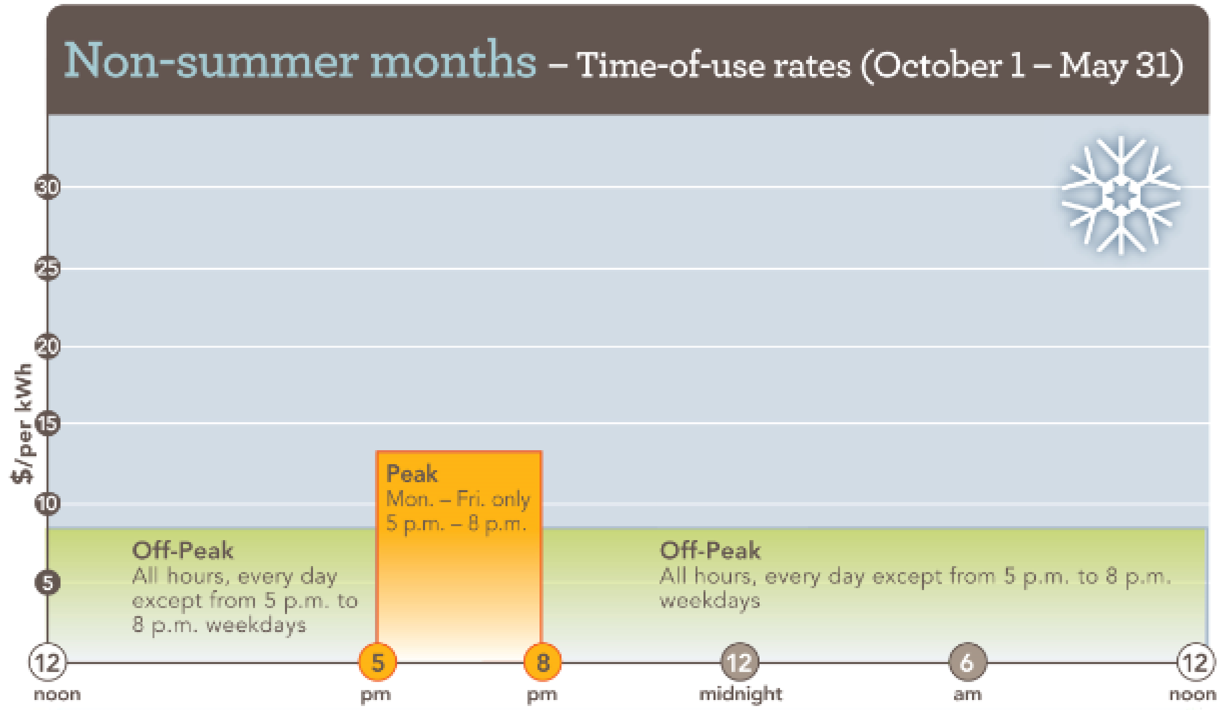
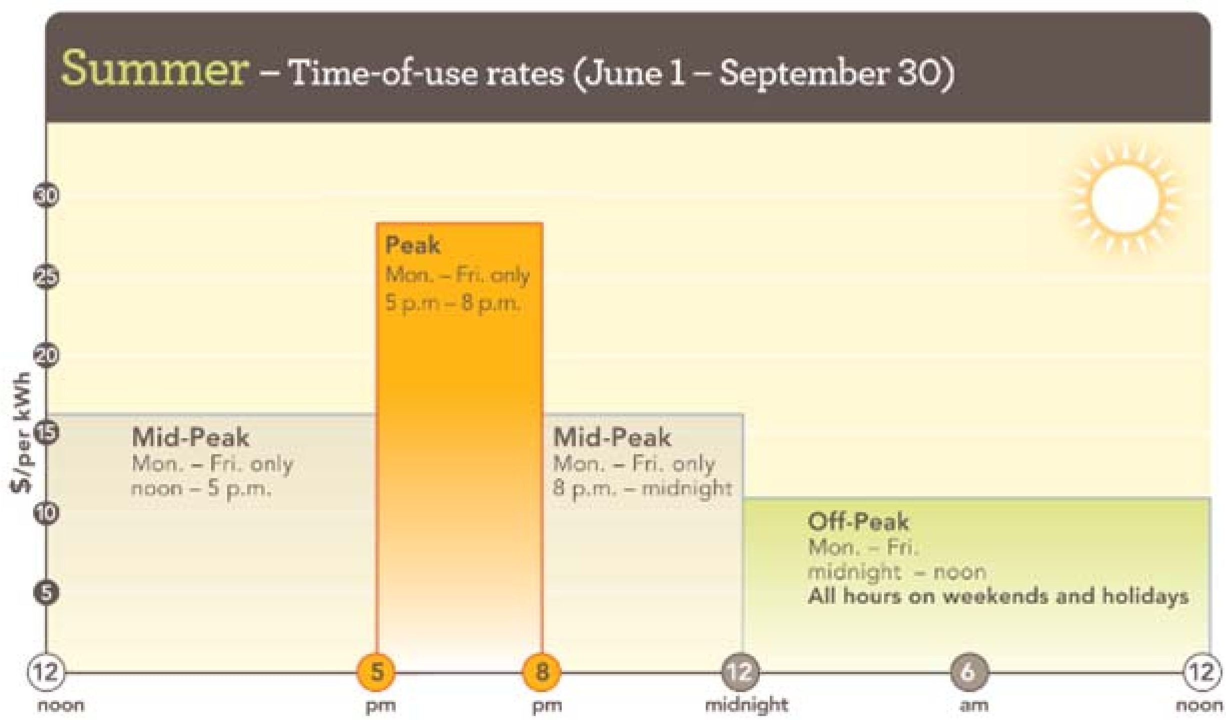
2018 Residential Time-of-Use Rate (RT02) Design Study





