Review of SRP Cost of Service and Rate Design

PREPARED FOR

Salt River Project Agricultural

Improvement and Power District

PREPARED BY

Philip Q Hanser

T. Bruce Tsuchida

Neil Lessem

Rebecca Carroll

Ben Qiu

Emily Shorin

December 2018

THE Brattle GROUP

Notice

- This report was prepared for Salt River Project Agricultural Improvement and Power District, in accordance with The Brattle Group's engagement terms, and is intended to be read and used as a whole and not in parts.
- The report reflects the analyses and opinions of the authors and does not necessarily reflect those of The Brattle Group's clients or other consultants.
- There are no third party beneficiaries with respect to this report, and The Brattle Group does not accept any liability to any third party in respect of the contents of this report or any actions taken or decisions made as a consequence of the information set forth herein.

Table of Contents

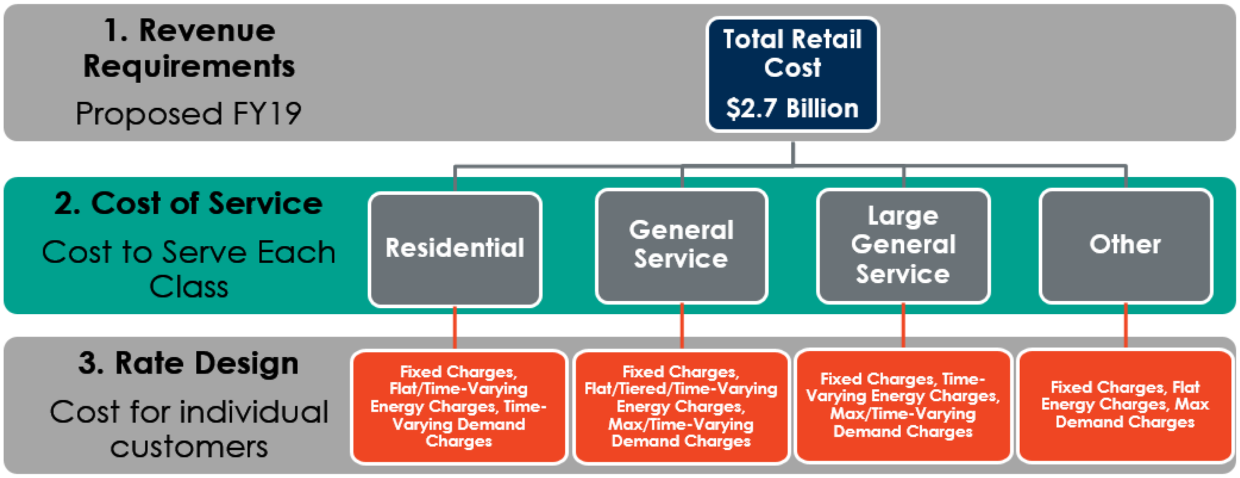
I. Introduction and Scope of Analysis

Electric utilities move electricity from where it is generated, to where it is needed by end-customers. In doing so, they must ensure that the infrastructure put in place to do so is sufficient to meet customers' current and future needs. This infrastructure (along with any generation the utility owns) is capital intensive, but can be shared by many customers. This means that until the infrastructure is at capacity, additional customers can be added at very little additional cost. If the total cost is shared among all users, then the average cost per unit of output falls as output increases. Having one utility serving all customers in an area is thus cheaper than having more than one. Thus, electric utilities are a natural monopoly and they are regulated so as to minimize long-run marginal costs subject to financial constraints. The rate setting process takes us on this journey in three steps:

1. Determine how much revenue the utility requires to cover its current obligations and to continue to operate in the future in order to serve its customers. This revenue requirement ultimately will be realized by the rates that the utility charges its customers.
2. Apportion this cost among customers based on the principle that whoever caused the cost to be incurred should pay for it (cost causation) by performing a cost of service study. Customers share many large infrastructure projects, and there is no uniquely correct way to determine cost causation. Since reasonable people may disagree on the correct methodology to do this, a cost of service study needs to be transparent and consistent. For practical reasons, customers are grouped together into "classes", each of which is relatively homogeneous based on observable service characteristics.
3. Design rates to collect the revenue required for each customer class. Rates that better reflect the costs of service signal customers about which of their actions would increase utility costs more than others. However, there are many objectives of rate design besides cost reflectivity, and rates typically differ in structure from the drivers of utility costs.

The three steps in rate design are illustrated graphically in Figure 1.

Figure 1: Steps in Rate Design



Brattle has been engaged by the board of Salt River Project to provide the board independent expertise and assistance in the Board's review of SRP Management's upcoming price proposal. As part of its work for the board, Brattle has been requested to provide to the board an independent assessment of the reasonableness of SRP's cost of service study results and rate design. In doing so, we have independently analyzed the inputs and steps taken throughout SRP's cost of service modeling. The assessment process occurred in parallel to SRP's development towards its final rate models. During this process, we were provided documents relevant to the modeling process, including key spreadsheet inputs and reports. We engaged with SRP's rates team via teleconferences and site visits during which we suggested enhancements to SRP's cost of service and rate design. Those which SRP deemed practicable to implement were incorporated in the final rate proposal. We have also included others in the report as opportunities for future improvement. Our report and recommendations are our own assessment of SRP's final cost of service and rate design process, independent of SRP.

We find that SRP's proposed revenue requirement is consistent with the financial plan that they presented to the board on March 13, 2018. It is also notable that SRP is asking for an overall rate decrease. SRP's financial plan shows operating expenses and retail revenues increasing over time at a similar rate as the past several years. SRP is planning an increase in the base electricity rate by 1.7 percent, which would allow for an average forecast rate of return of 3.8 percent.[1] This rate of return is below the 5.4 percent approved in the previous price process. However, SRP expects that it would still allow continued reduction in their debt service ratio over time. This measure of financial health will help SRP maintain a strong credit rating and enable SRP to continue to secure good borrowing rates. Despite the increase to base electricity rates, expected fuel costs are

1 SRP's rate of return is calculated as operating incomes as a percentage of net plant less Construction Work in Progress. In this calculation operating income excludes the Environmental Programs Cost Adjustment Factor and the Fuel and Purchase Power Adjustment Mechanism.

decreasing by 3.9%,[2] which creates a net average decrease of 2.2% in SRP's electricity rates for this price process.

In our review of SRP's cost of service and rate design process we have evaluated whether SRP is implementing rate changes in a manner consistent with both industry practice and SRP's Pricing Principles. While we have extensively reviewed SRP's primary models, the goal of this review was not to do a comprehensive audit of each and all calculations. We find that the methodology employed by SRP is consistent with both standard industry practices employed by other utilities and SRP's own Pricing Principles.

II. Cost of Service

A. Objectives of a Cost of Service Study

The objective of a cost of service study is to take the total revenue requirement and apportion this fairly and reasonably among customer classes. The primary principle underlying cost of service is cost causation. The grid offers a number of services to customers, for example: the ability to instantaneously obtain energy at any moment, the ability to consume varying energy levels at all times of the day, and the ability to export electricity to the grid. Different customers use the grid differently, though for the most part these differences are in the level of services demanded, rather than the kinds of services demanded. Different services have different costs. A cost of service study aims to distinguish between the different services offered by the grid and assign the costs of those services proportionally to customers' use of them.

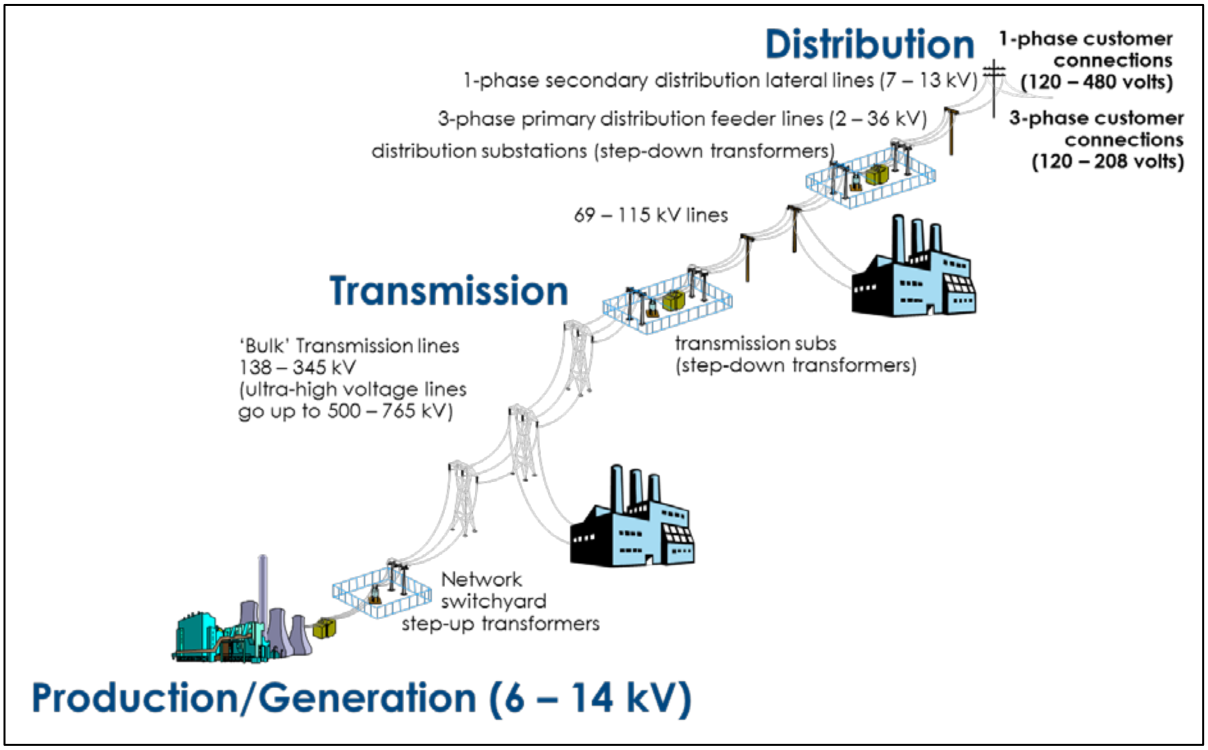
B. Steps in a Cost of Service Study

The revenue requirement that needs to be allocated to the different customer classes consists of historic accounting costs projected forward with a forecasted growth rate, as well as some line items for future projects. To better understand the cause of all of these costs, we first group them according to their role in the operating functions of the utility—Generation (Production), Transmission, Distribution, Meters and Services, and General Plant. This "**functionalization**" assigns costs to uses, that is, moves costs from an accounting perspective to an operational perspective, allowing planners to more easily describe the factors that are driving these costs (see Figure 2). The primary factor that drives or causes a particular cost is called a cost driver.

---

2 Expected fuel costs are lower due to a combination of expected lower market prices, optimization of the generation fleet, and refunding customers for over-collections from previous periods.

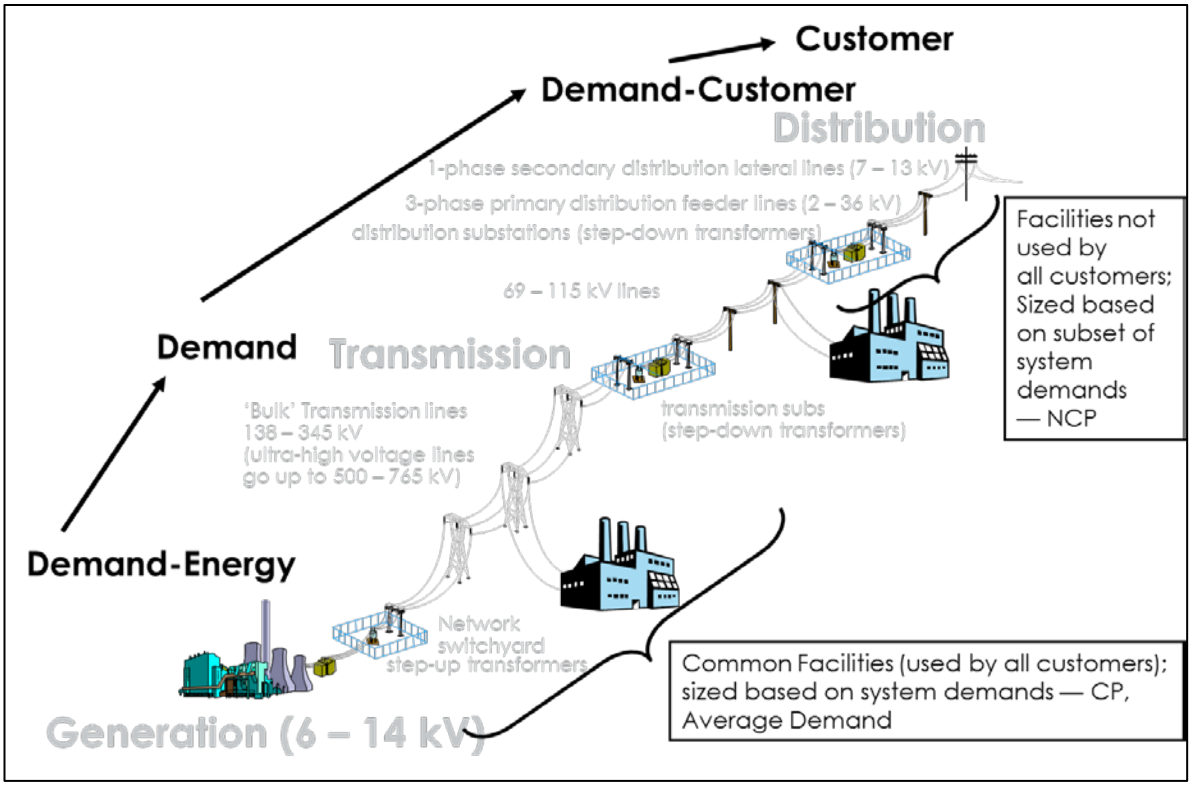
Figure 2: Cost of Service Step 1—Functionalization



"**Classification**" is the process of further separating the functionalized costs by the primary driver for that cost (see Figure 3). Primary cost classification categories include:

1. Demand-related costs (also known as capacity-related costs)
   - Demand-related costs are driven by the utility's responsibility to instantaneously supply a customer with sufficient electricity to meet the customer's needs whenever the customer requires it (subject to the type of connection the customer has). This includes having sufficient capacity to generate electricity, and the transmission and distribution systems necessary to convey it.
2. Customer-related costs
   - Those costs that vary with the number of customers on the system, irrespective of when and how customers use electricity. Examples of customer-related costs include meter reading, billing and account processing, and the costs of attaching customers to the system (service drops and poles). Sometimes other parts of the distribution system are also included to capture the distribution system's ability to connect all customers, irrespective of their load (including customers with a *de minimus* load).
3. Energy-related costs
   - Those costs that vary with the amount of energy generated (kWh), such as fuel, energy purchases from other entities, and generation variable operations and maintenance (O&M) (lubricants and/or consumables).

