,583,400	$ 87,204,450	$ 554,582,864	$ 7,473,151,247
Current Return, Current EPCAF Methodology	[18]	Sch 8	2.9%	1.9%	2.6%	2.3%	-3.3%	4.1%	4.4%	12.3%	39.8%	4.0%	5.3%	5.7%	3.4%
Proposed Return	[19]	=[16] / [17]	3.6%	2.6%	2.5%	3.0%	-1.8%	4.5%	4.7%	12.7%	40.7%	4.4%	5.7%	6.2%	3.8%
FPPAM Increase	[20]	=[11] / [1]	-3.6%	-3.4%	-3.3%	-3.8%	-2.3%	-4.0%	-3.8%	-3.4%	-2.8%	-4.5%	-4.4%	-5.6%	-3.9%
Base Increase	[21]	=[10]/ [1]	2.5%	2.5%	0.4%	2.5%	1.4%	1.4%	1.4%	1.4%	1.4%	1.4%	1.4%	1.4%	1.7%
Total Increase	[22]	=[20] + [21]	-1.1%	-0.9%	-2.9%	-1.3%	-0.9%	-2.6%	-2.4%	-2.0%	-1.4%	-3.1%	-3.0%	-4.2%	-2.2%

*Sum does not total. The total in row 10 includes an estimated revenue change from E-67 participation. E-67 was designed to generate the same level of revenues as E-65 if the rate was applied to all E-65 customers. However, some revenue loss is estimated due to eligible E-65 customers selecting the price plan optimal for them, which has been factored into the overall proposal.

Appendix A: Summary of Transmission Expenses and Net Plant Less CWIP

Schedule: Appendix A

Purpose: Summarizes total transmission expenses and net plant less CWIP for Fiscal Year 2020.

Methodology: Total transmission expenses are presented in Appendix A. Retail transmission totals are calculated for inclusion within the Cost Allocation Study model.

Net plant less CWIP is used as the basis for applying the return for the derivation of proposed revenues.

Appendix A: Summary of Transmission Expenses and Net Plant Less CWIP

	Line Number	Source	Total Transmission	Retail Transmission
% of Allocation	[1]	Network Transmission Peak Report		82.97%
Operating Expense				
Operations & Maintenance	[2]	Sch 1	$ 108,021,867	$ 89,629,532
Depreciation	[3]	Sch 1	$ 57,593,449	$ 47,787,305
In Lieu Tax	[4]	Sch 1	$ 16,657,566	$ 13,821,367
Transfer to Ancillary Services[1]	[5]	Sch 1	$ (22,250,909)	$ (18,462,360)
Transfer of Step Up to Generation	[6]	Sch 1	$ (1,928,207)	$ (1,599,901)
Total - Operating Expenses	[7]	=sum(of[2]-[6])	$ 158,093,766	$ 131,175,943
Net Plant Less CWIP	[8]	Sch 1	$ 1,475,728,646	$ 1,224,463,827
Transfer Step Up	[9]	Sch 1	$ (17,782,001)	$ (14,754,350)
Total Net Plant Less CWIP	[10]	=[8] + [9]	$ 1,457,946,645	$ 1,209,709,477
Proposed Return on Net Plant Less CWIP	[11]	Mgmt. Proposal	6.01%	6.01%
Proposed Operating Income	[12]	=[10] * [11]	$ 87,622,593	$ 72,703,540
Proposed Revenue	[13]	=[7] + [12]	$ 245,716,359	$ 203,879,483
Revenue Credits	[14]	Transmission Services	$ 1,000,000	$ 829,735
Proposed Net Revenue	[15]	=[13] - [14]	$ 244,716,359	$ 203,049,748

Note:

(1) Derivation of Proposed Changes to SRP's Transmission and Ancillary Services Rates.

Appendix B: Summary of Marginal Costs

Schedule: Appendix B

Purpose: Summary of SRP's marginal cost of providing electricity from Fiscal Year 2020. Marginal costs are used in rate design as a guide for setting prices and TOU hours. They are not used for setting overall price or revenue levels. The costs are presented in Fiscal Year 2020 dollars.

Methodology: Marginal costs can be defined as those additional costs incurred in the production of one more unit of any commodity. Alternatively, they can be defined as those costs avoided by foregoing the production of the last unit of the commodity.