OVERVIEW

SMUD's proposed rate structure as defined by the Chief Executive Officer & General Manager's Report and Recommendation on Rates and Services is based on by SMUD's Marginal Cost of service. Marginal costs are the additional costs SMUD incurs to provide electric service to a new customer, a new load or the savings expected from not serving that customer or load. These costs vary by the voltage at which electricity is delivered to the customer.

To provide electric service a utility must acquire power, maintain transmission and distribution systems to deliver the power, and provide customer service. Each of these basic functions has several components. SMUD provides power to a marginal customer from its marginal resource in the market. In addition to buying power for its customers, SMUD must provide ancillary services such as regulation and three types of reserves (spinning, non-spinning, and replacement), and transmission services.

Delivering power to customers requires a physical system of towers and poles, cables and wires, substations, transformers and other electrical equipment. These are the transmission, distribution, and distribution facilities systems.

Customer service includes a whole array of activities which range from the initial connection of the customer to the electrical system, to answering questions about a customer's bill. In general, these activities include electronic reading the customer's meter for usage, billing, maintaining customer records, operating and maintaining meters and part of the distribution system, customer accounts, and providing information and responding to customers' inquiries.

The 2016 Marginal Cost Study reflects the current state of California's power markets and SMUD operations. Generation (capacity and energy), transmission and distribution capacity marginal costs, including losses[1], are developed on an 8,760 hour basis and summarized by month, daytypes (weekday or weekend including holidays) and hour. For each time-of-use period, an average price is calculated from the corresponding summarized hourly prices weighted by the class's average hourly energy delivered.

For California publicly owned utilities, Senate Bill X1-2 and Senate Bill 350 legislatively establishes renewable power targets, 33% by 2020 and 50% by 2030, respectively. In this study, an adder is calculated to recognize additional costs for renewable power procurement and added to marginal energy costs.

Marginal customer costs include SMUD-owned distribution facilities that connect the customer to the 12 kV or 21 kV primary feeders, the meter, meter reading, billing, and a variety of aspects of customer care. To the extent accommodated by the $20 fixed charge established by Board resolution August 4, 2011, these costs are allocated on a per customer basis. To be consistent with the allocation convention from prior studies, the residual costs mostly consisting of distribution facilities are allocated 25% evenly across all hours and 75% on an hourly basis weighted by the hourly distribution of residential monthly non-coincident peak demands divided

[1] For the residential class, losses range from 5 to 7 percent depending on season, and reflect transmission and distribution losses down to the secondary distribution service level.

by the class's average hourly energy delivered. This residual cost is recouped in the energy charge.