Figure 3: Cost of Service Step 2—Classification



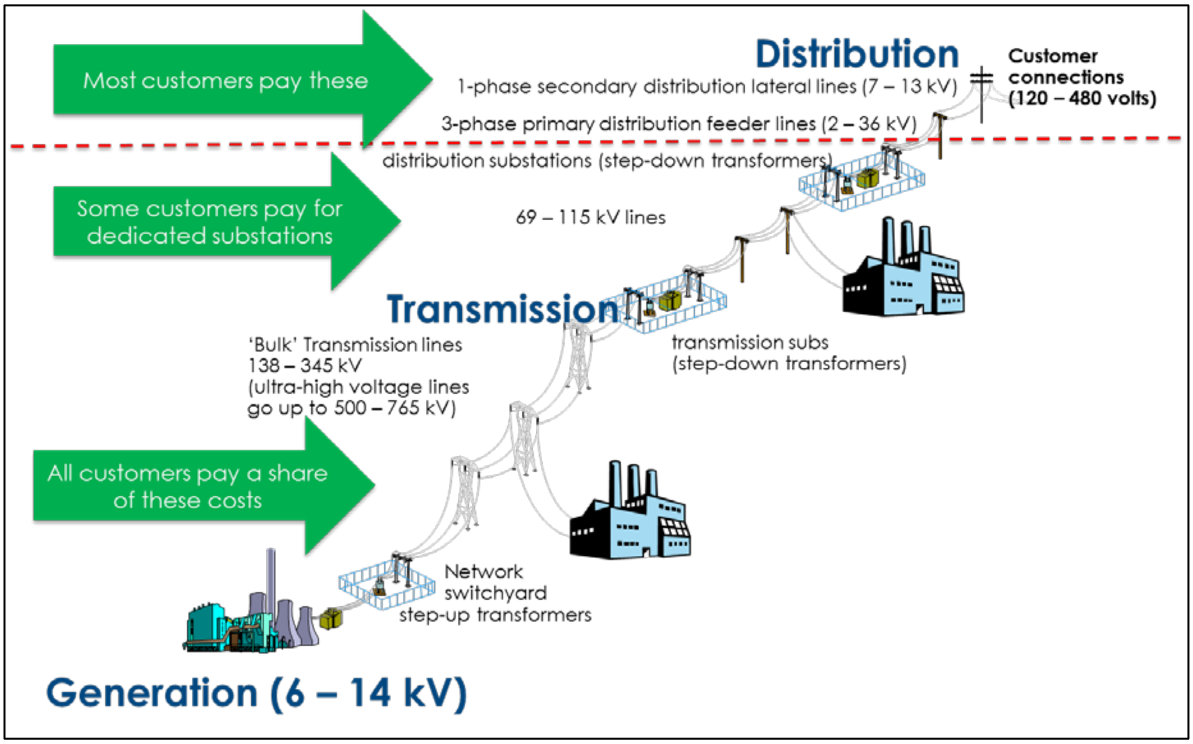
Once costs have been functionalized and classified, they can be allocated to different customer classes. Customer classes are groupings of customers with similar consumption profiles. **"Allocation"** assigns costs to each customer class according to that class's share of the cost driver. For example in a simple world, all fuel costs are driven by the volume of electricity (kWh) consumed. If one class uses 50% of the total kWh, they will be allocated 50% of the utility's fuel bill. Differently classified costs require different allocation methods. Customer classes will differ in how they use different facilities, if they use them at all. For example, large customers may not be connected to the distribution network. This is illustrated in Figure 4. The percentages that are derived from each applied allocation method must sum to 100%—all costs must be allocated to someone.

Allocation criteria should match the way that the system is actually planned, and the following criteria are utilized to evaluate the appropriateness of an allocation method:

1. The method should reflect the actual planning and operating characteristics of the utility's system.
2. The method should reflect cost causation, *i.e.*, should be based on the actual activity that drives a particular cost and on the rate classes' share of that activity.
3. The method should recognize customer class characteristics such as electric load demands, peak period consumption, number of customers, and directly assignable costs.
4. The method should produce stable results on a year-to-year basis.

5. Customers who benefit from the use of the system should also bear some responsibility for the costs of utilizing the system.

Figure 4: Cost of Service Step 3—Allocation



Cost drivers, which are used in the cost of service study, are a distinct concept from billing determinants, which are used in rate design. Cost drivers try to get at the underlying determinant of a cost so that the costs can be assigned (allocated) to the customers that cause this cost to be incurred. Billing determinants are the factors used to charge customers—they determine the customer's bill. While there may be some overlap between cost drivers and billing determinants, billing determinants are often simplifications of the cost drivers. These simplifications are like a caricature—they seek to emphasize key parts of the cost driver to act as a signal to customers.

C. Cost of Service Methodology at SRP

1. Functionalization

SRP has built up its expenditure totals using budgeted expenses arranged by operational function. These expenses are bottom up, constructed year by year, and independently collected and budgeted for from different departments. Separate types of escalations are used by SRP's Financial Planning team for the various expense types. SRP intentionally organized their budget forecast, which aims to transform costs from an accounting perspective to an operational perspective, to be more aligned with the functionalization step.[3]

SRP's functionalization method involves several steps, which begin with the board reviewed FY 2020 Functional Budget as described in Figure 5.

[3] SRP, "Cost Allocation Studying Support of Proposed Adjustments to SRP's Standard Electric Price Plans Effective with the May 2019 Billing Cycle", December 20, 2018, pp. 3-4.

Figure 5: Steps and Terminology used for Functionalization

Revenue Requirement

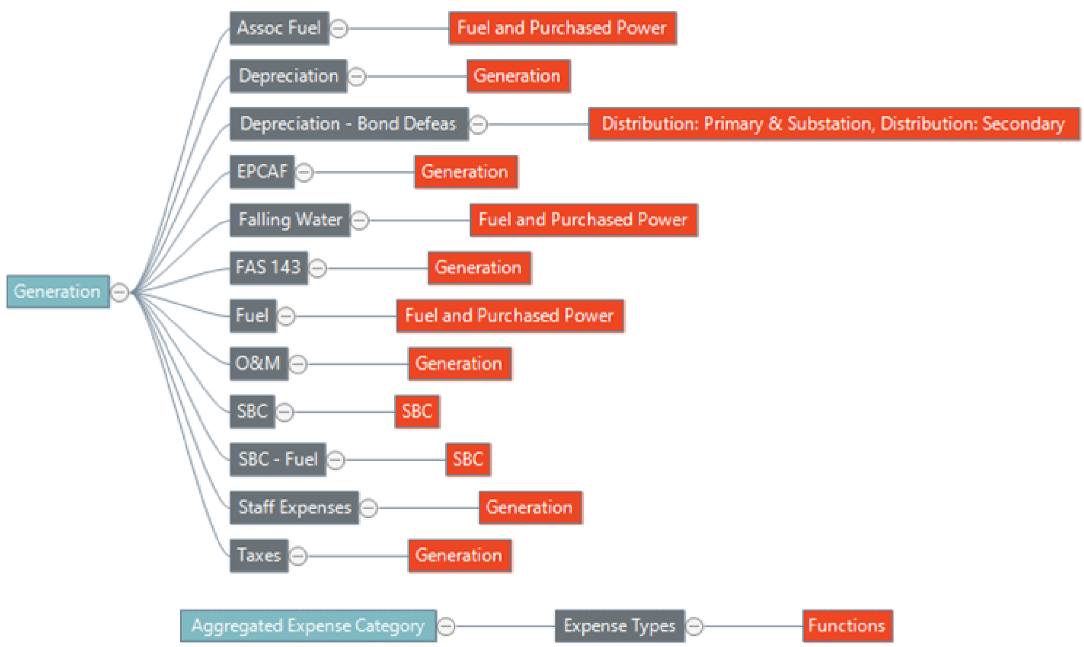
FY20 expenditure totals are organized bottom up using budgeted expenses arranged by operational function. These expenses are constructed year by year and independently budgeted by different departments.

Aggregated Expense Category

The rough groupings by operation function in the FY20 budget forecast are refined into aggregated expense categories (such as generation, customer, etc.). This is an intermediate step and these categories are not used further.

Expense Type

Within each aggregated expense category, individual expenses are categorized by the type of expense they represent ("O&M", "Depreciation", "Fuel", "Staff Expenses" etc.), and summed.



Preliminary Functionalization

Individual expenses types from each general expense category are then assigned to preliminary functionalization categories. The figure above shows an example of how generation is split by expense type and how these are then assigned to functionalization categories. The functional categories are more detailed than the expense categories. Some expense categories are split into several functions by expense type. Some expense types within an expense category are reassigned to a function stemming from another expense category. Within a function all expense types are aggregated.

Adjustments

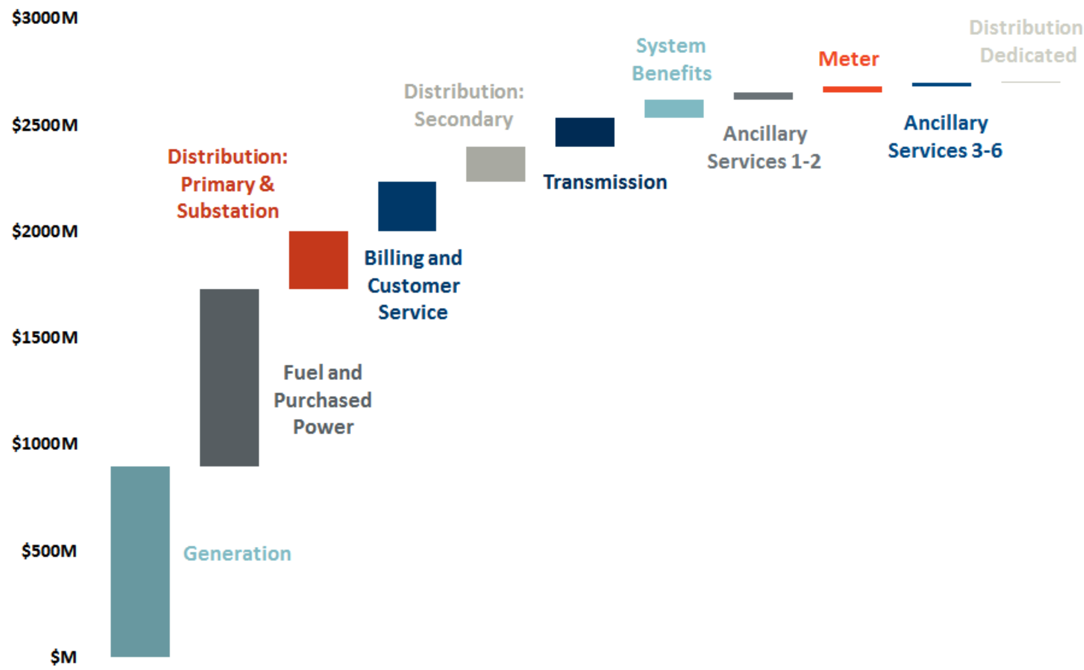
Adjustments are then made within the functions. Some of these are reallocations between functional categories, such as the transfer of expenses from Generation and Transmission to Ancillary Services, and the transfer of step-up plant expenses from Transmission to Generation. Other adjustments are to exclude expenses from being collected through the retail sale of electricity, such as the current proposal relating to lighting services offered by SRP, and fuel expenses that relate to the competitive wholesale side of the business. Further additional expenses such as the Economy Discount Rider, the Medical Discount Rider, and the Energy Efficiency Cap Program are added to the System Benefits Charge.

Final Functionalization

The final functional categories are used to allocate costs to customer classes in the cost of service and matched to billing determinants in the tariff design. The final functionalization categories are also referred to as "pricing components" by SRP.

Figure 6 shows the functionalized expense categories with the proposed revenue proportioned to them. Each customer class will have different service features and requirements and use each of the services (functions) differently and be responsible for a different share of the functionalized costs.

Figure 6: SRP Proposed Functionalized Expenses ($2.7b)



Each of the functionalization categories is described in greater detail below:

- **Generation** aggregates costs that are related to the utility's generation assets. These include depreciation, taxes, O&M, and staff expenses that are related to electricity production.
- Fuel related and purchased power are functionalized under the **Fuel and Purchased Power Adjustment Mechanism (FPPAM)** function. These include fuel, associated fuel costs, water for power, and purchased power. SRP has proposed that FFPAM will now also absorb costs related to renewable resources that were formally allocated to EPCAF.
- The **Reliability-Must-Run (RMR)** function is no longer included under SRP's proposal. RMR formerly accounted for generation units dispatched to relieve transmission constraints, but these constraints no longer occur. These generation units are therefore now all functionalized to Generation.
- Costs are allocated to the **Ancillary Services** function through transfers from other existing functions in the adjustment step. A proportion of Generation expenses are transferred to **Ancillary Services 3-6** (Energy Imbalance Service; Operating Reserve—Spinning Reserve Service; Operating Reserve—Supplemental Reserve Service). **Ancillary Services 1-2** (Scheduling, System Control and Dispatch Service; Reactive Supply and Voltage Control

from Generation Sources Service) receive transfers from both Generation and Transmission.[4]

- **Transmission** is a collection of transmission related costs that include depreciation, taxes in lieu, O&M, and staff expenses.
- **Dedicated Distribution** includes costs for substations and other assets put in place for specific customers at their request and that are used exclusively to serve these customers. These costs include depreciation, taxes in lieu, and O&M. Dedicated distribution expenses are not separately accounted for in the budget forecast for FY20, and are carved out of total distribution expenses based on the distribution marginal cost study and the share of dedicated distribution capital expenditure out of all distribution capital expenditure.
- **Primary and Substation Distribution**, also known as distribution delivery accounts for the higher voltage part of the network, ranging from the substation coming off the transmission network to the secondary stepdown transformer, while **Secondary Distribution**, also known as distribution facilities, accounts for the lower voltage facilities from the secondary stepdown transformer onwards to the line drop to the customer premises. Distribution Delivery costs are categorized based on its variation with demand, whereas Distribution Facilities are categorized based on its variation with customer count. SRP's cost of service separates distribution net of dedicated distribution into these two separate functionalization categories. The division is based on each function's share of the marginal distribution cost.
- The **Billing and Customer Service** function accounts for O&M expenses, depreciation, and taxes in relation to customer and billing services.
- **Metering** collects costs related to metering, which include expense types O&M, depreciation, and taxes.
- The **System Benefits Charge (SBC)** accounts for costs that include nuclear decommissioning and the economy discount rider, a program that assists limited income customers. SRP has proposed that energy efficiency programs, which were previously included in the EPCAF, be added to the SBC. EPCAF's primary purpose was to recover the costs of renewable generation. These generators are now seen as a core part of SRP's generation procurement strategy and EPCAF has been proposed for elimination as a functional category (see Section II.C.5 for more detail).