Economic theory holds that society tends to maximize efficiency of use under marginal cost pricing. Economists term this concept allocative or economic efficiency. SRP pricing design supports this philosophy; however, prices are not based solely upon marginal costs. Rather, they are set in conjunction with historical and budgeted costs, customer choice, cost trends, current prices, etc.

The marginal cost of supplying electric service can be separated into four major categories:

1. Marginal customer cost is defined as the cost associated with adding a customer to the system, without regard for customer load, and includes meter cost, meter O&M, customer service and marketing costs.

2. Marginal distribution facilities cost is defined as the cost associated with adding a customer to the system based on expected load, including feeders downstream of the first piece of equipment, line transformers, secondary transformers, and service laterals, but excluding meters and related costs. Cost for this service is incurred regardless of the actual load placed on the system by that customer.

3. Marginal demand cost is defined as the cost of expanding the electric system to accommodate the demands that customers place on the system, including generation, transmission and distribution substation costs, including that portion of the feeder to the first piece of equipment.

4. Marginal energy cost is defined as the cost of producing the next kilowatt-hour, or the cost avoided by not producing a kilowatt-hour, including fuel, variable O&M, and associated marginal related loadings.

Appendix B provides these derived marginal cost values by price plan, season and TOU period. The results are presented for SRP's three seasons:

- Summer (May, June, September and October)
- Summer Peak (July and August)
- Winter (November through April

Appendix B: Summary of Marginal Costs

Residential Service from Secondary (E-23)	Summer Peak	Summer	Winter
Customer-related cost ($/Customer per month):	$24.58	$24.58	$24.58
Distribution Facilities cost ($/Customer per month):	$26.25	$26.25	$26.25
	Summer Peak	**Summer**	**Winter**
Demand-related cost ($/kW per month):	$46.00	$4.59	$0.14
Energy cost ($/kWh):	$0.0361	$0.0282	$0.0273

Residential-TOU Service from Secondary (E-26)	Summer Peak		Summer		Winter	
Customer-related cost ($/Customer per month):	$23.81		$23.81		$23.81	
Distribution Facilities cost ($/Customer per month):	$32.46		$32.46		$32.46	
	On-Peak	**Off-Peak**	**On-Peak**	**Off-Peak**	**On-Peak**	**Off-Peak**
Demand-related cost ($/kW per month):	$33.60	$12.38	$2.49	$2.10	$0.04	$0.10
Energy cost ($/kWh):	$0.0459	$0.0336	$0.0321	$0.0272	$0.0302	$0.0265

Residential-TOU Service from Secondary (E-21)	Summer Peak		Summer		Winter	
Customer-related cost ($/Customer per month):	$22.32		$22.32		$22.32	
Distribution Facilities cost ($/Customer per month):	$29.62		$29.62		$29.62	
	On-Peak	**Off-Peak**	**On-Peak**	**Off-Peak**	**On-Peak**	**Off-Peak**
Demand-related cost ($/kW per month):	$16.74	$29.23	$1.25	$3.35	$0.01	$1.24
Energy cost ($/kWh):	$0.0485	$0.0349	$0.0323	$0.0278	$0.0282	$0.0272

Residential- CG Service from Secondary (E-27)	Summer Peak		Summer		Winter	
Customer-related cost ($/Customer per month):	$45.73		$45.73		$45.73	
Distribution Facilities cost ($/Customer per month):	$30.10		$30.10		$30.10	
	On-Peak	**Off-Peak**	**On-Peak**	**Off-Peak**	**On-Peak**	**Off-Peak**
Demand-related cost ($/kW per month):	$33.60	$12.38	$2.49	$2.10	$0.04	$0.10
Energy cost ($/kWh):	$0.0459	$0.0336	$0.0321	$0.0272	$0.0302	$0.0265

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Appendix B: Summary of Marginal Costs

General Service from Secondary (E-36)

	Summer Peak	Summer	Winter
Customer-related cost ($/Customer per month):	$40.60	$40.60	$40.60
Distribution Facilities cost ($/max. kW per month):	$11.22	$11.22	$11.22
	Summer Peak	**Summer**	**Winter**
Demand-related cost ($/kW per month):	$45.78	$4.57	$0.14
Energy cost ($/kWh):	$0.0360	$0.0281	$0.0273