In addition to the aforementioned marginal cost, a one cent adder is applied to the calculated marginal energy rate to recoup SMUD's Public Goods expenses for energy efficiency, low-income and medical assistance, advanced and renewable technologies, and research and development (R&D) expenses.

The proposed rate structure is completed by setting proposed rate revenues equal to rate revenues for the budget years. The reconciliation of marginal costs to rate revenues is accomplished through increasing final marginal cost energy charges by a scalar.

MARGINAL COST COMPONENTS

While marginal cost is described in the singular sense, it is actually made up of a number of components, as listed in Table A below.

Each category is associated with energy-related, demand-related or customer-related investment criteria for SMUD expenditures. Energy-related refers to expenses incurred when SMUD supplies energy services. Demand-related refers to the costs incurred when SMUD provides generation, distribution or transmission capacity. Customer-related investment is associated with connecting new customers to SMUD's distribution system and providing billing and other services. Finally, the table indicates major characteristics associated with each category. The following sections present a more detailed summary of each marginal cost component.

Table A: Classification of Marginal Cost Components

Category	Component	Description	Unit of Measure
Generation	Generation	Electricity production, ancillary services, line loss	Energy - $/kWh
	Capacity	Capital costs, fixed O&M for power generation	Demand - $/kW-year
	RPS	Cost for Renewable Portfolio Standard compliance	Energy - $/kWh
Transmission and Distribution	Transmission	230 kV lines and infrastructure	Demand - $/kW-year
	Subtransmission	115 & 69 kV lines and infrastructure	Demand - $/kW-year
	Distribution	21, 12 and 4 kV lines and infrastructure	Demand - $/kW-year
Customer	Distribution Facilities	Line extensions and step-down transformers	Customer - $/customer-year
	Meter	Meter, installation and O&M	Customer - $/customer-year
	Services	Meter reading, customer records, information and customer service	Customer - $/customer-year

SEASONS AND TIME-OF-USE (TOU) DEFINITIONS

This study frequently references time-of-use (TOU) periods. The TOU periods are the same throughout this report. There are two TOU seasons and a total of five TOU periods. The TOU seasons consist of a four-month summer (June 1 through September 30) and eight-month winter (October 1 through May 31). The TOU periods are as follows:

Table B: TOU Periods by TOU Season

Time Periods	
Summer Peak	Summer weekdays between 5:00pm and 8:00pm, exclusive of SMUD tariff designated holidays.
Summer Mid-Peak	Summer weekdays between noon and 5:00pm and 8:00pm to midnight, exclusive of SMUD tariff designated holidays.
Summer Off-Peak	All other Summer hours, including holidays.
Winter Peak	Summer weekdays between 5:00pm and 8:00pm, exclusive of SMUD tariff designated holidays.
Winter Off-Peak	All other Winter hours, including holidays.

Tariff designated holidays include New Years, Martin Luther King Jr.'s Birthday, Lincoln's Birthday, President's Day, Memorial Day, Independence Day, Labor Day, Columbus Day, Veterans Day, Thanksgiving Day and Christmas Day.

MARGINAL ENERGY, CALIFORNIA RENEWABLE PORTFOLIO STANDARD COMPLIANCE, ANCILLARY SERVICES AND GENERATION CAPACITY COSTS

The 2016 Marginal Cost Study calculates generation marginal costs by forecasting long-term California energy and capacity markets. It includes energy costs based on forecasts of market prices for energy, ancillary services and capacity for northern California. Essentially, the market prices for these products are SMUD's marginal costs for energy, ancillary services and generation capacity. Generation (capacity and energy), transmission and distribution capacity marginal costs, including secondary losses, are developed on an 8,760 hour basis and summarized by month, daytypes (weekday or weekend including holidays) and hour. For each time-of-use period, an average price is calculated from the corresponding summarized hourly prices weighted by the class's average hourly energy delivered.

Market Prices for Energy

SMUD prepares long-term forecasts for its hourly energy supply costs to use as the marginal energy cost. As shown in Table C, the residential class weighted average marginal energy cost is $0.0474/kWh.