2. Classification/Allocation

Once costs have been functionalized, they are then classified according to their primary cost driver, and then each class is allocated their share of that cost according to their *share* of the cost driver. Figure 7 shows this process in detail. For example, costs of the aggregated expense category "Generation" are first functionalized towards "Generation", "FPPAM," and "Ancillary Services 3-

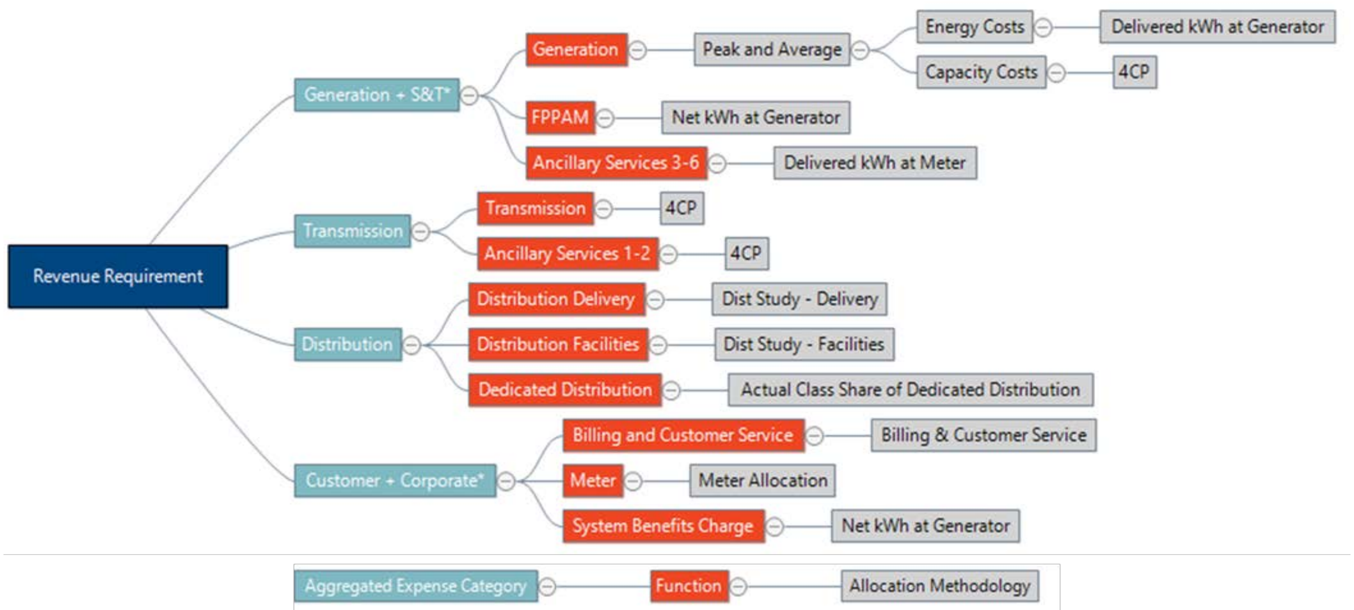
---

4 The amounts transferred are determined from SRP's Yellow Book "Derivation of Proposed Changes to SRP's Transmission and Ancillary Services Rates."

6”. Each of these functions then has different allocations methodologies assigned, these being “Peak and Average,” “Net kWh at Generator,” and “Delivered kWh at Meter” respectively.

As per standard allocation principles, energy-related functions are allocated using energy-based cost drivers (delivered and net kWh usage, with and without line losses) and demand-related functions are allocated using demand-based cost drivers (4CP, and the demand driven elements determined in the distribution marginal cost study). Billing and Customer Service and Metering functions are assigned largely by the number of customers per class, although many manual adjustments by subject matter experts to the customer service costs and meter costs are allocated using class-specific marginal meter costs.

Figure 7: SRP Allocation Methodology Proposed Mapping



* The “+” indicates that the aggregated expense category is combined for illustrative purposes

Energy-related costs are straightforward in the sense that they can be allocated on the basis of energy consumed. The only complication is that the energy generated and procured by SRP for its customers is greater than the amount of energy consumed by those same customers due to line and transformer losses. Technical losses are due to the transformation of kWh to heat, while non-technical losses may occur if there is electricity theft. Technical losses will vary by customer class, since a variety of class-specific factors cause technical losses:

- Voltage—higher voltage means lower losses,
- Voltage transformations—more voltage transformations from the generator to the customer mean more losses, and
- Distance—the greater the length of a given circuit, the greater the losses.

Low-voltage distribution customers, such as residential customers, have the highest loss factors.

For SRP, energy usage is recorded in four different ways, three of which are used to determine the contribution of each class: **net kWh at the generator** (including losses, and net of exports from customer-generators); **delivered kWh at the meter** (net of losses, and not taking into account exports by customer-generators); **and delivered kWh at the generator** (including losses, and not taking into account exports by customer-generators).[5]

Energy is used to allocate four functional categories:

1. FPPAM reflects direct fuel costs and is allocated by net kWh at the generator. This takes into account any line losses in delivering the energy, but also accounts for fuel savings when SRP uses exported customer-generation, which does not require fuel.
2. SBC has non-bypassable programs such as the nuclear decommissioning expense and economy discount rider. SBC is allocated on net kWh at the generator. We believe this should be modified and discuss it further in Section II.D.2.
3. Ancillary Services 3-6 relates to frequency control, energy imbalance services, and reserves. These are allocated using delivered energy at the meter. We believe this should be modified and discuss it further in Section II.D.2.
4. Generation includes a share of generation plant expenses that are used to meet energy needs as opposed to capacity needs. These are allocated using delivered kWh at the generator.

Demand-related costs vary with the necessity to have sufficient capacity to meet customers' instantaneous demand (kW). Often the utility can use the same resources to serve many customers since they have diverse needs and do not require the maximum use of the resource all at once. In such cases, the total size of the facility is driven by those times when many customers all require it at once (the system coincident peak). Other costs are driven more by the individual customer's needs, since facilities cannot be shared. For example, the wire that connects a residential customer's home to the grid (the line drop) serves only that customer and needs to be sized to meet their individual maximum demand, whenever this occurs (the customer's individual non-coincident peak). Each customer has an individual non-coincident peak, but the metric can be calculated for the class as a whole. In the latter case, one could imagine the local feeder in a residential neighborhood being sized to meet that neighborhoods non-coincident peak demand.

---

[5] SRP uses net kWh at the meter as an initial step to compute the three other types of energy usage. To arrive at delivered kWh at the meter, the net usage at the meter by solar customers is subtracted from the total, and the delivered usage at the meter by solar customers is added back. Delivered kWh at the meter by solar customers is calculated by taking the net usage at the meter by solar customers and multiplying it by the historical ratio of delivered to net usage at the meter by solar customers. To arrive at kWh usage (both net and delivered) at the generator, each corresponding kWh at the meter is multiplied by one plus the historical percent losses for the classes.

4CP is SRP's cost driver for coincident peak demand. This is determined by the average class contribution to the four hourly system peaks (once per month from June to September).[6] System demand for SRP peaks in the summer, it is logical that contribution to peak demand is measured from the peak monthly contributions that relate closest to the summer season. Having four months to average across instead of using 1CP (single peak) avoids gamification by customers and sends out a clear signal that there is a high probability that the system peak can occur in any of those four months.

System Peak responsibility is commonly used for the allocation of transmission costs. Non-Coincident Demand typically is used for the allocation of distribution demand-related costs.

Customer-related allocation methods are primarily based on the average meter and service costs per customer, which vary across rate classes, and the number of served customers, either weighted or non-weighted. The metric of weighted number of customers can be based on: the class-average meter costs, class average-billing cost, class-average service line costs, and class-average meter-reading costs.

The allocation factors for **Billing and Customer service** are determined by the customer services study: individual class allocations made at the accounting line item level. Most are based on the number of customers by class, but some are determined by subject matter experts, who either give a direct allocation or use a customized allocation formula (*e.g.* for one particular line item, large general service customers were weighed at 5% of total cost, with others such as residential, residential on-site generation, general service customers, and lighting are weighed at 95% before allocating by the number of customers). The final product sum of all line items and each corresponding level of class allocations produces the dollar amount assigned to each class. Since cost allocations are prepared by different departments and groups within SRP, SRP checks that any calculated differences in allocated costs between classes are driven by underlying differences in how the costs were generated, rather than the way they were allocated. Adjustments are then made to equalize costs for classes that should have similar billing and customer service expenses. The adjustment is achieved through taking the directly allocated dollar amount to each class, grouping similar classes together (EZ-3, E-23, and E-26; and E-32 and E-36) and then allocating the individual class contribution by the contribution it makes towards the grouped class by number of customers in the class. The class share of this dollar amount equals the Billing and Customer Service allocation factor. We suggest that future cost of service studies better systematically memorialize the rationale underlying allocations made by subject matter experts.

Metering is allocated by the class contribution to the product of multiplying the marginal cost of meters per class by the number of customers per class.

---

6 4CP is found by using hourly level forecast data for FY19, then: (i) finding the four system peak hourly usages, one per month, from June to September, (ii) finding the daily usage per class for those four days, (iii) dividing the daily usage per class by the number of accounts on the four peak days, and (iv) finding the average of the usage per account for the four days to arrive to one 4CP figure per class.

Fixed generation related costs (capacity) are allocated on the "Peak and Average" method, which separates the allocation method into energy and demand related parts. The energy component's share of generation costs is determined by the ratio of system average demand to system peak demand (the system load factor).[7] The demand component's share of generation costs is the remainder (1 – the system load factor). For SRP this is close to a 50:50 split since the system load factor is 48.3%.

Once separated, the energy component is allocated to the classes based on the class share of delivered kWh at the generator. The demand component is allocated based on the class share of 4CP.

Thus the class share of generation is the system load factor multiplied by the class share of delivered kWh at the generator plus (1 – the system load factor) multiplied by the class share of 4CP. In this way, Peak and Average is a measurement of both the intensity and duration at which customers are utilising generation assets.

The distribution marginal cost study examines class contribution to three sets of distribution assets: "Substation plus Getaway", "Primary & Feeder", and "Secondary/Transformer". Annualized costs for these assets are determined for each class within the marginal cost study. The marginal costs for "Primary & Feeder" and "Substation plus Getaway" are measured on a per kW basis, and the marginal costs for "Secondary/Transformer" are measured on a customer number basis. Each class's NCP kW and number of customers then dictate the final total marginal cost per class for each of the three sets of distribution assets (see Figure 8).[8]

---

7 A Load Factor (LF) is a measure that captures the degree of variation in a particular pattern of demand. It is a number between zero and one (*i.e.*, a percentage) and is calculated by dividing average demand by peak demand. Average demand is analogous to average speed on a trip and is calculated by dividing the total kWh of energy used in a period by the total number of hours in the period. Similarly, load factors can be computed at the system wide level—a system load factor is simply the average demand of the system divided by the system peak demand. High system load factors (near 1) indicate high utilization of the available system capacity. Since these capacity costs are spread over more kWh, customers with high load factors generally have a lower average total cost per kWh. High system load factor is a result of customer diversity or high load factor customers. In the future, with more variable and intermittent generation coming online, flexible customers who can constrain demand to meet generation and capacity constraints and ramp it up to absorb excess renewable generation may have greater value to SRP than high load factor customers.

8 Note that the same ratio determined in the marginal cost study was previously used to functionalize distribution expenses into "Distribution: Primary & Substation" and "Distribution: Secondary".

Figure 8: Example of Distribution Marginal Cost Study Results

Primary Allocation Factors

Rate/Class	MCS Per kW	NCP kW	Total MCS	Allocation Factor
E-23	$ 28.13	2,103,969	$59,187,832	31.5%
E-24	$ 28.13	628,972	$17,693,939	9.4%
E-26	$ 27.80	781,957	$21,738,179	11.6%
EZ-3	$ 28.02	1,185,968	$33,233,743	17.7%
E-27	$ 27.84	28,786	$801,531	0.4%
E-32	$ 19.87	619,334	$12,303,569	6.5%
E-36	$ 18.78	1,555,254	$29,214,904	15.5%
Pumping	$ 27.81	28,384	$789,458	0.4%
E-61	$ 27.65	374,056	$10,342,752	5.5%
E-63	$ 31.05	88,681	$2,753,593	1.5%
Total		7,395,360	$188,059,501	100.0%

Secondary Allocation Factors

Rate/Class	MCS Per Customer	Number of Customers	Total MCS	Allocation Factor
E-23	$ 77.02	466,799	$35,951,959	19.7%
E-24	$ 77.02	158,576	$12,213,257	6.7%
E-26	$ 101.07	126,466	$12,782,522	7.0%
EZ-3	$ 88.55	213,508	$18,905,164	10.4%
E-27	$ 93.43	5,647	$527,563	0.3%
E-32	$ 1,920.80	12,213	$23,457,760	12.9%
E-36	$ 903.02	82,737	$74,712,445	41.0%
Pumping	$ 916.53	549	$503,403	0.3%
E-61	$ 7,350.52	429	$3,149,698	1.7%
E-63	$ -	45	$0	0.0%
Total		1,066,967	$182,203,770	100.0%

Distribution Delivery consists of "Distribution: Primary & Substation" costs allocated by the sum of the class share of marginal cost for "Substation plus Getaway" and "Primary & Feeder".[9]

Distribution Facilities allocates "Distribution: Secondary" by splitting it into two. Firstly, distribution O&M costs from "Customer Systems" are allocated to each class based on the number of customers. These so called "Assigned Distribution" costs are part of the "Distribution: Secondary" costs. After netting them out, the remainder of "Distribution: Secondary" costs are allocated by the class share of marginal cost for "Secondary/Transformer" expenses.[10]

Dedicated Distribution is allocated by an allocator that is the contribution per class to the revenue collected under "Dedicated Distribution" (referred to as "Billing data"). In essence, these expenses are allocated based on amounts that are identical to what was actually charged (revenue from SRP's perspective) to these customers.

