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Memorandum

To: City of Riverside Public Utilities

From: NewGen Strategies and Solutions, LLC

Date: February 8, 2022

Re: Review of Riverside Public Utilities' Self-Generation Program

The City of Riverside (City) and Riverside Public Utilities (Utility) have retained NewGen Strategies and Solutions, LLC (NewGen) to assist in a review of proposed changes to its Self-Generation Program (referred to as Net Energy Metering [NEM] by other utilities). The proposed Self-Generation Program includes characteristics that are similar to rates offered or being proposed by other large utilities in California in that they compensate new solar customers according to the time they generate and provide excess power to RPU's electric system. This excess power is proposed to be credited at RPU's avoided cost of energy, which will ensure greater equity across the RPU service territory.

NewGen was retained to perform the following tasks:

1. Review the proposed rate structure and billing method applicable under the Self-Generation Program and provide an opinion as to the overall proposal, the assumptions within, and the application of the billing methods.
2. Evaluate two alternative rate structures which could be applicable under the Self-Generation Program for all rate schedules and provide an opinion as to the practicality and assumptions associated with these alternatives.
3. Review the avoided cost of energy calculation for accuracy and thoroughness. Provide guidance and pros and cons regarding components that may be included or excluded from the calculation. Provide guidance on how the avoided cost of energy calculation can be periodically updated.
4. Verify the bill impacts of the proposed Self-Generation Program billing method versus the current net energy metering program and customers without solar for 3 examples within each of the residential, commercial flat, commercial demand, and industrial classes. For each example, include 2 installed solar capacity scenarios.
5. Survey 10 utilities in California including the 3 large California investor-owned utilities and 7 similar publicly owned utilities regarding current and future net energy metering programs. Additionally, survey 5 public utilities in states other than California that have successfully implemented new and progressive net energy metering programs. Compare the results of the survey with the RPU proposal.
6. Review and comment on the overall Self-Generation Program components. Include comparisons to the results of the survey.

7. Assist RPU staff with developing customer outreach and education including but not limited to materials explaining the program, presentations, and website development.

Task 1 – Review Rate Structure/Billing Method

For Task 1, NewGen provided a review of the rate structure and billing method applicable under the proposed Self-Generation Program. A review of the rate components for the excess generation payment, referred to as the Avoided Cost of Energy (ACOE), provided to customers in the Self-Generation Program is summarized in Task 3. RPU proposes several structural changes to its existing Net Metering Program to be incorporated into its proposed Self-Generation Program. These include changes to the timing for settlement for individual accounts, utilizing hourly bidirectional meter data as the basis for determining excess generation, and moving Self-Generation to a time of use (TOU) rate schedule. Other changes to the program include administrative, technical, and/or operational considerations, such as no longer requiring a Utility Solar Agreement, eliminating the requirement for customer to install a production meter on their Distributed Energy Resource (DER) system, and an increase in the allowable size of PV (photovoltaic) system. DER is a collective term for all distributed energy systems, however, the primary focus of RPU's proposed Self-Generation program is on distributed PV systems. These non-billing related program changes were not reviewed for this task; however, they appear to be reasonable changes based on feedback from existing NEM customers and appropriately designed to address those concerns.

RPU uses bidirectional meters that measure the electricity utilized by a customer to determine the bill for the month. When a customer's PV system is generating electricity, the customer's consumption of RPU provided electricity is reduced. When a customer generates more from its PV system than it purchases from RPU in an hour, the bi-direction meter measures the "excess" generation that is sent back to RPU from that customer. Currently, RPU determines the "net" electricity purchased by the customer over the month to determine the bill for its NEM customers. This allows current NEM customers to effectively "bank" excess generation in any hour during the month to apply to consumption during non-solar hours during that month. Excess generation produced by the customer can be "carried" over to the next month, and if applicable the account is settled at the end of the fiscal year (any excess generation is paid out at RPU's published renewable cost of energy rate).

RPU proposes to change its monthly billing process for its Self-Generation Program customers. RPU proposes to bill the customer for each hour the customer consumes energy and credit the customer for each hour (at the ACOE) the customer has excess generation. The customer's monthly bill will be the total of the hourly consumption times the applicable published tariff rate, less the total of the hourly excess generation reads times the applicable ACOE rate. In this manner, the customer will be compensated for excess electricity at the time it is generated, and the account is settled at the end of the month. Any excess credit will be applied to other elements of the customer bill, which may include services provided by RPU or the City for electricity, water, wastewater, and solid waste (garbage pickup). Additionally, because the Self-Generation customer will be on a TOU rate, this provides a more effective price signal for both consumption and excess generation at the customer level. This change in settlement methodology is a fair and equitable manner to address the timing of a customer's load and PV generation profile. Further, this proposed methodology reduces the subsidy to other non-PV customers caused by the current settlement approach which allows for excess generation to be applied to consumption during hours of low or non-solar production.

Figure 1 provides an illustrative example of an hourly load profile for a hypothetical residential customer with solar generation. As indicated, each hour represents the total energy utilized (each hour is measured in kW, which summed for all hours is kWh). For example, in hour 1 (which represents hour ending at 1:00 AM), the customer's load is at approximately 0.6 kW, and their solar generation is not producing any energy. When the solar system begins to generate electricity, the electricity is initially consumed by the customer. In this example, hour ending 7:00 AM, the solar electricity is displacing a very small amount of the customer's load. However, as the sun begins rising and the solar irradiance increases, the amount of the customer's load that is offset becomes greater. In this example, at 10:00 AM, the entirety of the customer's load is offset by solar generation. From 11:00 AM to 4:00 PM (Hour 16), the solar generation exceeds the customer's load, resulting in excess energy sent back to the utility (RPU). As the sun begins to set, the generation reduces, but the load increases as the customer begins to utilize more electricity in the evening hours. By 8:00 PM, the solar system is no longer generating electricity, and the customer is purchasing all its load from RPU.