Table C. Generation Marginal Energy Cost by TOU Period

Period		Marginal Energy Costs ($/kWh)
Rates Time Of Use	Summer Peak	$0.0665
	Summer Mid-Peak	$0.0533
	Summer Off-Peak	$0.0438
	Winter Peak	$0.0566
	Winter Off-Peak	$0.0446
Weighted Average		$0.0474

California Renewable Portfolio Standard (RPS) Compliance Adder

"Governor Edmund G. Brown, Jr. signed into legislation Senate Bill 350 in October 2015, which requires retail sellers and publicly owned utilities to procure 50 percent of their electricity from eligible renewable energy resources by 2030."[2] The recent legislative requirement extends Senate Bill X1-2 which was "signed by Governor Edmund G. Brown, Jr., in April 2011 setting the RPS target at 33% by 2020."[3]

As shown in Table D, the RPS Cost adder recognizes the additional cost for energy related to RPS compliance and relies on a consultant developed average cost of renewable power (primarily provided by utility scale solar and wind technologies), conventional energy price forecasts and annual compliance targets[4] to calculate annual RPS premiums per kWh. The residential class RPS weighted average compliance adder of $0.0044/kWh has been included in this report.

Table D. RPS Compliance Cost by TOU period

Period		RPS Costs Compliance Adder ($/kWh)
Rates Time Of Use	Summer Peak	$0.0044
	Summer Mid-Peak	$0.0044
	Summer Off-Peak	$0.0044
	Winter Peak	$0.0044
	Winter Off-Peak	$0.0044
Weighted Average		$0.0044

[2] http://www.energy.ca.gov/portfolio

[3] http://www.energy.ca.gov/portfolio

[4] Annual RPS targets assume a gradual progression to the legislatively established RPS goals of 33% by 2020 and 50% by 2030.

Market Prices for Ancillary Services

The marginal costs for energy deliveries to SMUD customers also include the market prices of ancillary services. Ancillary services provide the operating reserves necessary for stable and reliable energy delivery. The market prices for these ancillary services relate directly to market prices for energy. National and regional reliability councils establish the amount of ancillary services that SMUD and other California utilities must provide as a percent of generation output. The current requirement for SMUD averages the percent of the annual energy delivered to SMUD's transmission system stated as a cost which is summarized for the residential class in the Table E.

Table E. Ancillary Service Cost Adder by TOU Period

Period		AS Cost Adder ($/kWh)
Rates Time Of Use	Summer Peak	$0.0003
	Summer Mid-Peak	$0.0002
	Summer Off-Peak	$0.0002
	Winter Peak	$0.0003
	Winter Off-Peak	$0.0002
Weighted Average		$0.0002

The generation marginal cost of energy combined with ancillary services costs and the RPS compliance adder forms the bundled amounts listed in Table F.

Table F. Generation Marginal Energy Costs by TOU Period (Bundled)

Period		Bundled Marginal Energy Costs ($/kWh)
Rates Time Of Use	Summer Peak	$0.0713
	Summer Mid-Peak	$0.0580
	Summer Off-Peak	$0.0484
	Winter Peak	$0.0612
	Winter Off-Peak	$0.0491
Weighted Average		$0.0520

Marginal Cost of Capacity with Generation/ISO Charges

The marginal cost of generation capacity represents the costs faced by SMUD for securing firm capacity through contracts or market purchases. Unlike marginal energy costs, which represent the variable expense of fuel and related maintenance, marginal generation capacity costs represent the fixed costs including those associated with the financing and construction of a power plant. Additionally, while not required, SMUD generally follows the California Public Utility Commission's (CPUC) Resource Adequacy Requirement (RAR) that requires load serving entities to demonstrate they have enough generation resources to cover 115-percent of their 1-in-2 probability peak load[5]. Thus, SMUD may procure generation capacity to meet the shortfall (if any) between its generation resource total and the "115-percent of peak load" target.

The 2016 Study forecasts generation marginal capacity costs using the following methods:

- Short-term Generation Capacity Costs – Short-term capacity costs are forecast using actual broker quotes for capacity obtained from SMUD's Energy Trading and Contracts group.
- Medium-term Generation Capacity Costs – a three year straight-line transition from short-term to long-term forecasts.
- Long-term Generation Capacity Costs – rely on a consultant-developed fundamental wholesale capacity price forecast.[6]

The levelized generation marginal capacity cost is subsequently distributed to monthly values using capacity allocation factors.[7] For example, capacity has more value during the summer months where capacity is most needed while non-summer months have little capacity value since loads are relatively low and capacity is abundant. The resultant levelized monthly generation marginal capacity costs are increased by the Resource Adequacy Requirement (RAR) percentage of 15%.