Both **Transmission** and **Ancillary Services 1-2** (Scheduling, System Control and Dispatch Service; Reactive Supply and Voltage Control from Generation Sources Service) use 4CP as an allocator. 4CP measures a class's contribution to peak capacity needs, which is the trigger for capacity investment.

Ancillary Services 3-6 (Regulation and Frequency Response Service; Energy Imbalance Service; Operating Reserve—Spinning Reserve Service; Operating Reserve—Supplemental Reserve Service) and the **Systems Benefits charges** are allocated by kWh usage—net kWh at the meter.

FPPAM or Fuel and Purchased Power Adjustment Mechanism (fuel costs incurred and power purchased) is recovered through net kWh at the generator.

---

9 A manual adjustment to the marginal cost share is made to account for lighting (E-50), as lighting is not included in the marginal cost study. Lighting is allocated by NCP.

10 As with Distribution Delivery, a manual adjustment is made for lighting.

3. Revenue Adjustments

After costs have been allocated to the classes and before rate design proceeds, several intermediate adjustments are made to obtain the final target of a $50 million increase to base rates (an overall increase of 1.7%):

1. SRP's proposed base increase of $56 million is allocated to the classes. The base increase represents a 1.9% increase in revenue across all customers (however, total revenue collected is still decreasing). The allocation is not cost-causal, but is intended to smooth out differences in the magnitude of revenue requirement changes between classes. Classes whose rate of return were already above average, were allocated a below average revenue requirement increase of 1.4%. This is 75% of the average base revenue increase of 1.9%. All other classes receive a base revenue increase of 2.5%, with the exception of E-24 and E-27, who receive an increase of 1.4%.

   E-27 receives a lower than average increase due to the incidence of unique customer-related costs that has made up a large share of the class's costs (see section II.C.6. and Figure 9). These costs are expected to decrease in the future as more customers join the class. As a result, SRP management decided to target a lower revenue increase.

   E-24 is given the lower rate, along with other measures to reduce their revenue requirement, as discussed below.

2. A downward revenue adjustment of $2.5 million is to be provided to E-24, in addition to the minimum base rate increase. E-24 is SRP's residential pre-pay rate. Historically pre-pay customers have required specialized meters and payment points and have been more costly to serve than regular post-pay customers. However, the mass rollout of smart meters and other technological improvements are reducing the costs of serving E-24 customers. These costs are likely to be more similar to those of the standard residential rate, E-23, going forward. As a result SRP has proposed that these two classes merge in the future. To smooth out the eventual decrease in E-24 service costs, E-24's required revenue is being gradually reduced. The proposed cost allocation does this through the direct $2.5 million allocation and the reduction in the base revenue increase to the minimal percentage allocation. These actions align with the long-term goal of equilibrating returns between classes—the adjustments made in the current price process is not sufficient to a complete price convergence, and further adjustments must be made in the next price process.

3. SRP has proposed a cap on individual customer contributions to energy efficiency (EE) of $300,000 for large customers. Any payments above $300,000 are returned to customers through a rebate. This rebate is paid for by all the remaining customers and is allocated on the same basis as SBC using net kWh at the generator.

4. SRP has proposed a new E-67 rate for Substation Large General Service customers with higher load rates (minimum load factor of 90%) and higher MW rate (minimum of 20 MW) who are currently on the E-65 rate. In anticipation of the lower level of revenue projected for customers that will move to the E-67 rate, a base revenue decrease of $3.7 million is estimated as the

difference in revenue E-65 and E-67 for customers who qualify for E-67. This reduces the overall rate of return to SRP.

4. Marginal Cost of Service Study

Marginal costs are forward looking costs that examine the incremental costs associated with producing one more unit of a particular item. If the benefit of consuming an incremental unit of a good exceeds the cost of producing it, we are better off if we consume more of it. If the incremental benefit is less than the incremental cost, we should consume less.

In the electricity sector, marginal costs can differ greatly from average costs. Many assets have large upfront costs that need to be incurred irrespective of usage. The average cost for these assets is the total cost divided by the number of units consumed. If these assets have spare capacity, then the cost of an extra unit is low compared to the average cost. If the assets are at capacity, then an additional unit of consumption may far exceed the average cost, since a new asset may need to be procured. This can lead to poor outcomes, where customers make decisions based on the prices they face (which reflect average cost) and these decisions lead to price increases in the future. Thus, it is important to continue to transition prices in a direction where they increasingly signal marginal costs to customers.

As a precursor to the cost of service study, SRP undertook a marginal cost study. SRP's study examined the incremental costs associated with serving an additional new customer account, meeting an additional unit of demand and producing an incremental unit of electricity (which varies by time of day and year). SRP has used these marginal costs to inform the allocation of distribution costs to customers in the cost of service study and the ratios of peak to off-peak electricity prices in their rate design.

In April 2017, NERA submitted a detailed review of SRP's marginal cost study for FY2015. We have reviewed NERA's report and have observed that SRP's implementation is consistent with their recommendations.

5. Changes in Methodology

1. SRP is proposing that EPCAF be eliminated as a distinct billing category, with EPCAF related expenses re-functionalized among generation, SBC, and FPPAM. Renewable generation costs will go to generation, SBC will absorb energy efficiency programs costs from EPCAF while FPPAM will absorb the costs of renewable resources (primarily purchased power costs). EPCAF primarily consists of expenses related to renewable generation. At the project onset, this was seen as outside of SRP's primary generation strategy and a separate expense category was set up to pay for it. However, renewable generation is now seen as a key component of SRP's generation procurement strategy and it makes sense to end the program. The proposed change does not alter the amount of expenses eligible for recovery, but it changes how the expenses are allocated and the rate of return calculation. SBC and FPPAM are now proposed to be allocated on net kWh at the generator. Previously, EPCAF was treated as pass through,

but now due to its contribution to SBC, it means the deficit (current EPCAF expenses are greater than current EPCAF revenues) will lower the current return.

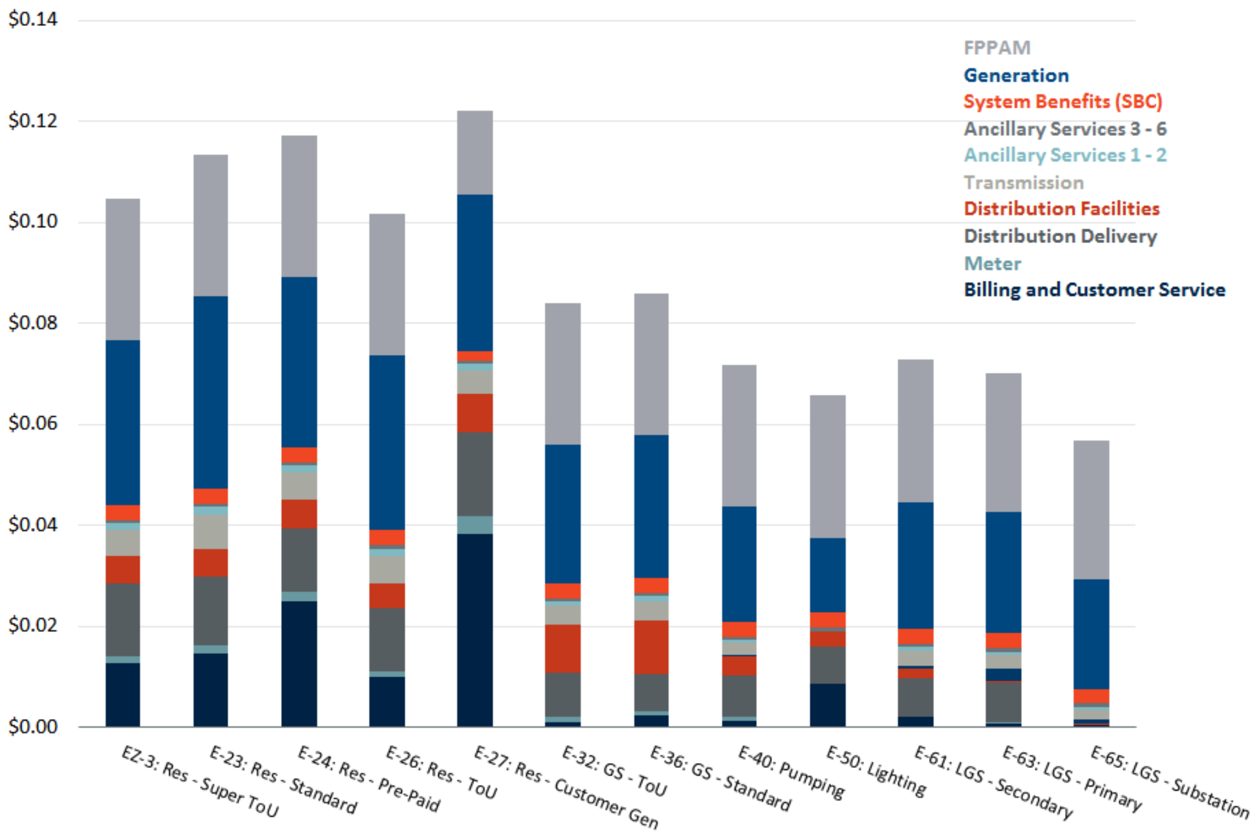
2. SRP has proposed a new E-67 rate for Substation Large General Service customers with higher load rates (minimum load factor of 90%) and higher MW rate (minimum of 20MW) who are currently on the E-65 rate. In anticipation of the lower level of revenue projected for customers that will move to the E-67 rate, a base revenue decrease of $3.7 million is estimated, this being the difference in revenue between E-65 and E-67 for customers who qualify for E-67.
3. Distribution expenses net of dedicated distribution are separated into primary and secondary distribution (also known as Distribution Delivery and Distribution Facilities). This division is based on the relative ratio between the marginal costs of the two distribution categories estimated in the Distribution Marginal Cost Study. SRP has proposed changing the allocation factors on Distribution Delivery and Facilities from NCP and SNCP, respectively, to using the marginal investment costs in Distribution Delivery and Facilities assets for each class, as estimated in the Distribution Marginal Cost Study.
4. Following a prior recommendation to SRP from Brattle, Reliability-Must-Run expenses are no longer functionalized to its own category, and are all totaled towards generation. RMR formerly accounted for generation units dispatched to relieve transmission constraints, but these constraints no longer occur. The demarcation is no longer necessary.

6. Results from Cost of Service Study

Figure 9 demonstrates the average cost or average selling price per delivered kwh (at the meter) for each class, along with the breakdown by functionalized expense category. This is the all-in price that the representative customer in each class will pay for every kWh they use. It includes customer service charges, demand charges, energy charges, and credits for exports back to the grid. Individual customers within a class will pay different amounts, depending on the structure of rates and how they use the grid.

In general, costs are as you would expect, residential customers have relatively higher average costs in comparison to general service classes, and large general service classes have the lowest average costs overall. Larger customers with higher load factors pay lower average prices as fixed and demand charges are spread over more kWh. Within the residential class, E-27, which is mandatory for new on-site generation customers, stands out from the other residential classes. This is expected since customer-generators who export power to the grid, use the grid very differently from those customers who do not. For example, E-27 has the lowest average fuel costs of all classes, as it receives fuel credits for exports back to the grid. There are some costs specific to serving on-site generation customers. These include the costs of approving on-site generation plans, site inspections, processing rebates, and dealing with customer inquiries about on-site generation and related issues.[11] These costs are all functionalized as billing and customer service, leading to this component being notably large for E-27, which consists solely of on-site generation customers. Metering costs are similarly higher, since customers with on-site generation require a second meter to measure total production.[12] While other classes may have customers with on-site generation who were part of the class prior to the introduction of E-27, these on-site generation customers are only a small share of the total customer group in these other classes, and the additional on-site generation costs are socialized over all of the customers in that class, irrespective of whether they have on-site generation or not.

Figure 9: Average Functionalized Cost by Delivered kWh at Meter



---

11 Services exclusive to solar customers include the following: the Customer Design—Solar Design/Inspection AMP team reviews proposed solar installation plans by the customer and the vendor in its compliance with SRP's standards for grid integration. Inspection coordination prior to commissioning is also managed by the same team. The Distributed Energy Programs team manages and applies solar incentive rebates, while also processing solar applications and coordinating with rooftop solar vendors. The solar specific portion of the Residential Contact Center has a Solar Team of Customer Service Representative who handle all solar related customer calls.

12 SRP uses customer generation data to enhance both grid operations and provide better customer service. Understanding when and how effectively customer generation is operating allows SRP to better monitor and control its network, while a full understanding of a customer's energy consumption enables customer representatives to address any customer queries more effectively.

D. Conclusions on Cost of Service

1. Assessment of SRP's Cost of Service

After undertaking a thorough conceptual review of SRP's cost of service, which consisted of independently evaluating SRP's documentation and supporting workbooks, extensive discussions with the SRP team to understand their underlying logic and a few minor suggestions, we are confident that SRP is making reasonable and fair decisions in allocating costs to customers. The methodologies they use to do so are generally accepted and commonly used, and costs are by-and-large allocated on the basis of cost causation. SRP has undertaken a distribution marginal cost study and is gradually introducing marginal cost into their rate design. The transition to marginal cost-based rates will help them to allocate future expenses to those customers who are causing those expenses when they occur, who may be different from those customers who incurred similar expenditures in the past. While all the minor contemporaneous issues we had with SRP's cost of service study have been addressed and we are satisfied that the study is fair, reasonable, and follows the principle of cost-causation, we still have several recommendations for SRP for the next price process. These are discussed below.

2. Recommendations

The following recommendations are suggestions to enhance the success of SRP's rates in future price processes and are not meant to suggest any serious deficiencies in SRP's overall cost allocation. Many of the suggested changes are intended to promote transparency and minimize the risks of errors for SRP in future years, without changing the cost allocation results, while the remainder will likely have only minor impacts on customer cost allocations. Any customer impacts will be further tempered by the rate design principle of gradualism.

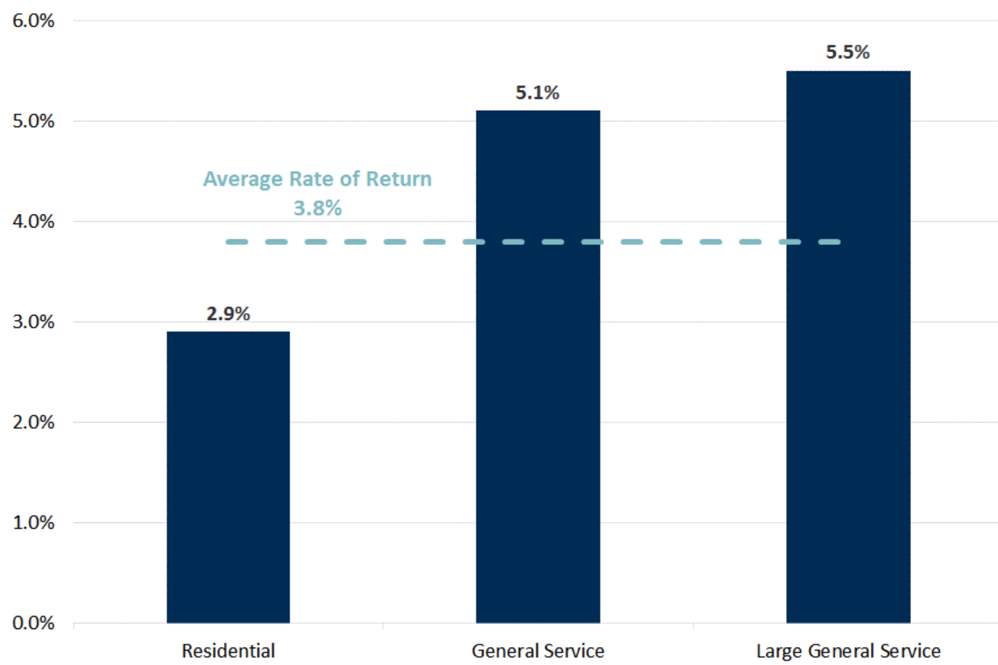
1. **Transparency:** The functionalization and allocation of customer and billing services are achieved on a line-by-line basis without systematic memorialization explaining the reasons for the used percentage breakdowns. Departmental decisions and reasons for deviations away from using customer count as an allocator should be transparent and justified. The same may be said for the revenue adjustments given to E-24 and E-65, the model should contain enough detail to be self-explanatory on why and how these adjustments came to be. We understand that SRP is in the process of improving this aspect of their modelling.

2. **Comparability:** We understand SRP is moving towards the FERC uniform system of accounts, and we recommend them to continue doing so. This will allow SRP to more easily develop performance yardsticks to compare with other utilities, for whom this information is readily available from the EIA.

3. **Efficiency:** Social goals and subsidies should be disaggregated from cost allocation so that they can be assigned in the least distortionary way within the rate design process. In particular, the returns for the residential classes are lower than those for the general

service and large general service classes, as shown in Figure 10. Although this revenue adjustment is intended, explicit, and transparent, and improves upon historical differences between the residential class and others, the costs of providing it are spread opaquely across the functionalized expense categories for general service and large general service customers. If the revenue adjustment were made more explicit (outside of the cost of service study), it could then be allocated to those rate components (such as the fixed charge), where it would be least distortionary on customer operating and investment decisions.

Figure 10: Proposed Returns by Customer Type



4. **Allocation:** FPPAM is allocated based on kWh. However, generation fuel costs vary daily and seasonally as different types of generation are used. For the next price process, SRP should consider using their production forecast models to obtain average and marginal generation fuel costs for every hour of the year and use class forecasted hourly load to allocate fuel costs. Using either marginal or average costs would be an improvement, although marginal is preferred, since it is focused on future behavior. Forecasted marginal production costs could also be used to inform the value of time-varying energy rates.

   SBC is allocated using net energy at the generator. This means that customer-generators are able to bypass much of the "non-bypassable" expenses since their net use is lower than the delivered electricity they receive from the grid. Non-bypassable expenses include charges for nuclear decommissioning, economy discounts, energy efficiency, *etc*. We suggest that SRP allocate SBC based on delivered energy at the generator.

   Ancillary Services 3-6 are allocated using delivered energy at the meter. These ancillary services include spinning reserves and frequency control. Although these services are not delivered to the customer and hence there is no line loss, the volume of ancillary services procured is going to depend on the volume and capacity of generation. The amount of generation needed increases with line losses and hence so will the amount of ancillary services required. We suggest that ancillary services 3-6 be allocated based on delivered energy at the generator.

5. **Accuracy (minor improvements):** The depreciation expense on dedicated distribution is calculated as a share of the total distribution assets depreciation expense. Total distribution includes other asset types and substations of different ages, so the depreciation rate may be quite different. We suggest that the depreciation expense on dedicated distribution be based on actual asset depreciation plus a relevant growth rate. We recognize that this is likely a trivial change in magnitude, but it is worth considering since there is the potential for dedicated substations to become a competitive service at some stage in the future. Additionally, once calculated dedicated distribution facilities could be removed and excluded from the cost of service, since they do not enter into rates. This will not change anything materially, but would be simpler and would remove the necessity to allocate it based on actual customer bills within a class.

   We suggest that SRP continue to monitor and evaluate its future load growth in the face of changing technologies and consumer behavior.

III. Rate Design

Rates are the prices faced by customers when consuming electricity. The magnitude and structure of these prices will influence customer decisions about how and when to use electricity in the short-run and what equipment they purchase in the long-run. Both the structure and level of electricity prices will impact customer bills and affordability. Prices are the mechanism that SRP uses, as do all electric utilities, to recover revenues from customers to ensure its long-term financial viability. SRP's Pricing Principles recognize the relationships between electricity rates, the future costs of providing electricity service, customer bills, and SRP's financial health. The following Pricing Principles were adopted by the SRP Board of Directors in December 2000:[13]

- **Cost Relation**—to establish prices in relation to costs and SRP's stewardship to its water constituents, and thus not to pursue the maximization of "profit"
- **Gradualism**—to enhance sound, economic decision-making by customers of all types through stabilizing price levels and smoothing the impact of cost movements that may be caused by temporary factors

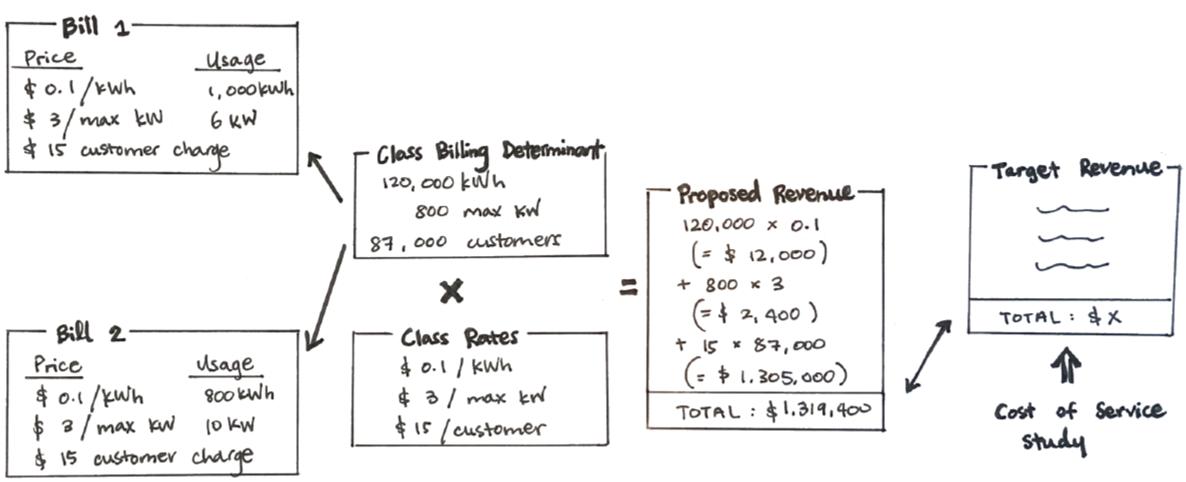
---

13 SRP, "Proposed Adjustments to SRP's Standard Electric Price Plans Effective with the May 2019 Billing Cycle", p.25

- **Choice**—to constantly improve customer satisfaction through the creative design of pricing structures that reflect customers' different desires or abilities to manage the consumption, assume more price control, or demand differentiated products and services, among others
- **Equity**—to treat customers of all types in an economically fair manner
- **Sufficiency**—to recover the cost of, and to invest and reinvest in a system of assets to perform its policy obligations, including its obligation to store and deliver water to the owners of land within the boundaries of the Salt River Reservoir District, to maintain SRP's financial well-being, and to follow the foregoing principles

In the ensuing rate review, we will examine SRP's proposed price adjustments for implementation in the May 2019 billing cycle. The overall magnitude of average price changes for each customer has been discussed in Section II (Cost of Service Study). In this section we examine the structure of the rates. For each class we discuss: 1) the types of charges each rate comprises and whether these have changed; 2) the relative magnitude of the different charge types; and 3) how these relate to the underlying cost structure and whether changes in the relative magnitude make them more or less reflective of these underlying cost structures. Even if the average price for a particular customer class remains unchanged, changes to the rate structure or the relative magnitude of charges will impact customer bills, with some customer bills increasing and some decreasing. Each type of charge the customer faces has a corresponding billing determinant. The billing determinant is the metric used on which to bill the customer. For example, the billing determinant for the energy part of a rate could be the customers kWh consumption in a month. If the kWh consumption is added up across all of the customers in a class, the class billing determinants result. If we take each customer's billing determinant charge and multiply it by the associated class billing determinant and then add all of these together, we get the proposed rate revenue for the class. The proposed rate revenue should be equal to the target revenue allocated to the class in the cost of service study. This is illustrated graphically in Figure 11.

Figure 11: Relationship between Customer Bills and Revenue Targets



Both the proposed revenue and targeted revenue are based on forecasted customer consumption. If customers change their behavior and reduce their actual billing determinants from the forecasted values, this will reduce the revenue that SRP collects. If the rate structure reflects the underlying cost to serve the customer, then this reduction in revenue will be offset by a corresponding decrease in costs. However, if rate structures do not reflect the underlying cost structures, then the reduction in revenue will impact SRP's financial health in the short-term and need to be recouped from other customers in the longer-run.

A. Residential Rates

1. Existing Rates

Residential customers at SRP who do not have on-site generation[14] have a choice of several existing rates, including a flat rate, two different time varying energy rates, and two prepay rates – one with flat and one with time varying energy charges.[15] The residential standard rate, E-23, is currently the most popular option, with 48% of residential customers, while all new customers default onto the Super-Peak Time of Use (ToU) rate, EZ-3. 22% of residential customers have remained on or actively selected this rate. The Super-Peak ToU (EZ-3) has a shorter peak period and higher peak price than the Standard ToU, E-26, which has 13% of residential customers. A further 16% of residential customers are on the prepaid M-Power rate. The remaining 1% of customers either have on-site generation, or are on one of three new rates. Customers without on-site generation can choose from two current rates that include alternative demand charges, and a super off-peak ToU rate to be used for charging electric vehicles (EVs). The Super-Peak ToU rate (EZ-3) has a three-hour peak, while the other residential ToU rates have a six-hour peak. This has been reduced from seven hours in the previous price process. The Super-Peak ToU design EZ-3 is actually split into three rates, the E-21 (main rate), and E-22/E-25 (experimental), all three rates are identical apart from the period of the three-hour peak. The Super-Peak periods are 3-6pm, 4-7pm, and 2-5pm respectively for E-21, E-22, and E-25. Out of the three EZ-3 rates, we will base our analysis only on E-21.The residential EV price plan (E-29) has a super off-peak period from 11pm-5am to encourage EV charging in this period. We commend SRP for having an EV charging rate and suggest that SRP explore further reducing the super off-peak price, with capacity related costs shifted from the off-peak period to the fixed charge. This will more accurately reflect the low cost of EV charging during these time periods. SRP should also consider monitoring the impact that customer response to the super off-peak price has on its local distribution network, as a number of EVs all start charging at the same time. Since early EV adoption tends to cluster in certain neighborhoods, this behavior could be problematic for the local distribution system.

Table 1 shows the structure of each of SRP's rates. The standard rate (E-23) consists of a tiered-flat volumetric rate and a fixed customer charge. Tiered energy rates encompass steps that increase the price of electricity as the customer consumes more. Tiers do not fully reflect underlying electricity costs and SRP is in the process of phasing them out in E-23. SRP has proposed flattening the tiered energy structure in E-23 from three to two tiers. Apart from reducing the number of tiers and

---

[14] Or who have on-site generation that was applied for before December 8, 2014.

[15] The Residential Pre-Pay ToU rate (E-28) has been approved but is yet to be fully implemented by SRP.

changing the ToU peak period length for all residential ToU rates apart from the Super-Peak ToU (E-21), there are no other proposed changes to the structure of SRP's proposed residential rates for customers without on-site generation. The E-28 Residential Pre-Pay ToU rate shares identical prices with E-26, the Residential Standard ToU rate. There are currently no customers on the E-28 rate, and is yet to be implemented fully. The on-site generation rate, E-27, has a tiered demand charge, meaning that high demand customers are paying a greater price per incremental kW than lower demand customers. SRP should continue monitoring whether the top tier demand charge exceeds SRP's marginal capacity costs. If this is the case, then lowering the top tier demand charge will make SRP and its customers better off, but at the same time, the lower tiered demand charges will have to be raised in response. The current top tier demand charge is approximately equal to the marginal capacity cost.

Apart from reducing the number of tiers and changing the ToU peak period length for all residential ToU rates apart from the Super-Peak ToU (E-21), there are no other proposed changes to the structure of SRP's proposed residential rates for customers without on-site generation. The E-28 Residential Pre-Pay ToU rate shares identical prices with E-26, the Residential Standard ToU rate.