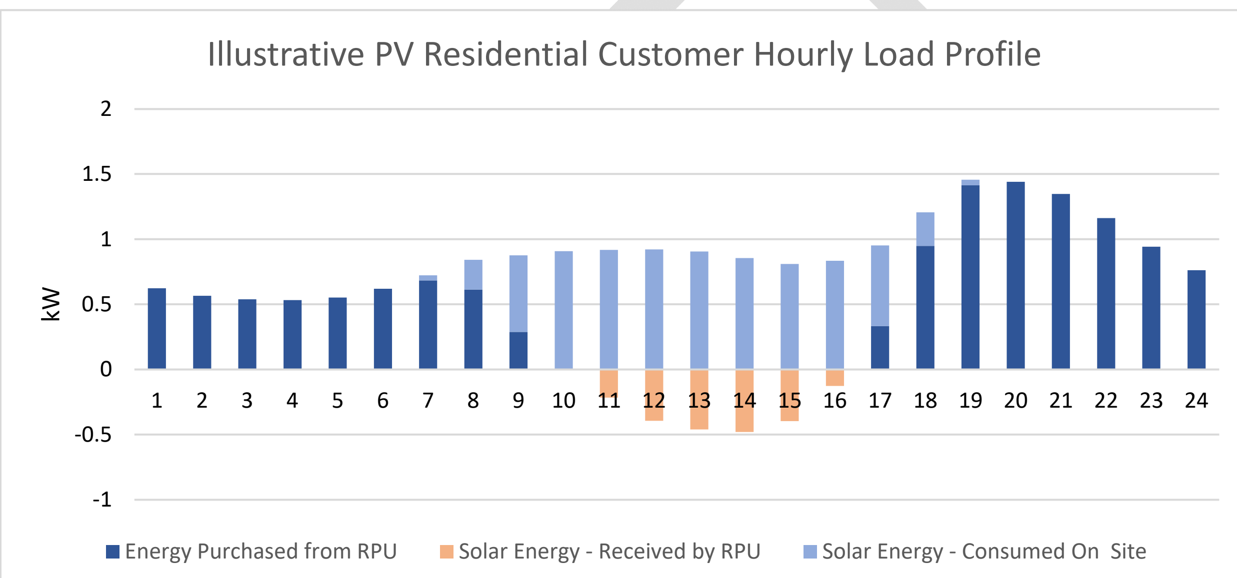

Figure 1. Illustrative PV Residential Customer Hourly Load Profile

The solar energy that is consumed on site reduces the amount of energy purchased from RPU and is effectively valued at the retail rate (under whichever applicable tariff the customer is being charged). This is shown in the light blue shaded bars in Figure 1. More importantly, this method will not change under the Self-Generation program. Under the current NEM program the Solar Energy – Received by RPU (the tan bars in Figure 1) is allowed to roll "forward" as an energy credit to offset or reduce the total energy purchased from RPU for the billing month, as indicated above. This means that the Solar Energy – Received by RPU is also effectively valued at the RPU retail rate. However, under the proposed Self-Generation program, the Solar Energy – Received by RPU will be valued at the ACOE rate, as described herein.

Currently, RPU allows for PV systems to be installed on a customer's premise after completion of NEM an interconnection agreement and extensive review by the City's permitting department. PV system installations are limited in size to part, or all, of the customer's own electrical requirements over the most recent twelve-month period on the premises or 1 megawatt (MW), whichever is less. The NEM program has no exceptions if a customer wishes to install a PV system that exceeds current capacity (size) limitations. One reason for the current capacity limitation is to reduce the subsidy provided to the customer in the billing process (as discussed).

The Self-Generation Program proposal includes a change in the allowed size limitation to 5 MW or 150% of the electrical requirements at the premise over the most recent twelve-month period. RPU is considering a limit on export capacity to be 1 MW of instantaneous energy supplied to the utility. RPU proposes to offer a variance program for increased PV system capacity under the Self-Generation program with proof from the customer of future electric requirements. The customer will be able to install a PV system within a reasonable size limitation and the PV system is intended to offset future electrical requirements at the premise. NewGen supports the revised approach proposed by RPU to allow for increased capacity at the customer premise.

As proposed, upon the effective date approved by the Board of Public Utilities and City Council, the Self-Generation program changes described herein would apply to customers installing new or updated PV systems, or to new customers who request service at a premise with an existing PV system. Any existing NEM customer who is eligible for Schedule NEM, shall remain on the Schedule NEM until either the Customer ceases to receive electric service at the premises where the PV system is located, increases the original PV system capacity by more than twenty-five percent (25%), or installs a new PV system, whichever is earlier. At that time, the customer would transition to the Self-Generation Program. RPU is not considering moving existing NEM customers to the proposed Self-Generation program. This approach is similar to how Anaheim is implementing its NEM 2.0 program with regard to its existing and future NEM customers.

Task 2 – Evaluate Two Alternative Rate Structures

NewGen reviewed two alternative rate structures in comparison to RPU's Self-Generation proposal. These included Anaheim Public Utilities' (Anaheim) NEM 2.0 offering and the proposed changes issued by the California Public Utilities Commission (CPUC) for the investor-owned utilities in the state. A description of the alternative rate program and a comparison to RPU's Self-Generation proposal on a representative month is provided below. A comparison of estimated bills (excluding any taxes, fees, or other charges) suggests that for a representative month (an average month of the year), the consumer would be expected to purchase approximately 750 kilowatt hours (kWh) during the month and have approximately 48 kWh of excess energy. This example assumes an hourly true-up methodology with a bidirectional meter, as proposed by RPU (see discussion below).

Anaheim Public Utility

Anaheim's NEM 2.0 customers may choose to be on Schedule D (Domestic Service) or the Developmental Schedule D-TOU-2 rate (Developmental Domestic TOU). NEM 2.0 customers are not allowed to bank excess energy (although excess credits can be carried forward). Anaheim's NEM 2.0 rates are published in their D-NEM tariff. NEM 2.0 customers are paid for excess energy at the Anaheim Annual Cash Compensation (ACC) rate which is multiplied by a time of delivery (TOD) factor (for D-TOU-2 customers). The components that make up the ACC rate include avoided energy charges, avoided transmission charges, and renewable energy adder. The TOD factor is a value dependent upon the period in which the renewable energy is supplied to the utility. Excess energy credits remaining at the end of a billing cycle are carried over to the succeeding bills until the end of the fiscal year. If energy credits remain at the end of the fiscal year, Anaheim pays the customer the value of the energy credits by check and has also proposed the option of rolling over the remaining credits (pending City Council approval on February 16, 2022).