As shown in Figure 1, the monthly generation marginal capacity costs were allocated to hours within each month using the probability-of-peak (PoP) factors provided by SMUD's Load Research and Forecasting department. The PoP factors were created in 2006 using over twenty years of historical load data to determine the statistical likelihood that SMUD will reach peak demand for each hour of the year.

[5] Details of the CPUC's RA program can be found on the CPUC's website: http://www.cpuc.ca.gov/PUC/energy/Procurement/RA/

[6] "Annual Capacity Values (nominal and real)," IHS North American Power Market Fundamentals-Rivalry, April 2016

[7] The monthly capacity allocation factors, developed by the long-term planning group, are consistent with the factors used in the 2009 study.

The hourly prices are summarized by month, daytypes (weekday or weekend including holidays) and hour. For each time-of-use period, an average price is calculated from the corresponding summarized hourly prices weighted by the class's average hourly energy delivered.

The generation capacity costs for the residential class are summarized in Table G.

Table G. Generation Marginal Capacity Costs by TOU Period

Period		Marginal Generation Capacity Costs ($/kWh)
Rates Time Of Use	Summer Peak	$0.0680
	Summer Mid-Peak	$0.0253
	Summer Off-Peak	$0.0126
	Winter Peak	$0.0096
	Winter Off-Peak	$0.0013
Weighted Average		$0.0108

DEMAND-RELATED MARGINAL COSTS

Demand-related costs include the installed capital costs, financing, and operation and maintenance (O&M) expenses to maintain SMUD's marginal investments in the transmission, sub-transmission and distribution systems. Additions to transmission and subtransmission systems are based on growth in the system's peak load. Additions to the distribution system are based on non-coincident peak load growth in each of SMUD's four distribution planning areas.

Marginal T&D Capacity Costs

SMUD's 230 kV transmission system allows SMUD to access power from energy markets. Marginal transmission investments represent the forward-looking capital costs and operating and maintenance (O&M) expenses of high voltage transmission facilities, interconnection facilities, and voltage support equipment. Marginal sub-transmission (at 69/115 kV) investments include the costs associated with bulk substations and the lines that connect the transmission system to the distribution system. Distribution system investments include the low voltage substations and the 21 kV, 12 kV, and 4 kV primary feeders that emanate from these distribution substations.

Marginal capacity costs include the installation costs, replacement costs from early retirements, O&M, general plant, administrative and general expenses (A&G), and working capital. The installed capital costs are annualized over the expected life of the equipment. Marginal capacity costs are measured in dollars per kilowatt-year of peak demand.

As shown in Figure 2, annualized costs which are projected to remain constant in real terms and rise nominally with inflation are levelized over the analysis period and allocated hourly based on the probability-of-peak (PoP) factors provided by SMUD's Load Research and Forecasting department.

These hourly costs are summarized by the hourly prices are summarized by month, daytypes (weekday or weekend including holidays) and hour. For each time-of-use period, an average price is calculated from the corresponding summarized hourly prices weighted by the class's average hourly energy delivered.

Table H presents the residential class's marginal transmission, sub-transmission and distribution capacity costs allocated to time periods and presented as cost per kilowatt-hour.

Table H. Marginal T&D Capacity Costs ($/kWh)

Period		Transmission	Sub-Transmission	Distribution	Total T&D Capacity
Rates Time Of Use	Summer Peak	$0.0215	$0.0118	$0.0356	$0.0689
	Summer Mid-Peak	$0.0077	$0.0042	$0.0128	$0.0248
	Summer Off-Peak	$0.0032	$0.0017	$0.0053	$0.0102
	Winter Peak	$0.0000	$0.0000	$0.0000	$0.0000
	Winter Off-Peak	$0.0000	$0.0000	$0.0000	$0.0000
Weighted Average		$0.0028	$0.0015	$0.0046	$0.0089

CUSTOMER-RELATED MARGINAL COSTS

Customer related costs are grouped into three major components: distribution facilities that connect the customer to the distribution system, installed meter costs, and customer services. The distribution facilities costs are calculated in dollars per customer-year. Facility installations are designed and built to accommodate customer specific capacity and voltage level requirements and fixed regardless of demand. In that respect, the marginal costs can be stated as a $/kW. Other customer costs are stated as dollars per customer and thus do not vary with customer energy usage or demand. These costs vary by number of customers and must be recouped by SMUD.