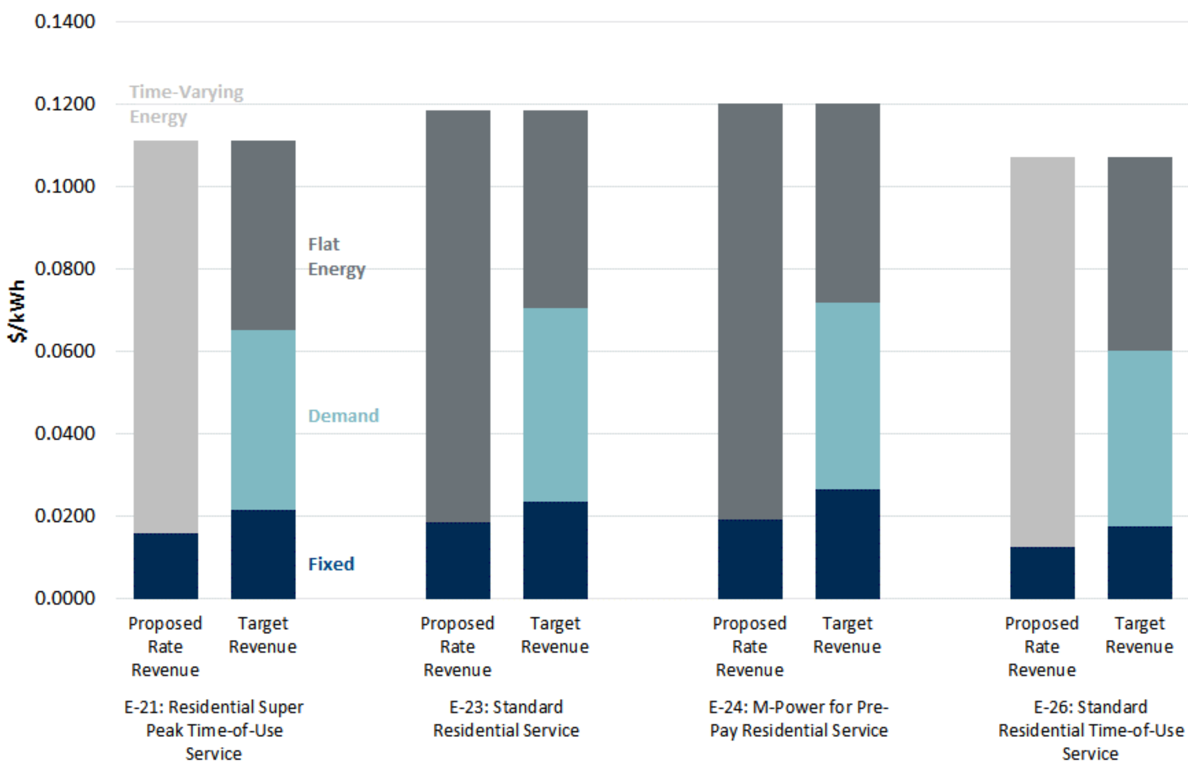
Table 1: Rate Structure for Residential Customers

	Energy (kWh)		Demand (kW)		Fixed Charge
	Flat	**Time Varying**	**Max**	**Time Varying**	**Fixed**
Existing rates					
E-21: Residential Super-Peak ToU		On/Off-Peak			x
E-23: Residential Standard	2 Tiers				x
E-24: Residential Pre-Pay	x				x
E-26: Residential Standard ToU		On/Off-Peak			x
E-27: Residential Customer Generation		On/Off-Peak		On-Peak (3 Tiers)	x
Existing pilots					
E-27P: Residential Demand Rate Service		On/Off-Peak		On-Peak (3 Tiers)	x
E-28: Residential Pre-Pay ToU		On/Off-Peak			x
E-29: EV Super Off-Peak ToU		On/Off/Super-Off-Peak			x
New rates					
E-13: DG ToU Export		Delivered On/Off-Peak			x
E-14: DG EV ToU Export		Delivered On/Off/Super-Off-Peak			x
E-15: DG Average Demand		On/Off-Peak		Average On-Peak Daily	x

Compared to flat rates, ToU rates better signal the underlying costs of electricity, which vary across the day, as well the cost of capacity required to meet peak demand. Three-part rates, which include time-varying energy and demand charges, even better reflect the substantial capacity costs of providing electric service. It is notable that SRP has 36% of their residential customers on rates that have either time-varying energy and/or demand components, both of which better reflect costs than the historically ubiquitous flat volumetric rate.

Figure 12 shows the breakdown of revenues by energy, demand, and fixed charges within each of the existing proposed rates, compared to that of the revenue target, which is based on the revenue breakdown implied by the cost of service study. SRP's cost of service is based on embedded costs and reflects the average costs a customer will face in the future, based on both current and past decisions. This is different from the marginal cost, which is forward looking and examines only incremental costs. SRP is in the process of transitioning towards rates that better reflect marginal cost. In doing so, differences may arise between the embedded and the marginal cost structures. The comparison between the proposed and targeted revenues reflects one dimension of cost-reflective rate design by comparing the revenue structure of the proposed rates with the revenue structure implied by the embedded cost of service study. It does not however reflect the other aspect of cost-reflective rate design—marginal cost. As SRP continues its transition toward marginal cost-based rates, we suggest that they create a transparent modeling process that illustrates where marginal costs are differing from embedded costs and which rate components are set at, or moving towards, marginal cost.

Figure 12: Structure of Proposed Existing Residential Rates Compared to Estimated Revenue Requirement ($/Net kWh)[16]



Note: The target revenue structure reflects the embedded (average) cost to serve customers. This may differ from the marginal (incremental) cost of service. SRP is in the process of transitioning towards marginal cost-based rates and the target revenue structure should therefore only be used as indicative of their embedded cost reflectivity.

16 E-27 is omitted from the figure due to the complexity of creating a suitably comparable graphical representation of the rate that encompasses both energy imports and exports. E-27 is discussed separately below.

In the previous rate period, SRP introduced a mandatory three-part rate, E-27, for new on-site generation customers (any customers who applied for on-site generation after December 8, 2014). This rate consisted of a tiered on-peak demand charge (monthly maximum demand in the peak period), a time-varying energy charge, and a fixed charge. The energy charge is levied on net consumption, which is imports from the grid less exports to the grid. This means that exports and imports have the same energy price. This three-part rate better reflected the underlying costs of serving these customer-generators, who were using the grid very differently from other residential customers. Table 2 shows the proposed energy price for E-27 compared to the class' marginal cost of energy (adjusted for marginal loss factors). The proposed energy price ranges from 23 to 44 percent higher than the marginal energy cost, across the ToU periods and pricing seasons.

Table 2 : Proposed and Marginal Energy Prices for E-27

Period		Marginal Energy Cost ($/kWh)*	Proposed Energy Price ($/kWh)	Percentage Difference
Summer Peak	On-Peak	0.0459	0.0622	36%
	Off-Peak	0.0336	0.0412	23%
Summer	On-Peak	0.0321	0.0462	44%
	Off-Peak	0.0272	0.0360	32%
Winter	On-Peak	0.0302	0.0410	36%
	Off-Peak	0.0265	0.0370	40%

* adjusted for marginal losses.

Setting the energy price for E-27 is complex and requires an understanding of the cost implications of the rate from both an importing and exporting perspective. As with all of their rates, SRP has considered both the embedded (average) cost of energy and the marginal (incremental) in setting the E-27 energy price. While there are many pricing principles, such as gradualism, to consider, moving the energy rate closer to the marginal cost of energy would better align both the import and the export price with their respective costs.

A similar rate to E-27 is available to customers without on-site generation, E-27P. E-27P identically matches the price structure and price levels of E-27. However, some of the costs that have been allocated to E-27 are specific to customers with on-site generation, including the costs of a second meter to measure total production,[17] approving on-site generation plans, site inspections, processing rebates, dealing with customer enquires about on-site generation and related issues. If E-27P is to become a standalone rate in the future, SRP should consider removing these on-site generation costs from E-27P's metering and billing and customer service pricing

17 SRP uses customer generation data to enhance both grid operations and provide better customer service. Understanding when and how effectively customer generation is operating allows SRP to better monitor and control its network, while a full understanding of a customer's energy consumption enables customer representatives to address any customer queries more effectively.

components, respectively. However, we also do recognize that in the proposed rates, SRP has set the return for the E-27 class (and hence E-27P) lower than it would have otherwise been owing to the inclusion of these costs, which SRP expects to decrease in the future.

Table 3 shows how the relative structure of each rate's charges is changing from current to proposed rates compared to the underlying (embedded) cost structure. The changes are in percentage points and a positive number indicates that it is moving in the direction of the cost reflective rate structure of target revenue. So for example if the proposed fixed charge increases from 5% to 10% of the current revenue and comprises 20% of the target revenue, we could say that the fixed charge has moved towards being more cost reflective. In Table 3 we would see that it has increased by 5% (five percentage points).

Table 3: Change in Residential Charge Type Relative to Underlying Cost Structure[18]

Classes	Change in Revenue (percentage points)		
	Fixed	Demand	Energy
E-21: Residential Super-Peak ToU	0.2	0.0	0.2
E-23: Residential Standard	0.1	0.0	0.1
E-24: Residential Pre-Pay	0.5	0.0	0.5
E-26: Residential Standard ToU	0.2	0.0	0.2
E-27: Residential Customer Generation	-0.3	0.4	0.2

For the residential class, none of the relative shares of revenue from energy, demand, and fixed charges change more than a half of a percentage point. Thus, none of the rates change their current cost reflectivity. As technologies continue to evolve along with how customers use the grid, SRP may wish to consider transitioning more customers to rates that better reflect the underlying costs of serving customers, and increasing the share of the fixed charge on all rates without demand charges, especially the flat standard (E-23) and pre-pay rates (E-24) to reflect the fact that the majority of customer costs are not volumetric.

2. New Rates

SRP's proposed rates include three new rates that extend choice to customers with on-site generation over the existing three-part rate (E-27). One of the rates, E-15, retains the three-part structure of E-27, but uses an alternative metric to measure demand. Instead of using the maximum on-peak demand for the entire month, E-15 uses a demand charge based on the average of the daily on-peak maximum demand. The other two options remove the demand charge and have a different price for exported and imported energy. For imports, energy is charged based on a ToU charge, while for exports the customer is credited a flat fee per kWh. The flat fee is based on the cost of new utility scale solar and accounts for the line losses that SRP would have incurred in

[18] E-29 does not have a target revenue as it is based on rates from E-26, and is omitted from the table.

transporting the electricity to the end-customer. SRP has indicated that they expect these three plans to be revenue neutral to E-27.

The new average demand charge for E-15 provides a weaker signal of the costs of capacity to customers than the monthly maximum on-peak demand of E-27, but will likely decrease the potential of bill volatility for customers. The average demand charge still emulates the underlying cost of service and offers an appropriate signal.

E-13 on the other hand is less cost reflective than E-27 (though more cost reflective than the standard rate E-23 with higher fixed charges). Since self-generating customers are billed on delivered energy (all imports), that the energy cost includes capacity costs is of less consequence, since customers cannot bypass these costs as they would under net energy metering. This ensures that customers pay their fair share of the costs of the grid. For exports, customers are paid a flat price per kWh that is based on the recent cost of new utility-scale solar plus line and transformation losses associated with the transmission and distribution systems.

If self-generation occurs during the E-13 peak period (2pm to 8pm), there may be some avoided capacity costs from self-generation. Generation and transmission capacity benefits are accounted for in the proposed export rate, since it is based on the power purchase price of utility-scale solar, which includes avoided generation and transmission capacity costs. Avoided distribution capacity costs are also accounted for, since the proposed E-13 rate is based on the E-27 target revenue, which uses net rather than delivered kWh to allocate distribution costs in the cost of service study. If E-13 becomes its own class in a future price process, SRP will need to continue to ensure to use net kWh as a cost driver (even though the billing determinant is delivered kWh) to account for distribution capacity benefits. The same will hold true for E-14, discussed below.

The final new rate for on-site generation customers is E-14, which is intended for on-site generation customers with electric vehicles. The energy prices of E-14 are set identical to E-29, the EV rate for customers who do not have on-site generation. As such, we suggest that SRP explore further reducing the super off-peak price (as with E-29), with capacity related costs shifted from the off-peak period to the fixed charge (or possibly the on-peak demand charge).

B. General Service Rates

The (smaller) general service rates, consist of customers with monthly consumption of less than 300,000 kWh who are not classified as residential, lighting or pumping customers. Consequently, smaller general service is a diverse customer group, including small stores, offices, non-agricultural pumps, large grocery stores, and small technology manufacturers, with demand ranging from less than 5 kW to over 1,800 kW.

Smaller general service customers have a choice between four rates, three of which have demand charges and variations in flat and time-varying energy rates and the fourth - a simple, pre-pay flat energy rate, with no demand charges. It should be noted that all demand charges are only levied on demand that exceeds 5kW. In this way, the demand charges are actually tiered, with the bottom tier having a zero price. Almost all of the smaller general service customers are on one of the three-part (demand) rate options, with most (87%) electing to remain on the default rate, E-36. E-36 includes a four-tiered flat energy charge, a monthly maximum demand charge, and a fixed charge. The tiers are based on energy per kW, making them essentially a tiered load factor rate.

Most of the remaining 13% of smaller general service customers select E-32, the ToU option, where the energy charge is based on On/Shoulder/Off-Peak, with a time varying demand charge, and a fixed charge. SRP customers have the option of a second ToU rate, E-33, which has a shorter peak period and a stronger ToU price signal. The demand charge for E-33 is based on maximum demand, which may counteract the stronger ToU signal on energy. This is because the off-peak demand charge is now the same as the on-peak demand charge and thus higher than the off-peak demand the customer would have faced under the standard ToU rate, E-32. E-33 is currently still an experimental rate and we suggest that SRP evaluate customer load shifting and potentially test alternative specifications for the demand charge.

Finally, smaller general service customers (single-phase only) have the option of a pre-pay rate (E-34) with no demand or time-varying energy charges. Except for slight variations in the fuel charge, this rate is identical in structure and prices to the residential pre-pay rate, E-24.

Table 4 summarizes the rate structures for the four rates on offer to the smaller general service customers. There are no proposed structural changes to any of the general service rates.

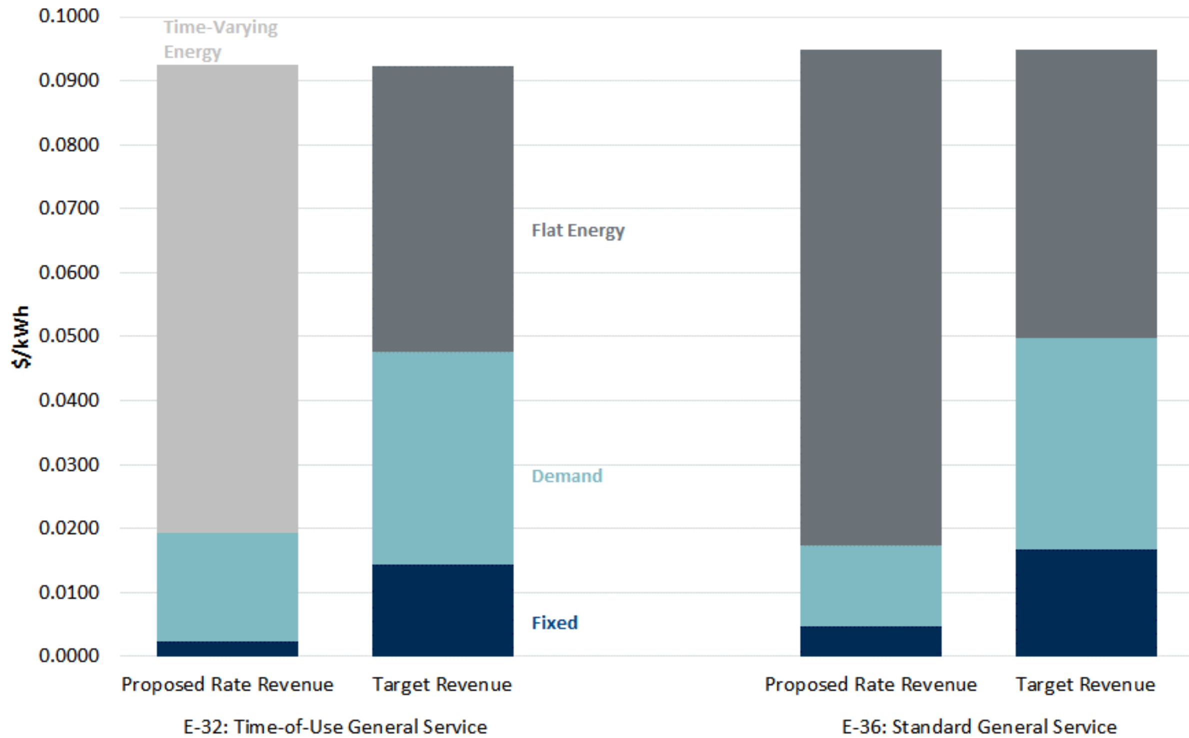
Table 4: Rate Structure for General Service Customers

	Energy (kWh)		Demand (kW)		Fixed Charge
	Flat	**Time Varying**	**Max**	**Time Varying**	**Fixed**
Existing rates					
E-32: General Service ToU		On/Shoulder/Off-Peak		On-Peak & Shoulder/Off-Peak	x
E-34: General Service Pre-Pay	x				x
E-36: General Service Standard	4 Tiers (Based on Load Factor)		x		x
Existing pilots					
E-33: General Service Super- Peak ToU		On/Off-Peak	(Summer and Peak Months)	On-Peak (Winter Months)	x

Figure 13 shows the structural split in the standard and ToU general service proposed rates between energy, demand and fixed charges.[19] This is contrasted with the structural split in the targeted revenue, which reflects the underlying cost of service for these customers. As can be seen in Figure 14, a larger part of the revenue for the general service class is recovered from energy than a cost reflective rate structure would suggest. However, since the energy price tiers for E-36 are based on load factor, the rate is more cost reflective than the figure would suggest.

19 There are no proposed or targeted revenues for the E-34 rate, as its prices are derived from E-24 directly, apart from fuel charge changes. Similarly, the experimental rate E-33 had its prices derived from E-32, it did not have its own design process involving proposed or targeted revenues.

Figure 13: Structure of Proposed General Service Rates Compared to Estimated Revenue Requirement ($/Net kWh)



Note: The target revenue structure reflects the embedded (average) cost to serve customers. This may differ from the marginal (incremental) cost of service. SRP is in the process of transitioning towards marginal cost-based rates and the target revenue structure should therefore only be used as indicative of their embedded cost reflectivity.

Table 5 shows how the relative structure of each rate's charges is changing from current to proposed rates compared to the underlying cost structure. The changes are in percentage points and a positive number indicates that it is moving in the direction of the cost reflective rate structure of target revenue. We can see that both E-32 and E-36 have improved on both the proportion of revenues recovered from demand and energy. For E-32 both the demand and energy share of proposed revenue improved by ~2.5 percentage points under the proposed rate, compared to the current rate. Since the demand charge share of the proposed rate revenue is lower than the demand charge share of the target revenue, this means that relative to the demand share of revenue of the current rate, the proposed demand charge revenue *increased* by ~2.5 percentage points. Similarly, because the proposed rate energy charge revenue is higher than the target would suggest, it means that the share of the proposed rate energy revenue *decreased* by the ~2.5 percentage points relative to the current rate. Similarly, for E-36, the charges have improved in the same direction for demand and share of energy, at ~0.6 percentage points. The share of the fixed charge remains relatively unchanged.

Table 5: Change in General Service Charge Type Relative to Underlying Cost Structure

Classes	Change in Revenue (percentage points)		
	Fixed	Demand	Energy
E-32: General Service ToU	0.1	2.5	2.6
E-36: General Service Standard	0.1	0.6	0.7

Even with proposed increases to the demand charge share of revenue, SRP's proposed general service rates are under-collecting revenue from demand and fixed charges, relative to what a cost-reflective rate structure would suggest. We suggest that SRP continue the transition to a more cost reflective rate structure, by continuing to shift costs away from energy charges towards demand charges, and increasing the fixed charge.

C. Large General Service

Large general service customers are those who have had gross consumption[20] of more than 300,000 kWh per month for three consecutive months, or who have dedicated distribution facilities. Classes are determined by the distribution connection, which ranges from secondary (E-61), to primary (E-63), to dedicated substation (E-65, E-66, E-67 and CPP). Most of the large general service customers are connected to secondary distribution (82%), with 9% of customers taking service from primary distribution and 9% from dedicated facilities. All large general service rates include time-varying energy, demand, and fixed charges. Only the largest of the large general service have a choice over rates, with the 49 customers with dedicated distribution facilities (E-65) able to choose between the standard rate, an interruptible rate and a critical peak pricing rate. E-65 customers with a sufficiently high load factor can also select the proposed new high load factor rate, E-67.

All of the existing rates for large general service customers include an on-peak demand charge to recover revenue for Distribution Delivery, Generation, and Transmission. E-61 and E-63 have an additional maximum demand charge to recover revenue for Distribution Facilities and Distribution Delivery. All of the rates for customers with dedicated distribution facilities include a customer-specific facilities charge. The new high load factor rate (E-67) differs from the other rate choices for customers with dedicated distribution facilities with the use of a maximum demand charge, rather than the on-peak demand charge that is included in all the other large general service rates. Consistent with the idea of this being a high load factor rate, this will ensure that customers are encouraged to reduce demand in all periods. The structure of billing determinants for all rates is summarized in Table 6.

[20] Gross consumption delivered energy, plus any self-generation used by the customer.

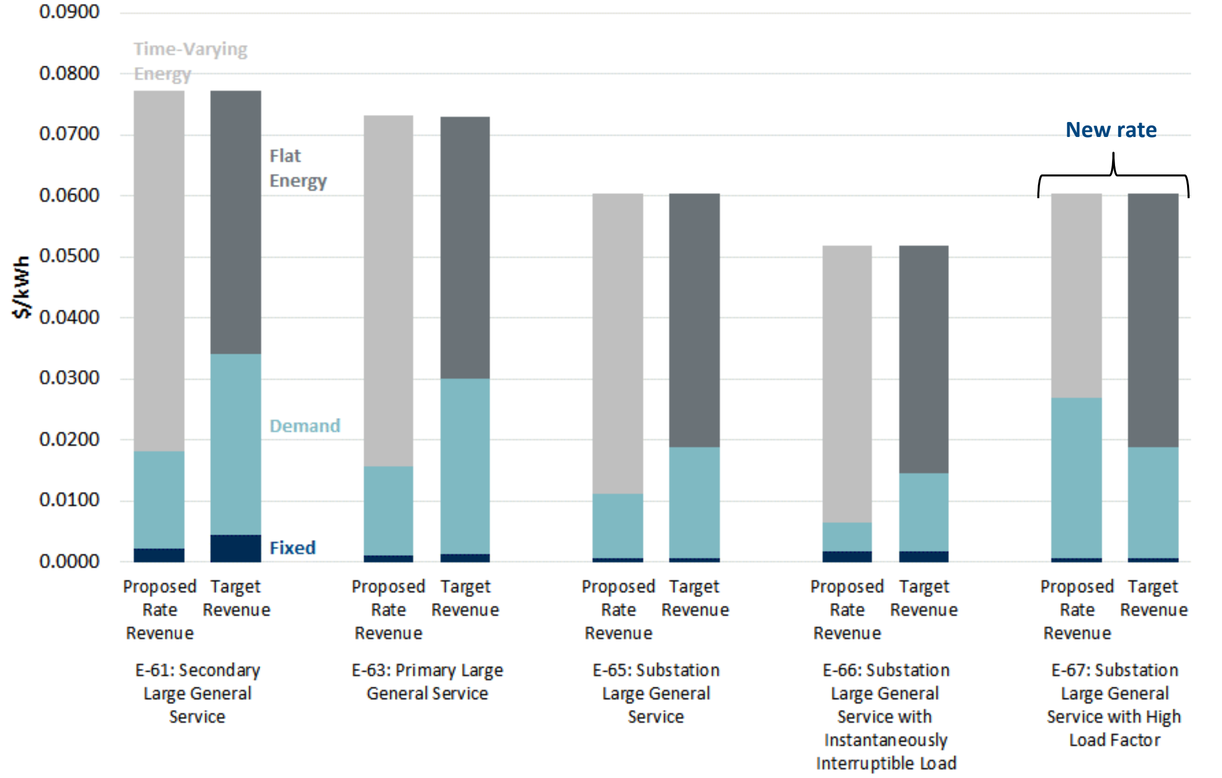
Table 6: Rate Structure for Large General Service Customers

	Energy (kWh)		Demand (kW)		Fixed Charge
	Flat	Time Varying	Max	Time Varying	Fixed
Existing rates					
E-61: Large General Service Secondary		On/Shoulder/Off-Peak	x	On-Peak	x
E-63: Large General Service Primary		On/Shoulder/Off-Peak	x	On-Peak	x
E-65: Large General Service Substation		On/Shoulder/Off-Peak		On-Peak	x
E-66: LGS Substation with Interruptible Load		On/Shoulder/Off-Peak (Weekday/Weekend)		On-Peak	x
Existing Pilot					
CPP: Large General Service CPP		CPP-On/Other-On/Shoulder/Off-Peak		On-Peak	x
New rates					
E-67: Large General Service High Load Factor		On/Shoulder/Off-Peak	x		x

The Critical Peak Price (CPP) is a pilot rate that allows SRP's customers the opportunity to respond to day ahead price signals associated with SRP's most expensive days to serve. The rate has a high price for energy during critical peak events and a lower on-peak energy rate during all other on-peak hours (compared to E-65). The rate is open to only five eligible E-65 customers, who SRP have assessed as having sufficient ability to shift load during critical peak pricing events. SRP can call between 10 and 40 CPP events per year. There are currently no customers on the CPP rate.

Figure 14 shows the structure of the large general service rates. For the most part, the rate structures have an oversized energy component and undersized demand charge. Fixed charges, which are spread over many kWh, are relatively small.

Figure 14: Structure of Proposed Large General Service Rates Compared to Estimated Revenue Requirement ($/Net kWh)



Note: The target revenue structure reflects the embedded (average) cost to serve customers. This may differ from the marginal (incremental) cost of service. SRP is in the process of transitioning towards marginal cost-based rates and the target revenue structure should therefore only be used as indicative of their embedded cost reflectivity.

SRP is actively transitioning to more cost reflective rates, and all of the proposed rates have lower energy charges and higher demand charges than the current rates. This is shown in Table 7, where, as before, positive changes signal the change is going in the correct direction to improve the cost reflectivity of the rate structure. For example for E-61, we can see that the revenue share of energy has improved by 7 percentage points relative to current rates. Since the energy share is higher than a cost-reflective rate structure would suggest, this means that the share of energy has decreased by 7 percentage points. This is achieved by an increase in fixed charges of 0.9 percentage points and demand of 6.1 percentage points. Similar results hold for all of the other rates.

The proposed new high load factor rate, E-67, has relatively high demand charges and low energy charges (compared to E-65), making the structure a better match for the target revenue. The target revenue was designed to generate the same level of revenues as E-65 if the rate was applied to all E-65 customers. However, not all E-65 customers qualify for this rate, only those with sufficiently high load factors. The rate is designed so that these customers will automatically benefit relative to E-65. This revenue reduction is intentional and accounted for by SRP, as they recognize the value of high load factor customers.

While we recognize the value of high load factor customers, flexible load customers may be more valuable in a future with higher concentrations of intermittent generation. We suggest that SRP adapt the CPP rate to make it more appealing to customers and extend the rate to more customer classes. SRP may also want to examine the idea of creating a targeted CPP rate in the future that could be called at the substation level and be used to alleviate local distribution constraints. In other jurisdictions, fewer CPP events are called and this may increase customer acceptance. We suggest SRP study the issue further.

Table 7: Change in Large General Service Charge Type Relative to Underlying Cost Structure

Classes	Change in Revenue (percentage points)		
	Fixed	Demand	Energy
E-61: LGS Secondary	0.9	6.1	7.0
E-63: LGS Primary	0.5	6.3	6.7
E-65: LGS Substation	0.1	5.9	6.0
E-66: LGS Substation with Interruptible Load	0.5	1.4	1.9

D. Lighting Rates

SRP has three lighting rates, these cover Traffic Signals (E-54), Public Lighting (E-56), and Private Security Lighting (E-57). These rates only serve lighting accounts that are unmetered, and variable charges to these customers are based on estimated usage. Metered lighting customers are served under General Service rates E-32 and E-36. Customers can choose to install meters on their lighting equipment if they wish to switch to General Service rates.

Unmetered lighting customers have their price plans determined by the lighting end-use. Traffic signal and related lighting owned by any governmental bodies are to be served by E-54. The lighting of streets (public and private), public parks and school grounds, thoroughfares, playgrounds, walkways, publicly-owned street signs and municipal parking lots are to be served by E-56. Private lighting on private residences and commercial properties are served by E-57.