General Service from Secondary (E-32)

	Summer Peak	Summer	Winter
Customer-related cost ($/Customer per month):	$62.11	$62.11	$62.11
Distribution Facilities cost ($/max. kW per month):	$9.86	$9.86	$9.86

	Summer Peak On-Peak	Summer Peak Shoulder	Summer Peak Off-Peak	Summer On-Peak	Summer Shoulder	Summer Off-Peak	Winter On-Peak	Winter Shoulder	Winter Off-Peak
Demand-related cost ($/kW per month):	$29.23	$6.86	$9.66	$2.07	$0.72	$1.79	$0.02	$0.02	$0.09
Energy cost ($/kWh):	$0.0468	$0.0397	$0.0322	$0.0321	$0.0313	$0.0261	$0.0281	$0.0322	$0.0263

Pumping Service from Secondary

	Summer Peak	Summer	Winter
Customer-related cost ($/Customer per month):	$167.85	$167.85	$167.85
Distribution Facilities cost ($/max. kW per month):	$2.87	$2.87	$2.87

	Summer Peak On-Peak	Summer Peak Shoulder	Summer Peak Off-Peak	Summer On-Peak	Summer Shoulder	Summer Off-Peak	Winter On-Peak	Winter Shoulder	Winter Off-Peak
Demand-related cost ($/kW per month):	$29.23	$6.86	$9.66	$2.07	$0.72	$1.79	$0.02	$0.02	$0.09
Energy cost ($/kWh):	$0.0468	$0.0397	$0.0322	$0.0321	$0.0313	$0.0261	$0.0281	$0.0322	$0.0263

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Appendix B: Summary of Marginal Costs

Large General Service (E-61/E-63)	Summer Peak	Summer	Winter
Customer-related cost ($/Customer per month):			
Primary	$1,174.41	$1,174.41	$1,174.41
Secondary	$1,028.13	$1,028.13	$1,028.13
Distribution Facilities cost ($/max. kW per month):			
Primary	$2.59	$2.59	$2.59
Secondary	$2.89	$2.89	$2.89

	Summer Peak			Summer			Winter		
	On-Peak	Shoulder	Off-Peak	On-Peak	Shoulder	Off-Peak	On-Peak	Shoulder	Off-Peak
Demand-related cost ($/kW per month):									
Primary	$37.65	$7.48	$0.13	$3.21	$0.89	$0.42	$0.02	$0.02	$0.09
Secondary	$38.02	$7.56	$0.13	$3.25	$0.90	$0.42	$0.02	$0.02	$0.09
Energy cost ($/kWh):									
Primary	$ 0.0451	$ 0.0386	$ 0.0298	$ 0.0316	$ 0.0308	$ 0.0243	$ 0.0277	$ 0.0318	$ 0.0259
Secondary	$ 0.0455	$ 0.0390	$ 0.0302	$ 0.0319	$ 0.0311	$ 0.0247	$ 0.0281	$ 0.0322	$ 0.0263

Dedicated Large General Service (E-65)	Summer Peak	Summer	Winter
Customer-related cost ($/Customer per month):			
1 Bay	$5,439.48	$5,439.48	$5,439.48
2 Bay	$5,713.65	$5,713.65	$5,713.65
3 Bay	$6,531.31	$6,531.31	$6,531.31
Customer-specific Dedicated Facilities cost:			
1-Bay MUS Substation	$13,745.16	$13,745.16	$13,745.16
1-Bay Stnd Substation	$46,917.50	$46,917.50	$46,917.50
2-Bay Stnd Substation	$63,769.07	$63,769.07	$63,769.07
3-Bay Stnd Substation	$88,139.30	$88,139.30	$88,139.30

	Summer Peak			Summer			Winter		
	On-Peak	Shoulder	Off-Peak	On-Peak	Shoulder	Off-Peak	On-Peak	Shoulder	Off-Peak
Demand-related cost ($/kW per month):	$33.67	$6.63	$0.06	$2.63	$0.74	$0.33	$0.02	$0.02	$0.09
Energy cost ($/kWh):	$ 0.0444	$ 0.0381	$ 0.0295	$ 0.0312	$ 0.0305	$ 0.0242	$ 0.0275	$ 0.0316	$ 0.0258