Marginal Customer Related Distribution Facilities

Distribution facilities costs are largely driven by voltage levels and transformer sizing. For residential customers who are served at the secondary voltage level, marginal customer distribution facilities costs include the SMUD-owned final step-down transformer and the lines that connect the customer to the 12 kV or 21 kV primary feeders. Marginal distribution facilities vary with the installed capacity of the customer. For the 2016 Marginal Cost Study, residential class distribution facilities costs are estimated to be $269.77 per year in 2015 and escalated via index[8] to the 2018 values of $292.15 per year or $24.35 per month.

Meter Costs

Meter costs include the capital, installation and O&M costs for servicing the meter. Meter costs vary by customer class and by the service voltage. Metering costs for customers served at higher voltages include voltage reduction equipment, wiring and the physical structures required for metering these customers. The customer related meter cost is estimated to be $33.81 for 2015 and escalated via index[8] to the 2018 values of $36.62 per year or $3.05 per month.

Customer Account Service Costs

Customer account service costs include the costs of meter reading, billing, and a variety of aspects of customer care. These services also include O&M expenses for the call center and information services, customer and Account Management services, collections, and the integrated computer system (SAP). Table I shows by description for 2015 and escalated via index[8] to the 2018 values of $147.47 per year or $12.29 per month.

Table I: Customer Account Service Costs Components

	2015		2018	
Description	**Annual**	**Month**	**Annual**	**Month**
Meter Reading	$5.05	$0.42	$5.35	$0.45
Customer Accounting	$81.78	$6.81	$87.10	$7.26
Uncollectible Accounts	$10.07	$0.84	$10.73	$0.89
Customer Information	$42.27	$3.52	$44.29	$3.69
Total	$139.16	$11.60	$147.47	$12.29

The customer-related distribution facilities cost, meter cost, and customer account services marginal cost forms the bundled amounts listed in Table K below.

PUBLIC GOODS MARGINAL COSTS

Public Goods expenses for energy efficiency, low-income and medical assistance, advanced and renewable technologies, and research and development (R&D) expense was calculated to be $0.0096 per kWh over the last 5 year period (2011-2015). This figure has remained steady in historical periods and thus no escalation was applied in study.

APPLICATION TO RATE DESIGN

Proposed Rate Design

SMUD's proposes the following two-part rate design comprised of a monthly fixed charge and an energy charge which varies by season and time period as shown in Table J:

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[8] Escalation indices were primarily developed based on Handy Witman and IHS provided cost indices. When available, SMUD distribution labor indices based on historical and approved average wage increases per Memorandum of Understanding. Loaders based on actual and budgeted cost 2003-2017.

Table J: Proposed Rate Design

Season and Charge Components	Unit	2018
System Infrastructure Fixed Charge	per month	$ 20.30
Summer Peak	per kWh	$ 0.2835
Summer Mid-Peak	per kWh	$ 0.1611
Summer Off-Peak	per kWh	$ 0.1166
Winter Peak	per kWh	$ 0.1338
Winter Off-Peak	per kWh	$ 0.0969

Season	
Summer	Summer Billing Periods (June 1 - September 30)
Winter	All non-summer months
Time Periods	
Summer Peak	Summer weekdays between 5:00pm and 8:00pm, exclusive of SMUD tariff designated holidays.
Summer Mid-Peak	Summer weekdays between noon and 5:00pm and 8:00pm to midnight, exclusive of SMUD tariff designated holidays.
Summer Off-Peak	All other Summer hours, including holidays.
Winter Peak	Summer weekdays between 5:00pm and 8:00pm, exclusive of SMUD tariff designated holidays.
Winter Off-Peak	All other Winter hours, including holidays.