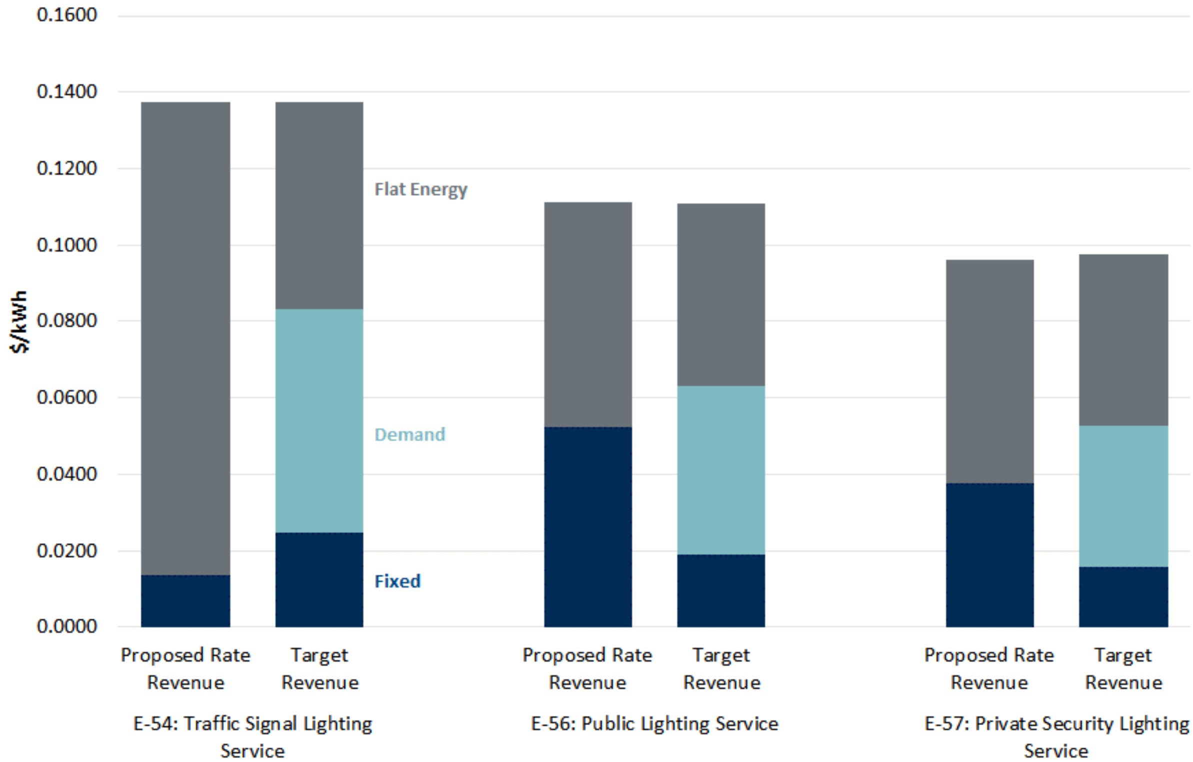
As can be seen in Table 8, all of the lighting rates have the same structure consisting of a flat energy charge and a fixed charge. Since the lighting is unmetered, the energy charge is estimated.

Table 8: Rate Structure for Lighting Customers

	Energy (kWh)		Demand (kW)		Fixed Charge
	Flat	Time Varying	Max	Time Varying	Fixed
Existing rates					
E-54: Lighting Traffic Signal	x				x
E-56: Lighting Public	x				x
E-57: Lighting Private Security	x				x

Figure 15 shows the breakdown of how the lighting rates are recovered. The structure of the proposed revenue for public and private lighting, E-56 and E-57, are fairly evenly split between energy and a fixed charge. The proposed rate for traffic lights, is however predominantly energy based, with a very small fixed charge.

Figure 15: Structure of Proposed Lighting Rates
Compared to Estimated Revenue Requirement ($/Net kWh)



Note: The target revenue structure reflects the embedded (average) cost to serve customers. This may differ from the marginal (incremental) cost of service. SRP is in the process of transitioning towards marginal cost-based rates and the target revenue structure should therefore only be used as indicative of their embedded cost reflectivity.

Table 9 shows that for the traffic light rate, E-54, the increase in the revenue share from fixed charge and decrease in the share of energy charge revenue is relatively small at 1 percentage point. E-56 and E-57 increased the share of revenue from fixed charges and decreased the share from energy by 4.8 and 4.4 percentage points, respectively. Generally accepted principles in rate design are that fixed charges are a good proxy for demand charges, since demand does not necessarily vary with energy. In this respect, the lighting rate changes are moving in the correct direction. However, new lighting technologies may have the ability to lower both future energy and demand costs. We suggest that SRP revisit this issue in a future price process.

Table 9: Change in Lighting Charge Type Relative to Underlying Cost Structure

Classes	Change in Revenue (percentage points)		
	Fixed	Demand	Energy
E-54: Lighting Service Traffic Signal	1.0	0.0	1.0
E-56: Lighting Service Public	-4.8	0.0	4.8
E-57: Lighting Service Private Security	-4.4	0.0	4.4

E. Pumping Rates

There are currently two types of pumping rates, E-47 and E-48, which serve customers from the Salt River Valley Water Users' Association, and customers with agricultural and municipal uses. E-47 is the standard pumping plan with over 500 customer accounts, and E-48 is the time-of-week pumping plan, currently seen as a legacy rate, with only 12 customers (the proposed recovered revenue for E-48 is $0.1 million, in contrast to $12.4 million for E-47). The E-48 rate provides its customers with lower demand charges for the avoidance of pump use during seasonal peaks. Pumping must be turned off on a predetermined weekday every week during the summer and summer peak seasons from 12pm-10pm. Customers who do so, receive lower demand charges during the summer and summer peak seasons.

Both pumping rates recover revenue through a fixed charge, a flat energy rate, and a max demand charge (see Table 10).

Table 10: Rate Structure for Pumping Customers

	Energy (kWh)		Demand (kW)		Fixed Charge
	Flat	Time Varying	Max	Time Varying	Fixed
Existing rates					
E-47: Pumping Standard	x		x		x
E-48: Pumping Time-of-Week	x		x		x

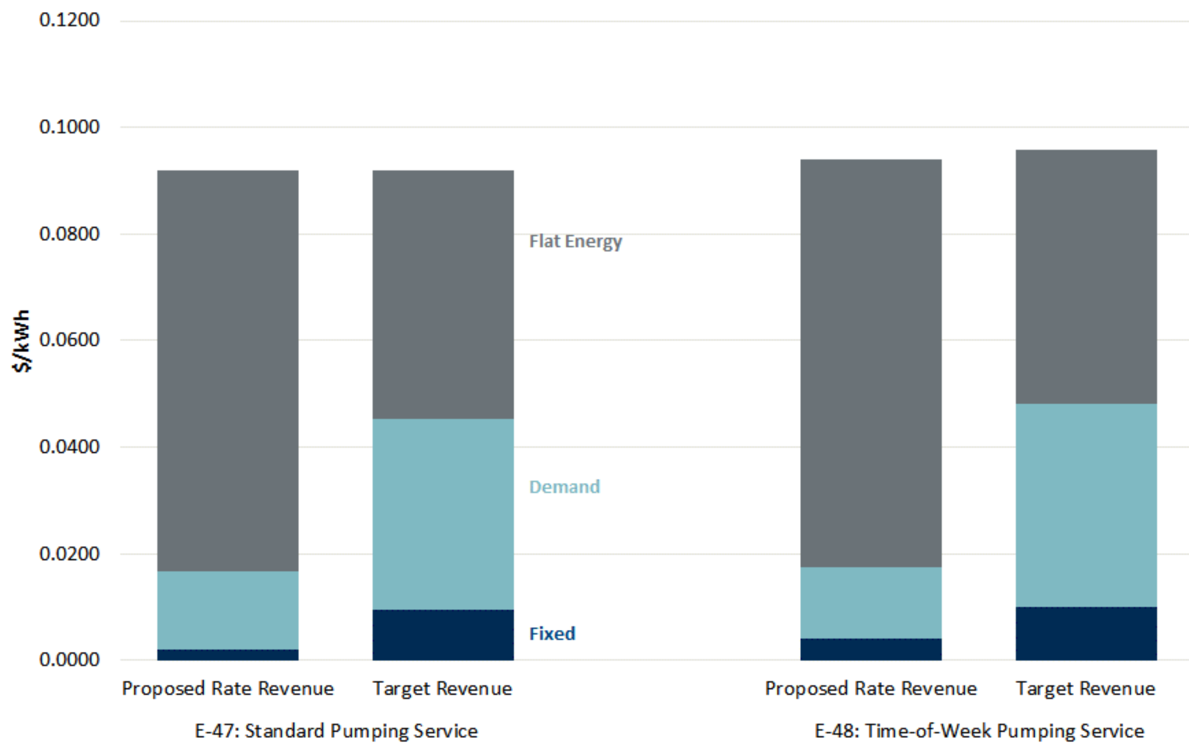
In an examination of the charge recovery structure between proposed revenues and targeted revenues (see Figure 16), both pumping rates over-collect on energy based charges and under-collect on demand based charges, in addition to a shortfall on fixed charge recovery. But, relative to the previous rate, both E-47 and E-48 have improved by decreasing its shares in percentage points of energy charges (2.1 for E-47, 1.0 for E-48), and increasing its shares in fixed charges (0.3 for E-47, 0.6 for E-48) and demand charges (1.8 for E-47, 0.3 for E-48) (see Table 11).

Customers who are currently on the pumping rates who can respond to price signals by varying their pumping use may benefit from moving to E-32, the General Service ToU rate. The E-32 rate is less restrictive than E-48 in dictating which periods the customer must decrease usage to avoid higher charges, and, in additional to time varying demand charges, E-32's energy charge is also time varying. As discussed before, these features present signals that are more reflective of underlying costs of electricity and the capacity costs in providing the electric service than flat rates. Customers who stay on the E-40 rate will be metered all day for demand charges in contrast to E-32 where they would be metered for on-peak periods.

Table 11: Change in Pumping Charge Type Relative to Underlying Cost Structure

Classes	Change in Revenue (percentage points)		
	Fixed	Demand	Energy
E-47: Pumping Service Standard	0.3	1.8	2.1
E-48: Pumping Service Time-of-Week	0.6	0.3	1.0

Figure 16: Structure of Proposed Pumping Rates Compared to Estimated Revenue Requirement ($/Net kWh)



Note: The target revenue structure reflects the embedded (average) cost to serve customers. This may differ from the marginal (incremental) cost of service. SRP is in the process of transitioning towards marginal cost-based rates and the target revenue structure should therefore only be used as indicative of their embedded cost reflectivity.

F. Conclusions on Rate Design

1. Assessment of SRP's Rate Design

After undertaking a thorough conceptual review of SRP's rate design, which consisted of independently evaluating SRP's documentation and supporting workbooks, extensive discussions with the SRP team to understand their underlying logic and a few minor suggestions at our behest, we are confident that SRP's proposed rate changes and new rate designs are in accordance with their five rate design principles. SRP's rates are decreasing in magnitude for all classes and most customers will experience bill decreases. Where changes to existing rates have been made, SRP has advanced rates in being more cost reflective. Changes are relatively minor though, in accordance with SRP's rate design principle of gradualism. SRP has undertaken a distribution marginal cost study and is gradually introducing marginal cost into their rate design. This process could be made more explicit in the rate design workbooks. SRP's new residential rates offer customers with on-site generation more choice, while the new large general service rate rewards customers with high load factors. While all the minor contemporaneous issues we had with SRP's rate designs have been addressed and we are satisfied that the study is fair and follows SRP's principles of rate design, we have several recommendations for SRP for the next price process. These are discussed below.

2. Recommendations

The following recommendations are suggestions to enhance the success of SRP's rates and are not meant to suggest any serious deficiencies in SRP's overall cost allocation or rate design.

1. **Marginal Costs:** We suggest that SRP should continue its transition towards marginal cost based rates. Marginal costs provide a signal to customers of the cost of producing one more unit of an item and guides them to make better decisions. Since marginal costs will vary from average costs, some prices can be set at the marginal cost, while others will be needed to recover the remainder of the required revenue. For example, two-part ToU rates are often set so that the on-peak energy charge matches the marginal cost of providing energy in the peak period, plus some share of the marginal capacity costs. In this way, the peak price signals to customers that consumption in this period is costly. If customers can reduce consumption in this period, they will lower the cost for all customers. Since the price matches the cost of consumption, the utility would not lose revenue on net if customers reduced consumption. Similarly, for customers with demand charges, the long-term goal is to have all capacity costs in a demand charge.

   In continuing with the transition to marginal cost based rates, we suggest that SRP evaluate the extent to which the proposed ToU and demand structure fully reflects the marginal cost of providing service, particularly with respect to the peak period. SRP should develop a roadmap on how to pursue marginal cost-based rates, where this roadmap outlines longer-term pricing goals, reviews the extent to which current rates reflect marginal cost, and lays out a transition plan to move rates towards the longer-term pricing goals.

2. **Peak periods:** Continue to monitor the on-peak periods, which may evolve over time in response to the rate or changes in customer usage. For example, significant penetration of rooftop solar can shift the peak period to later in the day. Additionally, the significant customer uptake of ToU may shift the peak, or cause ramping issues as the peak period ends. Consider shortening the summer period to two months if evidence shows that system peaks are unlikely to occur outside of the two peak summer months and the two months adjacent.

3. **Value flexibility:** Many of the high load factor technology companies have significant back-up generation or other means of modifying their demand in relatively short time periods. These customers will also likely argue their need for rate relief of various types.

Consider introducing a rate that values flexibility as a means of achieving a win-win negotiation stance with them.

Consider extending the CPP rate to more customer classes, since this is a flexible tool that SRP can use.

4. **Rate changes:** Tiered energy rates are not strongly cost-reflective and we recommend a long run goal of phasing them out.

   Consider phasing out the interruptible pumping load rate. Its current design is an anachronism.

   Ensure that ToU rates are suitably differentiated. If the prices in different time periods are similar, consider combining those periods (e.g., combining the shoulder and off-peak.

5. **Transparency:** Enhance the rate models architecture. Since SRP's rate development requires teams of individuals, it would be helpful to have a common model architecture to reduce staff effort in maintaining consistency in the rate design across the different classes and, in the long-run, will enhance rate creativity and transparency.

BOSTON
NEW YORK
SAN FRANCISCO

WASHINGTON
TORONTO
LONDON

MADRID
ROME
SYDNEY

THE Brattle GROUP