CPUC Proposed NEM Reform/Net Billing Tariff

In December 2021, the CPUC issued its proposed decision for what has become known as its Net Billing Tariff (this is the third iteration of NEM reform in California). This includes several significant changes that impact future PV customers in the state, as well as existing PV customers over time.

The proposed CPUC Net Billing Tariff, if approved, will apply to the investor-owned utilities (IOUs) in the state, primarily Pacific Gas and Electric (PG&E), Southern California Edison (SCE), and San Diego Gas and Electric (SDG&E). However, the Net Billing Tariff will provide guidance for municipally owned utilities (MOUs) in the state as they approach the regulatory threshold that will allow them to enact NEM rate reform. At a high level, the Net Billing Tariff is based on an avoided cost concept that sets an average monthly value for each hour. These include generation capacity, energy, transmission, and distribution, as well as a component for ancillary services, greenhouse gas (GHG) value, GHG emissions, and high global warming potential (GWP) gas emissions. The energy component is based on energy future pricing reflected in the CAISO market. Generation capacity is based on estimates of battery storage costs. The transmission and distribution components are based on marginal cost filings by the three investor-owned utilities in the state. Ancillary services costs are defined as a percentage of energy costs. The collective environmental avoided costs are based on cap-and-trade pricing for GHG allowances, short-run marginal GHG emissions, and methane and refrigerant leakage modeling for GWP gasses.

One of the more contentious elements of the proposed Net Billing Tariff is a proposed Grid Participation Charge. This is proposed to be a fixed monthly charge based on the nameplate capacity (kW) of a residential customer's PV system. Non-residential customers already have fixed and demand charges in their rate structures and will not be required to pay the Grid Participation Charge. The proposed Grid Participation Charge as adopted is $8.00/kW per month for all residential PV customers served by the IOUs in the state. The CPUC has also developed a transition plan for existing customers that is designed to reduce the impact of the proposed changes in the Net Billing Tariff. This transition plan is to cover a 15-year period, by the end of which all existing NEM 1.0 and NEM 2.0 customers will have been moved to the Net Billing Tariff rate. The transition plan is a gradual adjustment over this period to reduce the "rate shock" or sudden financial impact to those customers that have already invested in DER systems from the changes included in the Net Billing Tariff.

Structural Comparison of RPU, Anaheim, and CPUC NEM Rate Changes

A comparison of the structure of the Self-Generation rate proposed by RPU, the Anaheim NEM 2.0 rate currently in effect, and the proposed CPUC Net Billing Tarff rate is provided in Table 1. It should be noted that Anaheim's on-peak period is from 4:00 to 9:00 PM, whereas RPU's on-peak period is from 2:00 PM to 7:00 PM, and slight differences exist between their off-peak periods (Anaheim does not offer a mid-peak period, but rather an on-peak and off-peak and super off-peak, which is only applicable during the winter season). Additionally, the IOUs regulated by CPUC have an on-peak period from 4:00 to 9:00 PM as well.

All three utilities have a TOU element that is applicable to their NEM customers, which is either a delivered energy charge or a generated energy credit. This approach is a reasonable method to reflect the value of energy based on the time of day when it is generated or consumed. The basis for the energy credit is determined from the utility's avoided cost. The CPUC proposal includes an extensive list of individual elements to its avoided cost calculation, whereas RPU proposes a more limited number of elements in its ACOE. However, Anaheim includes only three elements in its avoided cost calculation. Additionally, all three utilities include fixed cost recovery mechanisms in the existing or proposed rate structures. RPU currently has a Network Access Charge (NAC) and a Reliability Charge in its rate schedules, which would apply to all customers (including those in the Self-Generation program). Anaheim's current NEM 2.0 rate includes a Customer Service Charge (which appears to be the same as the Customer Service Charge it applies to non-NEM customers). The CPUC proposal includes a TOU Customer Service charge (which is the same as the current Customer Service Charge), as well as a fixed charge based on the size (capacity rating) of the PV system installed, as indicated above.

Table 1
Residential Billing Structure Comparison

	RPU Self-Generation	Anaheim NEM 2.0	CPUC Proposed for SCE*
Metering/ Billing	Bi-Directional (hourly)	Bi-Directional	Bi-Directional (hourly)
Delivered Energy Charge	TOU billed on delivered energy	TOU or Non-TOU billed on delivered energy	TOU billed on delivered energy
Generated Energy Credit	Credits on excess energy sent back to utility with time of day pricing	Credits on excess energy sent back to utility with time of day pricing	Credits on excess energy sent back to utility with time of day pricing
Basis for Energy Credit	Avoided Cost	Avoided Cost	Avoided Cost
Other Charges	Customer Charge, Reliability Charge, and Network Access Charge	Customer Service Charge	TOU Basic Charge, PV Charge ($8.00/kW for Installed Solar Capacity), Market Transition Credit for 4 years ending 2027

*CPUC NEM proposal issued in December 2021.

Task 3 – Review Avoided Cost of Energy Calculation – Overview

RPU's proposed Self-Generation program recommends several changes to its existing NEM program. These changes include a revised calculation of RPU's Avoided Cost of Energy (ACOE) which applies to excess energy generated by a Self-Generation customer, as well as changes to how RPU calculates the monthly credit and other elements. This section provides a review of the proposed changes to the calculation of the ACOE, which follows the concepts of the CPUC Distributed Energy Resource (DER) avoided cost tool.

The CPUC DER avoided cost tool proposes ten avoided cost components that may be recognized and valued when computing the implied value of DERs. RPU has accurately valued many of these avoided costs categories; however, not all the cost categories apply to RPU's operations. Several methodologies exist for valuing specific benefits from customer-owned DER related to generation energy, generation capacity, transmission costs, environmental/GHG (greenhouse gas) costs, Renewable Portfolio Standard costs, ancillary services, and system losses. However, RPU is currently unable to identify specific benefits from customer-owned DER for renewable integration, avoided societal cost, and avoided distribution system costs. The following provides a summary of RPU's proposed methodology to determine its ACOE based on an average of the three-year Study Period (2018, 2019, and 2020), and our findings and recommendations as appropriate.

Avoided Generation Energy Costs

RPU recognizes that each kWh of energy produced by a customer-owned DER represents one less kWh of energy that RPU must purchase from the market. Therefore, RPU proposes to utilize the 3-year historic average of the hourly locational marginal price (LMP) of energy at the Vista take-out point as the basis for the avoided generation energy cost. The Vista take-out point is the node at which RPU interfaces with the California Independent System Operator (CAISO).

Further, RPU proposes to utilize the day-ahead (DA) market prices at this location, given that it operates in the DA market for most hours in the year and implements a strategy to avoid making purchases within the Real Time (RT) market. Specifically, RPU indicated that it operated in the DA market approximately 97% of the time over the Study Period. RPU's proposal is to overlay the market pricing data with the hours of solar irradiance utilizing historic production data to derive a weighted average avoided generation energy cost for its calculation of the ACOE.

NewGen agrees with the proposed methodology to utilize the DA LMP prices at the Vista take-out point to determine the avoided generation energy costs for RPU's ACOE. Utilizing solar irradiance data provided by the National Renewable Energy Laboratory (NREL) and available on its website, NewGen was able to independently estimate the avoided generation energy costs. While the source of the solar irradiance data was slightly different between NewGen and RPU, the resulting avoided generation energy costs were very similar (within $0.01/kWh).

NewGen conducted a review of the impacts of utilizing a combination of DA and RT market energy price data (97% and 3%, respectively) for the Study Period and determined there was an insignificant impact to the overall calculation of the avoided generation energy costs from the influence of the RT market prices. NewGen compared the RT and DA prices for the historic period of 2019–2020 and found that including RT prices with a 3% weighting insignificantly impacted the weighted average market price.

Further, based on our experience with other wholesale power markets, NewGen reviewed the potential impacts to the DA and the ACOE resulting from excluding market energy costs during periods of emergency declarations by the CAISO, as provided in the AWE Grid History Report (dated 9/15/2021, provided by RPU). Specifically, NewGen reviewed the impacts of the increases in hourly market prices coincident with solar irradiance (from NREL) for Stage 1, 2, or 3 Emergencies, or Transmission Emergencies, as defined by CAISO, which occurred during the Study Period.

Table 2 provides a summary of emergency events that have occurred since 2018 that were included in our analysis of market prices. It should be noted that the AWE Grid History report includes events referred to as "Flex Alerts," "Restricted Maintenance Operations," "Alerts" and "Warnings," and "1-Hour Probable Load Interruptions," all of which were excluded from our analysis for this Study.

Table 2
CAISO Grid History Report Summary (2018–2021) Events Included in this Study

	2018	2019	2020	2021	Total
Transmission Emergency	2	3	2	0	7
Stage 1 Emergency	0	0	0	0	0
Stage 2 Emergency	0	0	6	1	7
Stage 3 Emergency	0	0	2	0	2

Table 3 shows the remaining types of events and the average market price for energy during those periods. As indicated, the majority of the price increase during these emergency declarations occurred during the system peak hours, during which time the solar irradiance is either low or zero (depending on the hour and the time of year). NewGen calculated the impact from these emergency declarations for the avoided generation energy costs to be approximately $0.0011/kWh over the Study Period.

Table 3
Average Market Prices during CAISO Events ($/MWh)

Emergency Type	2018	2019	2020	2021
Transmission Emergency	$67.20	$53.77	$41.95	N/A
Stage 1 Emergency	N/A	N/A	N/A	N/A
Stage 2 Emergency	N/A	N/A	$728.38	$177.32
Stage 3 Emergency	N/A	N/A	$889.84	N/A
All Other Hours	$41.05	$38.24	$32.70	$47.34

Figure 2 provides a graphic representation of the average market energy prices (LMP) at the Vista take out point for the DA market for a selected period during September 2020. During this period the CAISO called two Stage 3 Emergencies, which resulted in energy prices that exceeded $800/MWh at those times.

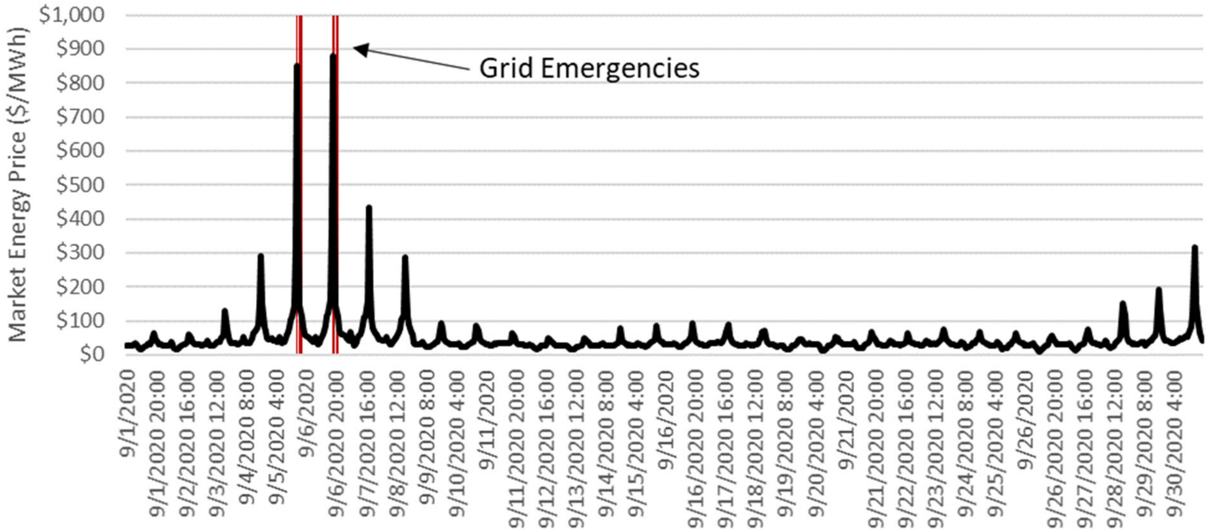

Figure 2. Average Market Prices for CAISO during Grid Emergencies in September 2020 ($/MWh)

NewGen recommends RPU consider including language in its proposed ACOE calculations to potentially exclude market pricing data from the calculation of its avoided generation energy costs during periods of emergency declarations by the CAISO. NewGen did not review local solar generation data coincident with the hours of emergency declaration to determine if the cause of the emergency impacted the ability of the DER to produce energy. Potentially, if the cause of the emergency declaration was related to an exogenous event (e.g., wildfires) or a meteorological phenomenon that could reduce solar production, RPU may want to consider excluding those hours from the calculation of its avoided generation energy costs.

Avoided Generation Capacity Costs

If a customer-sited DER generates energy during peak load, the resulting decrease during the peak period can result in savings in RPU's system Resource Adequacy (RA) costs. The impact to RPU's system RA costs form the basis for its proposed avoided generation capacity costs. In addition to its system RA cost, RPU proposes to include the impact from DER on its local RA requirement. The system and local RA costs are defined on a monthly capacity basis ($ per kilowatt [kw]) which is applied to the capacity rating of the total installed DER at the time of RPU's system peak averaged over a three-year historic period. The value for this reduction is estimated as the ratio of RPU's share of the Transmission Access Charge (TAC) related peak demand to RPU's status quo share of the TAC related peak multiplied by the marginal local RA value (provided by staff).

NewGen agrees with the proposed methodology to include both the system and local RA requirements at the time of the RPU system peak in the calculation of the avoided generation capacity costs applicable to DER. NewGen was able to replicate the avoided generation capacity costs developed by RPU using the RA cost data, system peak hours, and the capacity credit applied to the collective DER.

Avoided Ancillary Services Costs

RPU reviewed the ancillary service benefits associated with the installed DERs within its service territory. In general, RPU receives minimal ancillary service revenues from the CAISO for its internal generation assets and pays very minimal CAISO ancillary service uplift costs. However, RPU did find that the ancillary service uplift costs paid to the CAISO are impacted by the amount of energy it purchases, and therefore a reduction in overall load as a result of the DER did provide a benefit to the RPU system. Therefore, RPU proposes to include the historic savings in avoided ancillary services costs in its calculation of the ACOE.

NewGen reviewed the ancillary services calculation proposed by RPU for its ACOE and agrees with the methodology. Further, NewGen was able to reproduce the ancillary services portion of the ACOE rate with the data provided by RPU for the Study Period.

Avoided Transmission Costs

RPU pays a TAC to the CAISO based on the energy used to serve its load. Therefore, reductions in system load from customer-sited DER reduce RPU's transmission costs in direct proportion to the CAISO TAC rate. RPU proposes to use the monthly TAC rate applied to the total modeled DER energy production as the value to be assigned to the avoided transmission costs component of its ACOE.

NewGen agrees with the methodology proposed by RPU for the calculation of its avoided transmission costs in the calculation of its ACOE. Further, NewGen was able to replicate the avoided transmission costs based on the monthly TAC rate and estimated monthly generation of the DER installed in the RPU service territory for the Study Period.

Avoided Distribution Costs

RPU does not propose to include an avoided distribution cost component in its ACOE at this time. Impacts to the distribution system from customer-sited DER are specific to the local circuit where they exist. Because RPU does not dictate or encourage installation of DER based on the needs of its distribution system, it is difficult to determine if any incremental benefit or cost exists with the addition of customer-sited DER. It is the opinion of the RPU distribution engineering staff that as additional DERs impact specific circuits, RPU will most likely incur additional distribution upgrade costs, rather than realizing any cost savings as a result. Additionally, RPU indicates that it does not currently possess the ability to accurately quantify these potential costs on a systemwide basis. Therefore, RPU proposed to assign no value (either positive or negative) for avoided distribution in its ACOE.

NewGen agrees with the methodology proposed by RPU.

Avoided Environmental/GHG Costs

Under California's Cap-and-Trade program, RPU must tender its carbon emission credits to the California Air Resources Board (CARB) to offset its greenhouse gas emissions. RPU suggests that the zero emission DER energy "replaces" the non-zero emission system energy from its carbon producing resources. As a result, RPU would need to tender fewer carbon credits to CARB with the additional DER on its system. Therefore, RPU suggests that the value of the "avoided" carbon credits represents an additional avoided cost that can be directly attributed to the DER energy production. This argument assumes that

RPU would have met the extra (DER avoided) load serving needs using generation assets which have a carbon emission factor equal to or greater than that of its resource portfolio. RPU has based its calculation of the value of the avoided environmental/GHG costs on this assumption for the purposes of this component to its ACOE.

NewGen agrees with the methodology proposed by RPU for the purposes of determining the avoided environmental/GHG costs. NewGen reviewed RPU's calculations for this avoided component of the ACOE and was able to recreate the value from the data provided by RPU. It should be noted that over time, the carbon emission factor of RPU's resource portfolio will likely decrease as additional utility scale carbon-free resources are developed in the state and become a greater part of the CAISO market. Therefore, RPU may need to reevaluate the calculation of the avoided environmental/GHG costs over time to ensure that its assumptions for this calculation remain valid.

Avoided RPS Costs

Due to the California Renewable Portfolio Standard (RPS) legislative paradigm, RPU must acquire enough qualified renewable energy to meet specific percentages of its retail sales each year (for example, 33% in 2020). Therefore, as additional renewable DER comes online, RPU will need to acquire proportionally less wholesale renewable energy. The value of this "avoided" wholesale renewable energy represents another avoided cost that can be directly attributed to the DER energy production.

RPU proposes to utilize the market-based value of Renewable Energy Credits (RECs) as the proxy value for this avoided wholesale renewable energy. RPU suggests that REC values are equal to the value of the "green energy attributes," in comparison to non-renewable market power.

NewGen agrees with RPU's methodology proposed to determine its avoided RPS costs assigned to the ACOE. NewGen has reviewed RPU's calculations and REC pricing utilized to determine these avoided costs and was able to recreate the proposed value based on data provided by RPU for the Study Period.

Avoided Renewable Integration Costs

RPU indicates that it is currently unable to identify any avoided renewable integration costs associated with increasing DER penetration on its system. Therefore, RPU recommends that a zero value be assigned to this avoided cost component. Integration impacts from DER can be associated with distribution system impacts (as discussed above) as well as the broader impacts from management of the electrical system to integrate the solar output on the grid as a whole. NewGen reviewed a report developed by Synapse Energy Economics, Inc. (Synapse Study) which included a review of eight net metering studies regarding the benefit and costs of DER.[1] The Synapse Study indicated that "…costs associated with integration, administration, and interconnection of net energy metered (NEM) systems will increase revenue requirements, and thus are considered a cost." The eight studies reviewed by Synapse were from 2012–2014 and included analyses from NEM programs offered in Arizona, Colorado, Hawaii, Maine, Mississippi, Nevada, New Jersey, Pennsylvania, and North Carolina. The Synapse Study suggests that these individual state studies resulted in an average benefit that exceeded costs for the NEM programs reviewed. However, it also suggested that these studies revealed that integration costs do have an impact on

[1] "Caught in a Fix - The Problem with Fixed Charges for Electricity," Prepared for Consumers Union by Melissa Whited, Tim Woolf, Joseph Daniel with Synapse Energy Economics, Inc. February 9, 2016.

revenue requirement, which ranged from approximately $2/MWh to $23/MWh. Therefore, based on our experience and the Synapse Study, we agree with RPU's approach to not assign a benefit or value to the DER integration costs.

System Losses

System losses impact nearly all the applicable cost components in RPU's proposed ACOE, as energy from customer-sited DER energy flows directly into its secondary distribution system. System losses are a common element utilized when valuing DER. RPU proposes that the values associated with these cost components be adjusted (i.e., scaled up) in its avoided cost calculation to account for such losses.

NewGen agrees with RPU's methodology.

Avoided Societal Costs

Various state utility commissions across the country have assigned specific $/kWh values to avoided societal costs. It is generally recognized that this category of avoided costs represents a subsidy that is designed to further incentivize the installation of DERs (typically solar facilities) within a utility's service area. Many arguments against including collective societal costs in the avoided cost calculation are that they extend beyond the reach of the utility operations and are difficult to quantify. RPU is not proposing to include an avoided societal cost component to its ACOE as it violates cost-based rate setting principles.

NewGen agrees with RPU's proposal to exclude avoided societal costs in its avoided cost calculations.

TOU Structure

As indicated, RPU proposes to include a TOU structure to its ACOE rate to compensate Self-Generation customers for their excess generation if the customer is currently on a TOU rate structure. If applicable, the TOU structure is proposed to be seasonally adjusted for winter and summer periods. The TOU rates differences (the $/kWh difference between the TOU periods) are proposed to be identical to those for the Domestic TOU (DTOU) and Large General and Industrial TOU Service rate structures RPU has already adopted. The seasonal and time-based rates are designed to appropriately value the ACOE and encourage customers to provide excess energy when it is most valuable to RPU by sending a proper price signal (i.e., rate). A summary of the proposed seasonal TOU ACOE values is provided in Table 4.

Table 4
Domestic TOU Seasonal and TOU ACOE Rates Proposed ($/kWh)

Season	TOU	TOU Period*	Rate ($/kWh)
Summer (June–September)	On Peak	2:00 PM–7:00 PM	$0.1030
	Mid Peak	6:00 AM–2:00 PM; 7:00 PM–11:00 PM	$0.0689
	Off Peak	11:00 PM–6:00 AM	$0.0577
Winter (October–May)	On Peak	4:00 PM–9:00 PM	$0.0795
	Mid Peak	6:00 AM–4:00 PM; 9:00 PM–11:00 PM	$0.0636
	Off Peak	11:00 PM–6:00 AM	$0.0577

*TOU Periods apply every day.

A summary of the proposed seasonal TOU ACOE values for Large General and Industrial TOU rate customers is provided in Table 5.

Table 5
Large General and Industrial TOU Seasonal and TOU ACOE Rates Proposed ($/kWh)

Season	TOU	TOU Period*	Rate ($/kWh)
Summer (June–September)	On Peak	12:00 PM–6:00 PM	$0.0859
	Mid Peak	8:00 AM–12:00 PM; 6:00 PM–11:00 PM	$0.0705
	Off Peak	11:00 PM–8:00 AM	$0.0602
Winter (October–May)	On Peak	5:00 PM–9:00 PM	$0.0859
	Mid Peak	8:00 AM–5:00 PM	$0.0705
	Off Peak	9:00 PM–8:00 AM	$0.0602

*TOU on and mid peak periods apply weekdays except holidays.

Updates to the ACOE

As indicated, RPU proposes to utilize a three-year rolling average for its calculation of the ACOE. NewGen suggests that RPU conduct an annual update of its ACOE during the first six months of each calendar year that will review the market and utility data as appropriate from the prior year. This annual data will then be utilized to replace the previous earliest year in the three-year ACOE average (so data for 2021 would replace data for 2018 for the 2022 Effective ACOE rate). This six-month period will allow RPU sufficient time to evaluate market and system data to propose updates to its ACOE and to be approved for Self-Generation bills beginning July 1 of that year. This will allow RPU to adjust as necessary to address unforeseen issues, such as regulatory mandates as well as potential advancements in technology as appropriate.

Task 3 Summary

NewGen has reviewed the seven categories of avoided cost savings proposed by RPU to be included in its ACOE calculation. In general, we agree with the methodologies developed by RPU to determine these individual components to its ACOE. Further, NewGen was able to either replicate or produce similar results with independent analysis given data provided by RPU for each of the proposed ACOE components. A summary of these components based on the Study Period is provided in Table 6 for the NewGen and RPU calculated values.

Table 6
Comparison of RPU and NewGen ACOE by Component ($/kWh)

ACOE Component	RPU Value	NewGen Value
Avoided Generation Energy	$0.0289	$0.0278*
Avoided System and Local RA Capacity	$0.0100	$0.0104
Avoided Ancillary Costs	$0.0010	No Change
Avoided Transmission Costs	$0.0136	No Change
Avoided Environmental/GHG Costs	$0.0076	No Change
Avoided RPS Costs	$0.0072	No Change
System Losses (Applied to All)	5.40%	No Change
Proposed ACOE	$0.0722	

*Includes adjustments for market prices during CAISO grid emergency declarations.

Task 4 – Verify Bill Impacts

NewGen reviewed the bill impacts from the proposed changes to the Self-Generation program developed by RPU. NewGen utilized the data provided by RPU to recalculate the bill impacts for future Self-Generation program customers for two selected months for each customer class (Residential, Residential TOU, Commercial Flat, Commercial Demand, and Industrial TOU). The two selected months represented a summer (July) and non-summer (June) customer usage and estimated generation from hypothetical on-site solar facility. A total proposed electric bill was estimated under a condition of a customer without solar, under the existing NEM program, and under the proposed Self Generation program for each scenario. The rates included in RPU's analysis were consistent throughout the comparison and with RPU's applicable published rate tariffs. The RPU calculations for the total electric bill matched with our independent calculations with the provided data.

Table 7 shows the total electric bill for the month of July for selected RPU customer classes under the current NEM program (NEM 1.0) and the proposed Self-Generation program as calculated by RPU and NewGen. This analysis is for installed solar capacity that is 80%–90% of the customer's generation

(Scenario 1). The column on the far right provides a check for any differences in the calculation. For July, no differences were observed.

Table 7
Rate Impact Calculation Comparison – Scenario 1

Month	RPU		NewGen		
July	NEM 1.0	Self-Generation	NEM 1.0	Self-Generation	Check
Domestic	$53.42	$97.72	$53.42	$97.72	$-
Commercial					
Flat	$161.04	$174.37	$161.04	$174.37	$-
Demand	$850.50	$1,128.66	$850.50	$1,128.66	$-
Industrial TOU	$5,491.62	$6,487.39	$5,491.62	$6,487.39	$-

Table 8 shows a similar electric bill comparison as Table 7; however, this is for customers whose solar generation capacity is equal to 40%–50% of their monthly generation (Scenario 2) for the month of June for selected RPU customer classes under the current NEM program (NEM 1.0). For June, no differences were observed.

Table 8
Rate Impact Calculation Comparison – Scenario 2

Month	RPU		NewGen		
June	NEM 1.0	Self-Generation	NEM 1.0	Self-Generation	Check
Domestic	$118.44	$133.29	$118.44	$133.29	$-
Commercial					
Flat	$252.25	$255.78	$252.25	$255.78	$-
Demand	$1,656.09	$1,669.99	$1,656.09	$1,669.99	$-
Industrial TOU	$9,993.93	$10,018.20	$9,993.93	$10,018.20	$-

Task 5 – Utility Survey

NewGen surveyed 10 utilities in California including the 3 large California investor-owned utilities and 7 similar publicly owned utilities regarding current and future net energy metering programs. Additionally, we surveyed 5 public utilities in states other than California that have successfully implemented new and progressive net energy metering programs, and we compared the results of the survey with the RPU proposal.

California Publicly Owned Utilities – NEM Programs

Table 9 provides a summary of current NEM rates for "remaining credits" (excess energy) for 17 California municipal or publicly owned electric utilities. This table provides a description of the "true-up" period for the utility, which describes the period for which the utility will pay out any applicable excess energy credits. The majority (10 out of 17) utilize a monthly true-up period. We have included the remaining credits (excess energy price, which ranges from approximately $0.1078/kWh to $0.0175/kWh). We have also included the effective date of the utility's NEM rate, which indicates that approximately half of the utilities have revised or updated their NEM rate within the last two years (since 2019, 9 of the 17). The majority of the municipal utilities surveyed (11 of 17) utilized an avoided cost basis for their NEM credit.

Table 9
Review of Publicly Owned California Electric Utilities NEM Programs

	Utility	True-Up Period	TOU	Bidirectional	Remaining Credits Price $/kWh	Effective Date	Credit Type
1	Alameda	Monthly			$0.06968	12/31/2016	Avoided Cost
2	Anaheim	Monthly	x	x	=ACC rate *TOD factor	12/31/2020	Avoided Cost
3	Azusa	Yearly	x	x	$0.069	7/21/2021	Avoided Cost
4	Burbank	Yearly			$0.0455	7/1/2021	Retail Rate
6	LADWP	N/A			Retail Rate	9/1/2008	Retail Rate
7	Palo Alto	Monthly		x	$0.1078	1/1/2018	Retail Rate
8	Pasadena	Yearly	x		Avg. Energy	1/31/2020	Retail Rate
		Bimonthly	x		Avg. Energy + 0.066/kWh	1/31/2020	Retail Rate+
9	Redding	Monthly		x	$0.0608	1/1/2019	Avoided Cost
10	SMUD	Yearly			$0.0562	1/1/2021	Avoided Cost
11	Silicon Valley Power	Yearly	x		$0.0396	2/1/2021	Avoided Cost
12	Modesto Irrigation District	Monthly			$0.076	7/1/2020	Avoided Cost
13	Turlock Irrigation District	Monthly	x	x	Monthly Marginal Cost	1/1/2015	Avoided Cost
14	Lodi	Monthly		x	$0.0687	9/1/2017	Avoided Cost
15	Imperial Irrigation District	Yearly	x	x	$0.0698	1/1/2015	Avoided Cost
16	Shasta Lake	Monthly		x	$0.0175	11/1/2020	Avoided Cost
17	Roseville	Monthly		x	$0.0598	10/1/2018	Avoided Cost

Non-California Publicly Owned Utilities – NEM Programs

NewGen was tasked to survey and compare Non-California publicly owned utilities' NEM Programs. These utilities were selected based on comparable size to RPU and familiarity with their rate structures and NEM rate programs. The utilities selected were Orlando Utility Commission, FL; Lakeland Electric, FL; Jacksonville Electric Authority, FL; Nashville Electric Service, TN; and Fayetteville Public Works Commission, NC.

Orlando Utility Commission, FL:

OUC's net metering program pays their residential customers the retail rate for excess energy to OUC's grid. OUC true ups the outstanding energy credits yearly and they do not have TOU for residential customers. There are no current plans to change to TOU or bidirectional meters.

Lakeland Electric, FL:

Lakeland pays their residential customers the full retail rate for their excess energy. Lakeland's true up period for their credits is monthly. Net metering customers are moved to their Solar Price Plan. This plan places a demand charge during peak period (based on single highest energy usage during peak period over the billing period) and the energy rate is less than half of the normal energy rate. There is a transition for customers that interconnected before 1/1/2016. Grandfathered customers may stay on the original rate until 12/31/2025. Solar Price Plan Demand Charge is $6/kW and Energy Charge is $0.02427/kWh. Their residential rate has no demand charge but is tiered based on monthly usage (0–1000 kWh is $0.05085/kWh, 1001–1500 kWh is $0.05805/kWh, and above 1500 kWh is $0.06415/kWh). Lakeland has no mention of bidirectional meters in its published tariffs.

Jacksonville Electric Authority (JEA), FL:

JEA's program pays their residential customers an avoided cost of energy rate based on fuel costs. JEA true ups their outstanding credits yearly. JEA does not have TOU rates for residential customers. JEA also has bidirectional meters for their systems.

Nashville Electric Service, TN:

Nashville Electric Service customers can participate in the Dispersed Power Program to sell excess power back to Tennessee Valley Authority (TVA). TVA pays for the excess energy at TVA's avoided cost. TVA's avoided cost is based on TOU where Super Peak hours are 0600–0800 and 1700–1900; Peak hours are 0500–0600 and 0800–1100 and 1600–1700 and 1900–2200; Off-Peak hours are all weekends/holidays 0600-1100 and 1700-2200, and weekdays 1100–1600; and Super Off-Peak is weekends/holidays 0000–0600 and 1100–1700 and 2200–2400, and weekdays 0000–0500 and 2200–2400. Nashville's timing classifications are yearlong classifications.

Fayetteville Public Works Commission (FAYPWC), NC:

FAYPWC does not have a standard net metering program. Their program is based on a "buy all/sell all" structure where the residential customer buys all their energy demand from the utility at the residential retail rate and sells all the produced solar energy back to the utility at a Customer Credit rate. The retail residential rate includes a TOU structure with an on-peak rate of $0.1300/kWh and an off-peak rate of $0.08473/kWh. The Customer Credit rate for solar energy is $0.0663/kWh. FAYPWC's true up period is monthly. On-peak hours are Summer (April–October) 1500–1900, and Non-Summer (November–March) 0600–1000. Off-peak hours are all holidays and all other hours. The Customer Credit is set for the year initially, but the rate can be modified by changing one or more of the components within the year. The Customer Credit rate formula is as follows:

$$\frac{[(CP\ Demand\ Cost + Energy\ Cost + Transmission\ Cost\ (1 + System\ Loss\ Factor)] - Ancillary\ Credits}{Energy\ Consumption}$$

Tiered vs. TOU Rate Design for Self-Generation

RPU currently offers tiered rates as part of its standard rate offering for its residential (Domestic) and commercial rates. Currently, RPU proposes to offer its Self-Generation ACOE rate as a seasonally differentiated TOU rate (see above) for the Domestic TOU and Large General and Industrial TOU customer classes and a flat rate for customer classes that do not have a TOU rate structure. This rate is not proposed to follow a tiered rate structure, which would suggest differing rates for various levels of excess energy produced. Based on our experience, most avoided energy rates are not tiered because the methods used to calculate the rate are derived from annual or projected average rate components that are not defined by usage levels (not tiered). Of the 11 municipal or publicly owned utility rates revised in Table 9 that utilized an "avoided cost" approach, none of them were defined or structured to include tiered pricing.

Additionally, the proposed Net Billing Tariff does not propose a tiered structure for its avoided energy costs; however, it does include a TOU structure. A TOU structure for the avoided cost of energy, in general, is a more precise method to send a pricing signal reflecting when utility costs are incurred than a tiered method. Further, a tiered method of avoided cost may incentivize customers to add larger sized PV systems to their load (if it was an inclining block tier, where the more energy the customer sends back, the higher the unit rate ($/kWh)). This may be difficult to justify from a cost basis and NewGen supports RPU designing its ACOE rate based on a TOU instead of tiered rate structure.

Task 6 – Survey Comparison to RPU Proposed Changes

As indicated by the survey results presented in Task 5, changes to NEM programs are becoming more prevalent in California and other states. The purpose of this task is to provide a comparison of the recent and or proposed changes to NEM programs in California and other states to RPU's proposed Self-Generation program.

As indicated in Table 9, the majority of California publicly owned utilities surveyed utilize a monthly true-up period. However, it is not clear from the published tariffs if the utilities are using a "hourly settlement" period as proposed by RPU (discussed in Task 2). NewGen is familiar with other non-California utilities using an hourly settlement period based on bidirectional meter data. Further, it appears that the majority of the utilities surveyed utilize an energy-only or marginal energy rate to apply to excess energy provided by a NEM customer. Generally, those are energy rates that are lower than the full retail rate. From the data provided in Table 9, it appears that only Burbank and Los Angeles Department of Water and Power (LADWP) utilize a full retail rate for excess energy payments; however, it is not clear if the LADWP rate is based on its marginal pricing structure recently approved. As indicated, 11 of the 17 utilities surveyed utilize an avoided cost basis for their NEM credit, which is similar to the approach proposed by RPU's Self-Generation program.

The non-California utilities review suggests that most, but not all, have either reformed or set up their NEM programs to allow for an increase in fixed cost recovery for the utility. Most of those reviewed base their excess energy payments on their avoided costs, except for OPUC and Lakeland. However, Lakeland has implemented efforts to recover fixed cost through a monthly fee based on the capacity of the customer's solar facility (similar to what was recently proposed by the CPUC). Nashville and FAYPWC both implemented TOU rate structures for their NEM customers based on their underlying cost structures.

Task 7 – Public Outreach Material Review

NewGen was provided a draft of a marketing outreach material (brochure) developed by the RPU Communications group for review on November 4. NewGen provided written comments to RPU on November 15 via email and reviewed comments with RPU's working group on November 18, 2021. We understand these comments were provided to the RPU Communications group for inclusion in a revised draft of the outreach material. As additional material is developed, NewGen will provide review and comment as requested.