This design is influenced by SMUD's Marginal Cost of service as described in previous sections.

Site Infrastructure Fixed Charge

The SIFC is comprised of the marginal meter costs, customer service and accounting, unbilled as well as the marginal cost of service line and transformer (together distribution facilities) accommodated by the $20 fixed charge established by board resolution and outlined in Table K:

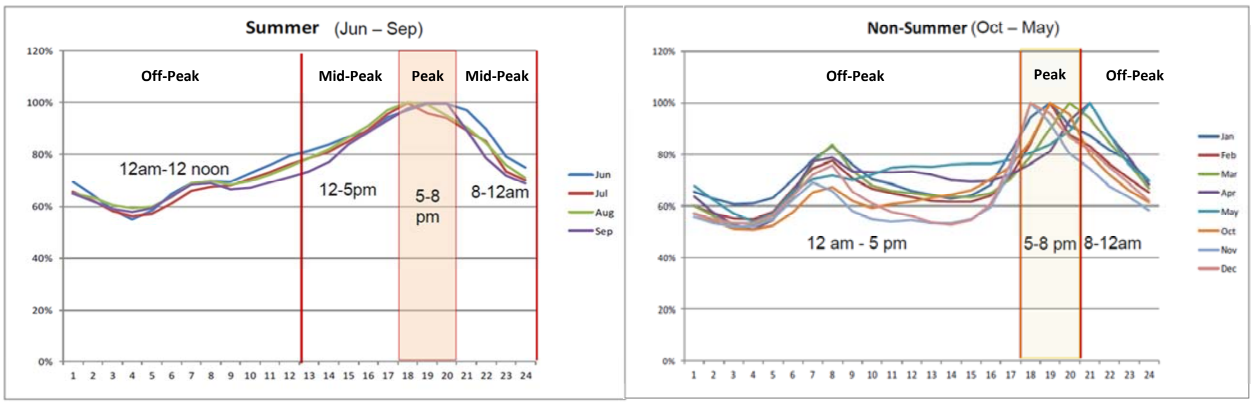
Table K: MONTHLY SITE INFRASTRUCTURE FIXED CHARGE COMPONENTS

Marginal Cost Component	2018 Monthly Marginal Cost	$20 SIFC Components
Meter Costs	$ 3.05	$ 3.05
Meter Reading	$ 0.45	$ 0.45
Accounts	$ 7.26	$ 7.26
Uncollectable	$ 0.89	$ 0.89
Customer & Information	$ 3.69	$ 3.69
Distribution Facility	$ 24.35	$ 4.66
Total	$ 39.69	$ 20.00

Factors that were considered in the selection of Time-of-Use Periods

In 2011, SMUD's Board adopted the Smart Pricing Option (SPO) Pilots rates, which tested three time-of-use rate designs featuring a 3-hour peak pricing period. The study concluded that customers were able to successfully react to higher prices established over 3-hours and conserve. Learning from the SPO study and in conjunction with Board Strategic Direction SD-2[9], this time-of-use rate design continues to signals the three hours where market energy prices were historically highest for SMUD with the winter peak price and the summer peak price both between 5pm and 8pm on weekdays as shown in the Figure 3 below[10]:

Figure 3: NP15 day-ahead market prices as a percentage of maximum values



In addition to the summer peak period, a summer mid-peak period between noon and midnight was established to further better align prices with the costs of electricity when it is used, and better match how SMUD incurs power supply cost.

Time-of-Use Energy Charges

SMUD's energy charges are comprised of generation (capacity and energy), ancillary service, RPS compliance, transmission and distribution capacity marginal costs, including losses, which are developed on an 8,760 hour basis and summarized by month, daytypes (weekday or weekend including holidays) and hour. For each time-of-use period, an average price is calculated from the corresponding summarized hourly prices weighted by the class's average hourly energy delivered.

In addition, the residual cost of distribution facilities are recouped as an energy charge. These residual costs are allocated 25% evenly across all hours and 75% on an hourly basis weighted by the hourly distribution of residential monthly non-coincident peak demands divided by the class's average hourly energy delivered.

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[9] Board Strategic Direction SD-2 Competitive Rates establishes the rate principles that prices should reflect the cost of energy when it used, and in particular, should signal the need to reduce energy during SMUS's high-cost peak periods.

[10] 2014-2015 NP15 day-ahead market prices as a percentage of maximum values.

Public Goods expenses for energy efficiency, low-income and medical assistance, advanced and renewable technologies, and research and development (R&D) expenses are estimated to be $0.0096 per kWh in 2018.

Table L: Time-of-Use Energy Marginal Cost

Time-of-Use		Energy, Ancillary Service & RPS Cost	Generation Capacity	Trans & Dist	Residual Distribution Facilities	Public Good	Total Energy Marginal Cost
Rates Time Of Use	Summer Peak	$0.0713	$0.0680	$0.0689	$0.0371	$0.0096	$0.2548
	Summer Mid-Peak	$0.0580	$0.0253	$0.0248	$0.0270	$0.0096	$0.1447
	Summer Off-Peak	$0.0484	$0.0126	$0.0102	$0.0239	$0.0096	$0.1048
	Winter Peak	$0.0612	$0.0096	$0.0000	$0.0398	$0.0096	$0.1202
	Winter Off-Peak	$0.0491	$0.0013	$0.0000	$0.0271	$0.0096	$0.0872

The proposed time-of-use energy rate is completed by setting proposed rate revenues equal to rate revenues for the budget year. The reconciliation of marginal costs to rate revenues is accomplished through increasing final marginal cost energy charges by a scalar of 9.2%.

Table M: Proposed Energy Charge

Time-of-Use		Total Energy Marginal Cost	Scalar 9.2%	2017 Energy Charges
Rates Time Of Use	Summer Peak	$0.2548	$0.0235	$0.2783
	Summer Mid-Peak	$0.1447	$0.0133	$0.1580
	Summer Off-Peak	$0.1048	$0.0097	$0.1145
	Winter Peak	$0.1202	$0.0111	$0.1313
	Winter Off-Peak	$0.0872	$0.0080	$0.0952

Revenue Requirement, Forecasted Residential Loadshapes for Budget Period 2018 and 2019

The marginal price signals in this study were developed using the historical 2013 average residential load shape, a year displaying historically typical weather characteristics for SMUD service area. As evidenced in SMUD's SPO study, introducing residential customers to time-of-use pricing as the standard for the forecast period is anticipated to result in the shifting of load from high price peak and mid-peak periods to lower price periods. Time-of-use rates developed using marginal cost pricing and the current typical average residential load shape (before load shifting), is anticipated to reduce the average rate charged for energy from 11.92¢ per kWh on a seasonal flat rate to 11.88¢ per kWh resulting in an energy rate reduction of 0.35%. As a result, the final energy charges calculated previously are adjusted by scalar to achieve a rate neutral design over the 2018 and 2019 budget period as shown in Table N.

Table N: Proposed Energy Charge Adjusted for Anticipated Budget Year Loadshape

Time-of-Use		2017 Energy Charges	Scalar 0.35%	2018 Energy Charges w/o Rate Increase
Rates Time Of Use	Summer Peak	$0.2783	$0.0010	$0.2793
	Summer Mid-Peak	$0.1580	$0.0006	$0.1586
	Summer Off-Peak	$0.1145	$0.0004	$0.1149
	Winter Peak	$0.1313	$0.0005	$0.1318
	Winter Off-Peak	$0.0952	$0.0003	$0.0955

For the budget period, staff proposes a residential rate increase of 1.5% in 2018. Table N shows the rate increase applied to residential charges:

Table O: Proposed Residential Charges Adjusted for Rate Increase

Proposed Rate Increase		0%	1.5%
Season and Charge Components	**Unit**	**2018 Energy Charges w/o Rate Increase**	**2018 Proposed**
System Infrastructure Fixed Charge	per month	$ 20.00	$ 20.30
Summer Peak	per kWh	$ 0.2793	$ 0.2835
Summer Mid-Peak	per kWh	$ 0.1586	$ 0.1611
Summer Off-Peak	per kWh	$ 0.1149	$ 0.1166
Winter Peak	per kWh	$ 0.1318	$ 0.1338
Winter Off-Peak	per kWh	$ 0.0955	$ 0.0969

Figure 4 below shows the margin cost decomposition of the proposed rates: