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NET-ENERGY METERING 2.0 LOOKBACK STUDY

Submitted to:
California Public Utilities Commission
Energy Division

With assistance from:
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GLOSSARY

Abbreviations and Acronyms

Acronym	Description
AB	Assembly Bill
ACS	American Community Survey
BTM	Behind the Meter
CARE	California Alternate Rates for Energy
CCA	Community Choice Aggregator
CHP	Combined Heat and Power
CoS	Cost of Service
CPUC	California Public Utilities Commission
CSI	California Solar Initiative
CZ	Climate Zone
DAC	Disadvantaged Community
DER	Distributed Energy Resource
DWR	Department of Water Resources
E3	Energy + Environmental Economics
ED	Energy Division
EPMC(D)	Equal Percentage Marginal Costs for Distribution
EPMC(G)	Equal Percentage Marginal Costs for Generation
FERA	Family Electric Rate Assistance
GRC	General Rate Case
IOU	Investor Owned Utility
IRR	Internal Rate of Return
ITC	Investment Tax Credit
LBNL	Lawrence Berkeley National Laboratory
LCOE	Levelized Cost of Energy
MCC	Marginal Customer Cost
MDCC	Marginal Distribution Capacity Cost
MEC	Marginal Energy Cost
MGCC	Marginal Generation Capacity Cost
MIRR	Modified Internal Rate of Return
MTCC	Marginal Transmission Capacity Cost
NEM	Net Energy Metering
NEMC	Net Energy Metering Cost
NGOM	Net Generator Output Meter
NREL	National Renewable Energy Laboratory
NSRDB	National Solar Radiation Database
OEHHA	California Office of Environmental Health Hazard Assessment
PA	Program Administrator
PCIA	Power Charge Indifference Adjustment
PCT	Participant Cost Test

Acronym	Description
PG&E	Pacific Gas and Electric Company
PTO	Permission to Operate
PV	Photovoltaic
RIM	Ratepayer Impact Measure
SB	Senate Bill
SCE	Southern California Edison Company
SDG&E	San Diego Gas & Electric Company
SGIP	Self-Generation Incentive Program
SOMAH	Solar on Multifamily Affordable Housing
SPM	Standard Practice Manual
TMY	Typical Meteorological Year
TOU	Time of Use
TRC	Total Resource Cost

Key Terms

Key Term	Definition
Biogas / Renewable Natural Gas	Methane that is derived from landfills, anaerobic digestion or other means and is used to fuel NEM generators.
CalEnviroScreen 3.0	CalEnviroScreen is a screening tool that evaluates the burden of pollution from multiple sources in communities while accounting for potential vulnerability to the adverse effects of pollution.
Census Tract	A census tract is a geographic region defined for the purpose of taking a census.
Combined Heat and Power	A capability of combustion engines, turbines, and fuel cells where useful waste heat is recovered and used to service on-site thermal loads.
Community Choice Aggregation	Community Choice Aggregation was created in California by Assembly Bill 117, which authorized local governments to aggregate customer electric load and purchase electricity for customers.
Consumption	Consumption is the total amount of energy utilized by NEM customer. If the NEM system were not present, then consumption would equal utility energy delivered.
Cost of Service	An estimate of the utility cost of servicing a customer. Includes costs developed from the GRC Phase 2 for marginal energy, generation, distribution, and customer costs. Regulatory, transmission, and costs unique to NEM 2.0 customers are added to the GRC costs.
Cost-Effectiveness	Cost-effectiveness in the context of this report is used to describe the test defined in the CPUC Standard Practice Manual.
Disadvantaged Community	Disadvantaged communities refers to the areas throughout California which most suffer from a combination of economic, health, and environmental burdens.
Energy Storage Charge	The amount of energy going into an energy storage device to increase the state of charge.
Energy Storage Discharge	The amount of energy leaving the energy storage system and decreasing the state of charge.
Equal Percentage Marginal Costs	Multipliers used to adjust the utility marginal cost components such that the revenue that results from these components equals the utility's revenue requirements.
Fuel Cell	A fuel cell is a type of generator that uses an electrochemical process to convert fuel (typically natural gas or renewable natural gas) into electricity. A fuel cell may also generate useful waste heat and used in combined heat and power mode.
Grandfathering / Grandfathered	Grandfathering, in the context of this report, is used to describe policies that allow a customer or a utility to maintain a specific rate in place during a transition period. For example, NEM 2.0 customers are allowed to stay on discontinued rates that may not be available to new customers for a period of time until they are required to transition to new rates.
Marginal Customer Cost	The incremental cost associated with adding a customer to the electric grid. These costs include, but are not limited to transformer, meters, administrative, and billing costs.
Marginal Distribution Capacity Cost	The incremental cost to service load growth on the distribution system.
Marginal Energy Cost	The cost for an incremental unit of energy.
Marginal Generation Capacity Cost	The cost for incremental energy generation.
Marginal Transmission Capacity Cost	The cost associated with projects that would be deferrable if there is lower incremental growth in transmission capacity requirements.

Key Term	Definition
NEM 1.0	The term NEM 1.0 is used to describe the NEM program in place prior to AB 327, which directed each large investor-owned utility to switch over to the current NEM program.
NEM 2.0	The term NEM 2.0 is used to describe the current NEM program. The current NEM program was adopted by the CPUC in Decision (D.) 16-01-044 on January 28, 2016 and is available to customers of PG&E, SCE and SDG&E. The current NEM program went into effect in SDG&E's service territory on June 29, 2016, in PG&E's service territory on December 15, 2016, and in SCE's service territory on July 1, 2017.
Net Energy Metering	Net Energy Metering (NEM) is a program that allows customers who install renewable generators to receive a financial credit on their electric bills for any surplus energy fed back to their utility.
Participant Cost Test	The Participant Cost Test is the measure of the quantifiable benefits and costs to the customer due to participation in the program.
Production / Generation	Production and generation are used to describe the energy that is produced from a NEM-eligible renewable generator. Production can be consumed on-site or exported back to the grid.
Program Administrator Test	The Program Administrator test measures the net costs of a program as a resource option based on the costs incurred by the Program Administrator (including incentive costs) and excluding any net costs incurred by the participants.
PV_LIB	The PV_LIB Toolbox provides a set of well-documented functions for simulating the performance of photovoltaic energy systems.
Ratepayer Impact Measure Test	The Ratepayer Impact Measure test measures what happens to customer bills or rates due to changes in utility revenues and operating costs caused by the program.
Standard Practice Manual	The Standard Practice Manual contains the Commission's method of evaluating energy saving investments using various cost-effectiveness tests.
Total Resource Cost Test	The Total Resource Cost Test measures the net costs of a program as a resource option based on the total costs of the program, including both the participant's and the utility's costs.
Utility Energy Delivered	Utility energy delivered is the amount of energy delivered by the utility to a customer.
Utility Energy Received / Export	Utility energy received and export are used to describe the energy that is exported from a NEM customer premise to the grid.
Wind Turbine	A wind turbine is a type of generator that converts the wind's kinetic energy into electrical energy.

1 EXECUTIVE SUMMARY

California's Net Energy Metering (NEM) policies, beginning in 1995 with the original NEM tariff or "NEM 1.0," have encouraged the adoption of customer-sited renewable resources like solar photovoltaic (PV) systems, fuel cells, and distributed wind turbines.[1] NEM tariffs incentivize the installation of customer-sited renewable resources by compensating NEM customers for energy that is produced and exported to the grid during times when it is not serving onsite load. This report contains the results of an evaluation of the current NEM tariff ("NEM 2.0"). Overall, we found that NEM 2.0 participants benefit from the structure, while ratepayers see increased rates.

1.1 NEM OVERVIEW AND HISTORY

California's NEM policies are one of a handful of tools available to the California Public Utilities Commission (CPUC) to encourage the adoption of customer-sited renewable resources. California Senate Bill (SB) 656 (Alquist, 1995) required every electric utility in the state, including privately owned or publicly owned utilities, municipally owned utilities, and electrical cooperatives that offer residential electrical service, whether or not the entity is subject to the jurisdiction of the CPUC, to develop a standard contract or tariff providing for net energy metering. SB 656 allowed NEM customers to be compensated for the electricity generated by an eligible customer-sited renewable resource and fed back to the utility over an entire billing period. SB 656 required California utilities to make this NEM tariff available to eligible customers on a first-come, first-served basis until the time that the total rated generating capacity in each utility's service area equaled 0.1 percent of the utility's peak electricity demand forecast for 1996.[2]

Since SB 656 in 1996, California's NEM policies have undergone several changes. Assembly Bill (AB) 1755 (Keeley, Olberg, and Takasugi, 1998) required utilities to provide a standard NEM contract for all eligible NEM customer generators and expanded the list of NEM-eligible technologies to include small wind.[3] Several other bills such as SB 1 (Murray, 2006)[4] expanded the NEM cap for Pacific Gas and Electric Company (PG&E), Southern California Edison Company (SCE), and San Diego Gas and Electric Company

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1 Customer-sited renewable resources are sometimes referred to as behind-the-meter (BTM) resources or simply rooftop solar.

2 California Senate Bill 656, Alquist. February 22, 1995. http://www.leginfo.ca.gov/pub/95-96/bill/sen/sb_0651-0700/sb_656_bill_950804_chaptered.html

3 California Assembly Bill 1755, Keeley, Olberg, and Takasugi. February 4, 1998. http://www.leginfo.ca.gov/pub/97-98/bill/asm/ab_1751-1800/ab_1755_bill_19980925_chaptered.html

4 California Senate Bill 1, Murray. August 21, 2006. https://leginfo.legislature.ca.gov/faces/billNavClient.xhtml?bill_id=200520060SB1

(SDG&E) beyond the initial value of 0.1 percent of the 1996 peak electricity demand forecast, and modified the maximum allowable customer-sited renewable resource system size.

Passage of AB 327 in 2013 (Perea, 2013), among other things, directed the CPUC to develop a new standard contract for NEM generation that the three large CPUC-jurisdictional investor-owned electric utilities (IOU) (i.e., PG&E, SCE, and SDG&E) must offer after reaching their NEM caps.[5] The NEM 2.0 program went into effect in SDG&E's service territory on June 29, 2016, in PG&E's service territory on December 15, 2016, and in SCE's service territory on July 1, 2017. The program provides customer-generators full retail rate credits (minus non-bypassable charges) for energy exported to the grid and requires them to pay charges intended to align NEM customer costs more closely with non-NEM customer costs. Customer-generators taking service under NEM 2.0 must pay a one-time interconnection fee, pay non-bypassable charges, and transfer to a time-of-use (TOU) rate.

1.2 STUDY OBJECTIVES

At the request of the CPUC, Verdant Associates; Energy and Environmental Economics, Inc.; and Itron Inc. conducted an evaluation to review PG&E's, SCE's, and SDG&E's NEM 2.0 tariffs. This study ("the NEM 2.0 Lookback Study") includes a cost-effectiveness analysis consistent with the CPUC's Standard Practice Manual (SPM) and CPUC Decision (D.) 19-05-019, which guides cost-effectiveness evaluation of customer-sited renewable energy resources. The SPM contains the CPUC's method of evaluating distributed energy resource investments using various cost-effectiveness tests. The four tests described in the SPM assess the costs and benefits of NEM 2.0 from different stakeholder perspectives: the total resource cost (TRC) test, the participant cost test (PCT), the program administrator (PA) test, and the ratepayer impact measure (RIM) test.

The evaluation also includes a cost of service analysis to compare the cost to serve NEM 2.0 customers against their total bill payments. The objectives of the evaluation are to examine the impacts of NEM 2.0 and to compare how different metrics have changed following the transition from NEM 1.0 to NEM 2.0.

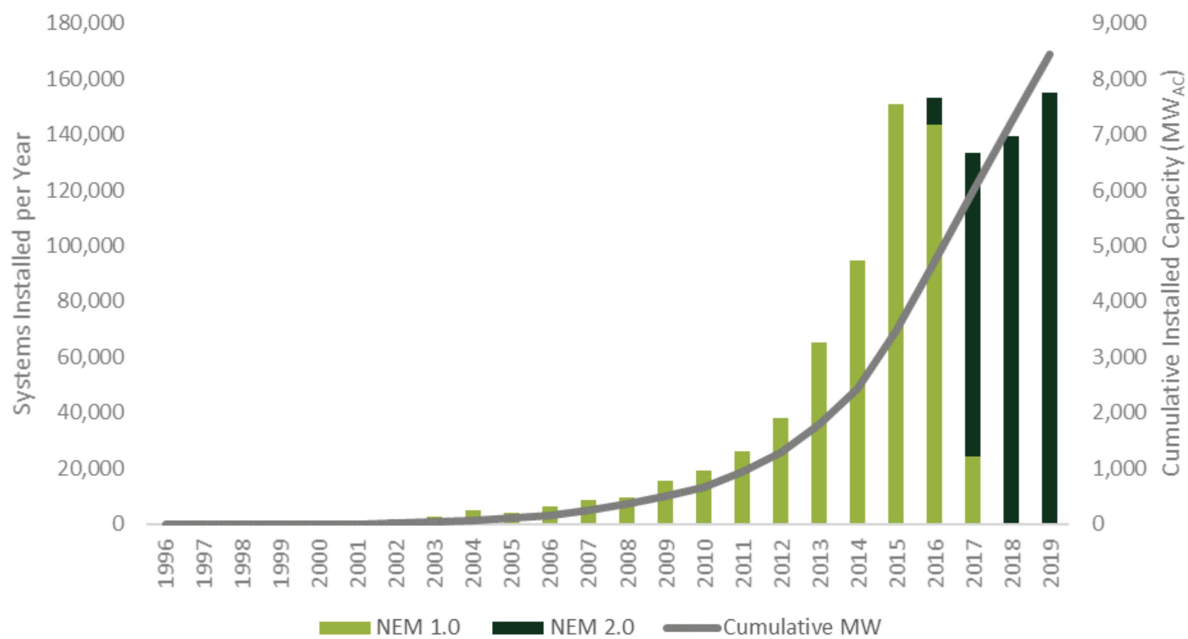
1.3 NEM POPULATION OVERVIEW

By the end of 2019, California customers had interconnected more than one million NEM generators onto the three large electric IOU systems representing nearly 8.5 gigawatts (GW_{AC}) of capacity. Figure 1-1 shows the growth in NEM 1.0 (defined as any interconnection prior to the current NEM tariff) and 2.0 projects over time. The number of NEM 1.0 interconnections peaked in 2015 and the last NEM 1.0 system received

5 CPUC Decision Adopting Successor to Net Energy Metering Tariff. Filed February 5, 2016. https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M158/K181/158181678.pdf

permission to operate during 2017. By the end of 2019, there were 616,308 NEM 1.0 systems and 413,982 NEM 2.0 systems interconnected on the grid.

FIGURE 1-1: INSTALLED NEM SYSTEMS BY NEM 1.0 / 2.0 TARIFF OVER TIME



1.3.1 System Size and Consumption

We compared the estimated electricity output from NEM PV systems to the customer electricity consumption. Table 1-1 presents the average annual load statistics for NEM 2.0 and NEM 1.0 residential customers. NEM 2.0 residential annual average energy consumption ranged from 7,824 kWh for SDG&E customers to 10,513 kWh for SCE customers. These consumption amounts are slightly higher than the normalized average annual consumption by all single-family customers of 7,701 kWh for PG&E, 7,450 kWh for SCE, and 7,453 kWh for SDG&E. Average NEM 2.0 generation accounted for 89 (PG&E) and 96 (SDG&E) percent of residential customer post-interconnection consumption.

TABLE 1-1: RESIDENTIAL AVERAGE ANNUAL LOAD STATISTICS

Customer Type	Metric	PG&E Residential	SCE Residential	SDG&E Residential
NEM 2.0	Avg. Pre-Interconnection Electricity Consumption (kWh)	8,425	10,513	7,824
	Avg. Post-Interconnection Net Consumption (kWh)	1,249		416
	Change in consumption after interconnection (kWh)	2,520	N/A	2,252
	Avg. Post-Interconnection Electricity Consumption[6] (kWh)	10,945		10,076
	Avg. System Size (kW_{DC})	5.9	6.9	5.6
	Avg. PV Annual Generation[7] (kWh)	9,696		9,661
	% Pre-Interconnection Consumption Supplied by PV	115%	N/A	123%
	% Post-Interconnection Consumption Supplied by PV	89%		96%
NEM 1.0 (CSI)	Avg. Post-Interconnection Electricity Consumption (kWh)	14,830	16,118	15,036
	Avg. System Size (kW_{DC})	5.3	5.9	5.9
	% Post-Interconnection Consumption Supplied by PV	63%	63%	69%
	Home Median Square Footage for CSI Customers (ft^2)	2,200	2,356	2,433
CA Statewide	Avg. Consumption for Single Family Residential Customers	7,701	7,450	7,453
	Home Avg. Square Footage for Single Family Residential Customers (ft^2)	1,859	1,877	2,018

1.4 NEM 2.0 COST-EFFECTIVENESS ANALYSIS RESULTS

Overall, our results show that the NEM 2.0 tariff is cost-effective to participants. However, NEM 2.0 projects overall are not cost-effective from the perspective of ratepayers.

6 Post installation consumption is the sum of net load from the utility meter plus generation. Generation is a mix of metered and simulated PV generation. The CSI/NEM 1.0 numbers reflect the sample of customers available for the CSI evaluation.

7 NEM 2.0 Generation is based on expected generation with the assumption that system sizes are AC and that DC (or nameplate) system sizes are 114 percent of AC system size and simulated performance in PVWatts using TMY weather and a 14 percent derate.

Verdant developed a model to quantify the cost-effectiveness of NEM 2.0 systems. The model calculates the bill impacts of technologies throughout their lifetime and the associated acquisition costs including financing, insurance, and tax costs (or credits). Looking from different perspectives, the model quantifies the changes in the utility's marginal operating costs and quantifies the present value of all cost and benefit streams for the entire life of the technology.

The cost-effectiveness model's primary purpose is to evaluate the cost-effectiveness of customer-sited resources under NEM 2.0 using the SPM tests including the TRC test, the PCT, the PA test, and the RIM test. Each test evaluates the tariff's cost-effectiveness from a different perspective, assessing the impact of the tariff on society, participants, program administrators, and ratepayers. The PCT is a measure of the quantifiable benefits and costs to the consumer due to participation in NEM 2.0. The TRC measures the net costs of NEM 2.0 as a resource option based on the total costs of the program, including both the participants' and the utility's costs. The RIM test measures what happens to customer bills or rates due to changes in utility and operating costs caused by the NEM 2.0 program. The PA test measures the net costs of NEM 2.0 as a resource option based on the costs incurred by the utility. Table 1-2 summarizes the cost-effectiveness of NEM 2.0 technologies by utility and technology type. A benefit-cost ratio greater than or equal to 1.0 indicates that the technology is cost-effective based on the SPM test.

TABLE 1-2: SUMMARY OF COST-EFFECTIVENESS RESULTS BY TECHNOLOGY TYPE AND UTILITY

Utility	Technology	Weighted Average Benefit-Cost Ratio			
		PCT	TRC	RIM	PA
PG&E	Solar PV	1.82	0.80	0.33	41.97
	Solar PV + Storage	1.52	0.74	0.38	28.52
	Wind	1.63	1.89	0.92	8,641
SCE	Solar PV	1.56	0.90	0.48	10.50
	Solar PV + Storage	1.39	0.95	0.56	17.63
	Fuel Cells	0.93	1.11	0.98	733.30
SDG&E	Solar PV	2.09	0.85	0.31	119.18
	Solar PV + Storage	1.55	0.78	0.39	439.77
	Fuel Cells	1.84	1.05	0.38	49,009
Total		1.77	0.84	0.37	22.98

Note that this study is a retrospective cost-effectiveness analysis. The study findings should not be interpreted as a sensitivity analysis except where explicitly mentioned. For instance, when comparing results for solar PV against solar PV + storage, note that these groups likely consist of a different underlying customer base.

Table 1-3 presents the cost-effectiveness results by utility and customer sector.

TABLE 1-3: SUMMARY OF COST-EFFECTIVENESS RESULTS BY CUSTOMER SECTOR AND UTILITY

Utility	Customer Sector	Weighted Average Benefit-Cost Ratio			
		PCT	TRC	RIM	PA
PG&E	Agriculture	1.72	1.19	0.41	590.70
	Commercial	1.79	1.12	0.37	437.07
	Industrial	1.47	1.17	0.51	6,128.90
	Residential	1.83	0.69	0.31	28.77
SCE	Agriculture	1.23	1.43	0.85	337.88
	Commercial	1.32	1.35	0.72	96.86
	Industrial	1.16	1.34	0.87	880.11
	Residential	1.62	0.80	0.43	8.20
SDG&E	Agriculture	1.51	1.25	0.53	821.47
	Commercial	1.87	1.18	0.37	1,344.24
	Industrial	1.57	1.21	0.49	16,696.43
	Residential	2.08	0.76	0.29	100.09
Total		1.77	0.84	0.37	22.98

Table 1-4 presents the middle 50 percent range for the SPM tests for the individual utilities and the statewide total.

TABLE 1-4: THE 25 PERCENT TO 75 PERCENT RANGE OF COST-EFFECTIVENESS RESULTS BY UTILITY

Utility	25% to 75% Range of Benefit-Cost Ratio			
	PCT	TRC	RIM	PA
PG&E	1.62 to 2.09	0.68 to 0.69	0.27 to 0.36	19.72 to 38.79
SCE	1.42 to 1.74	0.77 to 0.81	0.40 to 0.50	6.16 to 10.57
SDG&E	1.88 to 2.25	0.75 to 0.79	0.27 to 0.33	71.53 to 125.06
Total	1.61 to 2.09	0.69 to 0.78	0.28 to 0.41	11.06 to 45.77

1.4.1 Total Resource Cost (TRC) Test

The TRC test measures the net costs of NEM 2.0 as a resource option based on the total costs of the program, including both the participants' and the utility's costs. TRC benefits include utility avoided costs and potential federal tax benefits (not including the federal ITC). TRC costs include all expenditures associated with acquiring and installing the NEM system (i.e., upfront capital costs, financing costs, ongoing operations and maintenance costs, and insurance costs). If applicable, the federal ITC is treated as a reduction in the cost of the NEM system rather than a benefit. Utility costs associated with NEM (e.g., incremental metering, billing) are also a cost in the TRC test. Future cash flows are discounted at the utility discount rate.

The statewide NEM 2.0 population weighted average TRC benefit-cost ratio is 0.84 and the IOU-specific TRC ratios range from a low of 0.80 for PG&E to a high of 0.91 for SCE. At the aggregate utility level,we find that the NEM 2.0 tariff is not cost-effective based on the combined participant and utility perspective. The TRC benefit-cost ratio is consistently higher for solar PV systems when compared to solar PV + storage systems. This suggests that while energy storage systems can achieve higher avoided cost benefits, the incremental costs of energy storage are greater than the avoided cost benefits they currently provide. Future energy storage cost reductions would tend to improve the TRC for solar PV + storage systems.

1.4.2 Participant Cost Test (PCT)

The PCT is a measure of the quantifiable benefits and costs to the consumer due to participation in NEM 2.0. Participant test benefits include bill savings, state rebates (e.g., Self-Generation Incentive Program), and any tax refunds/credits that may apply. Participant costs are the capital, financing, and other expenditures associated with installing the NEM 2.0 system. The population weighted average participant benefit-cost ratio is 1.77, suggesting that the NEM 2.0 program is cost-effective for program participants. The participant test is primarily sensitive to the cost of the NEM system and the bill savings associated with operating the PV or PV + Storage system. The relationship between NEM system costs and the participant test benefit-cost ratio is intuitive – as the system cost increases the participant benefit-cost ratio decreases. Notably, the PCT benefit-cost ratio is consistently lower for Solar PV + Storage technologies when compared to standalone Solar PV systems. This suggests that the incremental bill savings opportunities available with energy storage (e.g., charging during off-peak periods and discharging during on-peak periods) are less than the incremental cost of energy storage. The participant benefit-cost ratio is also highest for residential customers; this is likely due to residential customers being able to achieve larger bill reductions than nonresidential customers. Most nonresidential NEM 2.0 customer rates have large fixed charges, minimum bills, and demand charges which tend to lower the potential for bill savings with solar PV.

1.4.3 Ratepayer Impact Measure (RIM) Test

The RIM test measures what happens to customer rates due to changes in utility operating revenues and costs caused by the NEM 2.0 program. The NEM 2.0 population weighted average RIM benefit-cost ratio is 0.37. Rates would increase for non-participating and NEM 2.0 customers if revenues collected under NEM 2.0 implementation (i.e., utility avoided costs) are less than the total costs incurred by the utility in implementing NEM 2.0 (i.e., reduced bill payments and program implementation costs). A RIM benefit-cost ratio less than 1.0 indicates the NEM 2.0 program will result in an increase in rates for all customers and an increase in bills for non-participating customers. The RIM benefit-cost ratio tends to increase as the participant benefit-cost ratio decreases. Bill savings for the participant equate to reduced revenue for the utility. Notably, solar PV + storage systems achieve a lower participant benefit-cost ratio and a higher RIM benefit-cost ratio. Put differently, solar + storage systems provide greater ratepayer benefits but reduced benefits to the participant. Avoided costs are higher, but customer economic effects (after accounting for storage acquisition costs) are less favorable.

1.4.4 Program Administrator (PA) Test

The PA test measures the net costs of a program as a resource option based on the costs incurred by the PA (including incentive costs) and excluding any net costs incurred by the participants. The PA test can apply to utilities or to third parties that may administer a program. NEM 2.0 tariffs are implemented by the three large California electric IOUs. The benefits in the PA test are the avoided costs due to the operation of a NEM 2.0 system. The costs are the utility's costs to operate the NEM 2.0 program (e.g., distribution upgrades, telemetry, and incremental billing costs). PA benefit-cost ratios are high across the board, suggesting that the total avoided cost benefits greatly outweigh the utility NEM implementation costs. The PA test results are highly sensitive to the assumptions made about utility upfront and ongoing NEM costs. Utilities that report the lowest NEM operating costs, like SDG&E, have the highest PA benefit-cost ratios.

1.4.5 Sensitivity to Federal Investment Tax Credit

The federal ITC is a reduction in cost for both the participant test and the TRC test. State incentive programs like the Self-Generation Incentive Program are cash transfers within California and therefore are excluded from the TRC. However, cash transfers from the federal government into California are included in the TRC.

In our model, the federal ITC is modeled at 30 percent of the cost of the solar or solar PV + storage system. We assume that all residential, commercial, agriculture, and industrial customers can take advantage of the 30 percent federal ITC. As of 2020 the ITC declined to 26 percent of system cost and is currently scheduled to be fully phased out by 2024 for residential customers. Given the potential ITC phaseout, there is merit in considering cost-effectiveness results that exclude the ITC. There is also value in considering cost-effectiveness from a federal TRC perspective, which would exclude the ITC as a cash transfer within the country. Cost-effectiveness results with and without the 30 percent federal ITC are summarized in Table 1-5.

NEM 2.0 is not cost-effective from a TRC perspective. Excluding the federal ITC reduces the solar and solar plus storage IOU specific TRC from 0.80 to 0.56 for PG&E, 0.91 to 0.65 for SCE, and from 0.84 to 0.59 for SDG&E. The RIM test and the PA test benefit-cost ratios (not shown) are unchanged since the ITC does not impact these tests. Removing the ITC also does not affect any of the cost of service results. The sector specific NEM 2.0 systems in SDG&E's and PG&E's territories still pass the PCT benefit-cost test when the ITC is eliminated. SCE's PCT benefit-cost ratios without the ITC do exceed one for the nonresidential sectors as SCE's nonresidential rates tend to have more fixed fees and demand charges than the other IOUs. SCE's TRC benefit-cost test values are higher than the other utilities as SCE has higher average avoided costs than those forecast for the two other IOU service territories.

TABLE 1-5: SUMMARY OF PCT AND TRC RESULTS BY CUSTOMER SECTOR AND IOU, WITH AND WITHOUT ITC

Utility	Customer Sector	With ITC		Without ITC	
		PCT	TRC	PCT	TRC
PG&E	Agriculture	1.72	1.19	1.32	0.78
	Commercial	1.79	1.12	1.39	0.73
	Industrial	1.47	1.14	1.07	0.74
	Residential	1.83	0.69	1.54	0.50
	All	1.81	0.80	1.49	0.56
SCE	Agriculture	1.23	1.43	0.83	0.96
	Commercial	1.32	1.35	0.92	0.90
	Industrial	1.21	1.40	0.81	0.93
	Residential	1.62	0.80	1.33	0.59
	All	1.55	0.91	1.24	0.56
SDG&E	Agriculture	1.51	1.25	1.11	0.83
	Commercial	1.87	1.18	1.47	0.78
	Industrial	1.53	1.23	1.14	0.81
	Residential	2.08	0.76	1.80	0.55
	All	2.03	0.84	1.72	0.59

1.5 NEM 2.0 COST OF SERVICE ANALYSIS RESULTS

The full cost of service analysis compares an estimate of the utility cost of servicing a NEM 2.0 customer for one year with an estimate of the customer's first year bills. The utility cost of servicing a NEM 2.0 customer is based on the customer's use of the grid and an allocation of the fixed costs of service. We used information from the utilities' General Rate Case (GRC) Phase 2 filings, regulatory costs, and NEM customer incremental costs to develop estimates of the cost of service for NEM 2.0 customers. The cost of service analysis finds that the prior to NEM 2.0 system installation, the average residential and nonresidential NEM 2.0 customer pays more in their utility bills than the estimated cost for the utility to provide them service. Post-installation, the average residential customer pays less in their utility bills than the utility's cost of service and the average nonresidential customer pays more in their bill than the estimated utility cost of service. Figure 1-2 shows the aggregate customer bills and cost of service estimates pre- and post-NEM installation for all nonresidential customers taking service under NEM 2.0. Figure 1-3 below illustrates the residential aggregate pre- and post-installation utility bill versus cost of service estimates.

FIGURE 1-2: NONRESIDENTIAL AGGREGATE FIRST YEAR BILL PAYMENT AND COST OF SERVICE PRE AND POST NEM 2.0

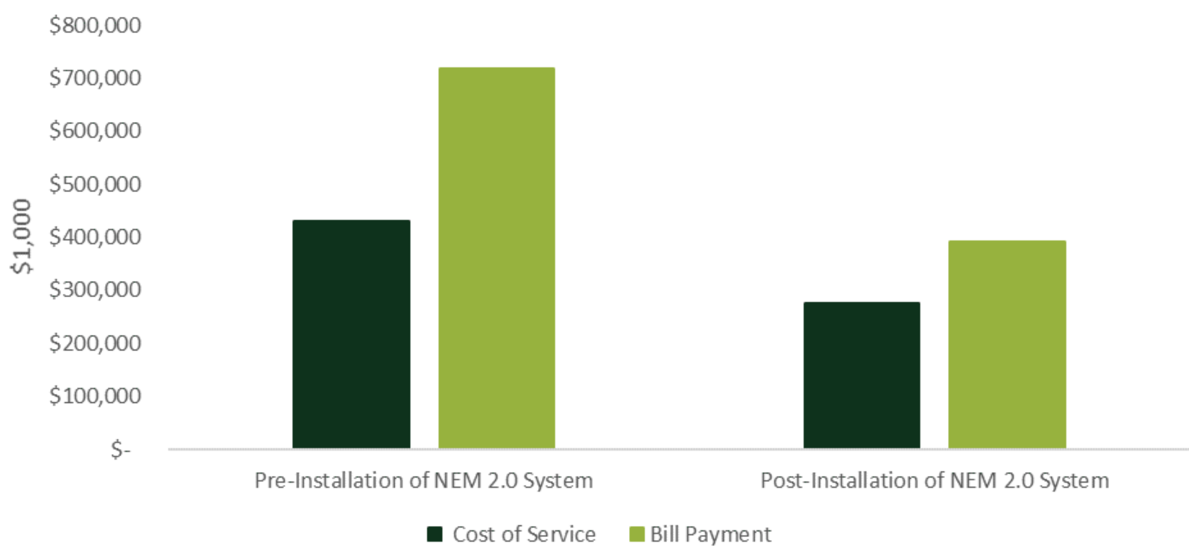
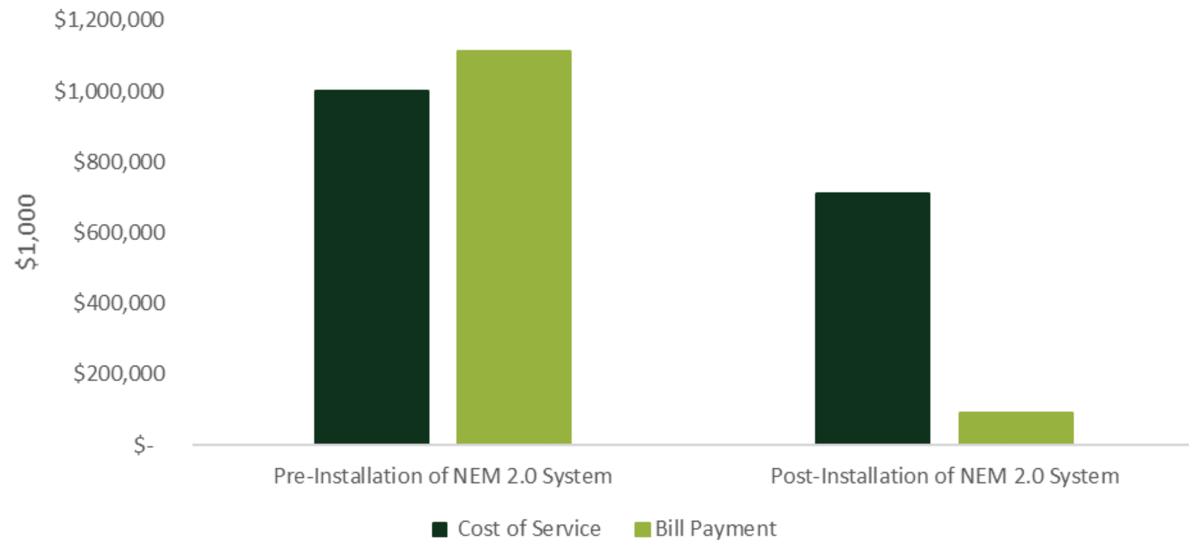


FIGURE 1-3: RESIDENTIAL AGGREGATE FIRST YEAR BILL PAYMENT AND COST OF SERVICE PRE AND POST NEM 2.0



Prior to the installation of the NEM-eligible generator, nonresidential customers that take service under a NEM 2.0 eligible tariff are estimated to pay higher bills than the cost of their utility service by $288 million. After the installation of the NEM generator, NEM 2.0 nonresidential customers pay approximately $117.5 million higher utility bills than the estimated cost for the utilities to provide them service.

Prior to the installation of the NEM eligible generator, residential NEM 2.0 customers pay approximately $112.5 million higher bills relative to the costs for the utility to provide them service. Following the installation of the NEM generator, these same customers are estimated to pay approximately $618.6 million less on their bills relative to the utilities' cost to provide service.

1.6 COSTS AND BENEFITS OF NEM 1.0 VERSUS NEM 2.0

Verdant did not perform any analysis to quantify the cost-effectiveness or cost of service impacts of NEM 1.0. We relied on the E3 2013 California Net Energy Metering Ratepayer Impact Evaluation for NEM 1.0 cost-effectiveness and cost of service results.[8] We re-created the NEM 1.0 RIM benefit-cost ratio using data from the E3 study. Table 1-6 compares the results from E3's NEM 1.0 analysis to the Verdant NEM 2.0 analysis. Overall, we find that the NEM 1.0 RIM benefit-cost ratio inferred from the E3 study is similar to the results calculated in this study for NEM 2.0 across utilities and customer sectors.

8 California Net Energy Metering Ratepayer Impacts Evaluation. Energy and Environmental Economics. October 28, 2013. https://www.cpuc.ca.gov/General.aspx?id=8919

TABLE 1-6: RIM BENEFIT-COST RATIO, COMPARISON OF NEM 1.0 TO NEM 2.0

Net Energy Metering Program	Sector	RIM Benefit-Cost Ratio		
		PG&E	SCE	SDG&E
NEM 1.0	Residential	0.35	0.47	0.41
	Nonresidential	0.61	0.88	0.62
	Total	0.45	0.50	0.46
NEM 2.0	Residential	0.31	0.43	0.29
	Nonresidential	0.39	0.76	0.39
	Total	0.33	0.49	0.31

Table 1-7 lists the pre- and post-installation ratio of customer bills to the utility cost of service from the NEM 1.0 analysis and from this study's analysis of NEM 2.0 customers. This comparison shows that under NEM 1.0 and NEM 2.0, customers who install NEM eligible systems pay utility bills that exceed their utility cost of service prior to NEM system installation. After the NEM system installation, the residential NEM 1.0 ratio of bill payment to cost of service is substantially higher than the post-installation ratio for NEM 2.0 residential customers. The large increase in PV system size relative to customer electricity consumption for NEM 2.0 customers compared to NEM 1.0 residential customers (see Table 1-1 above) has contributed to the substantially lower NEM 2.0 post-installation ratio. In contrast, the post-installation ratio of bill payment to utility cost of service for nonresidential customers is higher for NEM 2.0 than for NEM 1.0 customers. For nonresidential customers, rates include high fixed fees, minimum bills, and demand charges that work to limit the impact of PV systems on customer bills.

TABLE 1-7: RATIO OF BILL PAYMENT TO COST OF SERVICE, COMPARISON OF NEM 1.0 TO NEM 2.0

Net Energy Metering Program	Sector	Ratio of Bill Payment / Cost of Service					
		PG&E		SCE		SDG&E	
		Pre-NEM	Post-NEM	Pre-NEM	Post-NEM	Pre-NEM	Post-NEM
NEM 1.0	Residential	171%	88%	152%	86%	101%	54%
	Nonresidential	128%	106%	110%	105%	124%	122%
	Total	146%	99%	122%	100%	119%	111%
NEM 2.0	Residential	139%	18%	91%	9%	94%	9%
	Nonresidential	189%	152%	118%	108%	178%	166%
	Total	157%	60%	99%	34%	113%	46%

1.7 KEY TAKEAWAYS

We conducted an evaluation that quantified the cost-effectiveness and cost of service impacts of customer-sited renewable resources subject to NEM 2.0 rules. We found that in general, the benefits to customers (primarily bill savings and the federal ITC) outweigh the costs. NEM 2.0 systems are not generally cost-effective from a combined participant/utility perspective, as illustrated by a TRC benefit-cost ratio that is less than 1. We also find that the TRC benefit-cost ratio is highly sensitive to the inclusion of the federal ITC. Removing the ITC benefit from the TRC calculation results in the TRC benefit-cost ratio declining further below 1. On average, customer-sited renewables taking service under a NEM 2.0 tariff have a RIM benefit-cost ratio less than 1, indicating that the NEM 2.0 program may result in an increase in rates for ratepayers.

The cost of service analysis points to a similar conclusion. For both residential and nonresidential customers, we estimate that the average bill payments prior to installing a NEM 2.0 system are higher than the cost of service.Residential customers that install customer-sited renewable resources on average pay lower bills than the utility's cost to serve them. On the other hand, nonresidential customers pay bills that are slightly higher than their cost of service after installing customer-sited renewable resources. This is largely due to nonresidential customer rates having demand charges (and other fixed fees), and the lower ratio of PV system size to customer load when compared to residential customers.

2 INTRODUCTION AND OBJECTIVES

California's Net Energy Metering (NEM) policies, beginning in 1995 with the original NEM tariff or "NEM 1.0," have encouraged the adoption of customer-sited renewable resources like solar photovoltaic (PV) systems, fuel cells, and distributed wind. NEM tariffs incentivize the installation of customer-sited renewable resources by compensating NEM customers for energy that is produced and exported to the grid. In this section we provide an overview and brief history of California's NEM tariffs, we list the objectives of the study along with the key research questions, and we summarize the approach employed to address the research questions.

2.1 NEM OVERVIEW AND HISTORY

California's NEM policies are one of a handful of tools available to the California Public Utilities Commission (CPUC) to encourage the adoption of customer-sited renewable resources. California Senate Bill (SB) 656 (Alquist, 1995) required every electric utility in the state, whether or not the entity is subject to the jurisdiction of the CPUC, to develop a standard contract or tariff providing for NEM. SB 656 allowed NEM customers to be compensated for the electricity generated by an eligible customer-sited renewable resource and fed back to the utility over an entire billing period. SB 656 required California utilities to make this NEM tariff available to eligible customers on a first-come, first-served basis until the time that the total rated generating capacity in each utility's service area equaled 0.1 percent of the utility's peak electricity demand forecast for 1996.[9]

Since SB 656 in 1996, California's NEM policies have undergone several changes. Assembly Bill (AB) 1755 (Keeley, Olberg, and Takasugi, 1998) required utilities to provide a standard NEM contract for all eligible NEM customer-generators and expanded the list of NEM-eligible technologies to include small wind.[10] Several other bills such as SB 1 (Murray, 2006)[11] expanded the NEM cap for the three large CPUC-jurisdictional investor-owned utilities (IOU) beyond the initial value of 0.1 percent of the 1996 peak electricity demand forecast, and modified the maximum allowable customer-sited renewable generator system size.

9 California Senate Bill 656, Alquist. February 22, 1995. http://www.leginfo.ca.gov/pub/95-96/bill/sen/sb_0651-0700/sb_656_bill_950804_chaptered.html

10 California Assembly Bill 1755, Keeley, Olberg, and Takasugi. February 4, 1998. http://www.leginfo.ca.gov/pub/97-98/bill/asm/ab_1751-1800/ab_1755_bill_19980925_chaptered.html

11 California Senate Bill 1, Murray. August 21, 2006. https://leginfo.legislature.ca.gov/faces/billNavClient.xhtml?bill_id=200520060SB1

Growth in customer-sited renewable resources, driven by a combination of system cost reductions, state and federal incentives, and favorable NEM tariffs, led the California legislature to question the cost-effectiveness of NEM and its impact on non-participating ratepayers (i.e., the “cost shift”). In 2010, the CPUC retained Energy and Environmental Economics, Inc. (E3), which completed California’s first NEM Cost-Effectiveness Evaluation.[12] The report estimated that on a lifecycle basis, all PV generation on NEM tariffs would result in a net present cost to ratepayers of approximately $230 million over 20 years, and that the average net cost of NEM was $0.12 per kilowatt-hour (kWh) exported.

In 2013, E3 completed a follow-up NEM study for the CPUC that found, among other things, that the costs associated with NEM electricity exported to the grid under the then available NEM 1.0 tariffs were approximately $359 million per year, or one percent of the utility revenue requirement. The analysis also found that residential NEM customer bills were 54 percent greater than their cost of service, on average, before the installation of NEM generation.[13]

Passage of AB 327 in 2013 (Perea, 2013), among other things, directed the CPUC to develop a new standard contract for NEM generation that Pacific Gas and Electric Company (PG&E), Southern California Edison Company (SCE), and San Diego Gas and Electric Company (SDG&E) must offer after reaching their respective NEM program limits.[14] In 2015, E3 developed a NEM Successor Tariff Public Tool, which allowed users to evaluate different rate designs, simulating their impact on adoption of customer-sited renewable resources and on bills for all ratepayers, while accounting for feedback effects on future rates and lifecycle cost-effectiveness.

On February 5, 2016, the CPUC issued Decision (D.) 16-01-044, which created the NEM successor tariff, known as “NEM 2.0.”[15] The current NEM 2.0 program went into effect in SDG&E's service territory on June 29, 2016, in PG&E's service territory on December 15, 2016, and in SCE's service territory on July 1, 2017. The program provides customer-generators full retail rate credits for energy exported to the grid and requires them to pay charges intended to align NEM customer costs more closely with non-NEM customer

12 Net Energy Metering Cost-Effectiveness Evaluation. E3, January 2010. https://www.cpuc.ca.gov/WorkArea/DownloadAsset.aspx?id=4290

13 California Net Energy Metering Ratepayer Impacts Evaluation. E3, October 2013. www.cpuc.ca.gov/WorkArea/DownloadAsset.aspx?id=4292

14 California Assembly Bill 327, Perea. October 7, 2013. https://leginfo.legislature.ca.gov/faces/billNavClient.xhtml?bill_id=201320140AB327

15 CPUC Decision Adopting Successor to Net Energy Metering Tariff. February 5, 2016. https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M158/K181/158181678.pdf

costs. Customer-generators taking service under NEM 2.0 must pay a one-time interconnection fee, pay non-bypassable charges, and transfer to a time-of-use (TOU) rate.[16]

2.2 STUDY OBJECTIVES

At the CPUC's request, Verdant Associates, E3, and Itron ("the Verdant team") conducted an evaluation to review PG&E's, SCE's, and SDG&E's NEM 2.0 tariffs. The NEM 2.0 Lookback Study includes a cost-effectiveness analysis consistent with the Standard Practice Manual (SPM) and the CPUC Decision guiding cost-effectiveness evaluation of customer-sited renewable resources (D.19-05-019).[17] The evaluation also includes an analysis to compare the cost to serve NEM 2.0 customers and their total bill payments. The objectives of the evaluation are to examine the impacts of NEM 2.0 and to compare how various metrics have changed following the transition from NEM 1.0 to NEM 2.0.[18] The evaluation will answer the following questions:

- What are the characteristics of systems installed under NEM 2.0?
- What are the characteristics of customers taking service under NEM 2.0?
- What have been the costs and benefits of the NEM 2.0 tariff to participating customers, rate payers, program administrators, and society as a whole?
- What is the utility's cost of service for different types of NEM 2.0 customers?
- Do different types of NEM 2.0 customers pay more or less than the cost of providing them electricity service before and after they install NEM systems?
- How have answers to the above questions changed from NEM 1.0 to NEM 2.0?

2.3 SUMMARY OF APPROACH

The NEM 2.0 lookback study is divided into three main research activities:

1. **Analysis of NEM 2.0 interconnection datasets.** Verdant collected utility interconnection data to define the population of NEM 2.0 systems interconnected through the end of 2019. This allowed

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16 Additional information on the NEM bill calculation methodology, including the treatment of Net Surplus Compensation (NSC) and annual true-up statements, is included in Section 4.

17 CPUC Decision Adopting Cost-Effectiveness Analysis Framework Policies for All Distributed Energy Resources. May 21, 2019. http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M293/K833/293833387.PDF

18 The primary objective of this study is to evaluate the cost-effectiveness of DERs taking service under NEM 2.0. Comparisons between NEM 1.0 and NEM 2.0 are limited to literature review of prior NEM cost-effectiveness studies. Verdant did not perform any cost-effectiveness tests for the NEM 1.0 tariff as part of this evaluation.

us to answer questions like: are systems installed under NEM 2.0 materially different from NEM 1.0 systems in size, orientation, or other aspects?

2. **Cost-effectiveness analysis of NEM 2.0.** Verdant built a model that quantifies the cost-effectiveness of NEM 2.0 based on the Standard Practice Manual tests and consistent with CPUC D.19-05-019.
3. **Cost of service analysis of NEM 2.0.** Verdant performed an analysis to compare the actual bill payments that NEM 2.0 customers make to an estimate of the utility costs needed to serve the customers.

2.3.1 Analysis of NEM Interconnection Data

The NEM 2.0 Lookback Study is based on interconnection data received from PG&E, SCE, and SDG&E. We requested customer-sited renewable resource characteristics such as technology type, size, tilt and azimuth (PV only), and other relevant parameters (e.g., is the system paired with storage) for all NEM 2.0 customers receiving Permission to Operate (PTO) on or before December 31, 2019. These datasets form the basis of the evaluation.

Demographic Characteristics

The demographic characteristics of NEM 2.0 customers are based on the American Community Survey (ACS) datasets available through the U.S. Census Bureau.[19] We mapped the location of each system in the interconnection dataset to the appropriate census tract in the ACS dataset. Census tracts share demographic indicators over a relatively homogenized population.[20] The ACS data contain several key indicators relevant to solar adoption such as:

- Median household income
- Median home value
- Home ownership (as percent of owner-occupied units)
- Education (as percent of population over 25 years) with high school or higher and bachelors and professional degrees
- Median age
- Race

[19] The United States Census Bureau. https://data.census.gov/cedsci/

[20] Note that when merging the NEM population datasets to ACS census tracts, we can only describe the neighborhoods in which NEM customers are present. Census tracts can include hundreds of thousands of households, and not all customers in those census tracts will be NEM customers.

We also mapped the location of each system to the top 25 percent scoring census tracts as identified by the CalEnviroScreen 3.0 tool.[21] CalEnviroScreen identifies disadvantaged communities (DACs) that are disproportionately burdened by, and especially vulnerable to, multiple sources of pollution.

Section 3 includes a detailed description of the NEM 2.0 population and comparisons to NEM 1.0 systems.

2.3.2 Cost-Effectiveness Analysis

Verdant developed a model to quantify the cost-effectiveness of customer-sited renewable resources. We examine cost-effectiveness for various customer classes (e.g., residential, agricultural, commercial, industrial), technologies (e.g, solar PV, solar PV paired with storage), retail rates, and other relevant customer characteristics. The model calculates the bill impacts of technologies throughout their lifetimes and the associated acquisition costs including financing, insurance, and tax costs (or credits). Looking from the utility perspective, the model quantifies the changes in the utility's marginal operating costs and considers incentive payments and program administration/interconnection costs. The model quantifies the present value of all cost and benefit streams for the entire life of the technology, accounting for changes in retail rates, technology operating costs, and changes in utility marginal costs.

The cost-effectiveness model's primary purpose is to evaluate the cost-effectiveness of customer-sited renewable resources under NEM 2.0 using the standard practice manual (SPM) tests. The SPM contains the CPUC's method of evaluating customer-sited renewable resource investments using various cost-effectiveness tests. The four tests described in the SPM assess the costs and benefits of NEM 2.0 from different stakeholder perspectives: the total resource cost (TRC) test, the participant cost test (PCT), the program administrator (PA) test, and the ratepayer impact measure (RIM) test.

Additional details on the cost-effectiveness model including a user's guide and minimum operating requirements are included as Appendix A. Details on the inputs and assumptions used in the model are presented in Section 4.

2.3.3 Cost of Service Analysis

The full cost of service analysis compares an estimate of the utility cost of servicing a NEM 2.0 customer with their bills. The utility cost is based on the customer's use of the grid and an allocation of the utility's fixed costs. Verdant used information from each utility's General Rate Case (GRC) Phase 2 filings, regulatory costs, and NEM customer incremental costs to develop estimates of the cost of service.

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[21] CalEnviroScreen 3.0 | OEHHA. https://oehha.ca.gov/calenviroscreen/report/calenviroscreen-30.

The total cost of service has inputs that are similar to the cost-effectiveness analysis, but it also differs from the cost-effectiveness analysis in material ways. The total cost of service estimates the cost of servicing the total or net load while the cost-effectiveness analysis is based on an estimate of the cost savings from the reduction in usage after becoming a NEM 2.0 customer. For the cost-effectiveness analysis, the cost savings from reduced usage are evaluated using either the customer-sited renewable resource's lifetime of avoided costs or bill savings, depending upon the specific test (TRC, PA, PCT, or RIM). The cost-effectiveness analysis requires a lifetime forecast of the avoided costs and bill savings to compare to the cost of the renewable resource or the cost of a program. In comparison, the cost of service analysis compares the customer bill to costs of servicing the customer during the first year only.

The cost of service analysis reproduces, to the degree possible, the revenue allocation from the most recent GRC Phase 2 for PG&E, SCE, and SDG&E for NEM 2.0 customers. The GRC costs are the largest component of the full costs of service, but not all costs are assigned through this process. Additional costs include regulatory costs and fees including, but not limited to, nuclear decommissioning charges, public purpose program charges, and Department of Water Resources (DWR) bond charges.

Additional information on the cost of service methodology is presented in Section 4.

2.4 STAKEHOLDER ENGAGEMENT PROCESS

The NEM 2.0 Lookback study relies on stakeholder engagement to ensure that the methodologies and inputs that we propose and ultimately adopt are reasonable. The Verdant team developed a draft research plan that was released on November 27, 2019. The draft research plan included a description of the methodology and key inputs. On December 7th, we held an in-person public workshop on the draft research plan at the CPUC. We requested comments back on the draft research plan by December 20th. We received informal comments from Solar Rights Alliance (SRA), Coalition of California Utility Employees (CUE), California Public Advocates Office (Cal Advocates), Solar Energy Industries Association (SEIA), California Solar and Storage Association (CALSSA), Vote Solar, Sunrun, the Joint IOUs (i.e., PG&E, SCE, and SDG&E), and Solar Consumer Advisor. On February 26th, the CPUC released the final research plan which included revisions stemming from the stakeholder review and detailed responses to all comments.

The draft NEM 2.0 Lookback Study Report was released on August 14th, 2020. Stakeholder comments were requested no later than September 8th. We received informal comments on the draft NEM 2.0 Lookback Study Report from Aurora Solar, Cal Advocates, CALSSA, Foundation Windpower, LLC, GRID Alternatives, the Joint IOUs, California Wind Energy Association (CalWEA), The Utility Reform Network (TURN), Vote Solar, and SEIA. The final NEM 2.0 Lookback Study Report was released on January 21, 2021.

2.5 REPORT CONTENTS

This report is organized in the following sections:

- **Section 1** is the executive summary.
- **Section 2** introduces the NEM 2.0 Lookback Study, provides a brief history of California's NEM policies, presents the study objectives, and summarizes the approach.
- **Section 3** describes the NEM 2.0 population and provides insights into differences between NEM 1.0 and NEM 2.0 participants.
- **Section 4** summarizes the cost-effectiveness analysis and cost of service approach.
- **Section 5** presents the results of the cost-effectiveness and cost of service analysis.
- **Appendix A** describes the NEM 2.0 Lookback Study tool including operating instructions and minimum system requirements.
- **Appendix B** contains responses to stakeholder comments on the draft report.

The NEM 2.0 Lookback Study model, along with all accompanying input load shapes, datasets, and results, are available for download from the CPUC's NEM 2.0 Evaluation website:

https://www.cpuc.ca.gov/General.aspx?id=6442463430

3 NEM POPULATION OVERVIEW AND KEY TRENDS

In this section we present NEM 2.0 population characteristics and key trends. The statistics and key findings presented in this section are focused on NEM 2.0 customers. However, where possible, we make comparisons between NEM 2.0 customers, NEM 1.0 customers, and California's population overall. The discussion is divided into the following sub-sections:

- Data Sources and Methodology
- NEM Population and System Characteristics
- Residential NEM Customer Demographics

3.1 DATA SOURCES AND METHODOLOGY

The analysis presented in this section is based on geospatial analysis of various public and non-public datasets. Below we provide a brief description of the various data sources used, including a discussion of data limitations and assumptions.

3.1.1 NEM 1.0 and 2.0 Population Interconnection Datasets

We developed two population datasets for this analysis: one for NEM 1.0 customers and another for NEM 2.0 customers. These datasets were then merged to allow side by side analysis. The NEM 2.0 interconnection dataset, which includes all NEM 2.0 customer systems interconnected and operational by December 31, 2019, was requested directly from each utility for this analysis. The NEM 1.0 population dataset was developed from data used by the Verdant team for the Final California Solar Initiative (CSI) Impact Evaluation.[22] Some of the key fields utilized from these datasets include:

- Electric utility service territory (e.g., PG&E, SCE, and SDG&E)
- Customer rate class[23]
- Interconnection year[24]
- NEM tariff (1.0 or 2.0)

22 California Solar Initiative Final Impact Evaluation Report. Itron, 2020.

23 Customer sector (e.g., residential, commercial, agricultural) was not consistently defined across all utility interconnection datasets. For consistency, customer rate class was used as a proxy for customer sector.

24 Interconnection date was not consistently populated across all utility interconnection datasets. In many cases, we derived the year of interconnection from several date fields related to application and installation milestones unless the interconnection date was specified definitively.

- System characteristics, including: NEM generation system capacity (kW_{AC}) and nameplate rating (kW_{DC}), azimuth, tilt, tracking type (e.g., fixed, single-axis, dual-axis), and storage system characteristics (e.g., energy, power, duration)
- Equipment characteristics, including: inverter manufacturer, module manufacturer, installer company, and third-party ownership
- Location: city, county, ZIP code.[25]

3.1.2 Aggregation to ZIP Code Level

We used ZIP codes to identify location and did not have full system address data for many of the NEM 2.0 systems due to utility confidentiality concerns. Therefore, we aggregated census tract and CalEnviroScreen data to the ZIP code level. This aggregation limits the analysis granularity and results may trend towards ZIP code averages more than analyses that have taken advantage of data that includes street addresses such as the recently completed research by Lawrence Berkeley National Laboratory (LBNL).[26]

Since census tracts do not necessarily fall fully within one ZIP code (i.e., a census tract geography falls within one or more ZIP codes), it was necessary to account for spatial overlap when aggregating to the ZIP code level. To do this, we used the “ZIP-TRACT” Crosswalk file[27] provided by the United States Department of Housing and Urban Development (HUD) to proportionally assign census tract characteristics to a ZIP code. For example, if ZIP code A was comprised of census tracts X and Y and all of census tract X’s geography was located in ZIP code A, but sixty percent of tract Y’s geography was located in ZIP code A and forty percent in ZIP code B, then it was assumed that one hundred percent of tract X’s population and sixty percent tract Y’s population belonged to ZIP code A. Census tract characteristics were then population-weighted to the ZIP code level.

3.1.3 Demographic Data and Census Tract Information

The U.S. Census Bureau produces data on the American population and economy such as population count, age, race, income, and home value.[28] This information is reported by census tract, a subdivision of a county with between 1,500 and 10,000 people and an average population of around 4,000. Although the census is only performed every 10 years, the American Community Survey (ACS) updates these data

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25 Note that street addresses and other personally identifiable information (PII) were not available for all NEM 2.0 customers, therefore we used zip code as the location variable across all datasets.

26 Barbose et. al, Income Trends among Residential Rooftop Solar Adopters, February 2020, LBNL

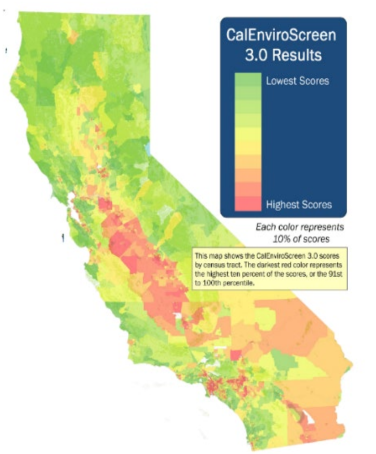
27 HUD USPS ZIP Code Crosswalk File | HUD USER. https://www.huduser.gov/portal/datasets/usps_crosswalk.html

28 United States Census Bureau. https://data.census.gov

more regularly. These data and the data from the 2014-2018 American Community Survey (ACS) five-year estimates were used for this analysis with incomes driven from 2018 data. Census tracts are preferable to counties or ZIP code boundaries for identifying demographic and economic trends within a defined boundary, but given the lack of address data beyond ZIP codes in the NEM 2.0 data, Verdant used ZIP codes for location as discussed in section 3.1.2 above.

The ACS data[29] were spatially merged with the utility interconnection datasets by the ZIP code assigned to each system. The key demographic indicators used to correlate adoption trends include:

- Median household income (in 2018 dollars)
- Median home value (in 2018 dollars)
- Home ownership (as percentage of owner-occupied units)
- Education (as percentage of population aged over 25 years) with high school or higher and bachelors and professional degrees
- Median age



3.1.4 Disadvantaged Community Data

CalEnviroScreen is a mapping tool that helps identify California communities that are most affected by multiple sources of pollution and where people are disproportionally burdened by and especially vulnerable to the effects of various sources of pollution.[30] CalEnviroScreen uses 20 different indicators of pollution burden and population characteristics to produce a weighted scoring system for every census tract in the state, allowing metrics of each community to be compared. Scores range from 0 to 100, with higher scores representing the most affected census tracts. CalEnviroScreen ranks communities based on data that are available from state and federal government sources.

We compared the deployment of NEM systems to the CalEnviroScreen score by census tract. The SB 535 designation of disadvantaged communities was used to assess population and poverty levels.[31]

29 The ACS data are also available at a block group level, which is a finer resolution than the census tract. For perspective, there are approximately 24,000 block groups in California versus 8,000 census tracts. However, using the block group level requires the precise location of systems. Because the interconnection data had several gaps in geolocation or street address data, we had to approximate the cross mapping to census tracts based on zip codes.

30 CalEnviroscreen | OEHHA. https://oehha.ca.gov/calenviroscreen

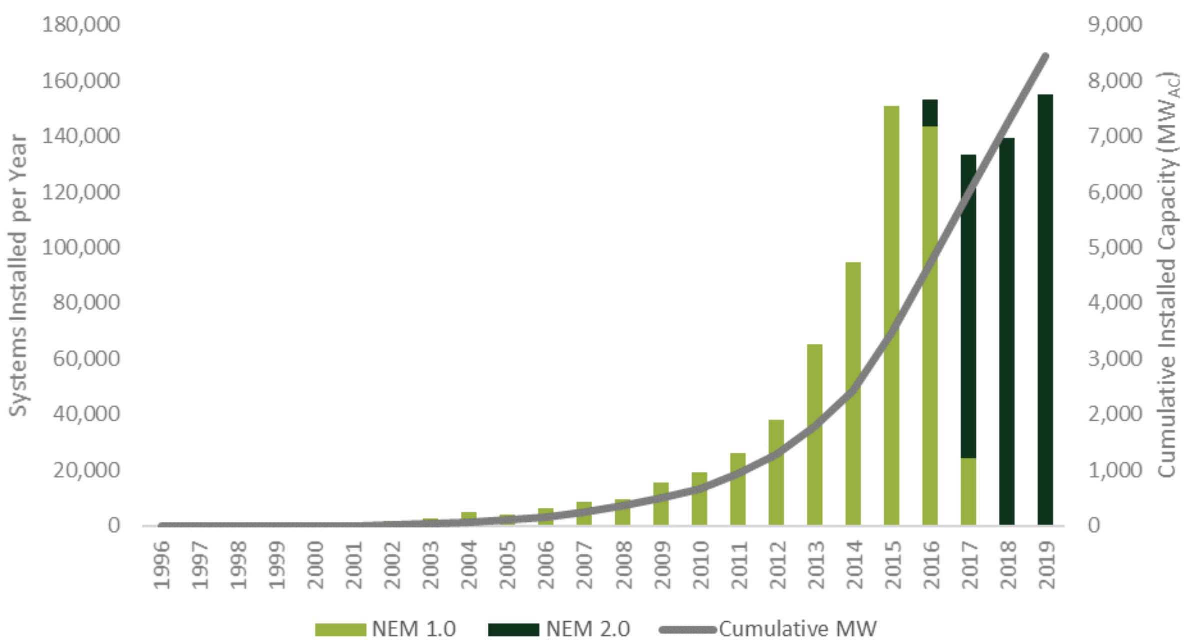
31 SB 535 Disadvantaged Communities | OEHHA. https://oehha.ca.gov/calenviroscreen/sb535

Disadvantaged communities are defined by the California Environmental Protection Agency (CalEPA) as the top 25 percent overall scoring areas from CalEnviroScreen, as well as the top five percent pollution burdened census tracts from CalEnviroScreen, but do not have an overall CalEnviroScreen score.[32]

3.2 NEM SYSTEM POPULATION AND CHARACTERISTICS

California has a growing population of solar PV, fuel cell, and distributed wind systems that are interconnected under the NEM tariff. Figure 3-1 shows installed NEM systems and capacities through the end of 2019.

FIGURE 3-1: NUMBER AND CAPACITY OF NEM SYSTEMS INSTALLED BY NEM 1.0 VS. NEM 2.0



The number of interconnections accelerated in 2007 (coincident with the launch of the California Solar Initiative program) and showed the first year over year decrease in 2017. The growth in the number of systems has been largely driven by residential customer adoption. Figure 3-2 shows annual NEM

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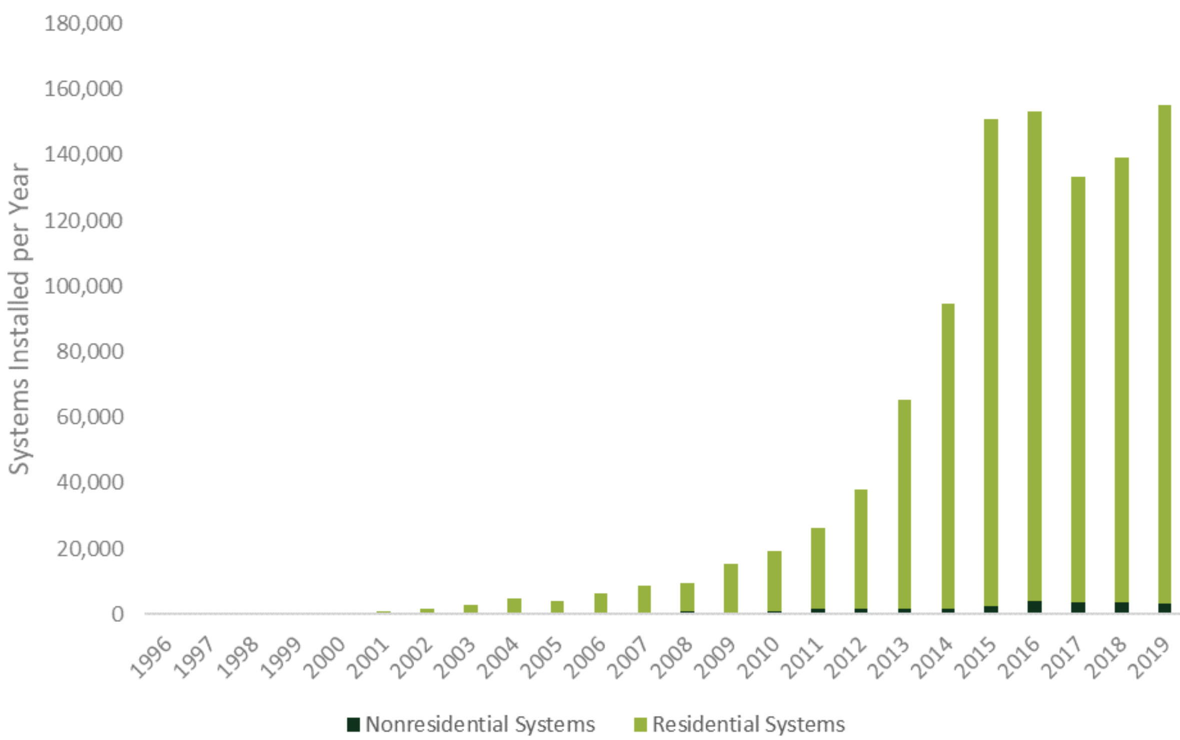
32 https://calepa.ca.gov/wp-content/uploads/sites/6/2017/04/SB-535-Designation-Final.pdf, "After reviewing the updated results from CalEnviroScreen 3.0 and taking into consideration previous comments and input received over the past two years, including workshops held in February 2017, CalEPA is designating the highest scoring 25 percent of census tracts from CalEnviroScreen 3.0 as disadvantaged communities. Additionally, 22 census tracts that score in the highest 5 percent of CalEnviroScreen's Pollution Burden, but do not have an overall CalEnviroScreen score because of unreliable socioeconomic or health data, are also designated as disadvantaged communities."

interconnections by sector (residential vs. nonresidential). Year after year, residential projects represent the vast majority of total NEM interconnections. Almost 98 percent of NEM systems interconnected during 2019 were residential. That proportion has remained relatively constant since 2013.

FIGURE 3-2: NUMBER OF NEM SYSTEMS INSTALLED BY SECTOR



In addition to the growth in the number and total capacity of installed systems, the median (and average) size of systems interconnected in California under NEM 1.0 and 2.0 has grown in recent years. Median system sizes have remained relatively consistent across recent years under NEM 2.0, as shown in Figure 3-3.

FIGURE 3-3: MEDIAN SYSTEM SIZE BY NEM 1.0/NEM 2.0[33]

Energy storage is increasingly being paired with NEM-eligible technologies, especially solar PV systems. For residential systems, the addition of energy storage is often driven by concerns about outages and the desire to self-consume solar PV energy. For nonresidential systems, demand charge management is often

[33] Sizing data for some datasets was provided in AC (assumed PTC CEC RTG). We changed this to Nameplate (or DC rating) by multiplying by 114 percent based on the difference between Nameplate (DC) and PTC_CEC_RTG in CSI tracking data.

the primary driver to include energy storage.[34] Figure 3-4 shows the proportion of NEM 2.0 systems paired with energy storage since 2016. More than 94 percent of NEM 2.0 systems interconnected during 2019 were standalone systems without energy storage. The proportion of residential systems attached with storage has steadily increased over time. The nonresidential storage attachment rate does not show any clear trends.

FIGURE 3-4: NEM 2.0 SYSTEMS WITH AND WITHOUT ENERGY STORAGE BY RESIDENTIAL / NONRESIDENTIAL

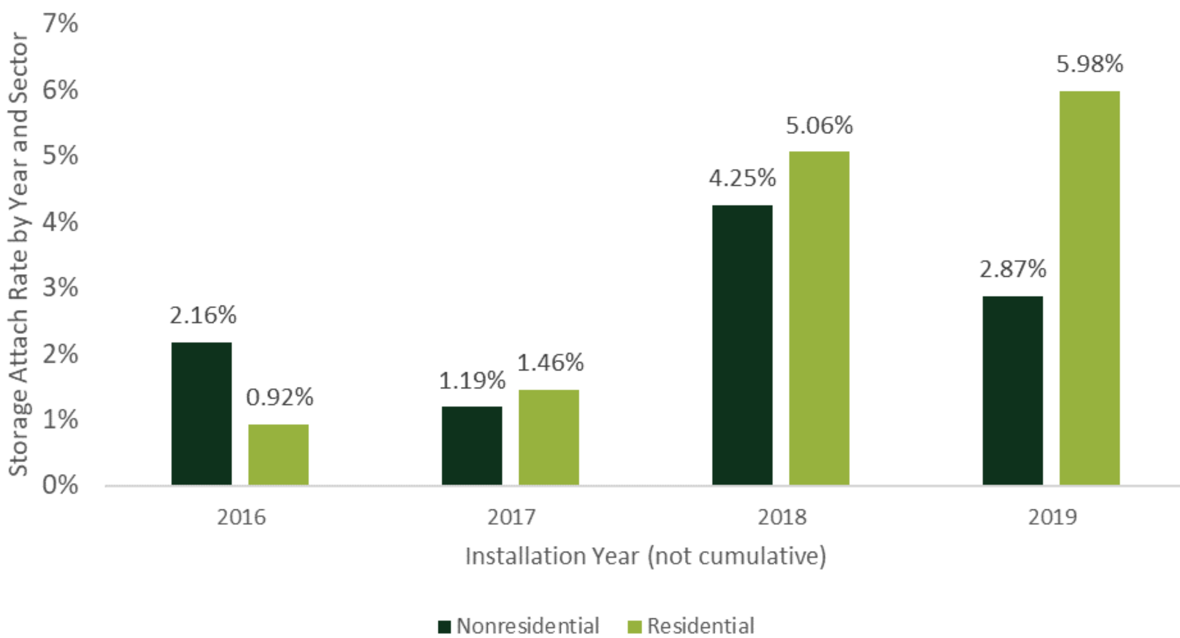
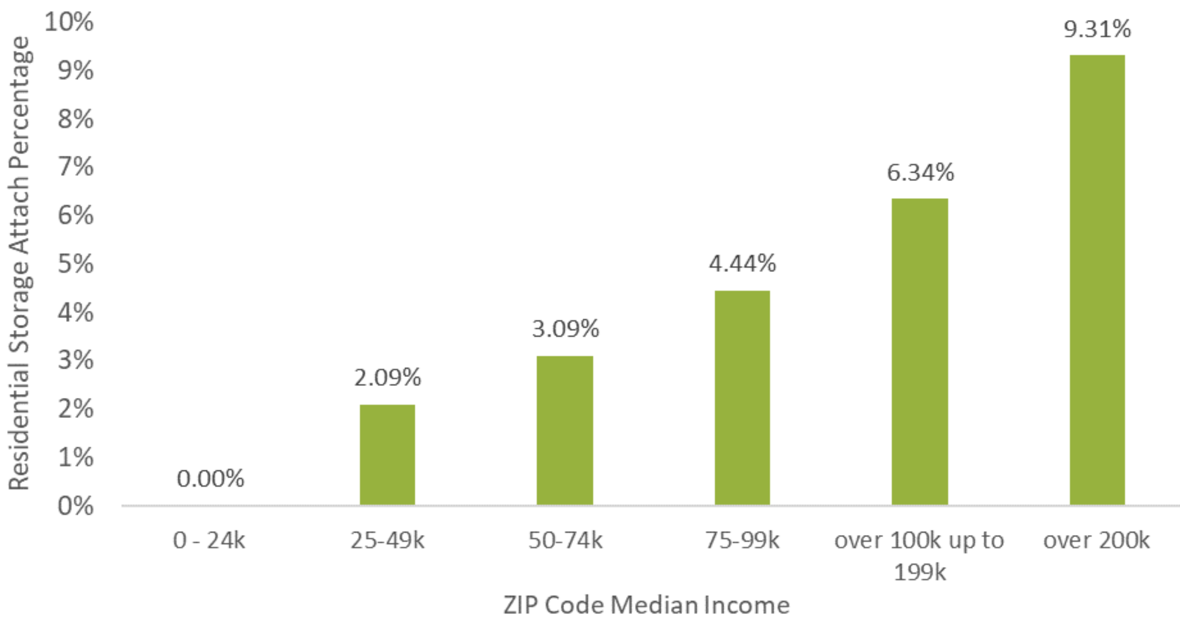


Figure 3-5 shows residential energy storage attachment rates by median customer income. Residential customers at the highest income levels (over $200,000) installed energy storage at higher rates (9.31 percent) relative to those at the lower income brackets.

34 2018 SGIP Advanced Energy Storage Impact Evaluation. https://www.cpuc.ca.gov/uploadedFiles/CPUC_Public_Website/Content/Utilities_and_Industries/Energy/Energy_Programs/Demand_Side_Management/Customer_Gen_and_Storage/SGIP%20Advanced%20Energy%20Storage%20Impact%20Evaluation.pdf

FIGURE 3-5: RESIDENTIAL NEM 2.0 SYSTEMS (2016-2019) WITH ENERGY STORAGE BY ZIP CODE MEDIAN INCOME



3.2.1 System Size and Consumption

The relationship between PV production and household electricity consumption is seldom measured on a large scale. Information on pre-installation electricity consumption is available, as is information on PV system size and post-installation net utility electricity usage. These data facilitate the comparison of PV system size and pre-installation electricity consumption. To understand the post-installation relationship, however, requires either the assumption that pre and post-installation electricity consumption is unchanged or the simulation of electricity production from the PV system.

Hourly simulations of PV production were produced using the PV_Lib Toolbox in Python. The PV_Lib Toolbox provides a set of well-documented functions for simulating the performance of PV systems. The toolbox was developed at Sandia National Laboratories and is available in MATLAB and Python versions. The evaluation team ran PV_Lib using irradiance, windspeed, and temperature data from NSRDB developed at the National Renewable Energy Laboratory (NREL). These data are instantaneous snapshots at the top and bottom of the hour. System configuration data, including system size (AC and DC), module type, tilt, azimuth, and other configuration details, were obtained from the population dataset and were used in the simulations. For Nem 1.0 (CSI) systems, DC capacity was directly available. For NEM 2.0 systems, we assumed that the nameplate (DC) rating was 114 percent of the reported AC capacity as based on comparisons of AC and DC ratings from the CSI program.[35] This correlates well with the approximate 14 percent derate from DC to AC capacities built in as default assumptions to PVWatts.

As shown previously in Figure 3-3, the median residential PV system has not changed substantially in size in the most recent years but has grown substantially since 2010. The percent of household electricity consumption that is supplied by customer-sited generation has changed substantially between data available from the California Solar Initiative Evaluation (NEM 1.0, with most systems in the CSI sample installed in 2010-2014) and our sample of NEM 2.0 customers. Table 3-1 presents the average annual load statistics for NEM 2.0 and NEM 1.0 (CSI) residential customers. The data for NEM 1.0 (CSI) are based on available data that were weighted to represent the population of CSI residential customers as further described in the Final CSI Impact Evaluation. Note that all systems included in the CSI Impact Evaluation analysis were under a NEM 1.0 tariff. California statewide values are derived from the 2009 Residential Appliance Saturation Survey (RASS).[36]

[35] CSI data were downloaded from https://www.californiadgstats.ca.gov/downloads/ as of June 2019. Nameplate or direct current (DC) capacity is the maximum DC output under Standard Test Conditions (STC) or 1,000 W/m^2 and a model temperature of 25°C. CEC PTC Rating (RTG) incorporates losses due to conversion from direct to alternating current and other losses. Additionally, the Performance Test Condition (PTC) ratings are at an ambient temperature of 25°C which results in a higher than 25°C module temperature and correspondingly lower (but likely more realistic) maximum power outputs.

[36] 2009 Residential Appliance Saturation Survey. California Energy Commission. https://www.energy.ca.gov/data-reports/surveys/2019-residental-appliance-saturation-study/2009-and-2003-residential-appliance

TABLE 3-1: RESIDENTIAL AVERAGE ANNUAL LOAD STATISTICS

Customer Type	Metric	PG&E Residential	SCE Residential	SDG&E Residential
NEM 2.0[37]	Avg. Pre-Interconnection Electricity Consumption (kWh)	8,425	10,513	7,824
	Avg. Post-Interconnection Net Consumption (kWh)	1,249		416
	Change in consumption after interconnection (kWh)	2,520	N/A	2,252
	Avg. Post-Interconnection Electricity Consumption[38] (kWh)	10,945		10,076
	Avg. System Size (kW$_{DC}$)[33 (Above)]	5.9	6.9	5.6
	Avg. PV Annual Generation[39] (kWh)	9,696		9,661
	% Pre-Interconnection Consumption Supplied by PV	115%	N/A	123%
	% Post-Interconnection Consumption Supplied by PV	89%		96%
NEM 1.0 (CSI)	Avg. Post-Interconnection Electricity Consumption (kWh)	14,830	16,118	15,036
	Avg. System Size (kW$_{DC}$) [33 (Above)]	5.3	5.9	5.9
	% Post-Interconnection Consumption Supplied by PV[38]	63%	63%	69%
	Home Median Square Footage for CSI Customers (ft^2)	2,200	2,356	2,433
CA Statewide	Avg. Consumption for Single Family Residential Customers (kWh)	7,701	7,450	7,453
	Home Avg. Square Footage for Single Family Residential Customers (ft^2)	1,859	1,877	2,018

The NEM 1.0 (CSI) residential customers, on average, consume significantly more energy than NEM 2.0 customers and IOU-specific residential averages. NEM 1.0 (CSI) residential customers' average annual post-interconnection consumption ranges from 14,830 kWh to 16,118 kWh, depending on the utility. The

37 These data were derived from a subset of participants that had at least 10 months of monthly billing data in both the pre- and post-interconnection periods, which substantially reduced the number of participants included in the summary (for SCE, there was not sufficient post-interconnection data to conduct this analysis). These data were also subset by removing participants with monthly consumption or system sizes in excess of the 95th percentiles for each metric, which had some large outliers that skewed the distributions of these variables. However, it should be noted that their removal means that the average annual usage and system sizes are reduced relative to the overall population.

38 Post installation consumption is the sum of net load from the utility meter plus generation.

39 NEM 2.0 Generation is based on expected generation with the assumption that system sizes reported in interconnection datasets are kW$_{AC}$ and that kW$_{DC}$ (or nameplate) system sizes are 114 percent of AC system size and simulated performance in PVWatts using TMY weather and a 14 percent derate.

average consumption of those participants is approximately twice as large as the average consumption for the typical utility specific single-family residential customer. Part of the higher electricity consumption for NEM 1.0 (CSI) participants may be due to these systems being installed on larger than average homes. However, the higher electricity consumption of NEM 1.0 (CSI) participants is also likely due to a substantially higher energy intensity or usage per square foot than the average California home.[40]

NEM 2.0 residential customers appear to have lower electricity consumption than their NEM 1.0 counterparts (10,076 kWh to 10,945 kWh for post-installation consumption). NEM 2.0 average system size is similar to systems in the CSI NEM 1.0 sample, but NEM 2.0 PV systems are producing a much larger propoortion of the household's consumption than NEM 1.0 PV systems. The NEM 2.0 system electricity production averages 89 to 96 percent of household post-installation electricity consumption while NEM 1.0 systems only produced 63 to 69 percent of average post-installation consumption.

The larger proportion of load served by NEM 2.0 systems is likely related to the smaller average consumption of NEM 2.0 households. NEM 2.0 customers may have chosen to install PV systems that could cover most of their electricity consumption due to a combination of falling solar PV prices and the move from volumetric tiered rates to TOU rates. The lower price of PV may have helped drive more customers to adopt solar sized at or above their consumption compared to the early NEM 1.0 years. Additionally, the new TOU rate structure has changed the customer economics such that customers with higher electricity consumption no longer receive larger benefits per kWh saved relative to customers who consume less electricity. These changes may help to explain the trend toward smaller annual household consumption by customers installing solar.

The California Energy Commission (CEC) recently assumed that residential PV systems produce 90 percent of a customer's electricity needs over a year.[41] This assumption is used for long-term load forecasting and, if inaccurate, could lead to procurement of too much or too little energy to meet California's needs. For NEM 1.0 customers, this estimate appears to overestimate average PV production relative to electricity consumption. For NEM 2.0 customers, the assumption of 90 percent could be slightly lower than actual.

Nonresidential NEM 1.0 and NEM 2.0 customers show some similar trends to residential customers. Table 3-2 shows the percentage of consumption met by NEM generation for NEM 2.0 and NEM 1.0 customers. As in the residential sector, it appears that nonresidential NEM 2.0 customers are sizing systems to meet more of their consumption than under NEM 1.0.

40 California Solar Initiative Final Impact Evaluation Report. Itron, 2020.

41 California Energy Demand 2018-2030 Revised Forecast, accessed on 12/23/2019 at https://efiling.energy.ca.gov/getdocument.aspx?tn=223244, page A-9.

TABLE 3-2: NONRESIDENTIAL AVERAGE ANNUAL LOAD STATISTICS (KWH)

	PG&E Nonresidential	SCE Nonresidential	SDG&E Nonresidential
Percent Consumption supplied by NEM 2.0 PV (PV/Cons)[42]	65%	56%	54%
Percent Consumption supplied by NEM 1.0 PV (PV/Cons)	30%	21%	37%

3.3 RESIDENTIAL NEM CUSTOMER DEMOGRAPHICS

In this subsection, we investigate how the demographics of areas with residential NEM 1.0 and NEM 2.0 installations compare to each other and the statewide population based on the ZIP code the systems are installed in. As previously noted, these comparisons are by ZIP code since individual addresses were not available across all datasets. This analysis focuses on residential systems to assess how the demographics of homes with solar compare to California's population and any key trends observed in those demographics over time.[43] This is intended to provide insights into the people installing solar on their homes. By last count, residential NEM systems comprise almost 98 percent of all NEM systems in California.[44]

Income

We analyzed solar adoption trends as compared to ZIP code median household income in 2018, using 2018 dollars. Figure 3-6 shows the distribution of NEM systems and California's population by the median income in each ZIP code. ZIP codes with median incomes between $50,000 and $74,000 and $75,000 to $100,000 have the largest proportion of NEM 1.0 and NEM 2.0 customers. This is also the income bracket with the highest proportion of Californians. However, areas with higher incomes show higher percentages of NEM installations relative to California's population.

42 Nonresidential NEM 2.0 customers with solar size less than 1 kW, average daily usage greater than 100,000 kWh or less than 5 kWh were excluded from the analysis. The analysis also dropped customers who appear to install PV systems whose electricity consumption was greater than twice as large as their pre-installation consumption.

43 This focus on residential demographics is in alignment with the NEM 2.0 Lookback Study Research plan that called for an analysis of demographics, but not of firmographics of nonresidential systems.

44 By the end of 2019, 1,000,936 NEM systems were installed in the residential sector and only 28,354 NEM systems were installed in nonresidential sectors.

FIGURE 3-6: DISTRIBUTION OF NEM SYSTEMS AND CALIFORNIA POPULATION BY ZIP CODE MEDIAN INCOME

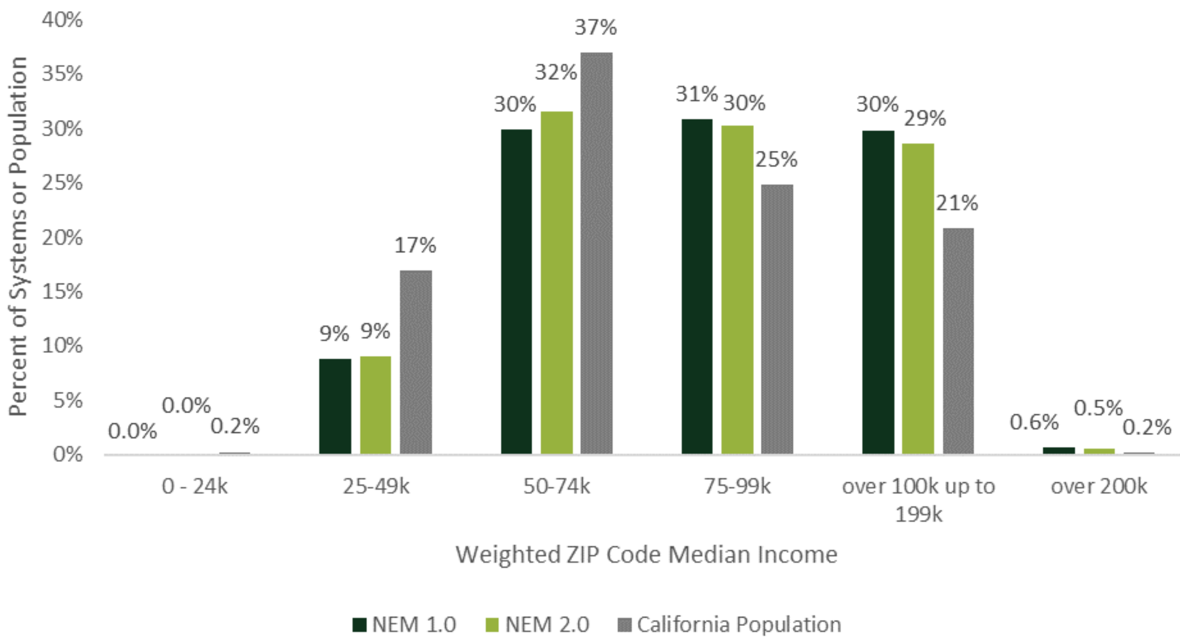
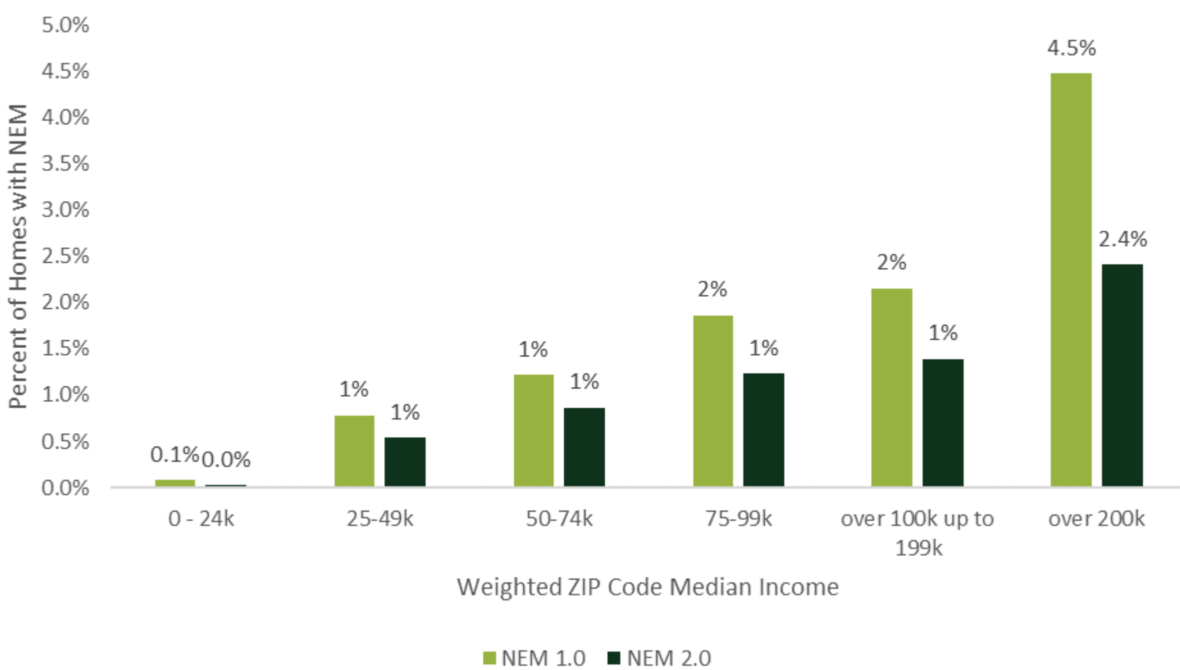


Figure 3-7 presents the percentage of homes with NEM systems by ZIP code median income.

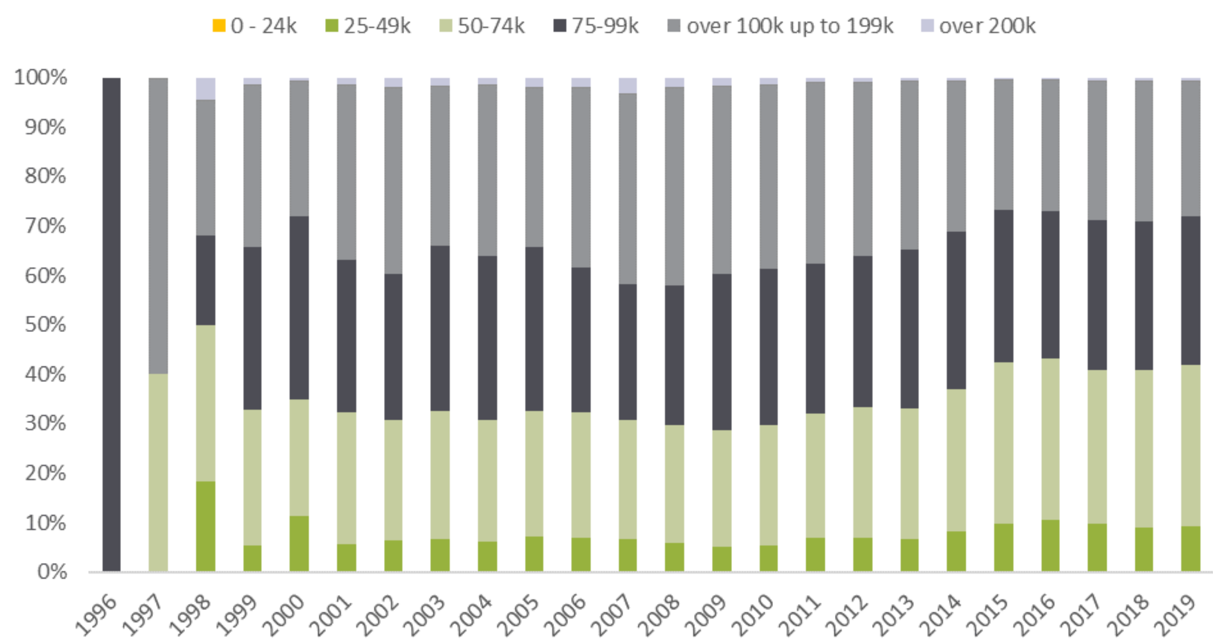
FIGURE 3-7: RESIDENTIAL NEM SYSTEM PERCENTAGES BY ZIP CODE MEDIAN INCOME



ZIP codes with higher median incomes show a higher fraction of homes with solar, but NEM 2.0 systems are slightly less concentrated in ZIP codes with the highest income brackets, versus those over just $75,000, than NEM 1.0 systems.

ZIP codes with lower median incomes have seen an increase in the proportion of solar PV installations in somewhat recent years as shown in Figure 3-8. Installations in upper income bracket areas (defined here as households earning more than $100,000 per year and shown in light gray and blue) have decreased over time while installations in relatively lower median income neighborhoods (defined here as households earning $50,000 - $99,000 and shown in light green and dark gray) increase starting in 2007 but have been somewhat static since 2015. This suggests that solar adoption was slowly increasing outside of the highest income bracket ZIP codes, though not at a very high rate. We observe a modest increase in solar PV installations among the lowest income bracket ZIP codes (households earning less than $49,000 per year). This may be correlated to increasing home ownership in low-income brackets as other studies have found that home ownership is a key factor in solar adoption rates.[26 above)] This study found that solar adoption has been gradually migrating toward lower income ranges over time, reflecting both a broadening and a deepening of U.S. solar markets.

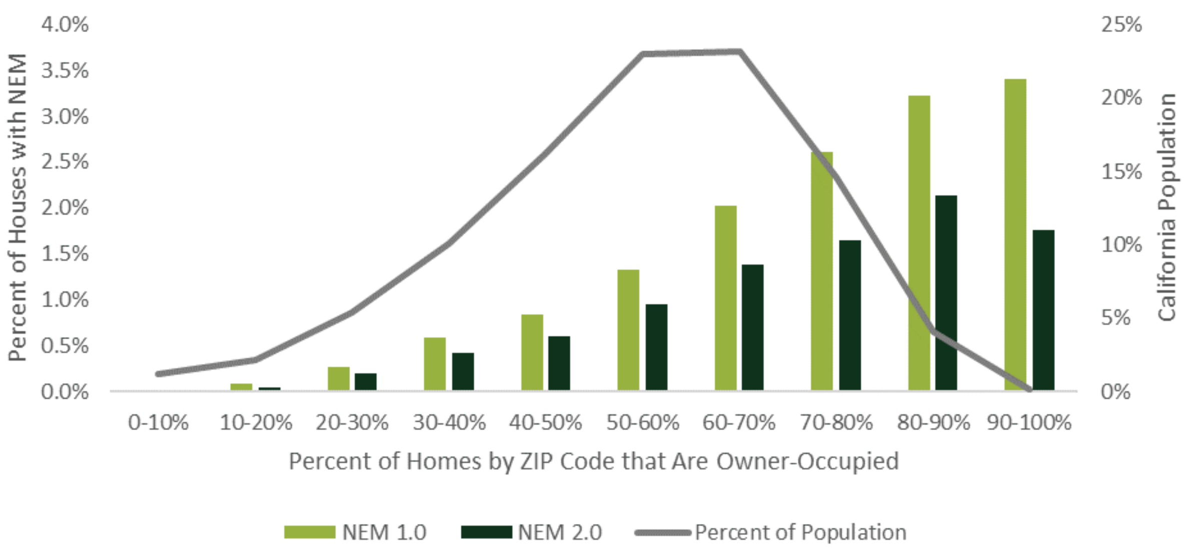
FIGURE 3-8: PERCENT OF SYSTEMS INSTALLED BY MEDIAN INCOME BRACKET BY YEAR



Home Ownership and Home Value

We analyzed solar adoption rates by home value and ownership by ZIP code. Areas with low rates of home ownership might be expected to have lower residential NEM installations since rental property owners normally do not pay utility electricity bills and therefore are not motivated to install energy saving measures. Recent initiatives such as the Solar on Multifamily Affordable Homes (SOMAH) program are intended to help increase solar installations on multifamily buildings, which tend to have a higher proportion of renters. However, no systems installed with the assistance of SOMAH were installed before the end of 2019 so no impact from that program will be evident in this study (systems installed through the end of 2019). Figure 3-9 and Figure 3-10 show the distribution of NEM 1.0 and NEM 2.0 customers by home ownership and median home value respectively.

FIGURE 3-9: NEM SYSTEMS BY HOME OWNERSHIP WITHIN ZIP CODE



Under both NEM 1.0 and NEM 2.0, more installations were observed in areas with higher home ownership rates. NEM 2.0 participation rates increase linearly as a function of home-ownership rate. NEM 2.0 participation rates drop in ZIP codes where over 90 percent of homes are owner-occupied relative to the 80-90 percent home-ownership bin. The distribution of installations appears to be less correlated with home values, as shown in Figure 3-10. The trends illustrated in Figure 3-9 and Figure 3-10 indicate that home ownership is more influential on NEM adoption than home property value.

FIGURE 3-10: NEM SYSTEMS BY ZIP CODE MEDIAN HOME VALUE

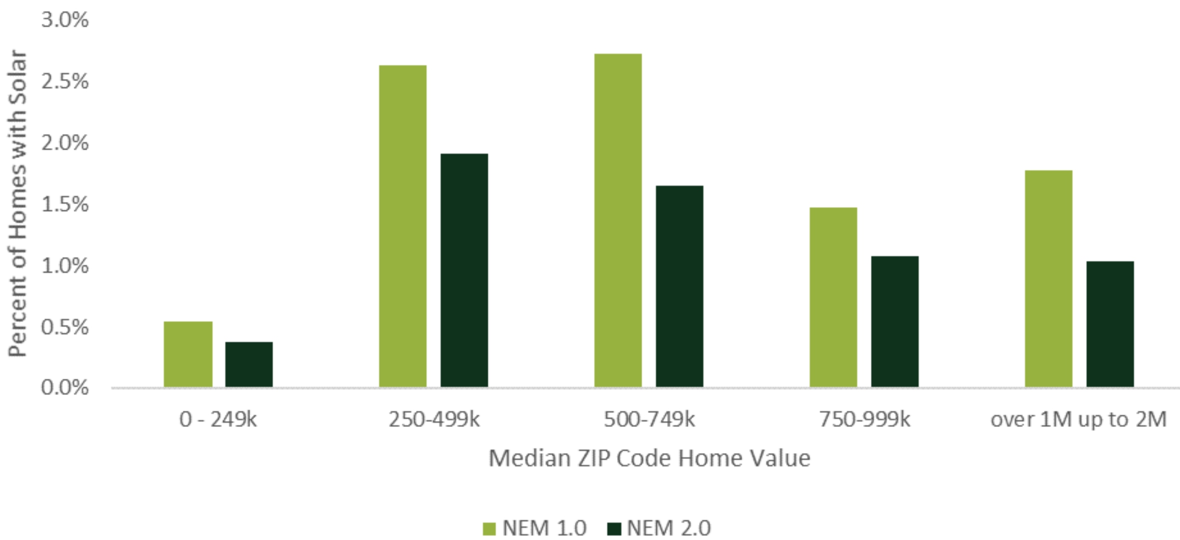
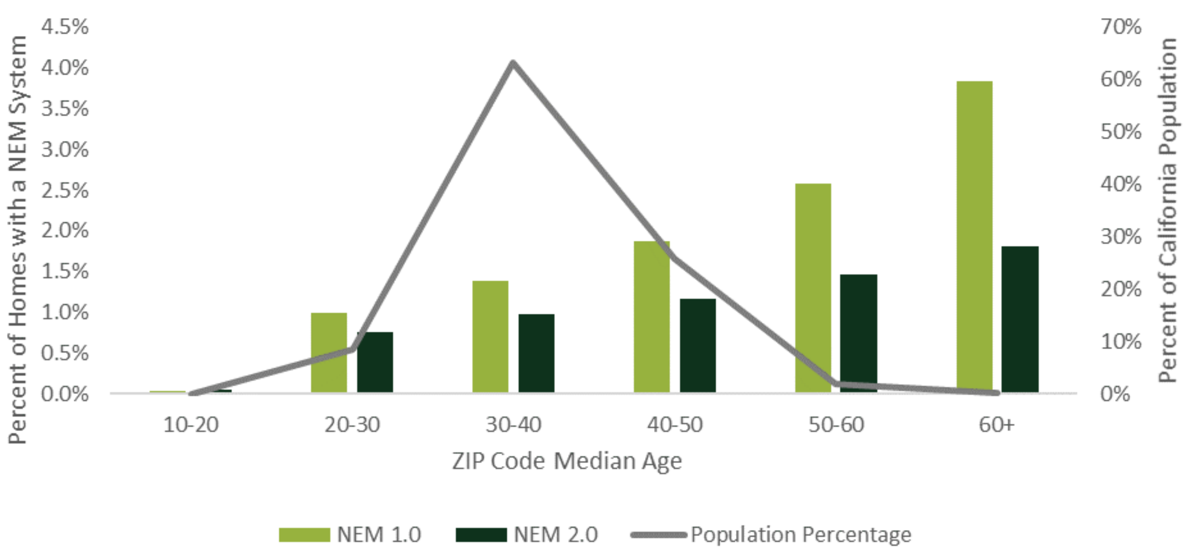


Figure 3-11 below shows the percentage of NEM installations and California's population as a function of median age in the census tract. The percentage of homes with NEM systems installed increases with increasing age, far out of proportion with the percentage of California's population at those higher ages. There is likely an underlying correlation between median age and income, and between median age and home ownership rate.

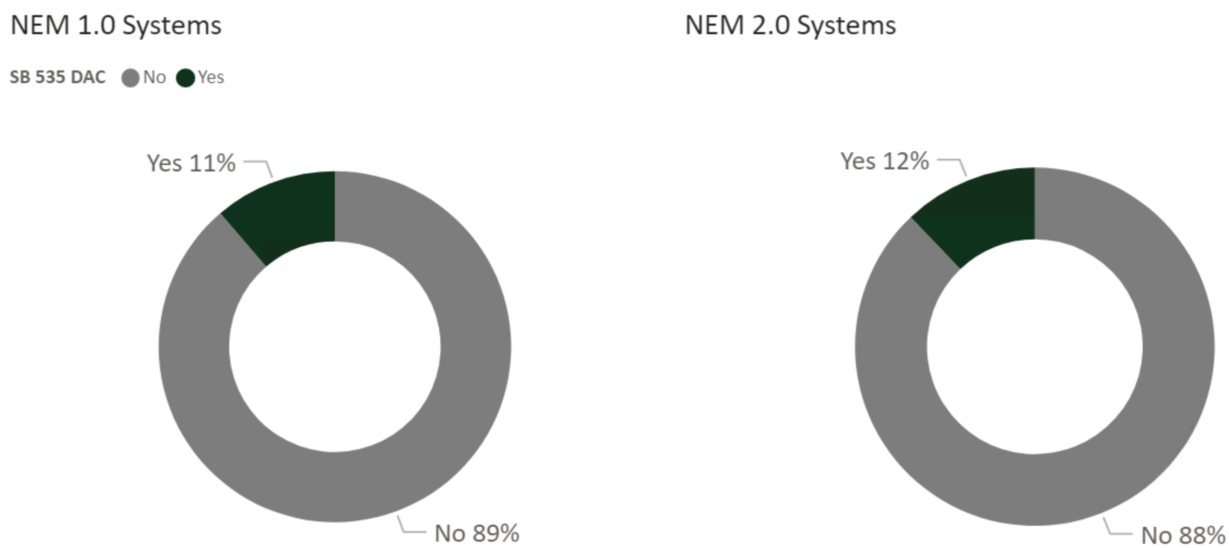
FIGURE 3-11: NEM SYSTEMS AND CALIFORNIA POPULATION BY MEDIAN AGE



NEM in Disadvantaged Communities

Solar adoption in disadvantaged communities (DAC) is shown in Figure 3-12. DACs are defined as areas with the top 25 percent of scores from CalEnviroScreen 3.0 (as updated in 2018), along with other areas with high amounts of pollution and low populations as defined by SB 535.[45] Eleven (NEM 1.0) to twelve (NEM 2.0) percent of residential NEM systems are installed in disadvantaged communities. This proportion is much lower than the population of the state with the disadvantaged community designation (25 percent).

FIGURE 3-12: RESIDENTIAL NEM SYSTEMS IN DISADVANTAGED COMMUNITIES



From 2014 to 2017, there was a noticeable increase in solar adoption in DACs. However, the adoption rate in DACs has shown some decrease since then, somewhat coincident with the advent of NEM 2.0, and remains lower in the most disadvantaged areas.

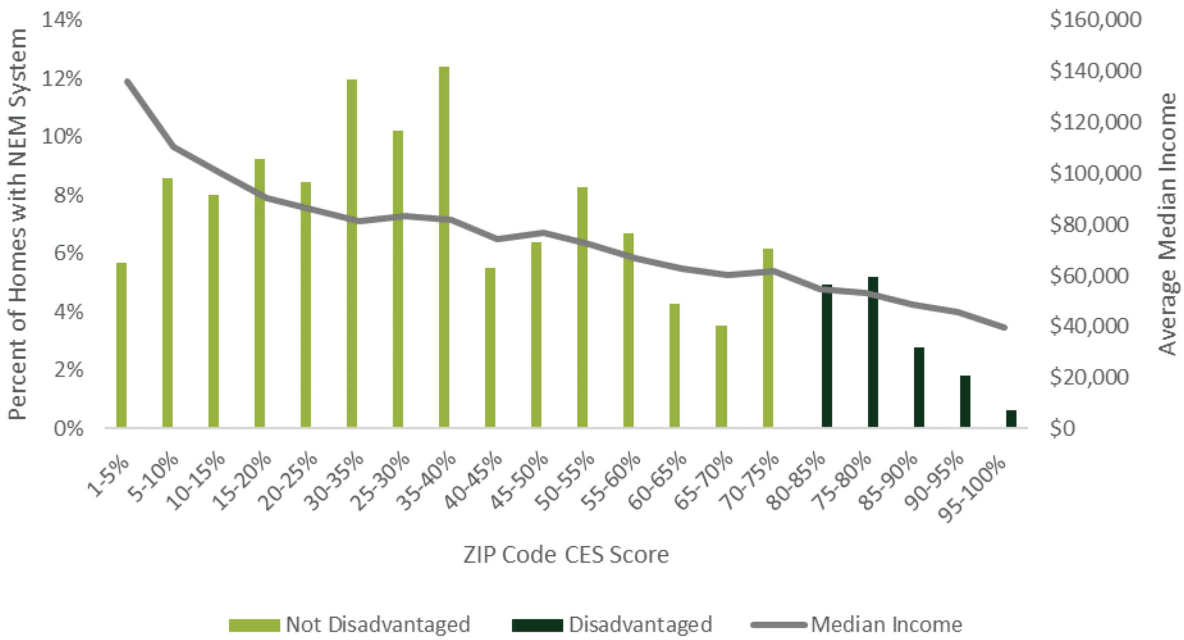
[45] SB 535 Disadvantaged Communities | OEHHA. https://oehha.ca.gov/calenviroscreen/sb535

FIGURE 3-13: SYSTEMS INSTALLED IN DISADVANTAGED COMMUNITIES BY YEAR

In most DACs, more than half the population lives significantly below the federal poverty line.[46] Figure 3-14 shows the distribution of solar adoption across the spectrum of CalEnviroScreen (CES) score bins by percentile. The lowest values are the least disadvantaged in terms of economic and environmental factors. These less disadvantaged communities tend to also have relatively more NEM adoption (bars in light green). By contrast, the more severely challenged communities show some of the lowest levels of solar adoption (dark green bars). The line is the median income of ZIP codes within each CES score bin, which largely positively correlates to the level of solar adoption in those communities. The lower the median income (and often the higher fraction of the population living below the poverty line) correlates to higher disadvantage points for the community in addition to lower solar adoption. All the factors that make a community disadvantaged also imply factors that affect solar adoption, such aslower home ownership status, lower median incomes, and lower median home values, among other related economic factors.

[46] The poverty level of over 50 percent of the population is two times below the federal poverty line.

FIGURE 3-14: DISADVANTAGED COMMUNITY SYSTEMS AND MEDIAN INCOME



NEM Demographic Summary

In general, we observed that a higher fraction of NEM systems have been installed in more affluent ZIP codes with higher percentages of homeownership than California's population on average. However, systems did show an uptick in in ZIP codes with lower incomes and in disadvantaged communities around 2015. Between 2007 and 2014, eight percent of residential solar systems were installed in disadvantaged communities. Beginning in 2015 through 2019, the proportion of systems installed in DACs increased to 12 percent. This trend could be related to the falling price of solar PV and other customer generation options. Programs such as SOMAH, the Single-Family Affordable Solar Homes Program (SASH), the Multifamily Affordable Solar Housing Program (MASH), and other equity-focused programs may further accelerate system installations in less affluent and more diverse areas going forward.

4 METHODOLOGY AND APPROACH

This section summarizes the sources of data and methodologies used in the cost-effectiveness and cost of service components of this study. The discussion is divided into the following sub-sections:

- Overview of approach
- Model description
- Cost-effectiveness calculation summary
- Cost of service calculation summary
- Model inputs and assumptions

4.1 OVERVIEW OF APPROACH

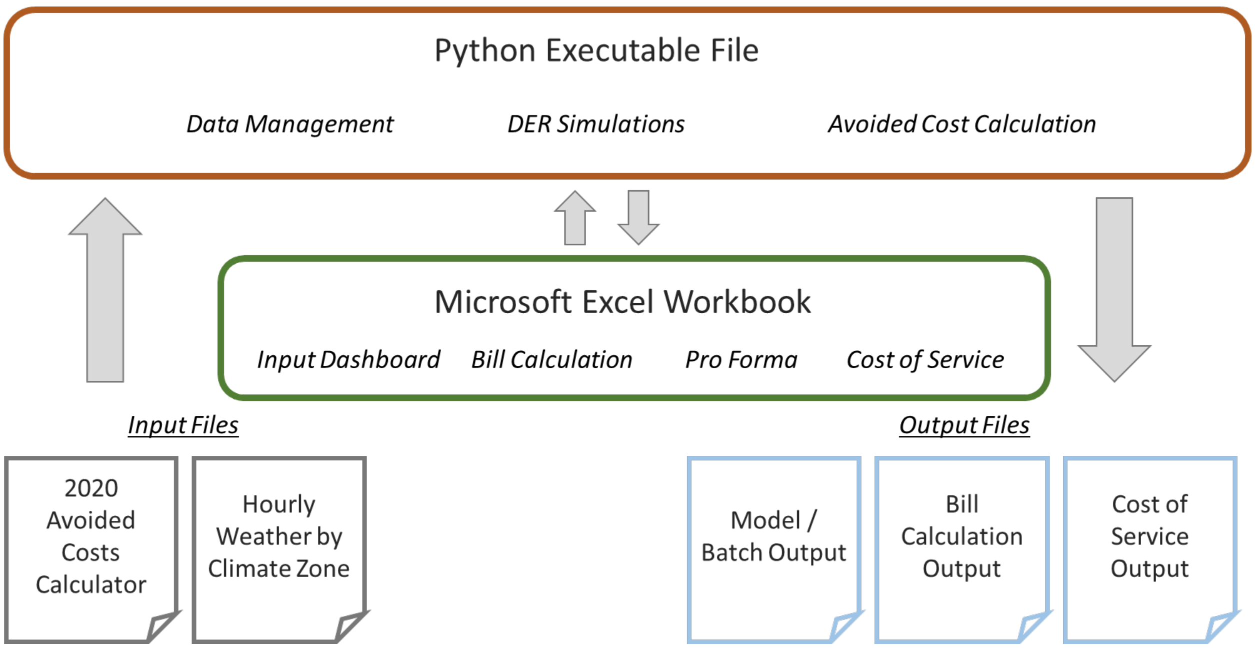
Verdant calculated the cost-effectiveness and cost to serve NEM 2.0 customers using a model built for this study. The model accounts for a customer's consumption, retail rate (including changes to retail rates over time), and distributed energy resource (DER) characteristics when calculating bill savings, cost-effectiveness, and cost of service. Below we provide an overview of the NEM 2.0 model and the overall methodology used in the cost-effectiveness and cost of service analysis. Section 4.2 describes the model inputs in more detail.

4.1.1 NEM 2.0 Lookback Study Model Overview

The NEM 2.0 Lookback Study Model is a DER simulation model that quantifies the various cash flows associated with the acquisition and operation of DERs including solar PV, solar PV paired with storage, wind turbines, and other renewable generation technologies. The model calculates the bill impacts of technologies throughout their lifetime and the associated acquisition costs including equity investments, financing, insurance, and tax costs (or credits). Looking from the utility perspective, the model quantifies the changes in the utility's marginal operating costs and considers incentive payments and program administration/interconnection costs. The model quantifies the present value of all cost and benefit streams for the entire life of the technology accounting for changes in retail rates, technology operating costs, and changes in utility marginal costs.

Figure 4-1 on the following page summarizes the model architecture and data flow. The NEM 2.0 Lookback Study model is built using Microsoft Excel 2016 and Python 3.8.5. The Excel workbook is where users select all model inputs. It also contains the NEM customer bill calculation, the pro forma analysis for DER economics, and the cost of service calculations. The Python model is compiled as an executable file to facilitate model usability (i.e., users do not need to install Python to use the NEM 2.0 Lookback Study model). The executable file is launched from the Excel user interface and is responsible for moving data between workbooks and tabs, simulating the output of all DERs, and performing the avoided cost calculation. The executable file also writes all the model results to the output destinations. Additional details on the model inputs and calculations are provided in subsequent sections. A quick start guide and model operating instructions are included in Appendix A.

FIGURE 4-1: MODEL ARCHITECTURE



4.1.2 Cost-Effectiveness Calculations

In 2009, the CPUC adopted an evaluation framework and methodology for assessing cost-effectiveness of distributed generation (DG) technologies.[47] The DG cost-effectiveness methodology is derived from the Standard Practice Manual (SPM) used for evaluating energy efficiency technologies and programs.[48] The 2009 CPUC decision on DG cost-effectiveness provides guidance on the tests to be used, the costs and benefits to be included in each test, and the avoided cost inputs to be used when calculating program costs and benefits. This analysis considers the cost-effectiveness of NEM 2.0 systems using five distinct

47 CPUC, "Decision Adopting Cost-Benefit Methodology for Distributed Generation," Decision (D.) 09-08-026, August 20, 2009

48 CPUC, California Standard Practice Manual: Economic Analysis of Demand-Side Programs and Projects, October 2001: https://www.cpuc.ca.gov/uploadedFiles/CPUC_Public_Website/Content/Utilities_and_Industries/Energy_-_Electricity_and_Natural_Gas/CPUC_STANDARD_PRACTICE_MANUAL.pdf

tests: The Participant Cost Test (PCT), Program Administrator (PA) test, Total Resource Cost (TRC) test, societal TRC test, and Ratepayer Impact Measure (RIM) test. We describe each test below.

Participant Cost Test (PCT)

The PCT is the measure of the quantifiable benefits and costs to the customer due to participation in the program. The benefits in the PCT include after tax bill savings[49] due to the installation and operation of a NEM 2.0 system and any other subsidies or incentives, including the Self-Generation Incentive Program (SGIP) rebate,[50] the federal Investment Tax Credit (ITC),[51] or the sale of Renewable Energy Credits (RECs).[52] The costs include all acquisition costs including the cost of the system, installation and interconnection, financing costs, ongoing operating and maintenance (O&M) costs, partial equipment replacement costs, and insurance costs. The NEM 2.0 tariff criteria set out in Section 2827.1(b)(1) lists the importance of ensuring that the NEM 2.0 tariff leads to the sustainable growth in customer-sited distributed generation (DG). The PCT is the SPM test best suited to measure the impact of the tariff on the future sustainable growth of customer-sited DG.

Program Administrator (PA) Test

The PA test measures the net costs of a program as a resource option based on the costs incurred by the PA (including incentive costs) and excluding any net costs incurred by the participants. The PA test can apply to utilities, including investor owned utilities (IOU) or municipal utilities, or to third parties that may administer a program. NEM 2.0 tariffs are implemented by the three California electric IOUs. The benefits in the PA test are the avoided costs due to the operation of a NEM 2.0 system. The costs are the utility's costs to operate the NEM 2.0 program (e.g., distribution upgrades, telemetry, and incremental billing costs).

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49 For residential customers, the bill savings are not taxable income. For nonresidential customers, the reduction in electricity costs are treated as a taxable income.

50 The SGIP rebate is available for fuel cells and combustion generators fueled by renewable fuels, wind turbines, and battery storage systems. Fuel cells, combustion generators, and wind turbines are NEM 2.0 eligible technologies while battery storage is eligible for SGIP and often paired with solar PV.

51 The federal investment tax credit provides a dollar for dollar reduction in the federal taxes for individuals receiving the credit. For systems installed and operational during the 2016-2019 time period of NEM 2.0, the ITC was 30 percent of the system's costs. For systems installed and operational in 2020, the ITC is 26 percent. More information on the federal ITC is available here: https://www.energy.gov/eere/solar/downloads/residential-and-commercial-itc-factsheets.

52 RECs are a legal instrument through which the environmental attributes of renewable energy generation are substantiated in the marketplace. https://www.epa.gov/greenpower/renewable-energy-certificates-recs

Ratepayer Impact Measure (RIM) Test

The RIM test measures what happens to customer rates due to changes in utility revenues and costs caused by the NEM 2.0 program. The population of ratepayers considered in the RIM test includes customers participating in the program and non-participants. The benefits in the RIM test are the avoided costs due to the operation of a NEM 2.0 system. The costs are the utility's costs to operate the NEM 2.0 program and the reduction in revenue received by the utility when participating customer bills decline due to the operation of the NEM 2.0 system. A RIM benefit-cost ratio less than 1.0 indicates the NEM 2.0 program will result in an increase in rates for all customers and an increase in bills for non-participating customers. In D.16-01-044, the CPUC discussed that the RIM test is a measure of two requirements in PUC Section 2827.1(b) (3) and (4). The RIM test compares the total benefits of the tariff (largely the avoided costs) to the total costs to the electrical system (primarily the customer bill savings).

Total Resource Cost (TRC) Test

The TRC measures the net costs of a program as a resource option based on the total costs of the program, including both the participant's and the utility's costs. The benefits in the TRC test are the avoided costs due to the operation of a NEM 2.0 system. Participant benefits received from outside California such as the federal ITC and revenue from the sale of RECs are also included as benefits. The costs include all participant acquisition costs, ongoing O&M costs, partial equipment replacement costs, and insurance costs. Federal taxes can be a cost or a benefit depending on whether the customer has a refund or a payment due. The costs also include utility program administration costs, NEM 2.0 interconnection costs, and NEM-specific costs on the distribution system.

The May 2019 CPUC cost-effectiveness decision (D.19-05-019) designated the TRC test as the primary cost-effectiveness test and adopted modified versions of the TRC, PA, and RIM tests for all distributed energy resources starting July 2019.[53] The cost-effectiveness analysis undertaken here is consistent with D.19-05-019, highlighting the TRC. The analysis also presents results from the five distinct tests (TRC, STRC, PA, RIM and PCT), emphasizing the PCT and the RIM consistent with D.16-01-044.

Societal Total Resource Cost Test

The Societal Total Resource Costs (STRC) test is a variant of the TRC test. In addition to the TRC benefits listed above, the STRC test can account for other societal, environmental, and health benefits. For this

[53] CPUC D.19-05-019, Decision Adopting Cost-Effectiveness Analysis Framework Policies for all Distributed Energy Resources, May 2019. http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M293/K833/293833387.PDF

analysis, the STRC test does not incorporate any additional benefits, however, it uses the societal discount rate rather than the utility discount rate.[54]

Table 4-1 summarizes what constitutes a cost and benefit for each of the cost-effectiveness tests, excepting the STRC test.

TABLE 4-1: STANDARD PRACTICE MANUAL TEST COMPONENTS

Component	Participant Cost Test (PCT)		Program Administrator (PA) Test		Total Resource Cost (TRC) Test		Ratepayer Impact Measure (RIM) Test	
	Benefit	Cost	Benefit	Cost	Benefit	Cost	Benefit	Cost
Electricity Avoided Costs			X		X		X	
Electric Bill Savings	X							X
State (SGIP) Rebate*	X							
REC Revenue	X				X			
Equity Investment		X				X		
Net Finance Costs		X				X		
O&M Costs		X				X		
Partial Equip. Replacement Cost		X				X		
Insurance Costs		X				X		
State Tax Refund / Paid**	X							
Federal Tax Refund / Paid**	X				X			

[54] CPUC D.19-05-019 adopts a three-element Societal Cost Test (SCT) to be tested through December 31, 2020 for informational purposes in the Integrated Resource Planning proceeding. Due to its experimental nature this test was not included in this analysis.

Investment Tax Credit†	X				X			
Utility NEM Costs††				X		X		X

* State incentives like the Self-Generation Incentive Program are typically considered costs in the PA test and the RIM test. However, for this analysis, we have excluded these costs from the PA and RIM test. We excluded these costs so that the RIM and PA costs would be limited to NEM costs and therefore indicative of NEM 2.0 cost-effectiveness.

** State and federal taxes can be costs or benefits depending on whether they are payments or refunds.

† The federal Investment Tax Credit (ITC) is considered a reduction in cost rather than a benefit in the TRC. For simplicity we have listed it as a benefit in this table.

†† Utility NEM costs in this context are the costs paid by the utility to set up and maintain a NEM customer.

4.1.3 Cost of Service Analysis

The full cost of service analysis compares an estimate of the utility cost of servicing NEM 2.0 customers with the customer's utility bills. The utility cost of servicing a NEM 2.0 customer is based on their use of the grid and an allocation of the fixed costs of service. To develop the cost of service, we used information from each utility's General Rate Case (GRC) Phase 2 filings. Transmission and regulatory costs were derived from the utility's rates. The cost of service estimates also include information on incremental costs the utilities bear due to NEM 2.0 customers. The incremental NEM 2.0 costs were developed from information each utility provided the CPUC in advice letters and additional information provided to Verdant on on-going administrative costs.

The total cost of service has inputs or components that are similar to the cost-effectiveness analysis, but it also differs from the cost-effectiveness analysis. The cost-effectiveness analysis is based on an estimate of the avoided costs (TRC, PA, and RIM) or avoided utility bills (PCT and RIM) from the reduction in usage after becoming a NEM 2.0 customer. The cost-effectiveness analysis requires a technology lifetime forecast of the avoided costs and bill savings to compare to the cost of the system (TRC and PCT) or the cost of the program (NEM 2.0 costs for TRC, PA, and RIM). In comparison, the cost of service analysis compares the customer bill from the analysis year to the utility's costs of servicing the customer in that year. The total cost of service estimates the cost of servicing the customer and their load. The cost of service includes marginal costs associated with energy generation and capacity, marginal distribution costs, embedded transmission costs, regulatory costs, fixed customer costs, and first-year NEM costs. For this analysis, we developed cost of service estimates for both the pre-installation consumption and the post-installation net load.

Cost of Service Development

To estimate the full cost of service, we reached out to each utility to receive the utility's most recent Phase 2 GRC filings. While the final allocation of utility costs to customer rates is a negotiated process that abstracts to some degree from the public information available in the Phase 2 GRC filings, using the GRC filings provides a transparent approach to approximating components of the utility's full cost of service.

Not all components of the cost to serve a customer are presented within the Phase 2 GRC. The regulatory and transmission costs and the costs specific to NEM 2.0 customers' interconnection, billing, and incremental grid costs were not presented in the GRC Phase 2 filings.[55] The regulatory and embedded transmission costs were derived from utility tariffs. The regulatory costs are items that are added to the customer bills but not developed as part of the GRC. The billing components that are included in the cost of service estimates are listed in Table 4-2 by utility. The regulatory costs listed in Table 4-2 include, but are not limited to, nuclear decommissioning charges, public purpose program charges, and Department of Water Resources (DWR) bond charges.

TABLE 4-2: BILLING COMPONENTS ADDED TO THE COST OF SERVICE

Utility	Bill Component added to Cost of Service
PG&E	Transmission Transmission Rate Adjustments Nuclear Decommissioning Charge Public Purpose Programs Reliability Services Competition Transition Charges Energy Cost Recovery Amount Department of Water Resources Bond Charge New System Generation Charges
SCE	Transmission Transmission Owners Tariff Charge Adjustments Transmission Access Charge Balancing Account Adjustment Competition Transition Charge Reliability Service Balancing Account Adjustment New System Generation Charge Nuclear Decommissioning Charge Public Purpose Programs Charge Department of Water Resource Bond Charge PUC Reimbursement Fee
SDG&E	Transmission Transmission Revenue Balancing Account Adjustment

55 PG&E included an estimate of their Marginal Transmission Capacity Costs (MTCC) in their GRC. Verdant examined using these costs as the transmission costs of service, but the resulting transmission costs were deemed too low. Verdant instead used the bill-related transmission costs when developing estimates of PG&E's cost of service.

Transmission Access Charge Balancing Account Adjustment
Department of Water Resources Bond Charge
Public Purpose Programs
Nuclear Decommissioning
Competition Transition Charges
Reliability Services
Total Rate Adjustment Component
Local Generation Charge

The embedded transmission costs are filed with the Federal Energy Regulatory Commission (FERC), not developed as part of the GRC. These embedded transmission costs are added to the customer bill and the cost of service estimates as transmission costs. For all three utilities, the regulatory and transmission costs are presented as a cost per kWh within the utility tariff structure. For the cost of service calculations, the regulatory and transmission components of the tariff structure were maintained, multiplied by the appropriate consumption/net load kWh, and added to the cost of service. The NEM 2.0 specific costs were developed from cost information the utilities provided the CPUC in advice letters. These costs are also added to the costs developed from the GRC filings.

Our approach uses the information described above to estimate the cost of service for the pre- and post-NEM 2.0 load shape. The estimates of cost of service are then compared to estimates of customers' pre- and post-NEM utility bills to analyze the utility, technology, and sector specific aggregate bill relative to the estimate of their average cost of service. Additional information on load shape selection, binning strategy, and weighting are included in Section 4.2.3.

Table 4-3 lists the marginal cost terms and sources that were used in the cost of service analysis.[56]

TABLE 4-3: COST OF SERVICE COMPONENTS AND SOURCES

Cost of Service Component	PG&E	SCE	SDG&E
Marginal Energy Cost (MEC)	2017 GRC	2018 GRC	2016 GRC
Marginal Generation Capacity Cost (MGCC)	2017 GRC	2018 GRC	2016 GRC
Marginal Distribution Capacity Cost (MDCC)	2017 GRC	2018 GRC	2016 GRC
Embedded Transmission (T)	Tariff Pass Through	Tariff Pass Through	Tariff Pass Through
Regulatory (Reg)	Tariff Pass Through	Tariff Pass Through	Tariff Pass Through

56 The COS inputs provided by PG&E were in 2020 dollars while SCE's were in 2018 and SDG&E's were in 2017 dollars. The COS analysis compares the first year COS to first year customer bills from rate sheets late in 2019 to early 2020. The SCE and SDG&E COS information was adjusted by a CPI adjustment to put the SCE and SDG&E COS information in 2019 dollars. The numbers listed below represent the numbers provided by the utilities. SCE's were adjusted by 1.016 and SDG&E's by 1.032 to adjust the information to 2019 dollars.

Marginal Customer Cost (MCC)	2017 GRC	2018 GRC	2016 GRC
Net Energy Metering Costs (NEMC)	Advice Letter 5640-E dated 10/10/2019	Advice Letter 4047-E dated 10/10/2019 and NEM Labor Costs[57]	Advice Letter 3426-E dated 9/30/2019

Each utility's full cost of service development is unique. In general, the utility marginal costs were multiplied by the NEM account's costing determinants, including hourly energy usage, peak demand coincident with generation, transmission and distribution peaks, and their maximum demand. A stylized full cost of service formula is described below:

$$\begin{aligned} Full\ COS = \ & MEC \cdot Load * EPMC(G) + MGCC \cdot GenerationAllocationFactor \cdot Load \cdot EPMC(G) \\ & + MDCC \cdot DistributionAllocationFactor \cdot Demand \cdot EPMC(D) + (T + Reg) \cdot Load \\ & + MCC \cdot EPMC(D) + NEMC \end{aligned}$$

Where:

Load: Hourly kWh observed by the utility.

EPMC: Equal percentage marginal costs are factors to scale the different marginal cost components to enable the utility to reach their revenue requirements. The MEC and the MGCC are multiplied by the EPMC for energy generation (G) while the MDCC and the MCC are multiplied by the EPMC for energy distribution (D). Multiplying the marginal cost components by the EPMC scales the marginal costs to the allocated cost of service.

Generation Allocation Factor: Generation allocation factors allocate the MGCC to hours where generation capacity needs are likely to be high. These factors were supplied by the utilities in responses to data requests.

Distribution Allocation Factor: Creates a weighted load for different customer classes where generation capacity needs are likely to be high. These factors were supplied by the utilities in responses to data requests.

Comparison of the estimated full cost of service to the estimated utility bills provides information on a group's over or under payment relative to their costs to serve, but there are many reasons why the estimates of the cost of service and their utility bill estimates may diverge. The GRC Phase 2 findings used for this study represent the GRC filings in effect during the NEM 2.0 lookback study time period. These

[57] NEM labor costs were provided in an Excel workbook provided by SCE to the Verdant team. Confidential R.14-07-002 Itron-SEC-001 Q.01 Attachment 2 of 8 NEM2.0Setups2017-2019 labor costs 06-30-2020.

filings, however, do not present the utility's cost of service differentiated by the customer's NEM 2.0 status. The cost of service estimate includes additional utility costs, not included in the GRC Phase II filings, associated with NEM 2.0 interconnection and distribution upgrades influenced by NEM 2.0 customers. It is likely, however, that the cost of service estimates developed for groups of NEM 2.0 customers differ from their utility bills due in part to incomplete information on NEM 2.0 specific costs, the regulated rate making process, and the heterogeneity of customer costs and bills that are difficult to reflect in modeling exercises. It is also true that the cost of service estimates and utility bills for NEM 2.0 customers in the year prior to their NEM 2.0 system installation may differ for many of the same reasons as why post-installation bill and cost of service estimates differ. Customer rates are a regulated process that can cause group-specific utility bills to differ from utility costs. Costs and rates are developed for large groups of customers; NEM 2.0 customers tend to have larger consumption than the average customer (See Section 3, Table 3-1), which could cause their bills to diverge from their cost of service. When reviewing the findings from the cost of service analysis, it is important to recall that both the cost of service and the bills are estimates and that there are many reasons why these numbers may diverge for specific groups.

The following sub-sections provide additional details on each utility's cost of service calculation.

PG&E Cost of Service

The PG&E cost of service estimates are based on information from PG&E's 2017 GRC. The PG&E cost of service analysis components are described below.

PG&E Energy Cost

$$Cost = MEC \cdot EPMC(G) \cdot Load$$

The *MEC* was provided for five time-of-use (TOU) periods and three voltage levels (see Table 4-4).[58] The *MEC* was multiplied by the *EPMC(G)* and the sum of the kWh during the TOU period.[59] PG&E's *EPMC(G)* for this analysis is 1.79.

TABLE 4-4: PG&E MARGINAL ENERGY COSTS BY TOU AND VOLTAGE ($/KWH)[60]

TOU Period	Marginal Energy Costs ($/kWh)		
	Transmission	Primary Distribution	Secondary Distribution
Summer On-Peak	0.0494	0.05033	0.05282

[58] The *MEC* listed in Table 4-4 incorporates line losses that differ by voltage level.

[59] The load applied to the *MEC* included both the energy received by the customer from the utility and the energy delivered by the customer to the utility.

[60] The *MEC* values are from Table 2.2 of PGE-02 Marginal Costs Volume 1 or 2 – GRC-2017-PHII_Test_PGE201606303781.pdf, pg 35.

Summer Partial Peak	0.0379	0.03861	0.04052
Summer Off-Peak	0.02665	0.02715	0.02849
Winter On-Peak	0.04192	0.04271	0.04482
Winter Off-Peak	0.02409	0.02454	0.02576

PG&E Generation Capacity Costs

$$Cost = Marginal\ Generation\ CapacityCost \cdot Load \cdot PCAF\ \cdot\ EPMC(G)$$

The capacity cost was provided to Verdant as a cost per kW-Year by voltage level. The capacity cost for transmission voltage is $28.64, primary distribution $29.48, and secondary distribution is $31.25.[61] The capacity cost is multiplied by the peak capacity allocation factor, the customer's hourly load, and the *EPMC(G)* factor (1.79). The peak capacity allocation factors sum to one and differ by PG&E rate groups and are used to allocate the peak capacity cost to hours with higher likelihood of energy demand.[62]

PG&E Distribution Capacity Costs

PG&E's MDCC values were provided in three categories: Primary Distribution, Primary New Business, and Secondary. All costs were provided by PG&E's 19 divisions. For the cost of service estimates, customers taking service under primary voltage are assigned the primary distribution and new business costs while customers taking service under secondary voltage are assigned all three cost components.

$$\begin{aligned} Cost = {} & Primary\ Distribution\ Cost + Primary\ New\ Business\ Cost \\ & + Secondary\ Distribution\ Cost \end{aligned}$$

Where:

$$Primary\ Distribution\ Cost = Primary\ Distribution\ Capacity\ Cost \cdot PCAF \cdot Load \cdot EPMC(D)$$

Primary Distribution costs are PG&E's primary marginal distribution capacity costs for the 19 divisions (See Table 4-5). The primary distribution capacity costs are multiplied by the peak capacity allocation factors that sum to one by division.[63] The load used for this calculation is the customer's hourly non-negative load. The hourly non-negative load is the utility delivered energy. The *EPMC(D)* was provided to Verdant by PG&E (2.2).

61 These capacity costs include line losses that differ by voltage level.

62 PG&E's Peak Capacity Allocation Factors were provided to Verdant in Excel format.

63 PG&E's Peak Capacity Allocation Factors were provided to Verdant in Excel format.

$$Primary\ New\ Business\ Cost = Primary\ New\ Business\ Capacity\ Cost \cdot FLTFactor \cdot Max\ Demand \cdot EPMC(D)$$

The primary distribution new business capacity costs were provided to Verdant for PG&E's 19 divisions. The primary new business capacity costs are multiplied by the final line transformer factor for residential and small commercial customers.[64] Residential and small commercial customers usually share final line transformers. The final line transformer factor is a number greater than zero and less than one that accounts for the diversity that is applied for customers who share a final line transformer. Larger customers often have their own final line transformer, eliminating diversity and resulting in a final line transformer value of one. These values were then multiplied by the customer's maximum annual demand and the *EPMC* for distribution.

$$Secondary\ Distribution\ Cost = Secondary\ Distribution\ Capacity\ Cost \cdot FLTFactor \cdot Max\ Demand \cdot EPMC(D)$$

The secondary distribution costs were provided to Verdant for PG&E's 19 divisions. For customers taking service on secondary voltage, the secondary distribution costs listed in Table 4-5 are multiplied by the final line transformer factor, the customer max demand, and the *EPMC(D)* to determine the estimate of the customer's secondary distribution cost.

Table 4-5 provides PG&E's marginal distribution capacity costs by division.

TABLE 4-5: PG&E MARGINAL DISTRIBUTION CAPACITY COSTS BY DIVISION ($/KW)[65]

Division	PG&E Marginal Distribution Capacity Cost ($/kW)		
	Primary Distribution	Primary New Business	Secondary Distribution
Central Coast	67.58	9.78	0.83
Fresno	38.66	12.23	1.25
North Valley	52.24	12.83	1.00
Sierra	29.98	13.12	0.97
Stockton	32.63	10.76	1.13
East Bay	19.55	10.5	0.61
De Anza	34.87	12.49	0.76
North Bay	28.78	9.94	1.42
Humboldt	72.35	8.81	0.83
Mission	13.34	10.18	0.72
Diablo	17.39	11.43	0.91
Kern	33.33	11.32	1.03

64 PG&E's Final Line Transformer Factors were provided to Verdant in Excel format.

65 The *MDCC* values are from Table 6.1 of PGE-02 Marginal Costs Volume 1 or 2 – GRC-2017-PHII_Test_PGE201606303781.pdf, pg 35.

Sacramento	40.02	11.74	1.04
Peninsula	31.09	8.49	0.77
Los Padres	55.25	9.38	0.82
San Jose	39.25	11.43	0.90
Yosemite	58.87	11.52	1.37
Sonoma	119.31	11.22	1.03
San Francisco	39.53	12.78	1.18

PG&E Customer Cost

$$Customer\ Cost = MCC \cdot EPMC(D)$$

The marginal customer costs are the costs associated with various customer costs, including but not limited to the customer's transformer, conductors, meter, and billing processing. For PG&E these costs were provided by customer class and voltage. Table 4-6 lists the MCC values. The EPMC(D) is 2.2.

TABLE 4-6: PG&E MARGINAL CUSTOMER COSTS ($/CUSTOMER-YEAR)[66]

Class	Size/Rate/Voltage	MCC ($/Customer)
Residential	N/A	$156.13
Agriculture	Ag A	$929.13
	Ag B Small	$2,863.69
	Ag B Large	$2,924.83
Small Commercial	Single Phase	$433.85
	Poly Phase	$1,557.37
Medium Commercial	A10-S/E-19VS	$3,259.13
	A10-P/E-19VP	$5,092.45
Large Commercial and Industrial	E19-S	$10,471.44
	E19-P	$8,829.94
	E19-T	$10,159.83
	E20-S	$11,093.22
	E20-P	$9,182.1
	E20-T	$11,224

SCE Cost of Service

The SCE cost of service estimates are based on information from SCE's 2018 GRC. Each of the different components of the SCE cost of service are described below.

66 The MCC values are from Table 7.2 of PGE-02 Marginal Costs Volume 1 or 2 – GRC-2017-PHII_Test_PGE201606303781.pdf, pg 117.

SCE Energy Cost

$$Cost = MEC \cdot EPMC(G) \cdot Load * LossFactor$$

The *MEC* was provided by SCE for six TOU periods (see Table 4-7). The *MEC* were multiplied by the *EPMC(G)* and the sum of the kWh during the TOU period.[67] SCE's *EPMC(G)* is 1.10. The line loss factors were provided by TOU periods and voltage.

TABLE 4-7: SCE MARGINAL ENERGY COSTS BY TOU ($/KWH)[68]

TOU Period	MEC ($/kWh)
Summer On-Peak	0.04884
Summer Partial Peak	0.04397
Summer Off-Peak	0.03559
Winter On-Peak	0.04622
Winter Partial Peak	0.03906
Winter Off-Peak	0.02475

SCE Generation Capacity Costs

$$Cost = MGCC \cdot Generation\ Allocation\ Factor \cdot Load \cdot EPMC(G)$$

The *MGCC* and the generation allocation factors were provided to Verdant as a $/kWh value for all hours of the year.[69] The allocated *MGCC* are applied to the positive load (utility delivered) by hour and multiplied by 1.1, the *EPMC(G)*.

SCE Distribution Capacity Costs

$$Cost = ((Circuit\ Peak\ Capacity\ Cost + B_{Bank}Capacity\ Cost + A_{Bank}Capacity\ Cost) \cdot Load \\ +\ Grid\ Cost * noncoincident\ demand) \cdot EPMC(D)$$

The *MDCC* is a combination of costs associated with the circuit peak, B-bank peak, and the A-bank peak capacity costs and the distribution grid costs. These costs were provided as the total distribution peak capacity marginal costs in the Errata GRC tool and the distribution grid costs. The peak costs were allocated across an 8,760 and applied to the positive customer load by hour while the distribution grid costs were applied to noncoincident peak demand. The distribution capacity costs were multiplied by the *EPMC(D)*. SCE's EPMC(D) is 1.23.

67 The load applied to the MEC included both the energy received by the customer from the utility and the energy export by the customer to the utility.

68 Values from SCE's MCRR model provided to Verdant.

69 MGCC and the allocation factors are derived from SCE's 2018 Errata GRC Tool

SCE Customer Cost

$$Cost = MCC \cdot EPMC(D)$$

The marginal customer costs may include, but are not limited to, the customer's transformer, conductors, meter, and billing processing costs. These costs differ by rate class and voltage. Table 4-8 lists SCE's MCC values and the EPMC(D) is 1.23.

TABLE 4-8: SCE MARGINAL CUSTOMER COSTS ($/CUSTOMER-YEAR)[70]

Rate Class	MCC ($/Customer-Year)
Domestic	$124.25
GS-1	$196.63
TC-1	$195.30
GS-2	$1,586.05
GS-3	$2,954.84
TOU-8-Sec	$4,236.37
TOU-8-Pri	$2,200.81
TOU-8-Sub	$15,322.55
AG&P < 200 KW	$1,141.04
AG&P >= 200 KW	$3,317.24

SDG&E Cost of Service

The estimates of SDG&E's cost of service are based on information from SDG&E's 2016 GRC. The different components of the SDG&E cost of service are described below.

SDG&E Energy Cost

$$Cost = MEC \cdot EPMC(G) \cdot Load \cdot LossFactor$$

The *MEC* was provided for six TOU periods (see Table 4-9). The *MEC* values were multiplied by the *EPMC(G)* and the sum of the kWh during the TOU period.[71] SDG&E's *EPMC(G)* is 1.4292. The line loss factors were provided by TOU periods and voltage.

70 The MCC values are from SCE's MCRR Tool, MC Distribution Tab.

71 The load applied to the MEC included both the energy received by the customer from the utility and the energy export by the customer to the utility.

TABLE 4-9: SDG&E MARGINAL ENERGY COSTS BY TOU ($/KWH)

TOU Period	MEC ($/kWh)
Summer On-Peak	0.055053
Summer Partial Peak	0.045749
Summer Off-Peak	0.037654
Winter On-Peak	0.049795
Winter Partial-Peak	0.044299
Winter Off-Peak	0.038204

SDG&E Generation Capacity Costs

$$Cost = MGCC \cdot Generation\ Allocation\ Factor \cdot Load \cdot EPMC(G)$$

The *MGCC* was provided to Verdant as a $/kW and the generation allocation factors were provided to Verdant as a vector of factors representing hours with the highest loss of load likelihood. The generation allocation factors are normalized to sum to one over the year.[72] The allocated *MGCC* values are applied to the positive load (utility delivered) by hour and multiplied by 1.4292, the *EPMC(G)*.

SDG&E Distribution Capacity Costs

$$Cost = MDCC \cdot Max\ Demand \cdot EPMC(D)$$

The *MDCC* is a combination of costs associated with feeder demand, local distribution demand, and substation demand. These costs were provided as a cost per kW-Year. The costs are multiplied by the customer's max demand and by the *EPMC(D)*. SDG&E's *EPMC(D)* is 1.639.

SDG&E Customer Cost

$$Cost = MCC \cdot EPMC(D)$$

The marginal customer cost may include but is not limited to the customer's transformer, conductors, meter, and billing processing costs. These costs differ by rate class, customer size, and voltage. Table 4-10 lists the MCC values and the *EPMC(D)* is 1.639.

[72] MGCC is derived from SDG&E's ALJ Request PD8-2-17 Ch 6 Workpaper Commodity Allocation and EPMC Proposed TOU. The generation allocation factors were provided to Verdant by SDG&E in an Excel workbook.

TABLE 4-10: SDG&E MARGINAL CUSTOMER COSTS ($/CUSTOMER-YEAR)[73]

Sector	Size (kW)	Voltage	MCC ($/Customer-Year)
Residential	N/A	Secondary	$152.09
Small Commercial	0-5kW	Secondary	$323.57
Small Commercial	0-5kW	Primary	$785.49
Small Commercial	>5-20kW	Secondary	$588.7
Small Commercial	>5-20kW	Primary	$785.49
Small Commercial	>20-50kW	Secondary	$1,232.43
Small Commercial	>20-50kW	Primary	$785.49
Small Commercial	>50kW	Secondary	$1,709.43
Small Commercial	>50kW	Primary	$785.49
Commercial/Industrial	<500kW	Secondary	$2,272.23
Commercial/Industrial	<500kW	Primary	$1,101.95
Commercial/Industrial	<500kW	Transmission	$7,365.07
Commercial/Industrial	500-1,200kW	Secondary	$5,452.08
Commercial/Industrial	500-1,200kW	Primary	$1,275.76
Commercial/Industrial	500-1,200kW	Transmission	$12,851.85
Commercial/Industrial	>1,200kW	Secondary	$5,452.08
Commercial/Industrial	>1,200kW	Primary	$1,923.27
Commercial/Industrial	>1,200kW	Transmission	$18,662.82
Agriculture	0-20kW	Secondary	$583.8
Agriculture	0-20kW	Primary	$918.69
Agriculture	>20kW	Secondary	$2,102.45
Agriculture	>20kW	Primary	$1,054.85

4.2 COST-EFFECTIVENESS AND BILL CALCULATION INPUTS AND ASSUMPTIONS

This section summarizes the inputs and assumptions used in the cost-effectiveness and bill calculation portion of the NEM 2.0 Lookback Study model.

4.2.1 Avoided Costs

The avoided costs used in this analysis are based on the CPUC 2020 Avoided Cost Calculator (ACC) v1c approved on June 25, 2020.[74] The avoided costs were generated for all utility and climate zone (CZ) combinations. The analysis includes all components of the avoided costs included in the 2020 ACC:

- Cap and Trade
- Greenhouse gas (GHG) Adder

[73] The MCC values are from 2016 GRC P2 Dist Rev Alloc (Chapter 5 Rebuttal Workpaper – Confidential).

[74] CPUC Cost-Effectiveness. https://www.cpuc.ca.gov/General.aspx?id=5267

- GHG Rebalancing
- Energy
- Generation Capacity
- Transmission Capacity
- Distribution Capacity
- Ancillary Services
- Losses
- Methane Leakage

For simplicity, we depict total electric avoided costs as a single sum of all electric avoided cost components for each utility and climate zone.

Customer bills are calculated based on utility baseline territories, which do not always have the same boundary definitions as the California Energy Commission (CEC) building climate zones.[75] Table 4-11 shows our mapping of utility baseline territories to climate zones used for cost-effectiveness simulations. We further collapse PG&E and SCE's climate zones into a handful of groups to minimize model redundancy and increase sample sizes. This process is described in Section 4.2.3.

TABLE 4-11: UTILITY BASELINE TERRITORY TO AVOIDED COST CALCULATOR CLIMATE ZONE MAPPING

Utility	Utility Baseline Territory	Avoided Cost Calculator Climate Zone
PG&E	P	CZ2 / CZ16
	Q	CZ3B
	R	CZ12 / CZ13
	S	CZ11 / CZ12
	T	CZ3A / CZ3B
	V	CZ1
	W	CZ13
	X	CZ2 / CZ4 / CZ12
	Y	CZ16
	Z	CZ16
SCE	5	CZ5
	6	CZ6
	8	CZ8

75 California Building Climate Zones. https://www.buildingincalifornia.com/wp-content/uploads/2014/02/Building_Climate_Zones.pdf

	9	CZ9
	10	CZ10
	13	CZ13
	14	CZ14
	15	CZ15
	16	CZ16
SDG&E	Coastal	CZ7
	Inland	CZ10
	Mountain	CZ14
	Desert	CZ15

4.2.2 Weather Data Sources

Weather data are used throughout this analysis for various purposes. Temperature data are used to normalize load shapes and align usage profiles with the avoided cost calculator (see Section 4.2.3). Irradiance, wind speed, and temperature data are used to model PV and distributed wind generation (see Section 4.2.4).

Ground-based weather data were used throughout this analysis. A single weather station location was assigned to each climate zone. Solar PV and distributed wind simulations for each climate zone are based on the weather station assigned to each climate zone. Similarly, load data for each climate zone were normalized using the weather data assigned to each climate zone. Table 4-12 on the following page lists the weather station locations assigned to each climate zone. Where more than one station is listed, data from both stations were combined to generate a single weather dataset. Other missing data were filled with linear interpolation. Weather data for 2004 – 2017 were provided by Energy and Environmental Economics, Inc. (E3) based on inputs used for development of the 2020 ACC. Temperature data for 2018 – 2019 were downloaded by Verdant directly from airport automated surface observation stations (ASOS).

TABLE 4-12: CLIMATE ZONE TO WEATHER STATION MAPPING

Climate Zone	Weather Station Name
CZ1	California Redwood Cost-Humboldt County Airport
CZ2	Charles M Schulz – Sonoma County Airport
CZ3A/CZ3B	Metropolitan Oakland International Airport
CZ4	Reid-Hillview Airport of Santa Clara County / Norman Y Mineta San Jose International Airport
CZ5	Santa Maria Public Airport Capt G Allan Hancock Field / San Luis County Regional Airport
CZ6	Zamperini Field Airport / Long Beach Airport Daugherty Field
CZ7	San Diego International Airport

CZ8	Fullerton Municipal Airport / John Wayne – Orange County Airport
CZ9	Bob Hope Airport
CZ10	Riverside Municipal Airport / Ontario International Airport
CZ11	Red Bluff Municipal Airport / Redding Municipal Airport
CZ12	Sacramento Executive Airport / Sacramento International Airport
CZ13	Fresno Yosemite International Airport
CZ14	Palmdale USAF Plant 42 Airport
CZ15	Palm Springs International Airport
CZ16	Blue Canyon – Nyack Airport

The 2020 Avoided Cost Calculator is based on a typical weather year (CTZ22) developed for the California Energy Commission's Title 24 Building Energy Efficiency Standards.[76] The CTZ22 weather year is developed by stitching together separate months from different years that are deemed representative of typical weather. The historical months used to develop the CTZ22 weather year are summarized in Table 4-13 on the following page. We used the CTZ22 weather year to develop DER simulations and to weather normalize historical load shapes. This ensures that the model inputs are aligned with the Avoided Cost Calculator. Section 4.2.3 describes the weather normalization of load shapes. Additional details on the DER simulation approach are provided in Section 4.2.4.

TABLE 4-13: CTZ22 WEATHER YEAR MAPPING

Month	Historical Year
Jan	2004
Feb	2008
Mar	2014
Apr	2011
May	2017
Jun	2013
Jul	2011
Aug	2008
Sep	2006
Oct	2012
Nov	2005
Dec	2004

[76] Time Dependent Valuation of Energy for Developing Building Efficiency Standards. Energy + Environmental Economics. May 2020. https://efiling.energy.ca.gov/GetDocument.aspx?tn=233345

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4.2.3 Load Shape Selection, Customer Binning, and Weather Normalization

Customers are assigned into simulation bins based on the following criteria:

- Electric utility (PG&E, SCE, or SDG&E)
- Sector (Residential, Commercial, Industrial, or Agricultural)
- Climate zone
- Total customer electricity consumption
- Ratio of customer size to DER system size
- Technology (Solar PV, Solar PV + Storage, Fuel Cell, Wind Turbine)
- NEM 2.0 retail rate
- Service type (all electric versus dual fuel), for residential customers
- Electric vehicle (EV) rate, for residential customers

We defined the customer's consumption as the usage prior to installing the NEM generator, with each customer's NEM permission to operate (PTO) date used to define the NEM installation period. Customers with pre-PTO load data with evidence of solar PV generation (i.e., negative load) were removed from the sample. In all cases we selected customers with a full calendar year of pre-PTO consumption data.

All the characteristics listed above could have an influence on cost-effectiveness and cost of service, so ideally the 8,760 hourly profiles applied to the simulations would account for all these characteristics by developing stratifications based on them. In practice, however, there were several considerations that required the generation of load profiles at a higher level of aggregation. The primary issue is the availability of enough data to sufficiently represent all the strata. In some cases, the number of accounts with a year of interval data was too few to maintain customer confidentiality and/or develop a representative load profile. An additional consideration was whether there was sufficient evidence that a characteristic yielded any meaningful difference in the load profiles. For example, the load profiles of customers who installed solar PV versus those who also added storage did not yield enough of discernible or intuitive difference to justify the additional complexity. In contrast, the comparison of customers under an EV rate and with different service types showed that it was important to capture these effects when possible.

Given these considerations, the development of load profiles was based on, for residential customers, a targeted level of stratification of utility, climate zone, customer size, service type, and EV rate. For commercial customers, the targeted level of stratification was utility, climate zone, and customer size. For industrial and agricultural customers, the level of stratification was only the utility, except for one utility that needed to split agricultural customers into two customer size groups. If there were not sufficient accounts to represent a targeted stratum, the final load profile was based on a more aggregated level.

The interval data provided for customers represent consumption from a variety of time periods covering various calendar years. These load data were aligned to the CTZ22 weather year using a day-mapping methodology developed by E3. All timeseries data are assigned in 24-hour days to bins by workday/weekend-holiday, and season. Within each bin, the timeseries data are ranked by a temperature metric for each day. The remapping then reorders the timeseries data by day within each bin by mapping temperature metric ranks for the master data (the CTZ22 weather year) and the customer load shapes. This ensures that the load shapes are aligned with the utility avoided costs.

Given variations in the interval data provided, there are some nuances to the alignment of data to the CTZ22 weather year that require some description. The E3 methodology is based on mapping a complete calendar year of data to the CTZ22 weather year. In cases where a customer's interval data is not based on a complete calendar year (e.g., from June 2017 to May 2018) the mapping methodology can result in a few days in the CTZ22 calendar without data. In these cases, these days were populated with the customer's month and day of week average, which prevents creating a load profile based on incomplete data. Given that the days without data were distributed essentially randomly and were at most two or three per customer, this method of data development does not consequentially change the customer's actual data, particularly once the data have been aggregated.

After mapping every customer's interval data to the CTZ22 calendar, the 8,760 profiles at the customer level were summarized at multiple levels of granularity, from the inclusion of all the targeted strata to various levels with different attributes removed, such as the service type or the differentiation between "small" and "medium" customer size bins. One issue we encountered in the averaging of load shapes was that there was a misalignment of when individual accounts experience their peak days. The results were aggregated load shapes that markedly lowered the load factor when compared to typical individual accounts. While the general timing and overall energy of these load profiles is accurate, they would lead to an underestimation of any charges related to peak demand. To remedy this, as part of the summarization, we calculated various percentiles in each hour in addition to the average. Where the summarized hourly values represented a monthly peak, these percentiles were used to adjust it upward so that the resulting load shapes had load factors that were similar to those seen in individual load profiles.

These multiple summaries were then merged with a template based on the complete set of target strata and the final selected load profile was based on whether the number of accounts met a minimum threshold. The load profiles for most strata were based on the full level of granularity. For some strata, however, and primarily in the residential sector, the number of accounts was well under the minimum of

15 required to safeguard privacy. For example, EV rate customers with dual fuel service in a specific climate zone and customer size would likely have only a few accounts, so an alternate load profile (such as one excluding the service type stratum) with a sufficient number of accounts was selected to represent this segment.

After the steps described above, there were two remaining issues with the 8,760 profiles. The first is that in many cases, the interval data provided was only a small fraction of the number of customers in a bin. The second was the reliance in some cases on alternate levels of aggregation (as described above) to develop the load profile. Both meant that the annual energy associated with the load profile was not always representative of the annual energy associated with all customers in a bin (as determined from the monthly billing data). For example, the average annual energy based on monthly bills for a bin might be 10 to 20 percent different from the sum of the hourly load profile. Consequently, the final load profiles were based on normalizing the load profiles so that they represented the percentage of annual consumption in each hour. These load shapes were then multiplied by the bin-specific annual consumption. This ensured that there was no disconnect between a load profile's annual energy and that of the customers in a bin.

Finally, we recognize that developing estimates of cost-effectiveness based on pre-interconnection consumption may result in over-estimating the ratio of PV generation to load and therefore distort cost-effectiveness findings. Customers often install solar PV while at the same time investing in an electric appliance, an electric vehicle, or making an expansion to the home. All of these decisions will result in an increase in consumption relative to the pre-interconnection consumption levels (see Table 3-1). The post-interconnection consumption is not directly measurable, therefore we estimate it by adding the simulated solar PV generation to the utility-metered net load. For purposes of this analysis, we assume the same consumption levels in the baseline (no-NEM) case as in the NEM case. As a final step in load shape development, we increase each hourly consumption value by the ratio of post-installation consumption to pre-installation consumption.

In summary, a single load profile applies to more than one bin, and therefore is used in multiple simulations in the study. For example, since the technology type was not a stratum used in developing the load profiles, the SDG&E, Coastal, Small Residential consumption shape will be used to model a customer who installed a small solar PV system and a different customer who installed a large solar PV system paired with storage. Nevertheless, the load profiles generated for the simulations are designed to capture as much of the relevant characteristics as possible.

4.2.4 DER Performance Modeling

The NEM 2.0 Lookback Study model generates simulated output for solar PV systems, solar PV systems paired with battery storage, fuel cells, and distributed wind technologies based on user defined inputs such as system size, tilt, azimuth, and storage round-trip-efficiency (RTE). Below we describe the modeling approach for each NEM eligible technology.

Solar PV Performance Modeling

Solar PV production is estimated using the PV_LIB Toolbox developed by the PV Performance Modeling Collaborative.[77] The PV_LIB Toolbox provides a set of well-documented functions for simulating the performance of photovoltaic energy systems. The NEM 2.0 Lookback Study model uses irradiance, temperature, and wind speed data from the CTZ22 weather files (see Section 4.2.2); along with DC system size, tilt, and azimuth; as inputs into the PV_LIB toolbox functions. We use the PV Watts model in PV_LIB to calculate AC power output net of losses.[78]

In our model, solar PV systems are assigned a useful life of 25 years.[79] We model PV systems as being paired with string inverters with a useful life of 13 years.[80] Hourly PV output is reduced by a 1.36 percent degradation rate per year.[81] This degradation rate accounts for module degradation along with other long-term performance factors like soiling and partial outages.

Storage Dispatch Modeling

Energy storage systems in the NEM 2.0 population are always paired with solar PV. Based on analysis of Self-Generation Incentive Program (SGIP) application data, we assume these systems are all lithium-ion (Li-ion) battery energy storage systems.[82] The NEM 2.0 Lookback Study model develops energy storage charge/discharge profiles based on the load shape selected by the model user and the PV generation profile. In the model, energy storage systems always choose to charge from solar PV. This is consistent

77 Sandia National Laboratories is facilitating a collaborative group of PV professionals (PV Performance Modeling Collaborative or PVPMC). This group is interested in improving the accuracy and technical rigor of PV performance models and analyses. https://pvpmc.sandia.gov/applications/pv_lib-toolbox/

78 PV Performance Modeling Collaborative | PV Watts. https://pvpmc.sandia.gov/modeling-steps/2-dc-module-iv/point-value-models/pvwatts/

79 Useful Life | Energy Analysis | NREL. https://www.nrel.gov/analysis/tech-footprint.html

80 Solar Power World. What is the Life Expectancy of a Solar Array? January 2017. https://www.solarpowerworldonline.com/2017/01/life-expectancy-solar-array/

81 California Solar Initiative Final Impact Evaluation Report. Itron and Verdant, 2020.

82 Self-Generation Incentive Program Weekly Statewide Report. https://www.selfgenca.com/documents/reports/statewide_projects

with data from the SGIP 2018 Energy Storage Impact Evaluation Report for systems paired with solar PV.[83] Discharge behavior is governed by two modes that mimic observed dispatch from SGIP energy storage systems.

- In TOU Arbitrage mode, the energy storage system will only discharge during the on-peak period of the customer's retail rate.
- In PV Self-Consumption mode, the energy storage system will attempt to discharge such that the customer does not draw energy from the grid after the PV system is offline.

Figure 4-2 below provides an illustrative example of the storage dispatch algorithm in TOU arbitrage mode. In this example the on-peak period is 4-9 PM. Multiple data elements are shown in Figure 4-2. The light solid grey line depicts the customer consumption (i.e., the household usage before the influence of solar PV and storage). The solid yellow area represents the solar PV production. The green bars indicate the battery storage system charging (positive) and discharging (negative). In this example, the energy storage system begins charging from solar PV at approximately 8 am and stops charging by 3 pm when the battery is at its full capacity (as indicated by the dashed line reaching 100 percent state of charge). The battery then begins discharging at 4 pm (hour ending 5 pm) and stops discharging by hour ending 9 pm. We see that the energy storage system does not discharge beyond the customer's underlying load, as indicated by the solid red line going to zero kWh but not negative.

[83] 2018 SGIP Advanced Energy Storage Impact Evaluation. Itron, 2020. https://www.cpuc.ca.gov/uploadedFiles/CPUC_Public_Website/Content/Utilities_and_Industries/Energy/Energy_Programs/Demand_Side_Management/Customer_Gen_and_Storage/SGIP%20Advanced%20Energy%20Storage%20Impact%20Evaluation.pdf

FIGURE 4-2: ILLUSTRATIVE EXAMPLE OF STORAGE DISPATCH, TOU ARBITRAGE

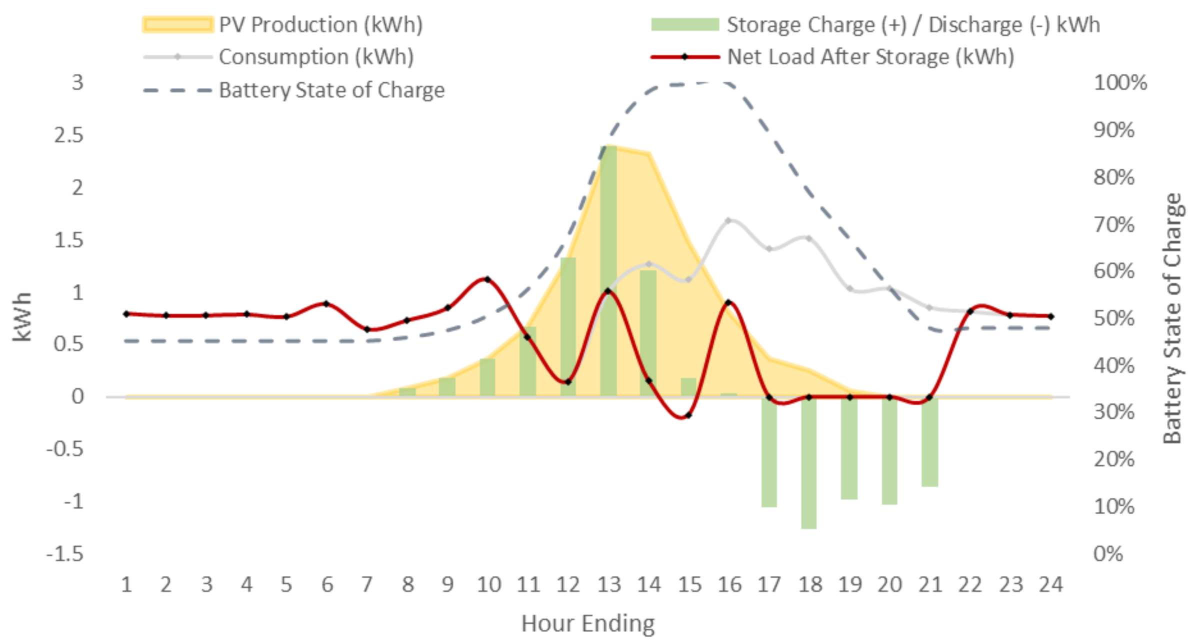

Figure 4-3 on the following page shows the storage dispatch algorithm on the same day in PV Self-Consumption mode. In this example, the energy storage system begins to charge at 8 am as in the previous example. However, the system discharges well beyond hour ending 9 pm (the on-peak period) and continues discharging through the evening to maximize solar PV self-consumption for the day. In this particular case, the battery would likely not have sufficient energy to continue serving load through the evening as indicated by the battery storage of charge dropping below 10 percent by midnight.

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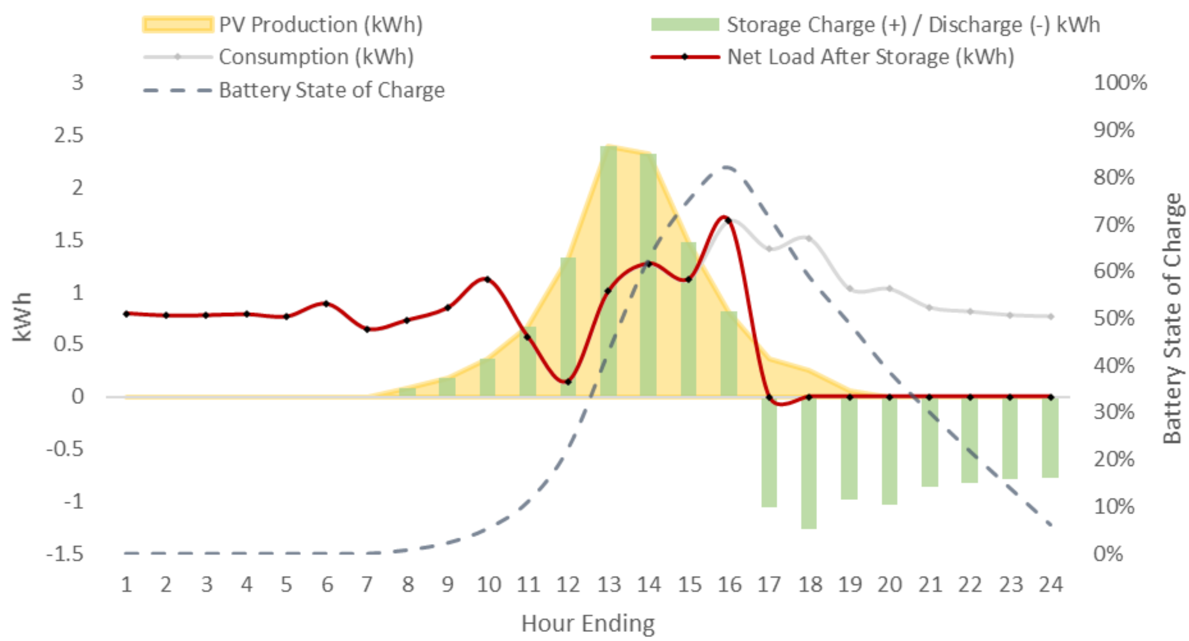
FIGURE 4-3: ILLUSTRATIVE EXAMPLE OF STORAGE DISPATCH, PV SELF-CONSUMPTION



Each mode also allows the model user to select whether or not the energy storage system can export to the grid or if the battery is constrained to discharge only to achieve zero net load. In our analysis, all systems are assigned the TOU arbitrage mode with the export limited constraint.

Energy storage systems are assigned an 80 percent round-trip-efficiency. The RTE is implemented as a loss on the energy used to increase the battery state of charge relative to the total amount of charging energy during each hour. Finally, energy storage systems are assigned a 13-year useful life before the entire system must be replaced.

Value of Reliability and Resiliency

Power reliability can be defined as the degree to which the performance of elements in a bulk system results in electricity being delivered to customers within accepted standards and in the amount desired. The degree of reliability may be measured by the frequency, duration, and magnitude of adverse effects on the electric supply.[84] In the context of this report, reliability can be quantified as the Value of Lost Load (VLL), or the monetary damage arising from a power interruption and therefore the private benefit captured by a NEM 2.0 customer with storage that is able to maintain their power supply through an

84 Measurement Practices for Reliability and Power Quality – A Toolkit of Reliability Measurement Practices. Oak Ridge National Lab, 2004. https://info.ornl.gov/sites/publications/Files/Pub57467.pdf

outage event or disruption. Numerous studies have attempted to quantify the VLL for residential and nonresidential customers.[85] In our modeling framework, the VLL would be included as a benefit in the PCT as this is a private benefit. Given the large degree of uncertainty associated with this value, Verdant chose not to include reliability benefits in the NEM 2.0 Lookback Study. Based on data presented in the 2019 SGIP Energy Storage Impact Evaluation Report, we recognize that residential customers with energy storage are experiencing reliability benefits. This same SGIP report found that, to date, there has been limited evidence of nonresidential customers experiencing reliability benefits. This behavior among nonresidential customers may change beginning in 2020 with the modification of SGIP incentive budget categories and the creation of the General Market Nonresidential Storage Resiliency Adder incentive offered to customers with critical resiliency needs.

Resiliency, as defined by the U.S. Department of Energy, is the ability of the system or its components to adapt to changing conditions and withstand and rapidly recover from disruptions.[86] The value of resilience is largely uncertain and is being explored as part of the CPUC Rulemaking (R.) Regarding Microgrids Pursuant to Senate Bill 1339.[87] The CPUC Microgrids and Resiliency Staff Concept Paper pursuant to SB 1339 and R. 19-09-019 begins to consider the characteristics of a resiliency valuation:

1. The system functions that are supported by the measure.
2. The type of disruptive events that are being protected against.
3. The aspects of resiliency that are affected by the measure:
    a. magnitude of disruption;
    b. duration of resistance;
    c. duration of disruption; and/or
    d. duration of recovery
4. The amount by which each aspect of resiliency is expected to improve as a result of the measure.[88]

In our modeling framework, the value of resilience would be included as a benefit in the PCT as this is a private benefit. Given the large degree of uncertainty associated with this value and the relative infancy

85 Updated Value of Service Reliability Estimates for Electric Utility Customers in the United States. Ernest Orlando Lawrence Berkeley National Laboratory, January 2015. https://eta-publications.lbl.gov/sites/default/files/lbnl-6941e.pdf

86 Energy Infrastructure Resilience. Framework and Sector-Specific Metrics. Sandia National Laboratories. https://www.energy.gov/sites/prod/files/2015/01/f19/SNLResilienceApril29.pdf

87 Order Instituting Rulemaking Regarding Microgrids Pursuant to Senate Bill 1339. https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M314/K274/314274617.PDF

88 California Public Utilities Commission Microgrids and Resiliency Staff Concept Paper. https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M344/K038/344038386.PDF

in our understanding of valuation metrics in general, Verdant chose not to include resiliency benefits in the NEM 2.0 Lookback Study.

Distributed Wind Modeling

Input weather data contain wind speed observations at 2 meters above ground level (AGL). Wind speeds are first extrapolated up to the wind turbine hub height using the power law:

$$v_2 = v_1 \cdot \left(\frac{z_2}{z_1}\right)^{\alpha}$$

Where:

v_1 = velocity at height z_1

v_2 = velocity at height z_2

z_1 = Height 1 (lower height)

z_2 = Height 2 (upper height)

α = wind shear exponent

Wind turbines less than 750 kW are assumed to have a hub height of 20 meters. Large wind turbines 750 kW or greater are assumed to have a hub height of 80 meters. We assume a wind shear exponent of 0.15.[89] Wind power output is then estimated based on a representative wind turbine power curve. We assume a cut-in speed (the minimum wind speed required for wind turbine power production) of 3 meters per second (m/s) and assume that the turbine can achieve full rated power output (P_{MAX}) at 10.5 m/s. We use linear interpolation to estimate power output between 3 m/s and 12 m/s. The following piecewise formula summarizes the wind power output estimation:

$$PowerkW(x) = \begin{cases} 0 \ , & x \leq 3 \\ P_{MAX} - (10.5 - x)\ \left(\frac{P_{MAX}}{7.5}\right) \ , & 3 < x \leq 10.5 \\ P_{MAX} \ , & x > 10.5 \end{cases}$$

Where:

x is the wind speed at hub height.

89 In the lower layers of the atmosphere, wind speeds are affected by the friction against the surface of the earth. The wind shear exponent is an indicator of the rate of change of wind speed as a function of altitude.

Biogas Fuel Cell and other Renewable Generation Modeling

Biogas fuel cells and other renewable-fueled generation technologies are eligible for NEM 2.0 and thus included in this analysis. As a simplifying assumption, we model renewable-fueled generation as 100 percent biogas (i.e., zero non-renewable fuel consumption).[90] This assumption means that operation of a biogas generator has no impact on the natural gas system and therefore no impact on the customer's gas bill. Fuel supply is assumed to come from a source of on-site biogas such as an anaerobic digester. The biogas is assumed to come from a source that would otherwise be flaring methane (as opposed to venting methane as is the case in small dairies) resulting in a net zero greenhouse gas impact from the consumption of biogas.

Fuel cells are assumed to operate as a baseload technology with an hourly capacity factor of 80 percent as required by the SGIP to receive the full incentive payment. Fuel cells are assumed to have an annual degradation of 5 percent and a useful life of 20 years.[91]

4.2.5 Bill Savings Calculation

Customer bills are calculated during each year for the expected life of the measure. The bill is calculated twice for each year, once for the case without the NEM generator (baseline counterfactual bill) and once for the case where the customer installed the NEM generator (NEM bill). The NEM bill includes the impact of the DER generation on the customer load shape, whereas the baseline counterfactual bill is calculated based only on the customer's consumption using the load shapes defined in Section 4.2.3. Annual bill savings are calculated as the difference between the NEM bill and the counterfactual baseline bill.

The model allows the user to assign a different retail rate to each analysis year for both the baseline case and the NEM case. For instance, a scenario might assume that a customer is on a tiered volumetric rate for the first three years of the baseline period and then is required to switch to a TOU rate starting on the fourth year. This customer's bill during the baseline period would be calculated based on the tiered volumetric rate for the first three years and using the TOU rate starting on the fourth year.

The model allows for three compensation mechanisms for NEM exports: traditional NEM 2.0, avoided costs valuation, and a fixed fee valuation. In the NEM 2.0 Lookback Study, we assume that the traditional 2.0 framework remains in place for 20 years. For technologies with a useful life greater than 20 years (i.e., solar PV), we assume that exports are valued at the avoided cost rate for years 21 – 25.

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90 Biogas generators are sometimes equipped with a non-renewable fuel supply (i.e., natural gas) to facilitate startup operations and to provide supplemental fuel if biogas supply is limited.

91 2015 Self-Generation Incentive Program Cost-Effectiveness Study. Itron, 2015. https://www.cpuc.ca.gov/WorkArea/DownloadAsset.aspx?id=7889

Non-Bypassable Charges

Non-bypassable (NBP) charges include the Public Purpose Program (PPP), Nuclear Decommissioning (ND), Competition Transition Charge (CTC), and Department of Water Resources Bond Charge (DWR-BC) charges. These are $/kWh charges assessed by the utility as part of the total electric rate. These charges are owed on all energy imported by the end-use customer, regardless of the NEM 2.0 customer exporting energy back onto the grid. Since these NBP charges are embedded in total utility rates, to calculate bills properly the NEM 2.0 Lookback Study Model subtracts out the NBP charges owed to the utility monthly. The total NBP charge per month is then assessed on all imported kWh on a by-month basis and added to the annual total.

Retail Rate Escalator

Retail rates are assumed to increase at 4 percent per year through the end of the analysis period. This escalator is consistent with the CPUC Proposed Decision Adopting Standardized Inputs and Assumptions for Calculating Estimated Electric Utility Bill Savings from Residential Photovoltaic Solar Energy Systems.[92] This escalator is compounded annually and applied to all $/kW and $/kWh components of each rate per year and the minimum bill amounts. This escalator is applied to baseline discounts (the amount by which certain portions of the bill for tiered rates is reduced if staying below a certain consumption threshold), but not baseline allowances (kWh allowances for each baseline tier).

Community Choice Aggregators

The model allows the user to specify a retail rate discount factor if the customer is enrolled in a Community Choice Aggregator (CCA) program. The model allows for a flat percentage discount on the overall energy commodity rate along with an additional Power Charge Indifference Adjustment (PCIA) charge, which is a $/kWh addition to the customer's bill. The PCIA values vary based on vintage, so the model uses a simple average of the PCIA from 2009-2019 vintage per IOU.

Baselines

Many residential rates include a specific kWh/day allowance for each customer depending on their location and service type. Tiered rates charge increasingly more per kWh once the baseline is exceeded, while some TOU rates provide a $/kWh discount if the customer stays within their allotted baseline amounts.

[92] CPUC Proposed Decision Adopting Standardized Inputs and Assumptions for Calculating Estimated Electric Utility Bill Savings from Residential Photovoltaic Solar Energy Systems. Note that as of August 11, 2020 this PD is subject to change.https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M339/K544/339544643.PDF

California Climate Credit

The model assumes a flat California Climate Credit (CCC) for all residential customers and a $/kWh credit for select nonresidential rates based on their tariff definitions. The $/month credit for residential customers varies by IOU, and the specific values can be found in the model.

Minimum Delivery Charge

Many residential rates include a minimum $/day delivery charge. If a customer's bill exceeds this minimum delivery charge, it does not have an impact on their bill. In general, this requires a customer to pay a minimum of approximately $10/month.

Monthly Flat Charge

Some rates include a monthly flat charge. This charge varies greatly between rates and sectors, with large commercial rates tending to have the largest monthly flat charges. Many small commercial and residential rates have daily per meter charges, these charges are accounted for under the monthly flat charge line items in the model.

Net Surplus Compensation

If a NEM 2.0 customer generates more energy than they consume in a year, they are entitled to an excess generation payment. This payment is called Net Surplus Compensation (NSC) and is based on a 12-month average of the market rate for energy. The model assumes a representative NSC value of $0.03065/kWh.

Taxes

The model assumes a flat 6 percent tax rate on the total monthly charges. Tax structures vary greatly between locations and customers; therefore, a simple tax was applied for consistency across every run of the model. This 6 percent tax can be a negative tax, which is consistent with what was found upon investigation of individual electric bills.

Model Validation

Monthly results from the NEM 2.0 Lookback Study Model were compared to a variety of residential monthly bills from each of the IOUs. The discrepancy between monthly electric bills as calculated in the model and those provided by the utilities varied between 0-10 percent. These discrepancies were largely from differences in implementation of the minimum daily charge, rate changes occurring in the middle of a billing cycle, and different taxes assessed on electricity bills throughout the state. Overall, we find the model's estimates of bill payments to be appropriate for this study.

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4.2.6 DER Costs, Tax Treatment, and Incentives

We developed upfront cost, O&M costs, and partial equipment replacement costs for all technologies. We also make assumptions about state incentives and federal tax credits for each technology. Below we present the assumptions for each technology. In all cases we assume that customers do not sell their RECs due to the unfavorable economics relative to the REC price. However, the capability exists in the model to quantify this revenue stream.

Solar PV

We relied primarily on the Lawrence Berkeley National Laboratory (LBNL) 2019 Tracking the Sun report for solar PV installed costs.[93] The report summarizes installed prices and other trends among grid-connected, distributed solar PV systems in the United States. The latest edition of the report focuses on systems installed through the end of 2018, with preliminary trends for the first half of 2019. The analysis is based on project-level data from approximately 1.6 million systems, representing 81 percent of all distributed PV systems installed in the United States through the end of 2018. According to the LBNL report, California median installed prices in 2018 were $3.8/W_{DC}$ for residential, $3.1/W_{DC}$ for small nonresidential (less than 100 kW), and $2.5/W_{DC}$ for large nonresidential (greater than or equal to 100 kW) solar PV systems. We have adopted these costs for solar PV simulations. The report also provides 20th percentile and 80th percentile installed prices for 2018. We use these values as sensitivity cases for low and high installed prices. The solar PV price inputs are summarized in Table 4-14.

TABLE 4-14: SOLAR PV INSTALLED PRICE, BASE CASE AND SENSITIVITIES

Sector	Installed Cost 2018 $/W		
	Base Case	High Cost	Low Cost
Residential	$3.8	$4.6	$3.2
Small Nonresidential	$3.1	$4.1	$2.5
Large Nonresidential	$2.5	$3.6	$1.8

Solar PV systems are assumed to have no O&M costs. However, we assume a single inverter replacement cost halfway through the useful life (year 13). We model the cost of the inverter replacement at $0.30/W.

We assume that residential, commercial, industrial, and agricultural solar PV customers are receiving the federal ITC at 30 percent of the total system upfront cost. Nonresidential customers are also able to receive tax benefits for the depreciation of the solar PV system by using accelerated depreciation. Namely,

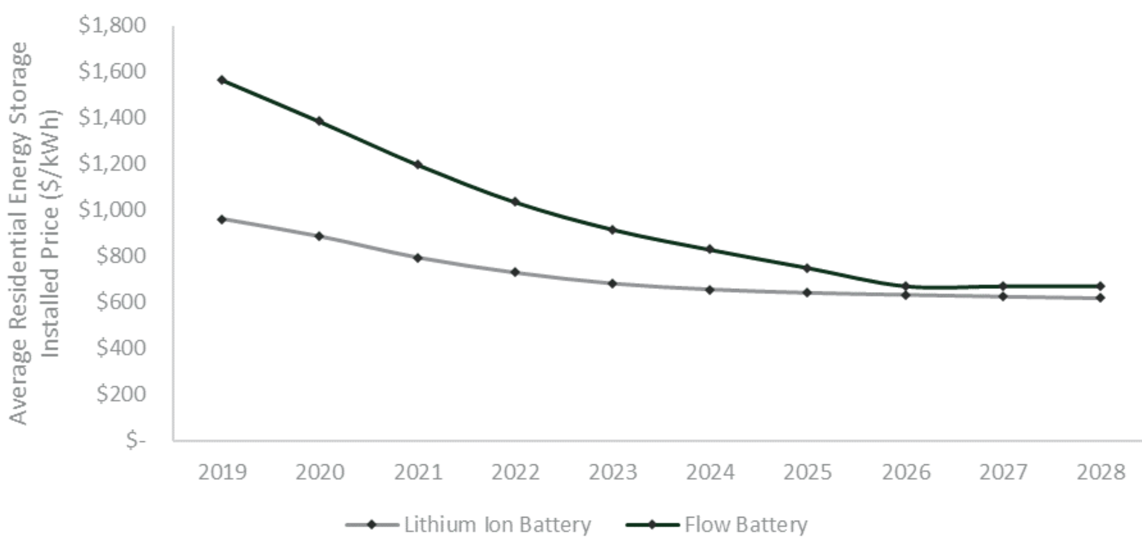
93 Tracking the Sun. Lawrence Berkeley National Lab. October 2019. https://emp.lbl.gov/tracking-the-sun

a one-year accelerated depreciation schedule is applied to all commercial, industrial, and agricultural solar PV customers at the federal level. A five-year accelerated depreciation schedule with a bonus first year depreciation is applied at the state level. The depreciation basis is reduced by 50 percent of the ITC amount (15 percent) at both the federal and state level. The accelerated depreciation schedule allows nonresidential customers to “front load” the depreciation of the solar PV system which improves the overall economics of the system.

Solar PV + Storage

Figure 4-4 presents installed cost projections from Navigant Research’s Residential Energy Storage Research Report. In general, Navigant Research forecasts average residential lithium ion energy storage installed costs for 2019 at approximately $960/kWh. Navigant expects the compound annual growth rate of installed prices for Li-ion batteries to be -4.8 percent. If we apply the expected cost reduction rate between 2019 and 2020 back to 2018, we arrive at a 2018 installed cost of $1,037/kWh. We use this value as the base case price for residential energy storage.

FIGURE 4-4: AVERAGE RESIDENTIAL ENERGY STORAGE INSTALLED PRICE FORECAST (ADAPTED FROM NAVIGANT RESEARCH)



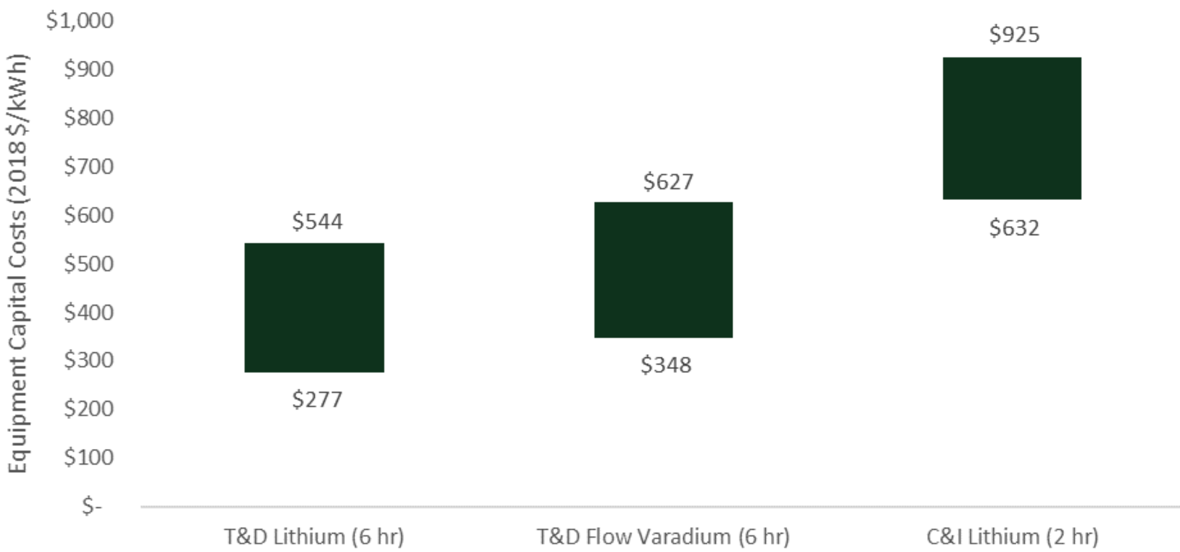
* Adapted from Navigant Research Residential Energy Storage Research Report. Q1 2019.

The Lazard Levelized Cost of Storage Analysis is a widely cited reference for energy storage cost assumptions.[94] Figure 4-5 on the following page summarizes Lazard’s capital cost comparison for

94 Lazard’s Levelized Cost of Storage Analysis – Version 4.0. November 2018. https://www.lazard.com/media/450774/lazards-levelized-cost-of-storage-version-40-vfinal.pdf

nonresidential energy storage. The $/kW values presented in the study were converted to $/kWh based on the assumed energy storage duration. For nonresidential lithium ion storage, we leverage the Lazard report, which suggests that capital costs for residential storage are approximately 33 percent higher than nonresidential capital costs. Therefore, we work backwards from the 2018 residential installed costs and reduce them by 33 percent. The 2018 base case installed price for nonresidential Li-ion storage is $695.

FIGURE 4-5: EQUIPMENT CAPITAL COST ASSUMPTIONS FROM LAZARD LEVELIZED COST OF STORAGE ANALYSIS VERSION 4.0



* Adapted from Lazard's Levelized Cost of Storage Analysis – Version 4.0

SGIP energy storage systems are required to have a minimum ten-year warranty. Lithium ion battery product warranties often cite ten-year coverage, guaranteeing energy retention of 70 percent at ten years following initial installation date. For this analysis, we assume a 13-year life for Li-ion systems. In our model, the customer will incur the cost of the battery replacement once it reaches its end of life. By choosing a 13-year life, we assume that the battery system is re-purchased once as a cash payment during the 25-year life of the PV system.

In our modeling, energy storage systems charge 100 percent from solar PV. Therefore, we assume that energy storage system costs are included in the ITC calculation. The energy storage system is also assumed to receive an SGIP incentive of $0.35/Wh. This incentive is paid 100 percent upfront for residential energy storage systems and paid as a performance-based incentive (PBI) for nonresidential systems. We assume that the PBI incentive is paid in full over five years. In other words, we assume the project meets all SGIP performance requirements. We do not tie the PBI payment to minimum dispatch requirements or target greenhouse gas reductions.

Fuel Cells and Distributed Wind

Fuel cell capital costs are estimated based on industry literature at $4,935/kW.[95,96] Capital costs include biogas cleanup equipment and equipment capital costs necessary to use biogas in a fuel cell. O&M costs are simulated as $0.079/kWh. This cost includes gas cleanup costs and levelized fuel cell stack replacement costs based on an 80 percent capacity factor.

We obtained distributed wind costs from the SGIP Weekly Statewide Report based on average qualified costs.[97] In our model, we classify systems less than 750 kW as small distributed wind, and systems greater than 750 kW as large distributed wind. Using this differentiation and filtering the SGIP Weekly Statewide Report for applications submitted on or after 2017, we arrive at a capital cost estimate of $4,128 for small distributed wind and $3,125 for large distributed wind.

4.2.7 DER Financing and Insurance

Behind-the-meter DERs can be financed using debt, leases, bonds, or power purchase agreements. In our model, customer-sited renewable generation technologies are assumed to be financed with equity and debt. As a simplying assumption, we modeled with 30 percent equity upfront payment and 70 percent debt financing. To estimate the cost of debt and loan term, we reviewed residential solar loan characteristics reported by Kroll Bond Rating Agency for recent securitizations completed by four solar financing companies (Dividend, Loanpal, Mosaic, and Sunnova).[98] Based on these data, we arrived at an estimate of 5 percent cost of debt with an 18-year loan term for use in the model. Residential customers are assumed to finance the DER system with a loan from a solar financing company, making their interest payments not tax deductible.

4.2.8 Net Energy Metering Costs

The NEM costs included in the cost-effectiveness and the full cost of service analysis are utility costs that are specific to NEM accounts. These costs are not included in the utility General Rate Cases or in regulatory

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95 Distributed Generation, Battery Storage, and Combined Heat and Power Characteristics and Costs in the Buildings and Industrial Sectors, May 2020. https://www.eia.gov/analysis/studies/buildings/dg_storage_chp/pdf/dg_storage_chp.pdf

96 A Comprehensive Assessment of Small Combined Heat and Power Technical and Market Potential in California. CEC-500-2019-030. March 2019. ICF.

97 SGIP Weekly Statewide Report. Accessed July 28, 2020. https://www.selfgenca.com/documents/reports/statewide_projects

98 ABS: Mosaic Solar Loan Trust 2019-2 New Issue Report, p.33, KBRA Comparative Analytic Tool. November 2019. Kroll Bond Rating Agency. https://www.krollbondratings.com/documents/report/25563/abs-mosaic-solar-loan-trust-2019-2-new-issue-report

costs. On February 5, 2016 the CPUC issued D.16-01-044, authorizing the IOUs to collect a one-time interconnection application fee for NEM 2.0 customers with NEM qualifying systems of less than 1 MW. The interconnection fee is based on interconnection costs illustrated by the utilities in advice letters. The NEM interconnection costs used for each utility in this study are derived from NEM costs itemized in the utility advice letters.

Table 4-15, Table 4-16, and Table 4-17 below list the utility-specific NEM interconnection cost components and costs that are waived for select NEM technologies paired with storage.[99] In the model, these costs are applied on an average cost per site basis. The waived costs are counted as cost components that are added to utility costs for sites installing solar PV and storage systems. For SDG&E's most recent advice letter, the costs were based on 27,393 systems. SCE's population was 46,697 systems with 96 NEM paired storage complex metering projects. SCE also provided data for ongoing costs such as ongoing metering, billing, and administrative costs. PG&E's population was 63,899 systems. For the model, the cost per customer and SCE's on-going costs are listed in Table 4-18. To develop the costs per customer listed in Table 4-18, the corresponding interconnection cost components were divided by the number of systems installed for each utility.

TABLE 4-15: NEM INTERCONNECTION COST COMPONENTS

Cost of Service Component	PG&E	SCE	SDG&E
Application Processing	$7,011,444	$1,443,739	$3,120,099
Distribution Engineering Costs, In-Office Review	$1,738,264	$52,299	$10,459
Meter Installation/Remote Meter Programming/Meter Change	$105,980	$74,551	$30,139
NEM Field Inspection	N/A	$3,389	$767,833
Distribution Upgrades	$14,485,595	$11,328,804	$44,832
Interconnection Facility Upgrades	$5,385,714	$2,110,173	$0

TABLE 4-16: WAIVED FEES AND COSTS FOR NEM-PAIRED STORAGE

Cost of Service Component	PG&E	SCE	SDG&E
Supplemental Review Fees	$12,500	$0	$127,921
Net Generator Output Metering	$1,380,333	$26,838	$6,073
Interconnection Application	$48,430	$17,250	N/A
Distribution Upgrades	$143,927	N/A	N/A

99 Verdant was instructed by SCE to not include the distribution upgrades when calculating the NEM interconnection costs per customer because these distribution upgrades are also impacted by the needs of other customers on the system. SCE also requested that the costs be multiplied by a factor that reflects their bundled labor costs, therefore the SCE costs reported above reflect their unbundled labor costs.

TABLE 4-17: NEM-PAIRED STORAGE COMPLEX METERING COSTS

Cost of Service Component	PG&E	SCE	SDG&E
Labor	N/A	$103,398	N/A
Material		$92,219	
ITCC		$46,885	
Other		$145,687	

TABLE 4-18: MODELED NEM COSTS

Technology	PG&E	SCE	SDG&E
Solar PV ($/Customer)	$449.57	$94.37	$145.05
Solar PV + Storage (all) ($/Customer)	$1,056	N/A	$203.95
Solar PV + Storage Residential ($/Customer)	N/A	$121.38	N/A
Solar PV + Storage Nonresidential ($/Customer)		$4,082.49	
Ongoing NEM Costs ($/Customer-Year)		$142.13	

5 COST-EFFECTIVENESS AND COST OF SERVICE RESULTS

This section presents the results from the cost-effectiveness and cost of service analyses. Section 4 included a detailed discussion of the methodology and key assumptions. The cost-effectiveness and cost of service results presented in this section represent the findings from 4,950 distinct residential and nonresidential simulations based on combinations of customer load shapes, technology, utility, climate zone, retail rates, and NEM 2.0 system size. At times throughout this section, we present findings averaged across a group of simulations to present overall trends. Other times, we highlight individual illustrative simulation results to explore the influence of specific cost and benefit components. By selecting individual simulation results, we are not implying that these findings are representative of all other NEM 2.0 systems. Instead, we select specific simulations for in-depth analysis as they allow us to highlight aspects of cost-effectiveness that we deem relevant or important.

Note that this study is a retrospective cost-effectiveness analysis. The study findings should not be interpreted as a sensitivity analysis except where explicitly mentioned. For instance, when comparing results for solar PV against solar PV + storage, note that these groups likely consist of a different underlying customer base.

5.1 COST-EFFECTIVENESS RESULTS

The cost-effectiveness model's primary purpose is to evaluate the cost-effectiveness of customer-sited resources under NEM 2.0 using the California Standard Practice Manual (SPM) cost-effectiveness tests. The SPM is a document designed to describe the procedures to determine the cost-effectiveness of utility-sponsored programs. The SPM cost-effectiveness tests include the total resource cost (TRC) test, the participant cost test (PCT), the program administrator (PA) test, and the ratepayer impact (RIM) test. Each test evaluates the tariff's cost-effectiveness from alternative perspectives, assessing the impact of the tariff on society, participants, program administrators, and ratepayers. Table 5-1 on the following page summarizes the cost-effectiveness of NEM 2.0 by electric utility using the SPM tests. Results are weighted to represent the entire NEM 2.0 population. The table includes ratios of the cost-effectiveness test by IOU and the statewide total and the net present value (NPV) of benefits and costs for the statewide totals.

The average statewide PCT benefit-cost ratio is greater than 1.0, indicating that installation of a NEM 2.0 eligible system is beneficial to customers leading to total NEM 2.0 customer net benefits of more than $9 billion. The PCT benefit-cost ratio is slightly higher for customers installing systems in SDG&E's territory than in PG&E's or SCE's. SDG&E's higher PCT benefit-cost ratio is driven by higher than average bill savings and lower than average NEM costs (see Section 4 Table 4-18).[100] The average statewide and the individual utility TRC benefit-cost ratios are slightly below 1.0 suggesting NEM 2.0 systems represent a small net cost to participants and the utilities. The RIM benefit-cost ratios are less than 1.0 which indicates that customers' utility rates are likely to increase due to the change in revenues from the program. The NPV of RIM costs exceed the RIM benefits by approximately $13,000 m. The PA benefit-cost ratio is considerably greater than 1.0, with SDG&E's PA benefit-cost ratio substantially larger than PG&E's, and SCE's substantially less than the other two utilities'. SCE's NEM 2.0-related costs, a cost in the PA benefit-cost ratio, includes an ongoing monthly cost associated with billing, administrative costs, and meter-related costs. SDG&E and PG&E provided first-year NEM 2.0 related costs but did not include any ongoing costs.

TABLE 5-1: SUMMARY OF COST-EFFECTIVENESS RESULTS BY ELECTRIC UTILITY

Utility	Weighted Average Benefit-Cost Ratio			
	PCT	TRC	RIM	PA
PG&E	1.81	0.80	0.33	41.08
SCE	1.54	0.91	0.49	10.99
SDG&E	2.03	0.84	0.31	129.58
Total	1.77	0.84	0.37	22.98
NPV Total Benefits ($M)	21,329	7,960	7,576	7,576
NPV Total Costs ($M)	12,041	9,462	20,583	330

In Table 5-1 SCE's PCT benefit-cost ratios are lower than the other utilities and their TRC ratios are higher. The PCT denominator includes the cost of the NEM 2.0 system while the TRC denominator includes the cost of the system plus the utility's program costs. Finding that SCE's weighted average PCT benefit-cost ratio is lower than those of PG&E and SDG&E is likely due to smaller utility bill savings for NEM 2.0 systems installed within SCE's territory relative to systems installed in PG&E's and SDG&E's territories. Many of SCE's nonresidential rates have substantial fixed and demand charges, limiting the bill savings for NEM 2.0 systems.

The higher SCE TRC values in Table 5-1 are primarily due to SCE having higher avoided costs than the other two IOUs. In 2020, the average of SCE's avoided cost values is approximately 5 percent higher than those of SDG&E and PG&E. In 2030, SCE's average avoided cost values are 6 percent higher than SDG&E's and

[100] For years 1-20 of the NEM system's life, the PCT and RIM tests value the bill savings using the utility rates while in years 21-25 of the system's life, the customer bill savings are evaluated at the avoided cost valuation. Scenario analyses are presented below where years 21-25 are valued at the utility retail rates.

15 percent higher than PG&E's. Differences in the IOU avoided costs contribute to their different TRC benefit-cost ratios.

The cost-effectiveness tests were developed for 4,950 different simulations that are designed to represent the approximately 400,000 NEM 2.0 customers. The results presented in Table 5-1 represent the weighted average benefit-cost ratio of all simulations. Table 5-2 presents the middle 50 percent range for the SPM tests for the individual utilities and the statewide total. Comparing these ranges to the weighted averages in Table 5-1 provides information on the distribution and skewness of test values. For example, SDG&E's weighted average TRC benefit-cost ratio is 0.84 while the 50 percent range (the 25^{th} and 75^{th} percentile values) of their TRC benefit-cost ratio is 0.75 to 0.79. This result indicates that most of SDG&E's TRC benefit-cost ratio results are within a relatively tight range. The weighted average benefit-cost ratio, however, is outside the 50 percent range. Further review of the TRC benefit-cost distributions indicate that residential customers, who represent the largest number of installation, tend to have lower TRC ratios while larger, nonresidential customer have higher TRC ratios. The larger benefits and costs of the nonresidential customers contribute to the IOU and statewide weighted average TRC exceeding the 50 percent TRC range. In contrast, the IOU and statewide weighted average PCT tends to be in the 50 percent range and the residential PCT ratios generally exceed the nonresidential values.

TABLE 5-2: THE 25 PERCENT TO 75 PERCENT RANGE OF COST-EFFECTIVENESS RESULTS BY ELECTRIC UTILITY

Utility	25% to 75% Range of Benefit-Cost Ratio			
	PCT	TRC	RIM	PA
PG&E	1.62 to 2.09	0.68 to 0.69	0.27 to 0.36	19.72 to 38.79
SCE	1.42 to 1.74	0.77 to 0.81	0.40 to 0.50	6.16 to 10.57
SDG&E	1.88 to 2.25	0.75 to 0.79	0.27 to 0.33	71.53 to 125.06
Total	1.61 to 2.09	0.69 to 0.78	0.28 to 0.41	11.06 to 45.77

Table 5-3 lists the SPM tests disaggregated by utility and sector.

TABLE 5-3: SUMMARY OF COST-EFFECTIVENESS RESULTS BY CUSTOMER SECTOR AND IOU

Utility	Customer Sector	Weighted Average Benefit-Cost Ratio			
		PCT	TRC	RIM	PA
PG&E	Agriculture	1.72	1.19	0.41	590.70
	Commercial	1.79	1.12	0.37	437.07
	Industrial	1.47	1.17	0.51	6,128.90
	Residential	1.83	0.69	0.31	28.77
SCE	Agriculture	1.23	1.43	0.85	337.88
	Commercial	1.32	1.35	0.72	96.86

	Industrial	1.16	1.34	0.87	880.11
	Residential	1.62	0.80	0.43	8.20
SDG&E	Agriculture	1.51	1.25	0.53	821.47
	Commercial	1.87	1.18	0.37	1,344.24
	Industrial	1.57	1.21	0.49	16,696.43
	Residential	2.08	0.76	0.29	100.09

This table highlights differences across both utilities and sectors. The PA benefit-cost ratio exhibits the most variability by customer sector while also differing substantially by utility. As described above, SCE's PA benefit-cost test values are lower than SDG&E's and PG&E's in part because SCE's NEM 2.0 costs include an ongoing and an upfront cost while SDG&E and PG&E only provided upfront costs. Upfront costs include one-time fees such as meter installation costs, distribution upgrade costs, and account setup costs. Ongoing costs include recurring expenses such as billing costs and any incremental staffing the results from the implementation and administration of the NEM 2.0 program. The PA test sensitivity to sector is likely a proxy for the magnitude of the avoided cost savings associated with each customer class. Industrial customers tend to be very large and install NEM generators that are larger than those installed in other sectors. Given that NEM costs do not vary significantly across customer classes, cohorts with larger NEM systems (and thus larger avoided cost savings) will result in higher PA benefit-cost ratios.

The results listed in Table 5-3 also show that the RIM benefit-cost ratio differs by utility and sector. NEM 2.0 systems in SCE's nonresidential sectors have RIM test benefit-cost ratios that are higher, and closer to 1.0, than for PG&E's or SDG&E's nonresidential RIM test ratios. SCE's residential and SDG&E's and PG&E's residential sectors, however, have RIM test benefit-cost ratios substantially lower than 1.0. The RIM test benefits are the avoided costs while the costs are the customer bill savings and the program costs. SCE's nonresidential aggregate RIM test values range from 0.72 to 0.87, suggesting that the estimated avoided costs approach the customer bill savings.[101] SCE's nonresidential RIM test values will be discussed in further detail below. Table 5-4 summarizes the cost-effectiveness of NEM 2.0 by technology type and utility.

TABLE 5-4: SUMMARY OF COST-EFFECTIVENESS RESULTS BY TECHNOLOGY TYPE AND UTILITY

Utility	Technology	Weighted Average Benefit-Cost Ratio			
		PCT	TRC	RIM	PA
PG&E	Solar PV	1.82	0.80	0.33	41.97
	Solar PV + Storage	1.52	0.74	0.38	28.52

[101] The NEM 2.0 program costs are small relative to the avoided costs or the customer bill savings and are abstracted for this discussion.

	Wind	1.63	1.89	0.92	8,641
SCE	Solar PV	1.56	0.90	0.48	10.50
	Solar PV + Storage	1.39	0.95	0.56	17.63
	Fuel Cells	0.93	1.11	0.98	733.30
SDG&E	Solar PV	2.09	0.85	0.31	119.18
	Solar PV + Storage	1.55	0.78	0.39	439.77
	Fuel Cells	1.84	1.05	0.38	49,009

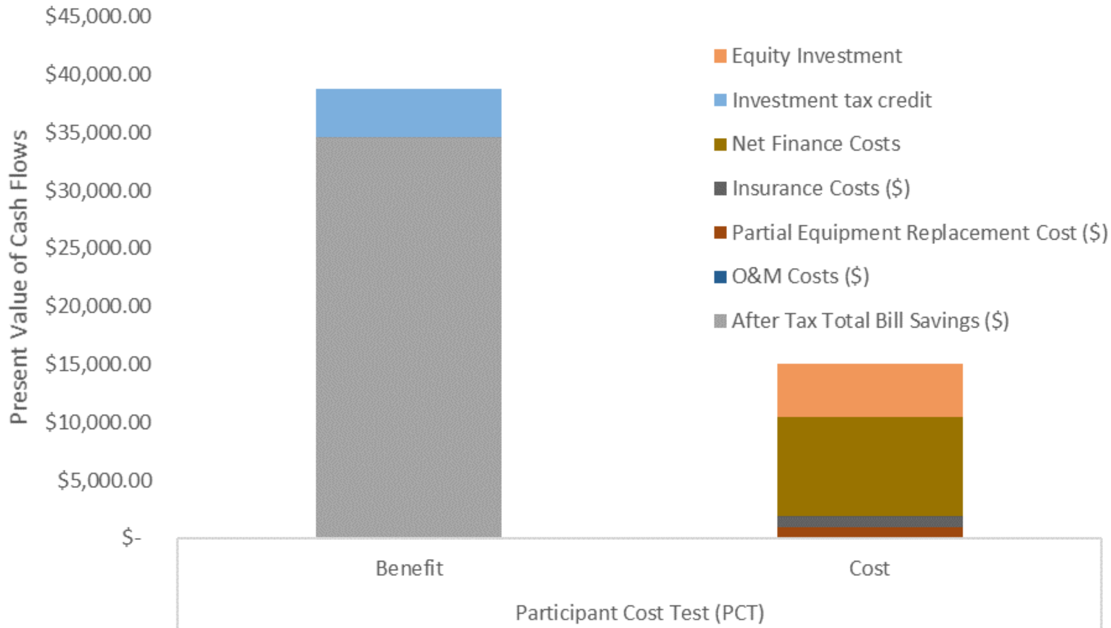
The PCT benefit-cost ratio is higher for solar PV customers relative to those who installed solar PV + storage. This suggests that the incremental bill savings from storage TOU rate arbitrage are less than the incremental costs of installing energy storage. Additional details on the PCT are presented in Section 5.1.1. The TRC benefit-cost ratio for solar PV customers is also generally higher than for solar PV + storage customers, indicating that the avoided cost benefits from storage TOU arbitrage are less than the incremental storage costs. The TRC benefit-cost ratio for fuel cells is slightly higher than one in SDG&E's and SCE's territory, illustrating that the large avoided cost benefits produced by fuel cells exceed their high measure costs. Fuel cells' large avoided cost benefits are further illustrated in their exceptionally high PA benefit-cost ratios.

The following subsections provide additional details and insights into each of the cost-effectiveness tests.

5.1.1 Participant Cost Test (PCT)

The PCT is a measure of the quantifiable benefits and costs to the consumer due to participation in NEM 2.0. Participant test benefits include bill savings, state rebates (e.g., Self-Generation Incentive Program), and any tax refunds or credits that may apply. Participant costs are the capital, financing, and other expenditures associated with installing the NEM 2.0 system. The population weighted average participant benefit-cost ratio is 1.77 and the NPV of lifetime PCT benefits exceeds the costs by $9,289 m. The participant test is primarily sensitive to the cost of the NEM system and the bill savings associated with operating the customer-sited renewable generator. The relationship between NEM system costs and the participant test benefit-cost ratio is intuitive – as the system cost increases, the participant benefit-cost ratio decreases. Figure 5-1 provides an illustrative example of the benefit-cost calculation for a residential SDG&E customer.

FIGURE 5-1: PARTICIPANT TEST BENEFITS AND COSTS, ILLUSTRATIVE CASE, SDG&E RESIDENTIAL



Electric bill savings are calculated as the difference between the bill with the NEM 2.0 system and the bill without the system. Under each condition customers are assumed or allowed to be on different rates – some rates apply to customers with eligible NEM systems installed and others do not. Customers can be on different rates over time depending on when they are required to transition from volumetric rates to TOU rates (baseline), or when they transition from legacy TOU rates (e.g., rates with early on-peak TOU periods) to current TOU rates with later on-peak TOU periods. The example in Figure 5-1 is for a large SDG&E customer with a dual fuel baseline in the coastal climate zone (Climate Zone 7). The customer is assumed to be on SDG&E's DR rate for the first year of the baseline period and then transition to SDG&E's DR-TOU1 rate in the second year and the DRSES rate after installing a 4 kW solar PV system.

In this illustrative example, the bill savings resulting from operating the solar PV system for 25 years outweigh the acquisition costs of the solar PV system. This results in a PCT benefit-cost ratio of 2.58. Note that this happens to be a particularly cost-effective scenario for the simulated customer and is not representative of all NEM 2.0 customers who install solar PV.

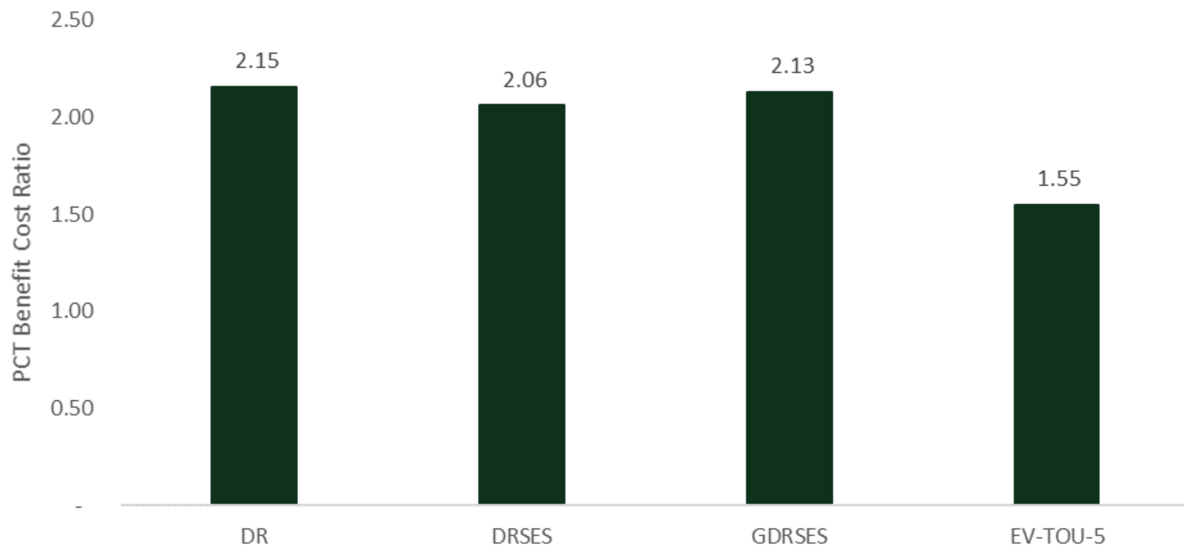
Figure 5-2 presents weighted average results for different SDG&E residential customers on different rates. Note, this is not a scenario analysis because the results are based on customers who were on these rates. In the first case, the customers are on the tiered volumetric domestic rate (DR) prior to installing their system. In the second year of the baseline period (where the customers did not install solar), the customer is assumed to transition to SDG&E's default TOU rate DR-TOU1. In the post-installation period, the customers are grandfathered onto SDG&E's DR rate and spend two years on the rate and are then transitioned to SDG&E's domestic solar energy system TOU rate (DRSES). The second case represents customers that transition directly to the DRSES rate immediately after installing their systems. The baseline non-solar rate for these customers is DR-TOU1. The third case are customers that are on the grandfathered SES (GDRSES) rate at the beginning of the simulations. These customers are assumed to stay on this rate for two years following the beginning of the cost-effectiveness simulations. At the end of the two years, the customers are transitioned to DRSES.[102] If the customers on GDRSES had not installed a solar system they are assumed to be on the DR rate during the first year of the no-solar baseline period, transitioning to SDG&E's default TOU rate in year two. The fourth case illustrated in Figure 5-2 is for customers on the EVTOU 5 rate both during the baseline and following the installation of their solar system. These customer owned an electric vehicle prior to their installation of their NEM 2.0 system.

The PCT benefit-cost ratio does not appear to be particularly sensitive to underlying rate grandfathering assumptions for the DR or the DRSES rates. In this illustrative example, customers on the legacy NEM rate (GDRSES) have an estimated PCT benefit-cost ratio that exceeds the DRSES PCT ratio by 0.07. Customers on the tiered volumetric rate (DR) increases the PCT benefit-cost ratio by 0.09 relative to customers on the DR SES rate.

Customers on the electric vehicle rate have the lowest PCT of the four SDG&E rates observed here. These customers have a load shape that differs from the solar only customers, typically consuming more energy during the late night and early morning hours. The EVTOU 5 rate also includes a higher monthly charge that may reduce the PCT benefit-cost ratio relative to other solar only customers and rates.

[102] The largest difference between the GDRSES and the DRSES is the timing of the peak period. The GDRSES peak period is from 11AM to 6 PM during the summer while the peak period for DRSES is 4-9PM.

FIGURE 5-2: PARTICIPANT BENEFIT-COST RATIO SENSITIVITY TO RATE CHANGES



The participant cost test and the customer payback period are two alternative ways of viewing the cost-effectiveness of the NEM 2.0 system from the participant's point of view. The payback period calculates the number of years needed for the bill savings, tax savings, and investment tax credit to cover the cost of the initial equity inventment, debt repayment, and the financing costs. Table 5-5 below presents the weighted average payback years by sector and IOU. This analysis shows that the residential sector has the shortest average payback period, similar to results presented in Table 5-3 showing that residential systems have the highest PCT benefit-cost ratio. In addition, SDG&E's shorter average residential payback period, relative to PG&E and SCE, is consistent with the PCT results presented above. The relatively higher residential bill savings, largely due to higher energy costs and the lack of demand charges, reduces the residential payback period relative to nonresidential installations.

TABLE 5-5: SUMMARY OF PAYBACK RESULTS BY SECTOR AND UTILITY

Utility	Weighted Average Payback Years			
	Agriculture	Commercial	Industrial	Residential
PG&E	9.4	10.9	13.4	10.2
SCE	16.5	15.8	18.3	10.8
SDG&E	13.1	10.7	13.4	7.9

Bill Saving Scenarios

Under the base case scenario presented above, NEM 2.0 export is valued at the utility rate accounting for nonbypassable charges. In years 21 to 25 of the NEM system measure life, however, the export is valued at the value of the avoided costs. To determine the sensitivity of the benefit-cost test ratios to this assumption, a scenario analysis was undertaken where export was valued at the utility rate minus nonbypassable charges for all 25 years of the measure's life. The data presented above also assume that the utility rates increase at 4 percent per year. Because the increase in utility rates is likely to be less than 4 percent in some years, a scenario was implemented assuming utility rates increased at 3.1 percent per year. Changes in the value of export and the growth of utility rates impact the PCT and the RIM test while having no impact on the TRC or PA tests. Table 5-6 presents the PCT and RIM benefit-cost ratios for the base case and two alternative bill savings scenarios.[103]

Valuing export for years 21-25 at utility rates increases the value of export to the participants relative to the avoided cost values. The SPM tests, however, discount the value of the impact of future bill savings using a net-present-value (NPV) approach. The discounting in the NPV calculation reduces the impact of bill savings and avoided cost benefits during years 21-25 on the PCT and RIM benefit-cost ratios. Given that the avoided cost and rate differences occur so far in the future, valuing export at avoided cost or utility rates for years 21-25 has little impact on the cost-effectiveness tests.

TABLE 5-6: PARTICIPANT AND RIM BENEFIT-COST RATIOS FOR BASE CASE, RETAIL RATE EXPORT ALL YEARS, AND RETAIL RATE 3.1 PERCENT GROWTH SCENARIOS

	Base Scenario (Utility Rates with 4% Rate Growth Years 1-20, Avoided Costs 21-25)		Utility Rates All Years (4% Rate of Growth)		Utility Rates Grow at 3.1% for Years 1-20, the Avoided Costs 21-25	
	PCT	RIM	PCT	RIM	PCT	RIM
PG&E	1.81	0.33	1.84	0.32	1.69	0.36
SCE	1.55	0.49	1.57	0.48	1.46	0.53
SDG&E	2.03	0.31	2.07	0.30	1.90	0.34

The third set of benefit-cost test results presented in Table 5-6 reflect the PCT and RIM test if utility rates are assumed to grow at 3.1 percent instead of the base case assumption of 4 percent. Slower growth in utility rates reduced the value of utility bill reductions, or the PCT benefits, relative to the base scenario. The reduction in PCT benefits reduces the PCT benefit-cost ratio, though the aggregate weighted PCT ratio for all three utilities remains substantially above zero. The decline in the value of utility bill reductions

[103] The results for the base case scenario differ from those listed in Table 5-1 because the results in Table 5-6 only include values for PV and PV plus storage systems.

increases the RIM benefit-cost ratio relative to the base case scenario, though all three utility's RIM values remain significantly less than zero.

The chages in the NPV of participant bills associated with the scenarios presented in Table 5-6 makes small changes to the point estimates of the PCT and RIM benefit-cost test ratios, but they do not change the conclusion that NEM 2.0 is cost-effective for participants (PCT ratio > 1.0) while imposing a cost on non-participating ratepayers (RIM ratio < 1.0).

5.1.2 Total Resource Cost (TRC) Test

The TRC test measures the net costs of NEM 2.0 as a resource option based on the total costs of the program, including both the participants' and the utility's costs. TRC test benefits include utility avoided costs and the federal income tax refund resulting from the acquisition, financing, and operation of the NEM generator (if applicable). TRC costs include all expenditures associated with acquiring and installing the NEM system (i.e., upfront capital costs, financing costs, ongoing O&M, insurance costs). If applicable, the federal ITC is treated as a reduction in cost of the NEM system rather than a benefit. Utility costs associated with NEM (e.g., incremental metering, billing) are also a cost in the TRC. Future cash flows are discounted at the utility discount rate.

The statewide NEM 2.0 population weighted average TRC benefit-cost ratio is 0.84 and the IOU-specific TRC ratios range from a low of 0.80 for PG&E to a high of 0.91 for SCE. Figure 5-3 shows the unweighted TRC benefit-cost ratio for each base-case simulation, ranked from lowest to highest. The horizontal line is drawn at the break-even TRC benefit-cost ratio of one. Sixty-eight percent of the simulations (4,168) resulted in a TRC benefit-cost ratio less than one. Of the 4,168 simulations with TRC benefit-cost ratios less than one, 1,178 are solar PV + storage systems. Energy storage systems represent an incremental capital cost on top of the installation of the solar PV system. If the incremental avoided cost benefits resulting from the operation of the energy storage system are less than the cost of the energy storage system, then the TRC benefit-cost ratio will decrease relative to the TRC benefit-cost ratio for standalone solar PV.

FIGURE 5-3: TOTAL RESOURCE COST TEST RESULTS, RANKED FROM LOW TO HIGH (UNWEIGHTED)

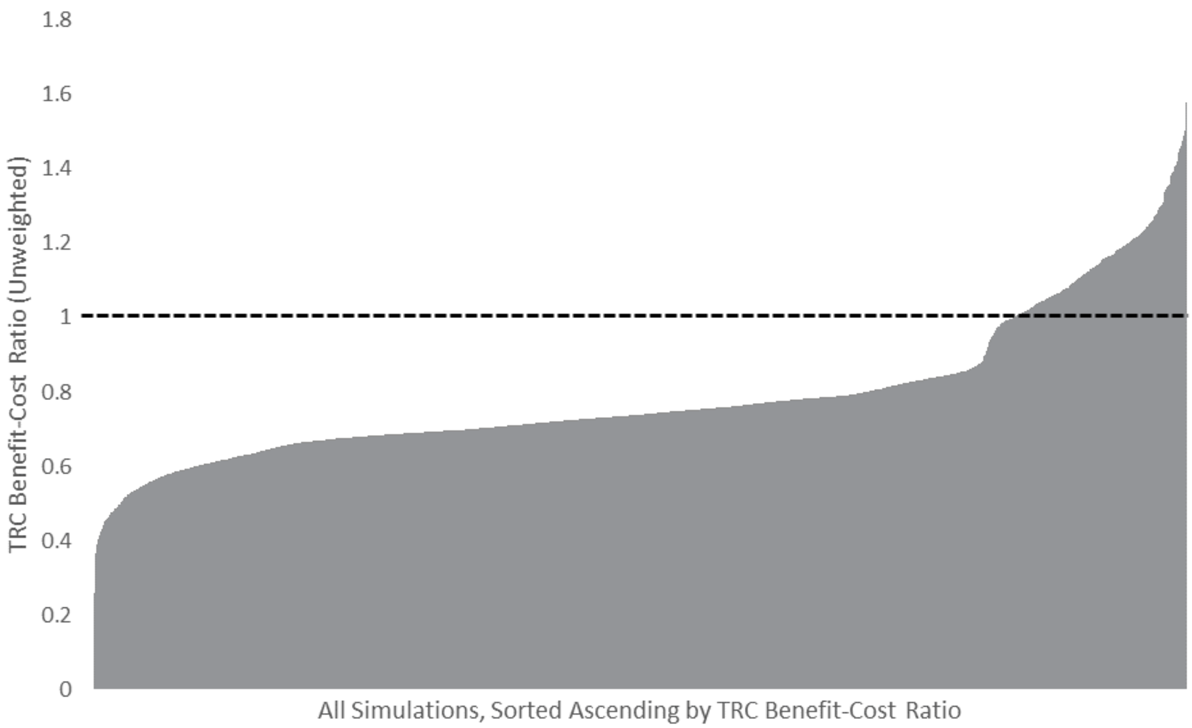
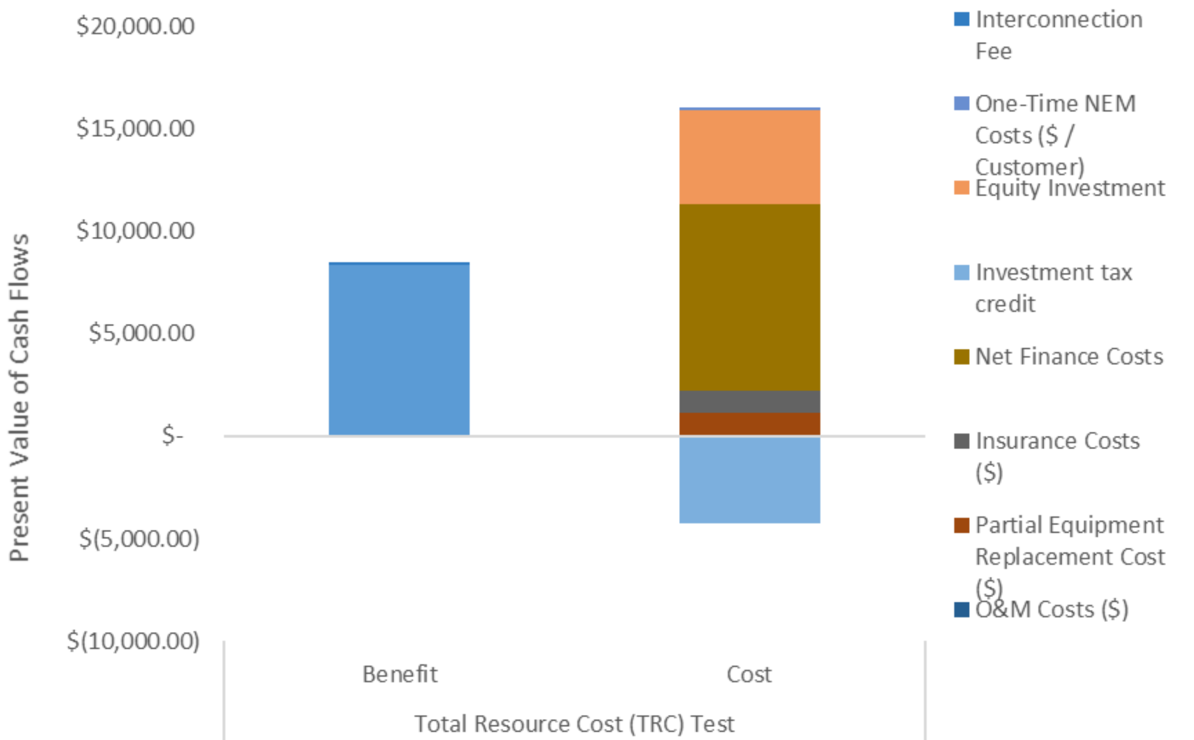


Figure 5-4 on the following page shows an illustrative example of the TRC calculation. The column on the left shows the net present value of benefits, which for a residential customer are the avoided costs. The column on the right shows the total costs, which include the equipment acquisition costs, insurance costs, and one-time NEM costs. The TRC for this example is 0.71, though this should be viewed as an individual example and not representative of SDG&E TRC ratios in general. We explore the sensitivity of the Standard Practice Manual tests to the federal ITC in the following subsection.

FIGURE 5-4: TRC BENEFITS AND COSTS FOR ILLUSTRATIVE CUSTOMER, SDG&E RESIDENTIAL



Investment Tax Credit Sensitivity Analysis

The federal ITC is a benefit in the PCT and a reduction in cost in the TRC test. State incentive programs like the Self-Generation Incentive Program are cash transfers within California and therefore are excluded from the TRC. However, per the SPM, cash transfers from the federal government into California are included in the TRC.

In our model, the federal ITC is modeled at 30 percent of the cost of the solar PV or solar PV + storage system. As of 2020, the ITC declined to 26 percent of system cost and will be fully phased out by 2024 for residential customers. Given the proposed ITC phaseout, there is merit in considering cost-effectiveness results that exclude the ITC.[104] There is also value in considering cost-effectiveness from a federal TRC perspective, which would exclude the ITC as a cash transfer within the country. Table 5-7 summarizes cost-effectiveness results by IOU, sector, and with and without the inclusion of the federal ITC. The results

104 Measures installed in 2022, when the ITC is scheduled to be zero, may have lower system costs than systems installed in 2020. If system costs decline, the value of the 2022 TRC may be higher than the values presented in Table 5-7 for the no ITC case. In addition, systems installed in 2022 will have higher avoided cost benefits under the current forecast of avoided costs.

presented in Table 5-7 show that the PCT and the TRC decline when the ITC is eliminated.[105] When the ITC is eliminated, PCT benefit-cost ratio declines by 14 to 33 percent. Removing the ITC from the TRC leads to a 27 to 38 percent decline in the TRC benefit-cost ratio.

TABLE 5-7: SUMMARY OF PCT AND TRC RESULTS BY CUSTOMER SECTOR AND IOU WITH AND WITHOUT ITC

Utility	Customer Sector	With ITC		Without ITC	
		PCT	TRC	PCT	TRC
PG&E	Agriculture	1.72	1.19	1.32	0.78
	Commercial	1.79	1.12	1.39	0.73
	Industrial	1.47	1.14	1.07	0.74
	Residential	1.83	0.69	1.54	0.50
	All	1.81	0.80	1.49	0.56
SCE	Agriculture	1.23	1.43	0.83	0.96
	Commercial	1.32	1.35	0.92	0.90
	Industrial	1.21	1.40	0.81	0.93
	Residential	1.62	0.80	1.33	0.59
	All	1.55	0.91	1.24	0.56
SDG&E	Agriculture	1.51	1.25	1.11	0.83
	Commercial	1.87	1.18	1.47	0.78
	Industrial	1.53	1.23	1.14	0.81
	Residential	2.08	0.76	1.80	0.55
	All	2.03	0.84	1.72	0.59

NEM 2.0 is not cost-effective from a TRC perspective in the residential sector and for all customers in aggregate. The TRC benefit-cost ratio declines further if we exclude the federal ITC. The RIM test and the PA test benefit-cost ratios (not shown) are unchanged since the ITC does not impact these tests. SCE's PCT benefit-cost values, both with and without the ITC, are lower than the other utilities' while SCE's TRC benefit-cost test values are higher than the other utilities'. SCE's TRC benefit-cost ratios benefit from higher average avoided costs than those forecast for the two other IOU service territories.

5.1.3 Ratepayer Impact Measure (RIM) Test

The RIM test measures what happens to customer bills or rates due to changes in utility and operating costs caused by the NEM 2.0 program. Table 5-3 lists the RIM test benefit-cost ratios by utility and sector,

105 The with-ITC PCT and TRC benefit-cost ratios differ from those found in Table 5-3 because the values included in Table 5-7 do not include fuel cells or wind. The results in Table 5-7 focus exclusively on solar PV and solar PV + storage.

showing that RIM values for all utilities are below one for all sectors. SCE's nonresidential RIM values, however, were substantially closer to 1.0 than those for the other utilities and sectors. Table 5-8 lists the SCE benefit-cost ratios for aggregate SCE rates, where residential is listed as a single rate group and multiple nonresidential rates are listed. The table is sorted so that the rate group with the highest RIM benefit-cost ratio is in the first row in the table and the rate group with the lowest RIM benefit-cost ratio is on the bottom. Customer bill savings are a cost in the RIM test and a benefit in the PCT.

TABLE 5-8: SCE BENEFIT-COST RATIOS BY RATE AGGREGATES

	Aggregate Weighted Benefit-Cost Ratios			
	PCT	TRC	RIM	PA
TOU-PA3-E	1.16	1.44	0.93	674
TOU-8-D	1.12	1.33	0.91	898
TOU-GS1-D	1.10	1.16	0.81	30
TOU-PA2-E	1.31	1.46	0.78	271
TOU-GS2-D	1.23	1.32	0.77	101
TOU-GS3-D	1.29	1.40	0.77	350
TOU-PA2-D	1.28	1.36	0.75	134
TOU-8-E	1.31	1.40	0.75	825
TOU-PA3-D	1.33	1.40	0.72	323
TOU-EV-NR	1.35	1.39	0.71	106
TOU-GS3-E	1.37	1.38	0.69	271
TOU-GS2-E	1.39	1.37	0.67	100
TOU-GS1-E	1.32	1.12	0.60	11
Residential	1.62	0.80	0.43	8

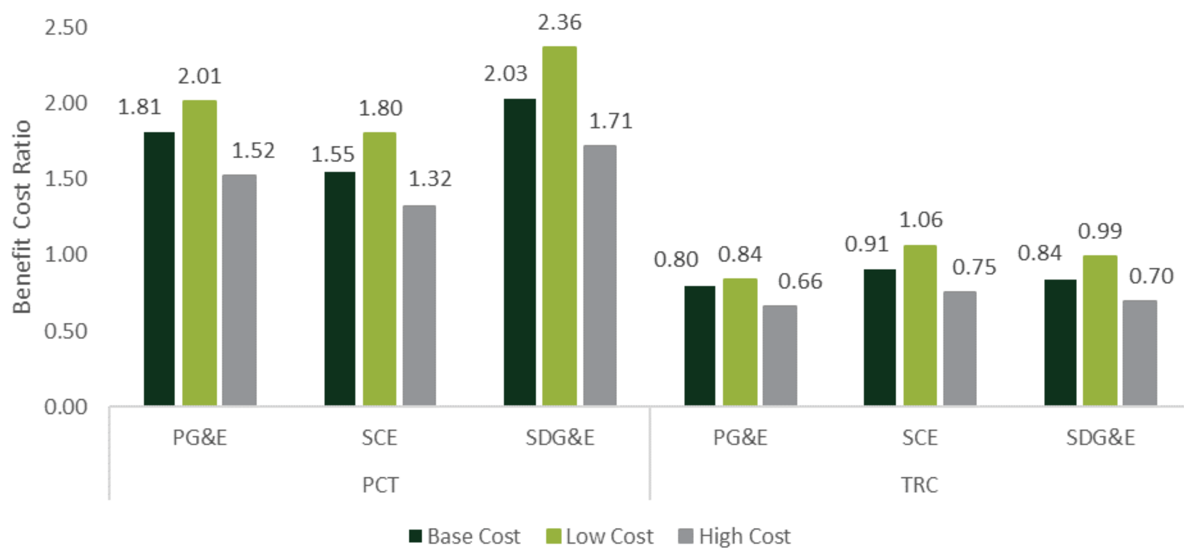
SCE's nonresidential rates are grouped by agriculture (rates with PA in the name), commercial (GS rates) and large commercial/industrial (TOU-8 rates). SCE's rates also include Option D and Option E. The Option D rates tend to have higher demand charges and lower energy rates while the Option E rates tend to have higher energy rates and lower demand charges. The sorted RIM test values show that Option D rates tend to have larger RIM test values and lower PCT values while Option E rates tend to have lower RIM test values and higher PCT values. Note that these values do not represent scenarios, as the values represent actual customer load shapes and customer choices. SCE nonresidential customers on rates with higher energy costs ($/kWh) who install NEM 2.0 systems are associated with larger bill savings, lower RIM values, and higher PCT values. SCE nonresidential customers on rates with a larger share of their bill associated with higher demand costs ($/kW), who install NEM 2.0 systems, are associated with smaller bill savings, higher RIM values, and lower PCTs. SCE residential rates are based solely on energy usage and are associated with lower RIM test values and higher PCT values.

5.1.4 Additional Sensitivity Analyses

Sensitivity to Solar PV Cost

We considered two solar PV cost sensitivities – a high-cost case and a low-cost case. We based the sensitivities on the 20th and 80th percentile prices reported in the LBNL Tracking the Sun Study (see Section 4.2.6). Changes in system cost impact the PCT and the TRC test. Figure 5-5 summarizes the cost-effectiveness results for residential and nonresidential customers installing NEM 2.0 Solar and Solar + Storage systems.

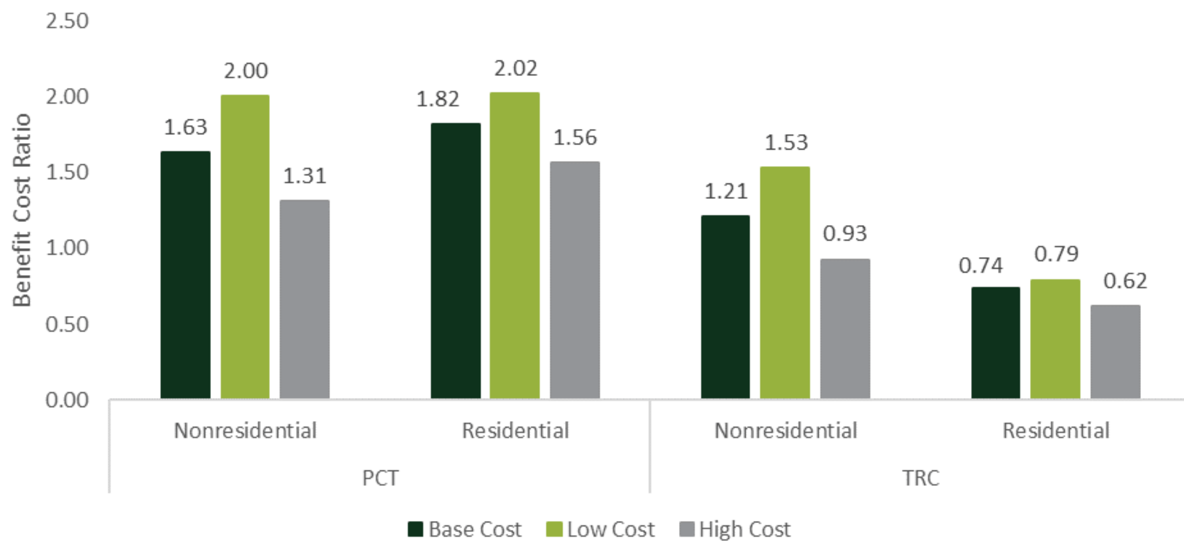
FIGURE 5-5: SENSITIVITY TO PV SYSTEM COST, COST-EFFECTIVENESS BY IOU



Increasing the system cost to the high-cost scenario lowers the participant test and the TRC benefit-cost ratios while reducing the system cost increases both test ratios relative to the base case scenario. In the three price scenarios analyzed for each IOU, all PCT benefit-cost ratios remain above 1.0, indicating that customer-sited systems installed under NEM 2.0 are cost-effective from the customer's perspective. Conversely, only SCE's low-cost scenario is cost-effective using the TRC benefit-cost ratio (from the perspective of customers and the utility). The RIM and PA tests are not impacted by the system cost.

The PCT and TRC benefit-cost test values differ by utility and by residential and nonresidential systems. The prices reported in the LBNL Tracking the Sun Study indicate that residential solar prices are higher than nonresidential prices. All else constant, the higher residential prices would cause the residential PCT and TRC ratios to be lower than nonresidential values. Residential and nonresidential rates and rate components, however, differ substantially. Nonresidential rates often include demand charges and higher fixed fees than residential rates. Nonresidential rate structures often limit the bill savings from solar relative to the savings potential of residential rates. As shown in the residential and nonresidential average PCT and TRC ratios under the three solar price scenarios in Figure 5-6, the impact of differences in the price of solar on the PCT and the TRC ratios is less than the impact of the residential sector's larger relative bill savings. Despite its lower solar prices, the nonresidential sector has lower PCT ratios and higher TRC test ratios than the residential sector.

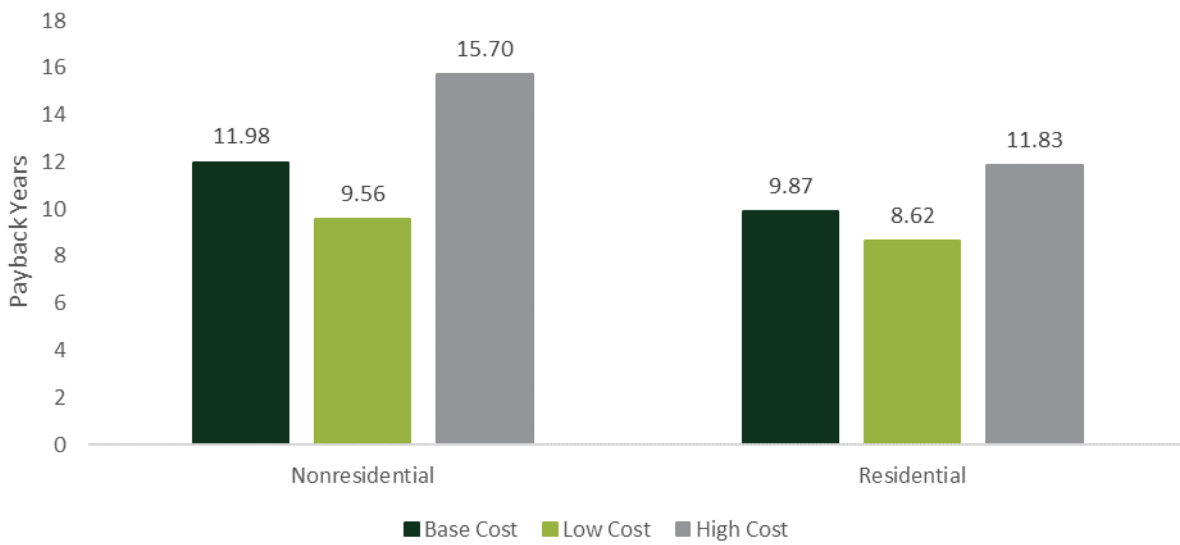
FIGURE 5-6: SENSITIVITY TO PV SYSTEM COST, COST-EFFECTIVENESS FOR NONRESIDENTIAL AND RESIDENTIAL CUSTOMERS



The nonresidential TRC ratio is greater than one, showing that the systems are cost effective from the joint customer and utility perspective, except in the high cost scenario. In contrast, the residential TRC ratio is less than one for all three cost scenarios. The difference in the residential and nonresidential TRC benefit-cost ratios is largely due to differences in the solar cost faced by residential and nonresidential customers given that the TRC benefits are largely derived from the avoided costs associated with the systems.

The effects of increases or decreases in the cost of solar on the customer can also be measured by looking at the estimated customer payback period. Figure 5-7 illustrates the nonresidential and residential payback period for the three PV cost scenarios. Under the base case analysis, the weighted average non-residential payback period is approximately 12 years while the the residential average is 9.9 years. The higher nonresidential payback is driven by the lower relative bill savings potential due to demand charges and higher fixed fees.

FIGURE 5-7: SENSITIVITY OF PAYBACK PERIOD TO SOLAR COST, NONRESIDENTIAL AND RESIDENTIAL



Residential Cost-Effectiveness Sensitivity to California Alternative Rates for Energy (CARE)

Low-income customers are eligible for reduced utility rates throught the California Alternative Rates for Energy or the CARE program. CARE customers receive a 30 to 35 percent discount on their electricity rates.

Table 5-9 lists the benefit-cost ratios for the SPM tests and the estimate of the payback period for CARE and non-CARE residential customers. The low-income customers on CARE have a lower participant cost test and a longer payback period than customers on non-CARE rates. The electricity rate reduction received through CARE reduces the customers' bills and the value of their benefits from installing solar. Installation of solar on CARE households, however, is associated with a higher RIM value as bill savings are a cost in the RIM test.

TABLE 5-9: COMPARISON OF RESIDENTIAL CARE AND NON-CARE COST-EFFECTIVENESS AND PAYBACK

Text	PCT	TRC	RIM	PA	Payback Period
CARE	1.14	0.73	0.59	12.37	16.99
Non-CARE	1.90	0.74	0.32	17.50	8.88

Paying market price for a solar system is often difficult for low-income households. Data presented in Section 3 of this report illustrated that these systems are less frequently installed in low-income and disadvantaged communities. The findings presented above show that NEM 2.0 systems also provide lower bill savings benefits to these households and have a longer payback period.

5.2 COST OF SERVICE RESULTS

The Cost of Service analysis compares estimates of NEM 2.0 customer bills to the utility's cost of service estimates for these customers. The estimates of the cost of service are derived from the utilities' General Rate Case, Phase II (GRC II) documents. The GRC II documents represent the regulatory process of determining the level of costs associated with the utility servicing a class of customers, developing rates for groups of customers based on their costs, and developing an estimate of the resulting revenue the customer group will provide the utility to enable the utility to meet its revenue requirement.

There are many reasons why estimates of the full cost of service will differ from estimates of customer bills. Comparing estimates of bills and cost of service prior to the installation of NEM-eligible technologies to the post-installation values, however, will provide evidence of whether the installation of NEM-eligible technologies is causing cost shifts. Analyzing the difference between bill payment estimates and cost of service estimates pre- and post-installation provides both qualitative and quantitative evidence on how the installation of NEM eligible technologies under NEM 2.0 can influence cost shifting across groups of customers.

Comparing bill payment estimates and cost of service estimates focuses on the differences between these two values for a single year, looking at the difference between the estimate of the cost of service and the per and post installation utility bill for the approximate year of installation. For this analysis, we compare the first-year of utility rate information from the cost-effectiveness analysis to the estimate of the cost to serve the customer for a year. Focusing on a year abstracts from future uncertainty in the growth of utility rates, avoided costs, and cost of service.

Table 5-10 lists estimates of bill payments in excess of their cost of service by sector and IOU for NEM 2.0 customers both pre- and post-installation of NEM eligible technologies. A positive dollar amount indicates that NEM 2.0 customers pay bills that are larger than their cost of service. A negative dollar amounts indicates that the average NEM 2.0 customer pays less than their cost of service following the installation of their NEM generator. Prior to the installation of NEM 2.0 systems, NEM nonresidential customers pay utility bills that average more than their estimated cost of service. Residential NEM 2.0 customers in PG&E's service territory, pay more in utility bills on aggregate than their estimated cost of service, while SCE and SDG&E residential customers pay slightly less in their aggregate utility bills than their estimated cost of service. Following the installation of NEM 2.0 systems, residential NEM customers aggregate utility bills are substantially less than their cost of service while nonresidential customers' aggregate utility bills continue to exceed their cost of service.

TABLE 5-10: AGGREGATE BILL PAYMENT IN EXCESS OF COST OF SERVICE, PRE AND POST NEM 2.0 ($1,000)

	PG&E		SCE		SDG&E	
	Pre-NEM Bill Payments Minus Cost of Service	Post-NEM Bill Payments Minus Cost of Service	Pre-NEM Bill Payments Minus Cost of Service	Post-NEM Bill Payments Minus Cost of Service	Pre-NEM Bill Payments Minus Cost of Service	Post-NEM Bill Payments Minus Cost of Service
Residential	$ 156,271	$ (264,919)	$ (27,050)	$ (198,543)	$ (16,668)	$ (155,172)
Nonresidential	$ 202,275	$ 76,724	$ 21,282	$ 6,301	$ 64,633	$ 34,476
Total	$ 358,547	$ (188,195)	$ (5,768)	$ (192,241)	$ 47,966	$ (120,696)

Figure 5-8 below shows the aggregate customer bills and cost of service estimates pre- and post-NEM installation for all nonresidential customers taking service under NEM 2.0. Figure 5-8 shows that prior to the installation of the NEM-eligible generator, nonresidential customers that take service under a NEM 2.0 eligible tariff are estimated to overpay on their bills by $288 million relative to their cost of service. After the installation of the NEM generator, NEM 2.0 nonresidential customers pay approximately $117.5 million more in their utility bills than their estimated cost of service.

FIGURE 5-8: NONRESIDENTIAL AGGREGATE FIRST YEAR BILL PAYMENT AND COST OF SERVICE PRE AND POST NEM 2.0

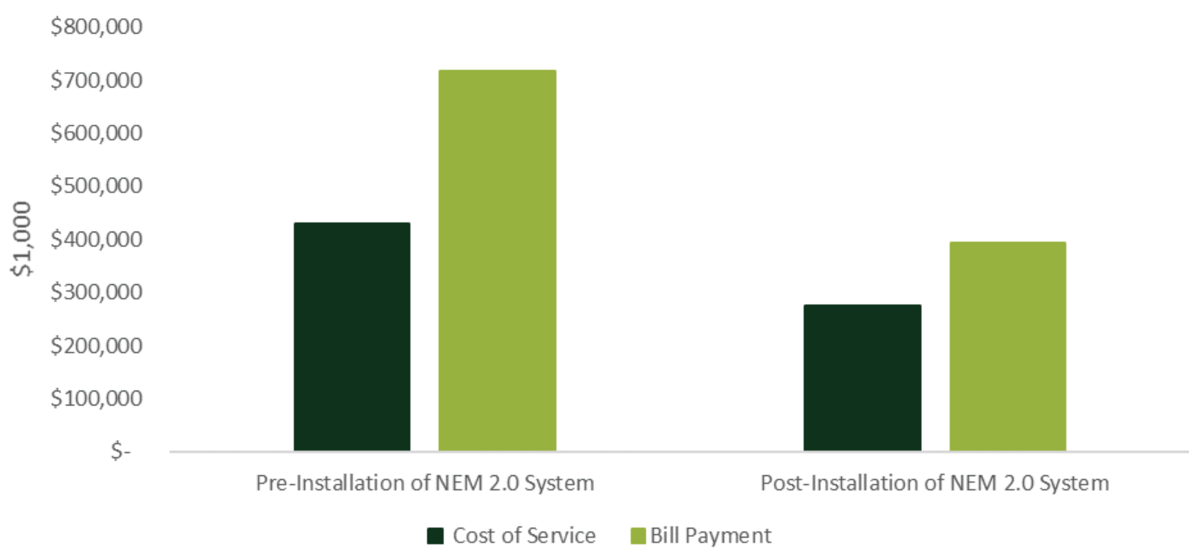


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Figure 5-9 below illustrates the residential aggregate pre- and post-installation utility billing versus cost of service estimates. Prior to the installation of the customer-sited renewable generator, residential NEM 2.0 customers overpay on their bills by approximately $112.5 million. Post-installation, these same customers pay $618.6 million less in utility bills than their cost of service. In Figure 5-9, the post-NEM 2.0 aggregate bill payment is slightly positive ($91 million) while the aggregate cost to serve residential NEM 2.0 customers is $710 million.

FIGURE 5-9: RESIDENTIAL AGGREGATE FIRST YEAR BILL PAYMENT AND COST OF SERVICE PRE AND POST NEM 2.0

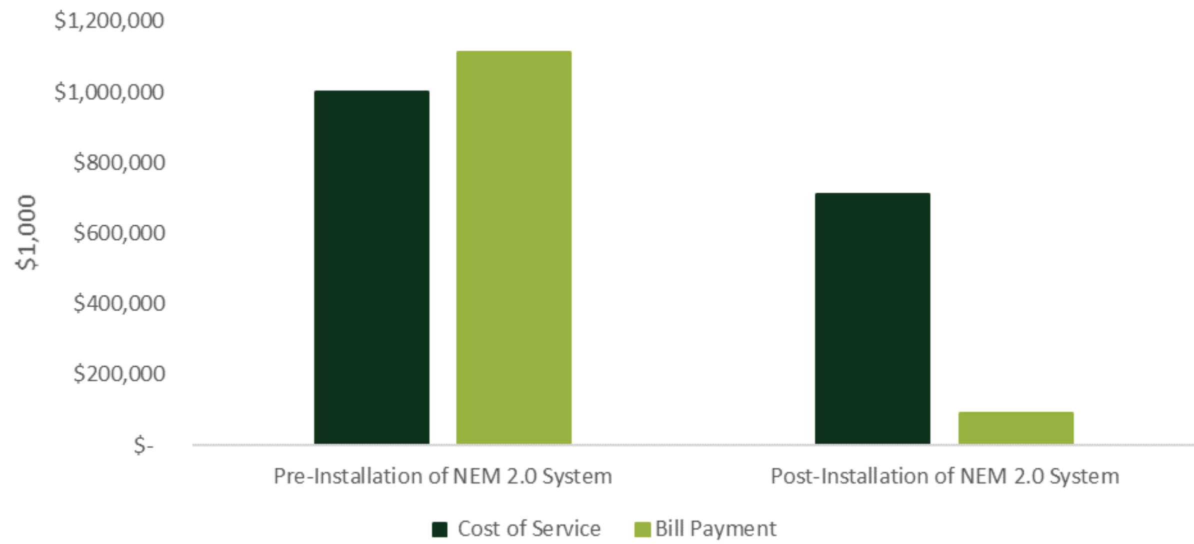


Table 5-11 presents the aggregate bill payment divided by the estimated aggregate cost of service, both pre- and post-NEM generator installation. Numbers greater than 100 percent indicate that customers were overpaying relative to their cost of service. For example, the 178 percent value for SDG&E nonresidential customers pre-NEM generator installation indicates that the aggregate pre-NEM 2.0 bills are estimated to be 178 percent of the cost to serve this customer class. In comparison, SDG&E nonresidential customers are estimated to pay approximately 166 percent of their cost of service following the installation of the NEM 2.0 technology. The less than 100 percent ratio for residential customers post-NEM installation indicates that residential customers are estimated to pay less than their cost of service following the installation of the NEM 2.0 system.

TABLE 5-11: SHARE OF BILL PAYMENT IN EXCESS OF COST OF SERVICE, PRE AND POST INSTALLATION FOR NEM 2.0 CUSTOMERS

	PG&E		SCE		SDG&E	
	Pre-NEM Bill Payments/ Cost of Service	Post-NEM Bill Payments/ Cost of Service	Pre-NEM Bill Payments/ Cost of Service	Post-NEM Bill Payments/ Cost of Service	Pre-NEM Bill Payments/ Cost of Service	Post-NEM Bill Payments/ Cost of Service
Residential	139%	18%	91%	9%	94%	9%
Nonresidential	189%	152%	118%	108%	178%	166%
Total	157%	60%	99%	34%	113%	46%

5.2.1 Impact of PV Sizing Relative to Consumption

The cost of service analysis was stratified by the ratio of estimated PV production to the customer's pre-installation consumption. The ratio variable bins are listed below where PV production is the numerator and consumption is the denominator. The first bin includes all customers whose estimate of annual PV production is less than 80 percent of their pre-installation consumption, increasing to a bin where customers have sized their PV system to be from 1.4 to 2 times as large as their pre-installation consumption.[106] Section 3 presents data on the average PV sizing ratio for NEM 1.0 and NEM 2.0 customers. These data show that the size to consumption ratio has grown dramatically. For example, SDG&E's residential ratio was less than 0.7 under NEM 1.0 and is approximately 1.12 under NEM 2.0. Section 3 also describes how customers typically increase their electricity consumption following the installation of their PV system. For the cost-effectiveness analysis, post-installation electricity consumption was analyzed. The influence of PV system size relative to consumption size maintained the pre-consumption groupings for the descriptive statistics while using the post-installation consumption for the cost of service and cost-effectiveness calculations. Figure 5-10 illustrates the share of residential and nonresidential customers by PV ratio bin.

106 The data cleaning process eliminated customers whose solar PV system was estimated to produce more than twice their pre-installation consumption. These customers were eliminated from the analysis because we assume they have errors in the PV size or the timing of the NEM interconnection data, or they had previously installed PV under NEM 1.0.

FIGURE 5-10: SHARE OF RESIDENTIAL AND NONRESIDENTIAL NEM 2.0 SYSTEMS BY RATIO OF PV GENERATION TO CUSTOMER CONSUMPTION

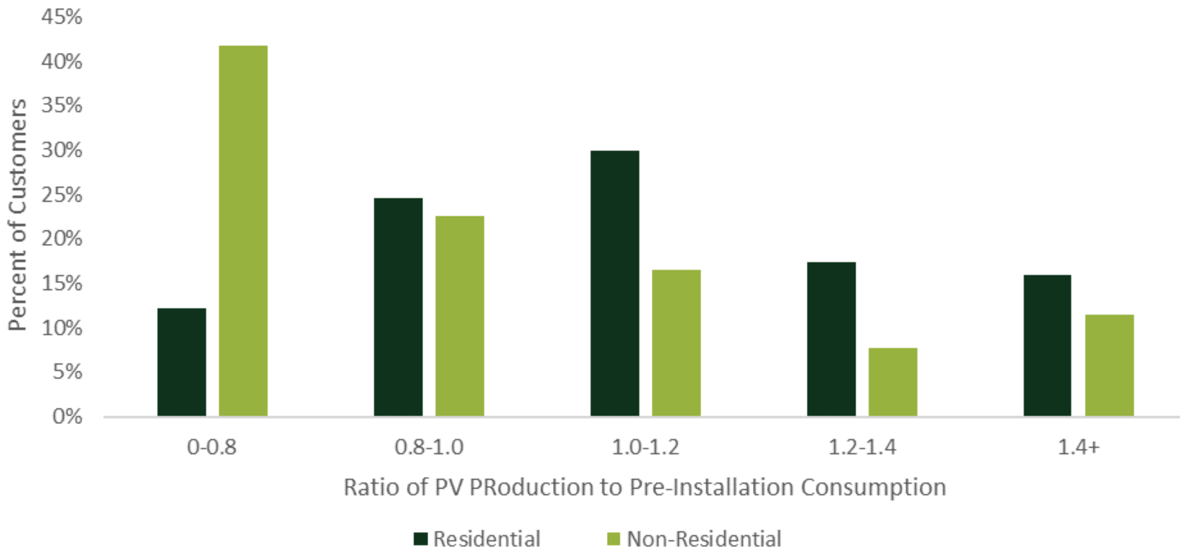


Figure 5-10 shows that only 42 percent of residential customers have PV systems sized to their load or smaller (extra small and small sized bins) while 63 percent of nonresidential customers sized their systems to their load or smaller. With the dramatic increase in PV sizing relative to load under NEM 2.0, it is important to determine how the ratio of PV sizing to load is impacting the under or overpayment of utility bills relative to cost of service.

Figure 5-11 and Figure 5-12 illustrate the share of the cost of service covered by the utility bills pre- and post-NEM system installation by the sizing of the PV system relative to customer consumption for residential and nonresidential customers respectively. Figure 5-11 shows that prior to NEM system installation, all ratio groups of residential customers were paying utility bills that covered at least their estimated cost of service. Following DG installation, however, none of the ratio groups of residential customers pay bills in excess of their cost of service. Customers with the smallest PV system relative to their load (0-0.8, the left-most set of columns), paid bills that averaged 120 percent of the cost of service prior to DG installation and only 44 percent of that cost following installation. Customers with the largest PV system relative to their load (1.4+, the right-most set of columns) paid bills that reflected 106 percent of their cost of service prior to DG installation but post-installation had a negative utility bill and they are estimated to leave the utility with 103 percent less resources than their cost of service. This graph illustrates that over sizing of systems under current rate structure has led to increasingly large cost shifts among customers.

FIGURE 5-11: STATEWIDE RESIDENTIAL SHARE OF UTILITY BILLS RELATIVE TO COST OF SERVICE BY PV SYSTEM SIZING RELATIVE TO CONSUMPTION PRE AND POST NEM 2.0

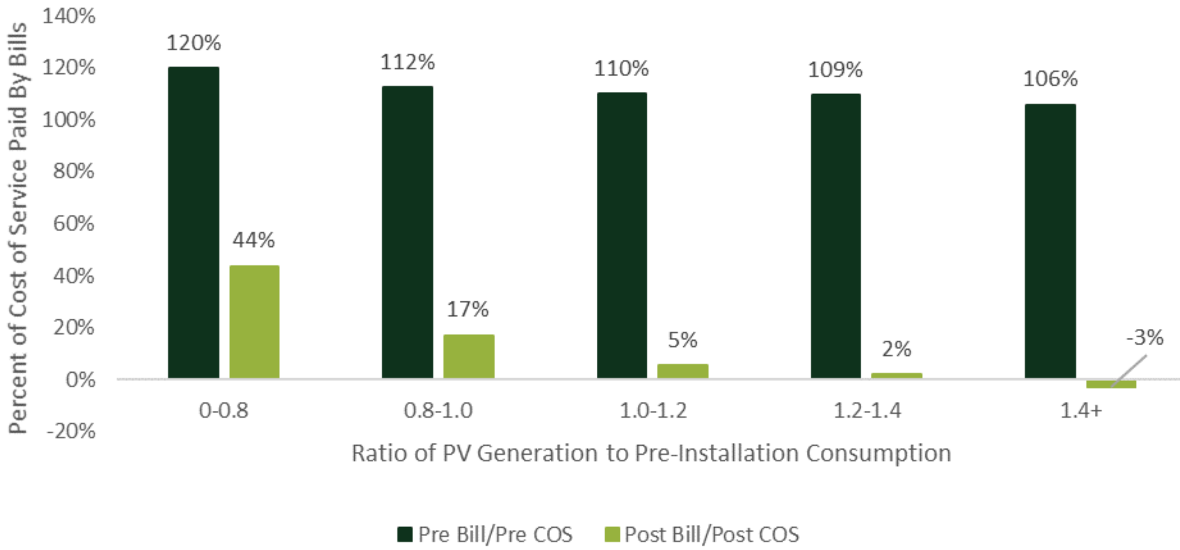
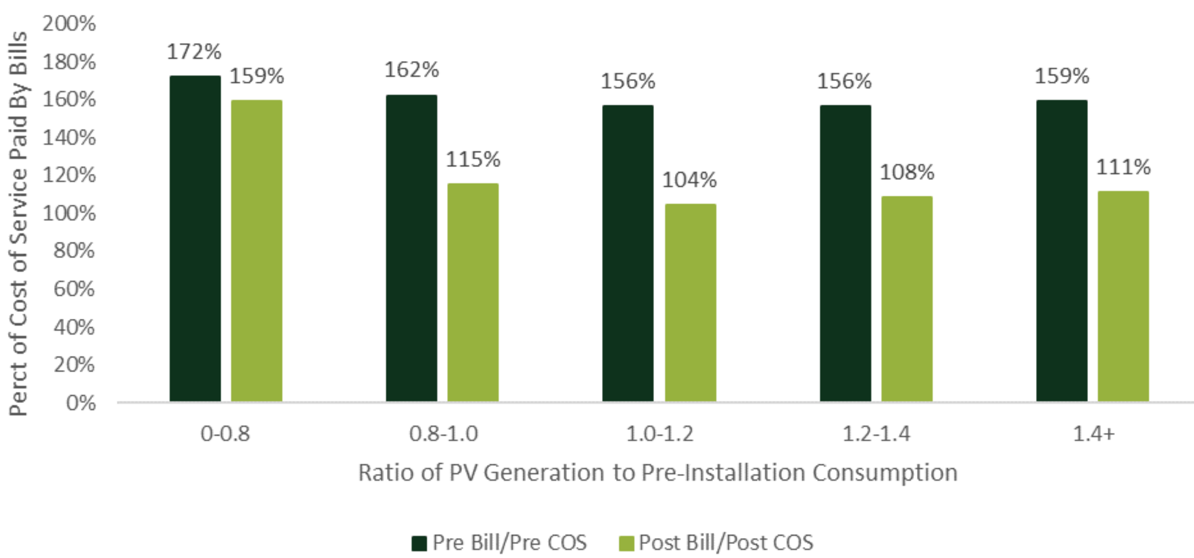


Figure 5-12 illustrates the relationship between bills and cost of service by system sizing relative to consumption for nonresidential NEM 2.0 customers.

FIGURE 5-12: STATEWIDE NONRESIDENTIAL SHARE OF UTILITY BILLS TO COST OF SERVICE BY PV SYSTEM SIZING RELATIVE TO CONSUMPTION PRE AND POST NEM 2.0



These data show that all groups, when disaggregated by system sizing ratio, paid aggregate bills in excess of their cost of service prior to NEM systems installation. Post NEM system installation, nonresidential customers continued to pay bills that covered more than their estimated cost of service regardless of the size of the PV system relative to customer electricity consumption. Nonresidential rates have fixed fees and demand charges that help maintain the relationship between the cost of service and customer bills.

APPENDIX A NEM 2.0 MODEL QUICK-START GUIDE

This section contains a quick start guide for installing and running the NEM 2.0 Lookback Study Model.

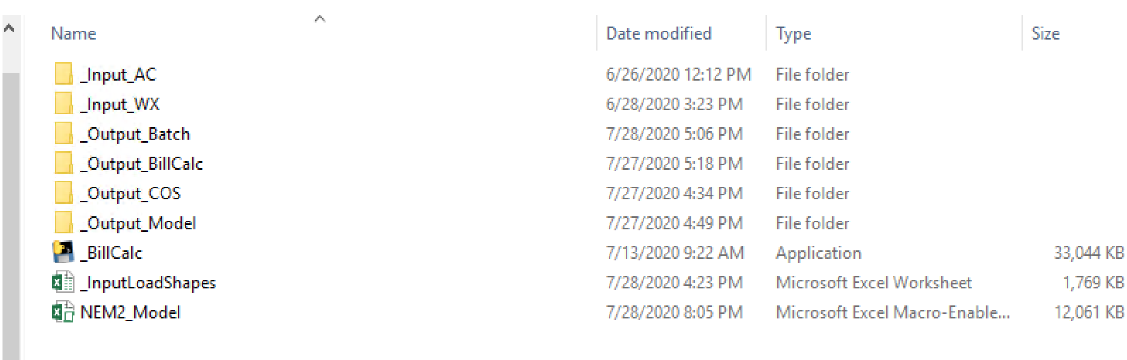
A.1 SYSTEM REQUIREMENTS

The NEM 2.0 Lookback Study model is built using Microsoft Excel 2016 and Python 3.8.5. The Excel workbook is where users select all model inputs. It also contains the NEM customer bill calculation, the pro forma analysis for NEM 2.0 system economics, and the cost of service calculations. The Python model is compiled as an executable file to facilitate model usability (i.e., users do not need to install Python to use the NEM 2.0 Lookback Study model). The executable file is launched from the Excel user interface and is responsible for moving data between workbooks and tabs, simulating the output of all DERs, and performing the avoided cost calculation. The executable file also writes all the model results to the output destination. Additional details on the model inputs and calculations are provided in subsequent sections. The model was developed on machine running Windows 10 Enterprise.

A.2 INSTALLING THE MODEL

The model is downloaded as a .zip archive. To install the model, extract the .zip archive to your computer. The model directory will appear as in Figure A-1. Note that the model will not function properly if it is extracted in a SharePoint environment.

FIGURE A-1: MODEL DIRECTORY



A.3 RUNNING THE MODEL

To start the model, double click the file called “NEM2_Model.xlsm”. If this is your first time running the model, you may need to click “Enable Content” or “Allow Macros”. The model will open to the Inputs tab, as shown in Figure A-2. As a check, the field “Current Directory” (cell N10 in tab ‘Inputs’) should point to the folder containing the model files.

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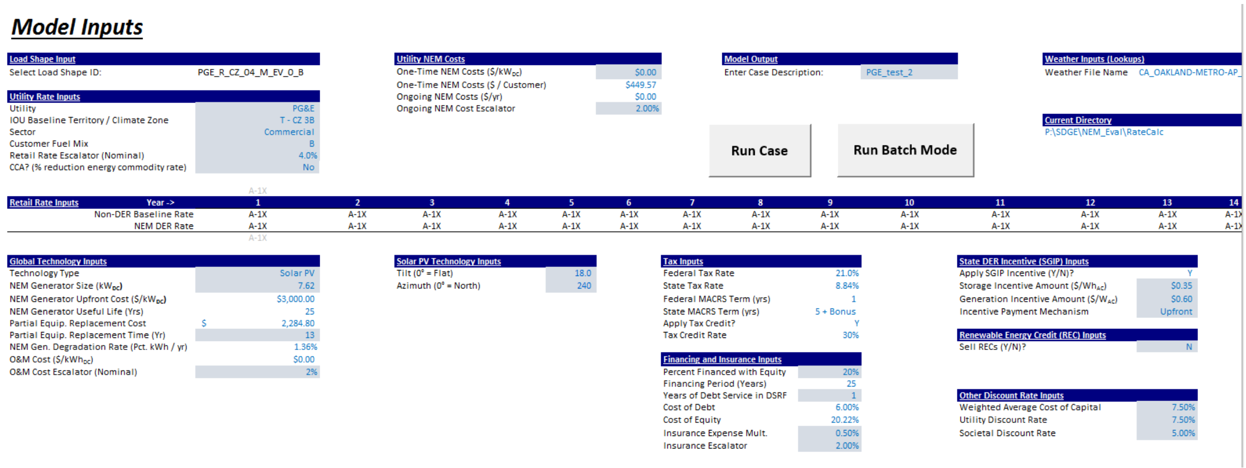
FIGURE A-2: MODEL INPUTS TAB



The model is pre-populated with load shapes and values that allow the user to run the model immediately. To run a single case, press the 'Run Case' button. The user can also run multiple cases at once using batch mode. To use batch mode, the user must enter all the relevant inputs in the 'batchInputs' tab and click 'Run Batch Mode'.

After running a single case, the model will output three files:

- A copy of the model will be saved to the _Output_Model folder
- A copy of the bill calculations will be saved to the _Output_BillCalc folder
- A copy of the cost of service calculations will be saved to the _Output_COS folder

When running the model in batch mode, a single file will be created with summary data. This file is saved to the \Output_Batch folder.

After the model has finished running, the excel workbook will close.

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APPENDIX B COMMENT MATRIX AND EVALUATOR RESPONSES

TABLE B-1: DRAFT REPORT COMMENT MATRIX WITH EVALUATOR RESPONSE

Comment #	Commenter	Page or "Overarching" for general comments	Comment/feedback/change requested	Evaluator's Response
1	Aurora Solar, Inc.	Overarching	Using our software—Aurora—solar providers are able to design optimal PV systems, remotely model shading, generate accurate performance results, calculate pre-solar and post-solar utility bills from green button data or by estimation from monthly bills, calculate financial returns, and generate sales proposals. We know that it is fairly common to very common for installers to include energy upgrades along with solar, or for customers to request solar PV specifically because they choose an EV, i.e., energy consumption can change considerably after solar is installed. How are these consumptions changes accounted for? This could be done by viewing the customer's post-solar bills after NEM interconnection—perhaps by comparing estimated post-solar bills to the actual post-solar bills, or by calculating post-solar net consumption from post-solar actual bills and then comparing that to the estimated post-solar net consumption from the pre-solar consumption and estimated production. This information would be generally valuable to the solar industry and is also a key part of the cost factors in the test metrics. Is there a way to look at the post-solar bill or net interval data of a set of these customers for a sanity check? If the evaluator has access to post-solar bills, and we would like to see a confirmation of this post-NEM production/consumption ratio from a large sample of customers.	We agree. We have adjusted the customer load profiles used in the model. Previously the model used the pre-interconnection consumption shape and added PV. The analysis has been adjusted to account for increases in post-interconnection consumption. We have added expected solar PV generation to the post-interconnection usage. This tells us how much consumption increased relative to the pre-interconnection usage level, and we have applied a multiplier to each hour of the pre-interconnection load shape.

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2	Aurora Solar, Inc.	Overarching	It's highly improbable that NEM-2 residential customers pay close to zero bills on average after installing solar.	We agree that once accounting for load growth it is unlikely that customers would pay zero bills. This is no longer the case with the adjusted load shapes.
3	Aurora Solar, Inc.	Overarching	The bill calculations and calls to PV_LIB are in Python but are not in the downloadable model. Would it be possible to obtain a copy of the python code used?	The bill calculation happens entirely in excel, you can see it in the 'byMonthBills' tab. The final version of the code will be released along with the final report.
4	Aurora Solar, Inc.	Overarching	It's unclear how a 18-20% capacity factor was achieved while using 14% losses. Can you expand on this?	We assume this question refers to the assumed capacity factor used to estimate the PV generation as a share of consumption. We had previously assumed a 20% capacity factor to provide a high level estimate, which was based on the reported CEC PTC AC size of the system. We have now moved away from an assumed capacity factor and applied actual simulated values from PV Watts to estimate the PV share of consumption.
5	Aurora Solar, Inc.	Overarching	CPUC's report puts the actual utility rate escalator at 3.1%; this is the percent this study should use. 4% was rounded up to allow for future escalation.	We agree that the CPUC reported the historical retail rate escalator at 3.1%, however after consulting with CPUC Energy Division we believe the 4% retail rate escalation is appropriate. We have added a sensitivity case using the 3.1% escalator.
6	Public Advocates Office, Alec Ward	Overarching	Verdant should incorporate impacts of Net Energy Metering (NEM)'s credit levels. In the "Net Energy Metering 2.0 Lookback Study" (Report), Verdant uses four cost-effectiveness tests: the Total Resource Cost (TRC) test, the Participant Cost Test (PCT), the Program Administrator (PA) test,	We assume this comment is asking us to report first year RIM benefits and costs separately, perhaps also normalized by PV

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			and the Ratepayer Impact Measure (RIM) test. A crucial issue in the upcoming NEM 3.0 proceeding will be determining the appropriate credit level for energy exported by NEM 3.0 customers. Only the RIM test accounts for the credit level of a NEM customer's exported energy in its calculation. The RIM test currently sets the credit level per kilowatt-hour at the customer's retail rate. Factoring in NEM's current credits at the retail rate drives RIM's average score to a significantly low 0.46. This average RIM score is weighted by the number of NEM 2.0 customers in each investor-owned utility's (IOU) service territory. The RIM score includes NEM 2.0 cost impacts on NEM program participants, as well as non-NEM participants. These factors are all relevant when evaluating the appropriate NEM credit. Therefore, the RIM test results should be utilized when evaluating any future NEM proposals. In addition to calculating cost-effectiveness ratios, Verdant should include the overall cost to NEM participants and NEM non-participants' bills due to NEM 2.0's credit levels. The Sacramento Municipal Utility District (SMUD) recently took this approach in its "Value of Solar and Solar + Storage Study." This study found that the current value of solar is 3-7 cents per kWh. That this value is significantly less than the current credit level received by NEM 2.0 customers shows the utility of this analysis for program evaluation. SMUD's report also notes that all solar and solar plus systems operating in its territory in 2020, including those participating in NEM 1.0 and NEM 2.0, cost non-participating SMUD customers $25 - $41 million each year. The actual impact on NEM non-participants' bills is a more accurate assessment of non-participant cost impact, and therefore, Verdant should include these impacts in the Report.	generation kWh. This has been added to the analysis.

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7	Public Advocates Office, Alec Ward	Overarching	Verdant should correct the calculations for energy generation from NEM systems to ensure meaningful program analysis. In its "NEM 2.0 Lookback Study - Draft Report Webinar" on August 20, 2020, Verdant noted the "angle of incidence on PV [photovoltaic] panels was being set incorrectly, causing PV yield to increase beyond reasonable levels." Verdant claimed the levels of energy generated may be off by 10 percent. This PV overgeneration is a meaningful level of error in the calculations and would impact the TRC and PCT tests. Along with the Report, Verdant released a NEM 2.0 Model (Model) that it used to run the cost-effectiveness tests. The Report provides an average result across multiple load shapes for each cost-effectiveness test. The Model provides a single residential load shape for each IOU. On August 29, 2020, Verdant updated the Model to fix errors, including the PV overgeneration it noted in the webinar. These fixes changed the Model's cost-effectiveness test results, especially for the TRC test. Table 1 below demonstrates that, using the updated Model, the TRC result for SCE's residential NEM 2.0 customers drops from the Report's 1.37 TRC to 0.88. SDG&E's TRC result similarly drops to 0.88 using the updated Model. PG&E's TRC result drops to 1.03. Given the large differences between the updated Model and the Report TRC results, Verdant should update the Report to incorporate cost-effectiveness tests. The conclusion that NEM 2.0 is now shown to be not cost-effective in most service territories should also be reflected.	We agree. The report has been incorporated using the corrected version of the model.
8	Public Advocates Office, Alec Ward	Overarching	Verdant should analyze low-income data at a more granular level to increase the Report's accuracy. In Section 3.3, the Report shows that less than 40 percent of NEM 2.0 and 1.0 customers have an annual household income below $75,000, and less than 10 percent have incomes below	We agree that the report's accuracy could be increased with more granular data. However, we were limited by the IOU interconnection data which in some cases

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			$25,000. However, in Report section 3.1.2, Verdant claims it "did not have full system address data for many of the NEM 2.0 systems due to utility confidentiality concerns." A more granular assessment is necessary to accurately analyze low-income customer participation in NEM 2.0. Specifically, in section 3.1.2 of the Report, Verdant aggregates CalEnviroScreen census tract data to the zip code level. Verdant calculates the median household income for each zip code and analyzes the number of NEM 2.0 customer within each zip code. Verdant should include more granular data on household income for all NEM 2.0 customers to ensure low-income NEM customers are not being overcounted. For example, the Report does not identify whether only the most affluent customers in each zip code participate in NEM 2.0. If this were the case, the Report would not account for the lack of actual low-income NEM 2.0 customers. The Report would only reflect the participation of more affluent customers in zip codes with low average household incomes. Instead, Verdant should examine more granular household income data, while remaining within the bounds of NEM customer privacy protections. For example, a recent "Income Trends among U.S. Residential Rooftop Solar Adopters" report by the Lawrence Berkeley National Laboratory (LBNL) found that only 15 percent of 2018 rooftop solar adopters are below 80 percent of their respective area median income To reach this figure, the report authors identified rooftop solar customers using LBNL's "Tracking the Sun" dataset and BuildZoom, which use actual household enrollment data but aggregated to the zip code level. The authors modeled household value and income for the addresses using Experian,	only included zip-code level information. We have included multiple caveats in the report about this limitation and moved the already included reference to the LBNL report earlier in section 3.

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			which is a consumer data base with consumer demographics including income level. The authors then compared results with U.S. Census zip code area median income. Verdant should employ similar methodology that includes customer addresses and income ranges, including using Experian household income levels. Verdant should then aggregate the data to protect customer privacy. In addition, Verdant should utilize the California Alternate Rates for Energy and Family Electric Rate Assistance Program eligibility data. This data is collected by the IOUs to identify specific households with the greatest need for financial assistance.	
9	Public Advocates Office, Sophie Babka	Overarching	Verdant should utilize the correct annual investment tax credit (ITC) level in TRC and PCT tests, and it should clearly indicate which analyses apply to a given level of ITC. While the ITC has been in effect during the NEM 2.0 period, any evaluation of cost-effectiveness for NEM programs in the future should set the ITC rate corresponding to the year the NEM system installation began. In Section 4.2.6, Verdant states, "[w]e assume that residential, commercial, industrial, and agricultural PV customers are receiving the federal ITC at 30% of the total system upfront cost." In Section 1.4.5, Verdant notes the decline in ITC for 2020 to 26 percent and its ultimate phase out in 2022 for residential customers. In Section 1.4.5, Verdant writes "[g]iven the potential ITC phaseout, there is merit in considering cost-effectiveness results that exclude the ITC." Verdant notes in Section 1-7 that including the ITC impacts the PCT and TRC test, noting the "TRC benefit-cost ratio is highly sensitive to the inclusion of the federal ITC. Removing the ITC benefit from the TRC calculation results in the TRC benefit-cost ratio less than 1." Table 1 above shows that the TRC results in the updated Model for residential NEM 2.0 customers dramatically drops when the 30 percent	We currently apply a 30% tax credit to all solar PV and solar PV + storage systems in the analysis. Our population is defined as systems interconnected on or before 12/31/2019, therefore all customers would have access to the 30% ITC. We include a "No ITC" case to understand the influence of the ITC on cost-effectiveness, but it is not meant to follow the proposed phaseout of the ITC.

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			ITC is removed. The SCE and SDG&E TRC results lower to 0.61, and the PG&E TRC result drops to 0.72. For all TRC and PCT calculations throughout the report, Verdant should clarify which years the ITC was applied and at what rate. Table 1-5 shows the impacts on PCT and TRC by customer sector and IOU with and without ITC. However, in Appendix C, which contains the simulations results for all cost effectiveness tests performed, it is not clearly indicated when and how the ITC was used. The report should include analysis that clearly reflects the ITC levels NEM customers face at the time of installation. Following the federally legislated ITC levels, residential systems that began construction before 2020 should factor a 30 percent incentive, 26 percent for systems installed in 2020, 22 percent for systems installed in 2021, and no incentives for residential systems that began construction after 2022, as the residential ITC expires.	
10	Public Advocates Office, Sophie Babka	Overarching	To enhance report accuracy, Verdant should use California-specific data rather than national data, which may not accurately reflect the relevant price of PV systems in the state. In Section 4.2.6, Verdant notes it relied on the LBNL's 2019 "Tracking the Sun" data which provides nationwide information on the installed prices of PV systems. Verdant should instead use California-specific prices of installed PV systems. In Report Section 4.2.7, Verdant states its models "assume 20% equity upfront payment and 80% debt financing for the life of the system." However, in Section 5.2.9 of Itron's "2019 [Self-generation Incentive Program] SGIP Energy Storage Market Assessments and Cost-effectiveness Report," Itron assumes customers finance their systems with 40 percent equity. Verdant does not provide the basis of its	We have adjusted the upfront cost to reflect the California-specific average installed price of PV rather than the national average. We have also adjusted our financing assumptions based on additional research to reflect the most likely financing scenarios for residential customers. In the draft and in the final report we have included sensitivity analyses based on the 20th and 80th percentile PV prices based on the LBNL study. These sensitivities should capture

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			assumption that "customer-sited renewable generation technologies are assumed to be financed with equity and debt." Verdant also does not prove whether this assumption is reflective of the average financing mechanism (debt, leases, bonds, or power purchase agreements) used for NEM systems in California. Verdant should corroborate the Report's customer finance assumption with more local pricing data to ensure it truly reflects of the distribution of the finance mechanisms used in the California PV market. According to the "Solar-Estimate," the price of PV in California fluctuates greatly depending on the finance mechanism used to install solar. The finance mechanism causes PV prices in California to span \$2.78/W for cash-purchased PVs to \$3.11/W for financed PVs. TRC results are also sensitive to financing options. In Table 1 above, the TRC results in the updated Model for residential NEM 2.0 customers drop dramatically when customers finance their systems with 40 percent equity, following the SGIP report's assumptions, instead of the Report's assumed 20 percent. The SCE and SDG&E TRC test results drop to 0.79, and the PG&E TRC test result lowers to 0.93. In the Report, Verdant should assess the distribution of financing mechanisms in California and use a weighted installed cost that is reflective of this distribution to account for these fluctuations in PV pricing.	the variability in cost-effectiveness that might result from the financing mechanism.
11	Public Advocates Office, Alec Ward	Overarching	The Report should be amended to include feedback from other parties. The preceding comments could require important and substantial alterations to the Report's key testing methods and results. Verdant should consider all stakeholder feedback and issue a draft that corrects important errors in the current draft before opening comments are due	The report and the model have been amended to include feedback from parties as appropriate.

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			for the Order Instituting Rulemaking in the NEM 3.0 proceeding. If Verdant is unable to make the preceding changes to the Report, Cal Advocates recommends the Energy Division consider a second phase of the report that incorporates the changes. In the upcoming NEM 3.0 proceeding, parties will be relying on the test results and other analysis in this Report to form and support their positions. Supplying decision makers, parties, and the public with accurate data through this Report is vital to an effective NEM 3.0 proceeding.	
12	CALSSA	Throughout	The study uses averaged customer electricity usage data to measure customer bill savings and utility revenue. Customers are divided into bins according to customer segment, climate zone, and size. This makes the calculation manageable at normal computing capacity. However, it is a major shortcut with unknown impacts on overall results. To test the accuracy of the customer bins and the overall approach, Verdant should run a comparison case with real customer data. This control sample should include at least 100 customers in each customer segment tested and should test a majority of customer segments. Failing to do a robust quality check on the accuracy of customer averaging risks the accuracy of all of the study's findings.	While the suggested approach is interesting, it is outside the scope of this project as laid out in the final research plan. We verified the accuracy of the bill calculation using individual customer information and we don't believe that the averaging process, which is consistent with the research plan that was subject to public comment, introduces significant error to the analysis.
13	CALSSA	Throughout	It is common for customers to install solar at the same time that they increase their load by adding an electric vehicle, installing an electric appliance, or expanding their home. Home renovation and other changes in consumption can be the reason people pursue solar. In these cases, gross consumption will be greater after solar than before. By assuming that post-solar gross consumption is the same as pre-solar gross consumption, the study overestimates the generation-to-load ratio and underestimates post-solar bill payments. The study should use real customer data for post-solar gross consumption for a large sample of	The study has been updated to account for increases in consumption after the installation of a NEM 2.0 system.

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			customers and use the findings to make corrections in the load patterns in customer bins.	
14	CALSSA	4-23	The draft study also indicates that there were not enough customers to create an average consumption profile for some segments of EV customers. Verdant should verify that the substitute customer bin is one specific to EV customers and non-EV customer consumption profiles are never used for EV customers.	EV customer profiles are always based on customers with EV rates and vice-versa. When sample sizes were small, we used customer profiles from other climate zones or size bins.
15	CALSSA	Throughout	Verdant should also verify that NEM Aggregation customers were either excluded or the load of all benefitting accounts was included in the generation-to-load ratio.	We did not find any evidence of NEM-A customers in our metered sample. We also applied numerous quality control screens that would discard customers with usage or generation-to-load ratios that are unexpected.
16	CALSSA	4-28	The study uses a utility rate escalator of 4%. Verdant staff indicated this is drawn from the recent Commission decision on standardized inputs for solar savings calculations, D.20-08-001. It is reasonable to use that decision as the source for a figure for utility rate escalation, but Verdant drew the wrong number from the decision. The decision set a cap on the assumption for utility rate escalation that solar providers can use in solar savings estimates presented to consumers. The Commission found that the actual historic figure is 3.1%. For the cap they rounded the number up to 4%. The decision states, “The average escalation rate of electric utilities in California over the past five years of currently available data (2014-2018), weighted by their proportion of customers, is 3.1 percent. To allow for fluctuations over time and for simplicity, the modified staff proposal rounds this figure upward to four percent.” (D.20-08-001, p. 17) The NEM lookback study should use the best estimate for utility rate	We agree that D. 20-08-001 lists the average rate increase at 3.1% and rounds up to 4%. The 4% represents the maximum allowable for solar installers in their presentations to customers. Given the future uncertainty and the needs to reduce the carbon intensity of the grid, it is likely that the growth in utility rates will exceed the current history of 3.1%. Recent GRCs also point to higher increases. The use of the 4% rate increase is consistent with the study's initial research plan and has been approved by the CPUC after receiving public comments.

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			escalation rather than an upper boundary that was developed for sales presentations. It should use 3.1% instead of 4%.	
17	CALSSA	response to questions	The study calculates cost benefit results over a 25-year system lifetime for solar. This is consistent with typical solar panel warranties. CALSSA does not object to this time horizon. However, Verdant assumes that customers continue to take service under the NEM-2 tariff after Year 20. This is inaccurate. NEM grandfathering is for 20 years. Nobody expects NEM to be the same at the end of that grandfathering period. Verdant should instead assume that export credits will be valued at the level generated by the Avoided Cost Calculator for the relevant year or for 2038. The study period for the lookback study is January 2017 through June 2019. A mid point is 2018. Customers installing solar in 2018 will have NEM-2 grandfathering through 2037. A 2038 avoided cost figure is therefore a reasonable estimate for NEM credit value in Years 21-25 of a system's lifetime.	We agree – we have changed the base case methodology such that exports are valued at the avoided cost rate for years 21-25. However, we have kept 2020 as the base year, not 2018.
18	CALSSA	webinar slide 11	For purposes of comparing solar system output to customer consumption, Verdant used a 20% capacity factor. That is far too high. Only the best performing systems produce that much, and it is rare in real world conditions. PG&E recently concluded that the right number to use for an average solar capacity factor is 17.2%. (PG&E Advice Letter 5634-E-A; PG&E Form 79-1151-A, revised July 2020) That is a reasonable average and should be used by Verdant. The report should also explain that comparing expected system output to historical load ignores the factor that many customers install solar when they are expecting an increase in load due to an electric vehicle, major new appliance, home expansion, or change in business activity. The study should correct for this impact as explained above.	The report has been adjusted to eliminate this capacity factor assumption and to account for load growth.

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19	CALSSA	missing	The study does not appear to adequately consider the resiliency value of behind the meter storage paired with solar. The study only appears to value the additional rate arbitrage opportunity created by the addition of energy arbitrage in the PCT as well as the TRC, without considering the benefits of resiliency, load shifting and backup power in the case of a grid outage. Verdant should assign a monetary value to avoided outages in the TRC and PCT.	We agree that energy storage customers, particularly residential energy storage customers, are motivated by the resiliency benefits of storage. However, we don't believe that resiliency value would impact the TRC. Resiliency is a private benefit that accrues to the customer, not society. Regarding the PCT, we chose not to include the resiliency benefit due to the large ambiguity that exists in defining this value.
20	CALSSA	webinar slide 36	Verdant assumes that solar customers on legacy rates will remain on those rates for an additional eight years for commercial customers and 2-3 years for residential customers. That is excessive. The TOU decision of January 2017 (D.17-01-006) set the grandfathering terms at five years from system installation for residential customers and ten years from system installation for commercial customers. With the exception of public sector customers, commercial customers needed to be on a legacy rate by January 31, 2017. Public sector customers had to be on a legacy rate by December 26, 2017. Residential customers had to be on a legacy rate by July 31, 2017. It is therefore a small subset of NEM-2 customers that are on legacy rates. For those that are, the grandfathering clock starts at PTO. An SDG&E residential customer installing solar under NEM-2 in July 2016 will only be able to stay on the rate until July 2021, less than a year from now. The latest date that a residential customer can be on a legacy rate is July 2022. One year would be a more accurate estimate for residential customers. Very few commercial NEM-2 customers should be on legacy rates. NEM-2 started in late December 2016 for PG&E and July 2017 for SCE. The decision states that in no case shall legacy rate grandfathering for commercial customers extend beyond July 2027 for non-public-sector customers. That is less than seven	In our model we are estimating the lifetime benefits of PV from their time of interconnection, not necessarily from 2020. Therefore, while our model might show customers staying on legacy rates beyond 2027, they remain on legacy rates for a period of time that would be expected relative to their interconnection date.

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			years from now, and for some customers it will be less. Verdant should assume a rate transition after seven years or less for NEM-2 commercial customers on legacy rates.	
21	CALSSA	Figure 5-9	The draft study finds that NEM-2 residential customers pay close to zero bills on average after installing solar. That must be in error. It is true that many customers have systems that produce more than the customer consumes in a year and net surplus compensation and the Climate Credit can both work to offset minimum bills. However, it is a minority of customers that fully offset the minimum bill. The Climate Credit was $28-33 in 2019, depending on utility. There is therefore a difference of $90 between the $120 per year minimum bill and the Climate Credit. To make up this difference in net surplus compensation would require overgeneration of nearly 3,000 kWh at a net surplus compensation rate of 3.065 cents/kWh. To say that is the average amount of generation is simply untrue.	We have resolved an issue in the model that was resulting in over-generation of Solar PV. We have also adjusted the post-installation load shapes to reflect our estimate of post-installation consumption. These factors have resulted in considerably fewer zero or negative bills, and residential customers on average arrive at a net positive bill. We also note that the California Climate Credit is paid twice per year.
22	CALSSA	Figure 5-9	Verdant should also compare its modeled net surplus generation amounts with information from the utilities on how much net surplus compensation has been paid.	We assume this comment relates to the previous finding that average bills were at or near zero dollars for the year. We have made various changes to the model and customers on average to not utilize the NSC nearly as much as in the draft.
23	CALSSA	Figure 5-9	In the methodology, Verdant should break down its findings on total net generation/consumption per year, minimum bill payment, and Climate Credit payment for different customer segments.	We will expand the results section to describe the influence of the California Climate Credit and NSC.

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24	CALSSA	3-6	The draft report uses one news story to attribute a trend in storage attachment rate "for many solar installers." CALSSA does not believe it is a representative number for many solar installers.	We have removed this footnote.
25	Foundation Windpower, LLC	Pages 1-7, 4-3, 5-4 and Tables 4-15 and 5-4.	Should there be some acknowledgment that the cost of distribution upgrades are not borne by the utilities for systems > 1MW.	We agree, we will add this reference.
26	Foundation Windpower, LLC	Page 4-27	Wind turbines operated under NEM 2.0 by Foundation Windpower (all of which are > 1MW) had hub height at 80 meters	Thank you, we have adjusted the hub height for large wind systems to 80 meters.
27	Foundation Windpower, LLC	Page 4-27	Wind turbines operated under NEM 2.0 by Foundation Windpower (all of which are > 1MW) tend to reach max. rated power at around 10-10.5 m/s	Thank you, we have adjusted the power curve to reach max power output at 10.5 m/s.
28	Foundation Windpower, LLC	Overarching	We would urge that the study account for the generation profile of CA-based wind resource, which is reliably producing during on-peak periods.	We have used California weather stations to develop estimates of wind power output.
.29	GRID Alternatives	Overarching	The draft study omits any review of NEM systems using a VNEM tariff, which is a significant oversight. Verdant confirmed on the webinar that the Commission did not ask them to include customers on VNEM. VNEM customers include many lower-income customers who received a solar incentive and who are benefitting from net metered solar savings. Indeed, the Solar on Multifamily Affordable Housing (SOMAH) program requires customers to be on the VNEM tariff, and it is reasonable to assume that a large portion of the Multifamily Affordable Solar Housing	We agree that VNEM is important and provides a valuable resource to multifamily customers. Based on the 2020 CPUC California Solar Initiative Annual Program Assessment, the VNEM population represents a small proportion of the overall NEM population. However, this study had limited resources and Energy Division chose

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			(MASH) program projects also use the VNEM tariff. A data search on California DG Stats (https://www.californiadgstats.ca.gov) indicates that since July 2017, 18.5 MW of MASH 2.0 applications have been completed since the NEM 2.0 commencing July 2017, and 6 MW of SOMAH applications have been completed. It is reasonable to assume that 20+ MW of low-income VNEM solar under NEM 2.0 is therefore left out of the NEM 2.0 lookback study. The exclusion of VNEM therefore leaves out a significant number of low-income beneficiaries of NEM 2.0. Low-income households are more likely to rent than to own their housing. According to a 2020 study by the Census Bureau, homeownership rates for households above area median incomes ranged from 78% to 80%, and homeownership rates for households below area median incomes ranged from 48% to 55% over the past 5 years (https://www.census.gov/housing/hvs/files/currenthvspress.pdf). Since the VNEM tariff serves multifamily affordable rental housing, the exclusion of this tariff from the NEM Lookback study will by extension exclude many low-income households benefitting from solar under the NEM 2.0 program. Figure 3-7 in the NEM Lookback study reports the lowest adoption rates for the lowest income customers: 0% of households earning $0 - $25K benefit from NEM 2.0, and 0.5% of households earning $25K - $50K benefit from NEM 2.0. However, these adoption rates likely under-report the true adoption of solar by the lowest income households, given the exclusion of the VNEM tariff. GRID strongly encourages Verdant to include the VNEM tariff in its lookback report, and adjust low-income numbers accordingly. If this is not possible, GRID encourages Verdant to acknowledge the likelihood that the Lookback Study is under-reporting low-income NEM 2.0 solar adoption.	to focus efforts on the aspects of California's Net Metering policy that have the largest participation and therefore impact on ratepayers. VNEM is outside the scope of this evaluation, though it is an interesting area that deserves additional research.

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30	Joint Utilities	Overarching	The modeling underlying the draft report had a glitch which overestimated solar generation by about 40%. This distorts all the conclusions of the draft report, making it difficult-to-impossible to properly evaluate it. The CPUC and its consultant should issue a second draft report and allow stakeholders another opportunity to provide feedback on a report which has updated results. Notwithstanding this request, the IOUs have attempted to provide additional feedback based on the initial draft.	This has been corrected, thank you for your comment.
31	Joint Utilities	Overarching	Cost effectiveness results are only reported as ratios, which are difficult to interpret. The final report should include the following additional metrics which Itron/Verdant committed to providing the in the project scope: • Total Levelized Savings/Costs for each test • Payback Period and IRR for NEM 2.0 systems • Year 1 Cost Shift (aka Net RIM Costs in Year 1) The last item is particularly useful – the model's base assumptions result in rates escalating at 4% and avoided costs escalating at a similar rate, resulting in the NPV being more influenced by the interplay of these escalation assumptions than current conditions. The present cost shift (year 1 RIM) is a far more comprehendible number and informs stakeholders on the impacts of the NEM program on affordability today. The utilities also suggest the following other ways of presenting the cost effectiveness test results, all of which were also produced in the NEM 2.0 Public Tool. Based on a review of the model, these all are calculated by the model and therefore only need to be aggregated for the report. • Total Annualized Net Benefits/Costs • Annualized Net Benefits/Costs per kWh of Generation • Levelized Bill Savings per kWh of Generation (Continued)	We have added several of these components to the model output: - NPV of total savings and costs for each test - payback period calculated using the subtraction and the averaging method. - IRR - RIM cost shifts in year 1 - Annualized benefits and costs of the SPM tests - First year Levelized bill savings per kWh of generation - First year Levelized avoided costs per kWh of generation - LCOE

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			• Levelized Avoided Cost per kWh of Generation • DER LCOE	
32	Joint Utilities	Overarching	While still awaiting final release, Itron also wrote the California Solar Initiative Final Impact report, which has data that would enhance this report if integrated. For example, the CSI report includes actual capacity factors from metered PV generators, which are generally lower than what is assumed in this tool (20% in Table 1-1, for example). Likewise, it also has the useful metric of what portion of customer energy usage is supplied by solar (Onsite Solar Usage/gross usage) and export percentage (exports to the grid/gross generation).	We have updated capacity factor assumptions used in the model to be climate-zone specific and no longer assume 20%.
33	Joint Utilities	4-34	The study assumes all systems are financed for the purposes of the PCT and TRC tests, and that all residential systems are financed via home equity loans. While the former could be a reasonable simplifying assumption, there is no evidence that home equity loans make up even a plurality of the manner in which residential solar customers pay for their systems. Home equity loans are only available to a subset of relatively wealthier customers, even among the already wealthier subset of customers that include solar adopters. Further, there are no sources cited for the terms of the financing (duration, debt to equity ratio, and interest rates). The structure of the financing assumption distorts the LCOE metric as well – by backing into a very high cost of equity, the model exaggerates the impact of the ITC on the levelized of the system, resulting in unusually low LCOE. LCOE is generally a fraught metric, but particularly so when using a discount rate over 20%. The final report should carefully document what the basis for these	We have updated the residential financing assumptions. We no longer assume a home equity load and we assume a 30% equity investment. Assuming the residential customer is using other types of financing also lead to a higher debt rate and the interest on the load is no longer tax deductible.

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			financing assumptions are and why they are reasonable, citing to industry reports whenever possible. In addition, the report should include a sensitivity that assumes 100% equity financed systems (aka cash purchase), which will demonstrate cost effectiveness.	
34	Joint Utilities	4-24	The report evaluates solar on a 25-year time horizon, with the justification that this is the lifetime of the asset. If the report is indeed evaluating NEM 2.0, the tariff is only available to participating customers for 20 years, and the lifetime of the asset is irrelevant. Likewise, the model assumes systems are financed over 25 years, despite almost all financing being 20 years or less. Even if TRC's scope remains 25 years, the RIM and PCT tests should only be evaluated over 20 years.	The financing period has been reduced to 18 years to reflect a weighted average financing period based on secondary research. We agree – we have changed the base case methodology such that exports are valued at the avoided cost rate for years 21-25. However, we have kept 2020 as the base year, not 2018.
35	Joint Utilities	1-5 1-7	The IOUs recommend that a sensitivity be added to the TRC test for the Investment Tax Credit (ITC) benefit. This sensitivity should include the TRC results with interim ITC levels of 22% and 26% for residential customers, and those with no ITC included. It is appropriate to include the ITC in the TRC for purposes of the lookback study to evaluate NEM 2.0 in the past; however, on a going forward basis – it is more beneficial to remove the ITC from TRC results – since these benefits are set to expire in 2022. The IOUs recommend presenting the TRC with ITC levels of 10% for commercial customers on an ongoing basis.	The evaluation is estimating the cost effectiveness of technologies that took service under NEM 2.0 and were installed prior to 2020. These technologies were eligible for the 30% ITC. A scenario was estimated with the ITC set to zero to illustrate the sensitivity of results to this assumption. This scenario does not illustrate the cost effectiveness of the technologies actually installed as part of this analysis, but it provides a bookend estimate of the TRC and PCT results.

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36	Joint Utilities	4-28	Retail rates are assumed to increase at 4% per year through the end of the analysis period. Although the report cites the Proposed Decision Adopting Standardized Inputs and Assumptions for Calculating Estimated Electric Utility Bill Savings from Residential Photovoltaic Solar Energy Systems as its source for a 4% annual rate escalation, now adopted as D. 20-08-001, the decision states that 4% is a cap on rate escalation, and sets a prescribed calculation for determining a rate escalator based on historical publicly available data. The IOUs recommend adding a sensitivity to toggle this rate escalator – as it is not necessarily the case that rates will escalate at this rate. There is not requirement or accurate future projections that justifies a 4% retail rate escalator to be included in the analysis.	We agree with the benefit of including a sensitivity on the retail rate escalation.
37	Joint Utilities	4-4	The Report generally describes the cost-effectiveness tests accurately and appears to be including the appropriate costs and benefits for each test. However, on page 4-4, the Report states: The May 2019 CPUC cost-effectiveness decision (D. 19-05-019) designated the TRC test as the primary cost-effectiveness test and adopted modified versions of the TRC, PA, and RIM tests for all distributed energy resources starting July 2019.6 The cost-effectiveness analysis undertaken here is consistent with Decision 19-05-019, highlighting the TRC and presenting results from the five district tests (TRC, STRC, PA, RIM and PCT). This is an incomplete rendering of D.19-05-019. The Decision specifically exempted from the designation of TRC as the "primary" test any situation where there was a statutory or regulatory determination that finds otherwise, and specifically mentioned NEM as one where statutory requirements would dictate otherwise (D.19-05-019, page 24, footnote 43). Further, in D.16-01-044 the CPUC discussed how to determine	The report presents the TRC as the primary test, consistent with the D.19-05-019. The report also presents the RIM and the PCT because these tests have value in evaluating the cost-effectiveness of NEM. The parties' description of the findings of D.19-05-019 are misleading, as the cited footnote simply states PG&E's opinion that NEM is an instance where legislation or a Commission Decision has required a specific test to be performed. The Commission did not adopt PG&E's position on this matter in D.19-05-019.

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			compliance with statutory requirements for the NEM successor tariff. For two requirements (PUC Section 2827.1(b)(3) and (4), the CPUC extensively discussed the RIM test as the best measure (among the SPM tests) to evaluate compliance, along with the PCT.	
38	Joint Utilities	4-4	The ITC also must be removed from the Societal Test results, since these benefits are simply an income transfer among US taxpayers. The omission of the ITC from the societal test is pursuant to the CPUC cost-effectiveness standard manual and D.19-05-019, where the Societal test is described as structurally similar to the TRC but differs in that “tax credits are omitted from the Societal test”.	The CPUC has provided guidance that the Societal Cost Test (SCT) should not be used outside of the IDER proceeding where it is being examined. The societal test presented in the NEM 2.0 model uses a state view where the ITC can continue to impact the STRC. It assumes a lower discount rate than the TRC.
39	Joint Utilities	Section 3	The report should qualify that zip code level demographic data suffers from regression to the mean, and should include a comparison to the data in the LBNL study cited in the report (“Income Trends among US Residential Rooftop Solar Adopters”, Feb. 2020), which finds that the actual income skew of adopters is higher than indicated by zip code level data.	The draft report already included a reference to the LBNL report. Unfortunately, we did not have the locational data needed to present more information than is presented in this section.
40	Joint Utilities	Overarching/ Modeling	The model is not very user friendly. Some recommendations to improve this include: • Inputs are embedded into nested “If” statements instead of having a lookup table with the inputs in it. This is particularly noticeable for the technology costs. In addition to making it more difficult to update, this modeling practice is very error prone. • All inputs must be changed manually – ideally you could select a scenario from the batch inputs tab, and the “Inputs” tab could have override cells.	We appreciate the feedback and will attempt to make this model update in the final release.

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41	Joint Utilities	ProFormaResults	Undocumented assumption – residential PCT results appear to use an 8% discount rate, not 7.5%. If this is intended, please document why this assumption is used in the report.	We believe residential customers in general should have a slightly higher discount rate than commercial customers or the utility. We believe that individuals discount the future more than corporations and that corporations discount the future more than society.
42	Joint Utilities	4-5	SGIP rebates are excluded from the PA and RIM test, with the rationale that only the costs and benefits of the NEM program are being evaluated here. This could be appropriate if these SGIP funds would be spent regardless of the design of the NEM program, which the PCT results of the study show is probably not the case – PCT results are lower for solar+storage than for standalone solar, meaning that absent NEM battery storage would not be able to pass the PCT at present battery prices. At the very least, the final report should show a sensitivity analysis where SGIP funds are included in the RIM/PA test.	The choice to treat the SGIP funds as non-NEM program funds will be maintained for this study. We want the cost-effectiveness tests to reflect the influence of the NEM rate design.
43	Joint Utilities	4-14	Cost of service calculation does not account for the grid portion of SCE distribution costs. Distribution grid costs must be included as part of SCE cost of service. SCE believe Verdant misunderstood SCE's cost components. Distribution Grid is part of cost of service and is not an avoidable cost, while distribution Peak costs is also part of cost of service, but are avoidable.	SCE provided Verdant with additional data on the MDCC associated with Distribution Grid costs. These have been added to the COS analysis.
44	Joint Utilities	Overarching	SCE has disputed the CPUC's interpretation of its GRC distribution marginal costs in the ACC. This results in SCE appearing to have much higher distribution avoided costs than the other IOUs. While it recognizes that for now the official version of the ACC includes this interpretation, SCE requests that the final study include a sensitivity excluding the "grid" marginal cost from the SCE results, which SCE asserts is non-avoidable in this context.	We have been directed not to deviate from the 2020 ACC in developing benefit/cost estimates for this analysis. Thank you for the information.

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45	Joint Utilities	2-2	In describing the results of the 2013 NEM study, the report only cites the estimate that NEM exports would result in a cost shift of $359 million per year at full NEM 1.0 subscription. This appears to be a misquote – Table 1 of the 2013 report puts the cost shift at $370 MM in 2012 dollars and would therefore be higher today. Further, the final report should cite the full generation cost shift number which is consistent with the RIM test conducted in this report, which was $1,093 MM (2012 dollars). Converted to 2020 dollars, this will allow the reader to understand the full scale of the overall NEM cost shift when combined with the 2020 cost shift which Itron/Verdant committed to providing in the study scope.	We agree and will update this wording.
46	Joint Utilities	Model (Rate Input Options)	The IOUs are unable to validate the finding summarized in this table that NEM 2.0 customers have far lower gross usage than NEM 1.0 customers. While our data indicate that there has been a slight downward trend in gross usage over time, the ~33% decline between NEM 1.0 and 2.0 appears to be overstating the change by 2 to three times. It is possible the "data quality checks" described in footnote 16 were overbroad or applied inaccurately (for instance, the decision to remove large PV systems is certainly excluding large estate homes as much as they exclude multifamily installations). Alternatively, the methodology for NEM 1.0 may not be apples-to-apples for NEM 2.0. Verdant should verify that this finding is correct, and that data issues are not skewing the result. The table could also include median statistics, which would be less vulnerable to the outlier skew concerns driving the data filtering. Further, the capacity factor assumed for solar does not appear to be documented in this table, but was described as 20% in the webinar. If	These findings have been reviewed and updated. The information provided for NEM 1 customers was for their consumption following the installation of their NEM systems. The NEM 1 customers used in the analysis were a sample of NEM 1 customers where Itron was able to receive metered data on the production of the system. It is possible that the NEM 1 customers included in the CSI report do not represent a cross section of NEM 1 customers. We will update the description in the report. The data for NEM 2 customers will include both pre- and post-consumption data. It is also possible that the data quality checks across the two studies are slightly different.

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			accurate, this is too high, which is borne out by the results of the corrected model and the 2020 Final CSI report which found Further, the RASS data on average residential energy usage are over a decade out of date, and more accurate data on average residential IOU customer usage can be found in each utilities rate implementation advice letters.	
47	Joint Utilities	Overarching	While the 2020 ACC is the current official view of the CPUC regarding avoided costs, the final report would benefit from sensitivity analysis showing the results with the 2019 ACC. This would illustrate the impact of uncertain long run avoided cost forecasts on the conclusions of the model, or lack thereof.	We appreciate the suggestion, but we will only be using the 2020 ACC in this study.
48	Joint Utilities	Overarching	NEM-A and VNEM installations appear to be excluded from the cost effectiveness analysis. Verdant said on the webinar that that was not requested to be part of the scope. However, in their comments on the draft scope the IOUs recommended that NEM-A be included, as it is a significant contributor to adoption in the agricultural sector. While it is challenging to analyze NEM-A installations, when reporting total cost effectiveness results (i.e. total dollars vs ratios), Verdant should at least attempt to “scale up” results to account for NEM-A installations which it was unable to model.	Scaling up the NEM 2.0 results to include NEM-A implies that these systems have the same cost effectiveness relationships as other parts of NEM. It is not clear that this is accurate. Furthermore, we understand that NEM-A is a very minor proportion of the overall NEM population, meaning it will likely have a minor impact on overall cost-effectiveness.
49	Joint Utilities	5-14	The section exploring the impact of CCAs does not seem to accurately model the key differences of CCA billing compared to bundled service. CCA’s generally aim to achieve approximate cost parity net of PCIA, rather than targeting a discount from the bundled generation rate without consideration of the PCIA level. A more accurate method would instead include a user input for the net discount (or premium) for CCA service and ignore the PCIA. Further, CCAs often have very different (and diverse) NEM program	We appreciate the input on the various nuances associated with CCA billing. We did not intend for the section on CCAs to be definitive and instead meant for it to be qualitative. We will amend the section accordingly.

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			features from bundled NEM, including monthly true ups and higher net surplus compensation. Given that the current sensitivity analysis finds little impact and does not appear to model the actual pricing of CCAs or the different program characteristics of the CCAs, the IOUs do not think the current sensitivity needs to be in the final report. Instead, it could be replaced by a qualitative discussion of why CCA status would not significantly impact the results.	
50	Joint Utilities	Table 4-4/Model	PG&E's Marginal energy costs appear to be incorrectly inputted into this table and the model, with off peak MECs being set to peak MECs and vice versa.	PG&E provided Verdant with updated MEC that were updated in the COS analysis.
51	Joint Utilities	4-10	The report says that MGCC PCAFs "sum to one by PG&E's 19 divisions and are used to allocate the peak capacity cost to hours with higher likelihood of energy demand." It is unclear what this means, but to clarify MGCC PCAFs are calculated at the system level, not the division level.	PG&E provided Verdant with updated MGCC allocation factors that are calculated at the system level. These were added to the model.
52	CalWEA	Overarching	The draft report should be re-issued for comment after correcting for the modeling error that resulted in substantially overestimating solar generation, which will affect the report's findings.	We intend to release a final draft only.
53	CalWEA	Overarching	Reporting cost effectiveness in terms of ratios is not intuitive. The final report should also include other metrics, such as customer payback time and cost-shifts between customers.	Additional metrics have been added to the model and report.
54	TURN	Model - ProFormaResults tab	Row 48 "Total Bill Savings" should not be flowing into the income tax or equity cash flow calculations for costing the non-residential NEM generator. This will distort the cost the generator in the PCT, TRC and sTRC tests.	The model was updated to correct the equity cash flow calculation.

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55	TURN	Model - ProFormaResults tab	In the PCT, the avoided bill for tax paying non-residential customers should be discounted by (1 minus the all-in tax rate) to reflect that utility bills are tax deductible for these customers. Discussion of this issue should be added to the report.	The nonresidential avoided bill has been updated in the PCT.
56	TURN	Model - ProFormaResults tab	Return on equity is missing from the tax calculation for commercial customers. The target equity return is a post-tax value.	The return on equity flows into the tax calculations for non-residential customers.
57	TURN	Model - ProFormaResults tab	The PCT does not appear to be including a return on equity invested in the NEM generator. Cell BI25 references invested equity (i.e., return of equity). Note that cell AT143 which is described as "Total After-Tax Equity Cash Flow" is not after-tax equity cash flow. Same comment for TRC and sTRC tests.	The after-tax equity cash flow has been updated. Thanks for the comments.
58	TURN	4-31	Operating costs for solar PV should be non-zero. For example, NREL lists $11.50 per kW-yr for residential systems, and $12 per kW-yr for commercial systems, excluding inverter replacement. See p. 14 https://www.nrel.gov/docs/fy19osti/72399.pdf.	The operating costs for solar PV will remain at zero for years when the system does not need an inverter replacement.
59	TURN	Model - CostofServiceValues tab	Please check the marginal energy costs against the GRC values. In Table 4-4, PG&E's On-peak and Super Off-peak marginal energy costs appear to be switched. The on-peak values should be higher than the off-peak values. This issue appears to be impacting the model also.	PG&E has provided an update to the MEC in the general rate case.
60	TURN	4-7	Should the climate credit be included in the cost of service? If the cost of service should collect the residential class revenue requirement over all residential customers, and if bills collect the cost of service and include the climate credit, there may be a mismatch if it is not included. If it is correct to exclude the climate credit from the cost of service, it would be helpful if an explanation is provided in the report.	The climate credit has been added to the COS.

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61	TURN	Model - Inputs tab	Inputs Cell O33: the weighted average cost of capital of 7.5% seems too high for a residential system, especially one assumed to be financed 80% with a HELOC. This is resulting in a ~ 25% opportunity cost for residential equity. Consider assuming 100% HELOC financing. This can be accomplished by assuming 0% federal and state tax rates, 100% equity capital structure, and an interest rate of 4.5 * (1 minus the all-in residential tax rate). ITC is not zeroed out under these assumptions.	The model has been updated to assume a 30% equity investment. The model no longer assumes a home equity line of credit.
62	TURN	4-34	"Residential customers are assumed to finance the DER system with a home equity line of credit, making their interest payments tax deductible." The report should acknowledge that a material portion of residential NEM 2.0 systems are financed with leases. It would be helpful if the report could provide additional results assuming residential systems are leased rather than purchased. At a minimum, the report should provide the rationale for why the purchased assumption was made, and acknowedge that the ownership assumption may not appropriately reflect the cost of leased systems. We expect that there is data available regarding the number of NEM 2.0 systems that are owned versus leased.	This assumption has been eliminated, though the model does not go through a leasing scenario. The IOUs did not provide comprehensive data on system payment type.
63	TURN	3-17	"Beginning in 2015 through 2019, the proportion of systems installed in DACs increased to 13 percent". Is the 13% figure the same as the 12% shown in Figure 3-12? It would be helpful to add text to the report describing why these figures differ, or correct the report, as appropriate.	This has been updated in the text to reflect 12 percent, thanks for pointing out this inconsistency.
64	TURN	3-15	It would be helpful if the report could provide additional DAC data. For example, percentage of home ownership for NEM 2.0 systems in DACs, the size of NEM 2.0 vs NEM 1.0 systems in DACs, and DAC NEM customer participation by successor tariff rate schedule.	These are all very interesting questions, and the distribution of DER systems in DACs deserves additional research. Unfortunately, it would require much finer data such as street addresses for NEM 2.0 customers that was not available to Verdant per NDA limits with the IOUs.

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65	TURN	5-19	Figure 5-10 indicates that more than 30% of residential customers and more than 20% of non-residential customers have at least 20% more PV generation than load. Similarly, Table 1-1 indicates that PG&E and SDG&E NEM 2.0 systems are sized on average to supply 112% of annual load. However, the NEM 2.0 tariff states that Generating Facilities that are sized larger than the Customer's electrical requirements are not eligible for NEM. If this issue has not been remedied with the correction that was made to generation output, it would be helpful to add an explanation regarding how these customers remain NEM eligible.	The model has been updated to use the post-installation net load plus the PV generation. The sections you reference will be updated, but it is still true that systems are being installed that exceed the customers pre-installation load. Customers are increasing their electricity consumption.
66	TURN	4-30	The NEM 2.0 tariff states that Generating Facilities that are sized larger than the Customer's electrical requirements are not eligible for NEM and, therefore, are not eligible for NSC. If this issue remains material following the generation output correction, it would be helpful to present results showing how many systems and how much annual generation (kWh) receive NSC, perhaps broken out by residential and commercial customer types.	Using the post consumption, the average production is less than consumption.
67	TURN	4-3	It would be helpful if a definition for "partial equipment replacement costs" could be provided in the report.	We will add this description.
68	TURN	Model - Inputs tab	It appears that the partial equipment replacement costs for storage, referenced on report p. 4-26, may not have been incorporated in model results. On the Inputs tab, cells C34 and C37 are blank but are referenced in the formula in cell C26. Cost escalation does not appear to be applied in the pro forma - it should be added, otherwise these inputs must be entered in replacement year nominal dollars.	Thank you for the comment. This was an omission in the main inputs tab which was designed to mirror our analysis inputs but was being captured in the batch inputs used in the analysis.

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69	TURN	5-10	Per current federal income tax regulations, ITC for commercial customers will remain at 10% for solar systems achieving COD from 2023. Table 5-5 seems to say that no ITC was assumed for non-residential customers in the "Without ITC" column. Consider instead presenting the bookend for such customers assuming 10% ITC.	The ITC 0% scenario was ran to illustrate the impact of the 30% ITC on the cost effectiveness test results, it was not intended to reflect current or future reality - as this would be inconsistent with the lookback nature of this analysis. The study will maintain the 0% ITC for all sectors for this scenario. Thanks for your comments.
70	TURN	5-5	The report should include an explanation of the discount rate that is used in the PCT. Same comment for PA and RIM tests.	We will update this section of the report.
71	TURN	Model - ProFormaResults tab	Please confirm whether the state tax depreciation basis should incorporate the 15% ITC deduction. California likely does not conform to Federal tax on this issue.	We cannot find clear evidence that California does or does not follow the IRS on this issue. We have maintained the current treatment.
72	TURN	Model - ProFormaResults tab	A DSRF is likely not applicable for any BTM assets because they are not project financed. Suggest hard coding cell C11 to be zero. The model does not appear to incorporate DSCRs in leverage decisions, which is appropriate for BTM resources that are not project financed.	We have set the DSRF to zero.
73	Vote Solar (VS) and Solar Energy Industries Association (SEIA)	Overarching	The draft study completely omits any review of NEM systems using a VNEM tariff, which is a significant problem. Verdant confirmed on the webinar that the Commission did not ask them to include customers on VNEM. VNEM customers include many lower-income customers who received a solar incentive and who are benefitting from net metered solar savings. These customers are therefore omitted from the cost-effectiveness analysis and the demographics analysis; in other words, the draft appears to underreport the number of NEM systems serving low-income customers and to exclude the impact of these customers on cost-	We appreciate your comment and agree that VNEM is an important tariff and opportunity for lower-income customers to receive the benefits from solar. We believe that this tariff needs additional study but it is outside the scope of the current analysis.

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			effectiveness. Given that the proposed NEM 3.0 OIR explicitly includes VNEM tariffs in scope, it is unclear what data the Commission and stakeholders will be able to use to assess VNEM progress under NEM 2.0.	
74	VS / SEIA	Overarching	To be useful to the Commission and other stakeholders, cost-effectiveness results should be shown separately for major different types of technology and major different sub-classes of residential ratepayers. Thus, residential cost-effectiveness results should be shown separately for (a) solar-only customers and (b) solar + storage customers, and separately for (1) Non-CARE customers and (2) CARE customers.	The draft report already presents SPM test by technology. The report will add findings for CARE and non-CARE customers.
75	VS / SEIA	4-4	The only difference in the NEM 2.0 model between the Total Resource Cost (TRC) and Societal Cost (SCT) tests is the use of a lower societal discount rate in the SCT test. VS/SEIA are concerned that the societal discount rate is too high, and numerous other societal benefits are omitted, as discussed below.	The societal discount rate has been reduced to 3%.
76	VS / SEIA	4-4	**Societal Discount Rate.** The societal discount rate used in the model is 5.0% (Cell O35 of Inputs tab of RateCalc_NEM2_Model). The societal discount rate approved for the SCT by the Commission in D. 19-05-019 is 3.0%, which is the value that should be used here.	This has been updated.
77	VS / SEIA	4-4	**Health Benefits from Reduced Criteria Air Pollution.** D. 19-05-019 approved an initial SCT that also includes health benefits from reduced criteria air pollution (initially $6 per MWh of output from distributed resources).	While we appreciate your comments, the CPUC has provided guidance that the Societal Cost Test (SCT) is not approved for use in the NEM Lookback Study. This analysis will maintain what we are calling the Societal Total Resource Cost (sTRC) test, which only differs from the TRC in the lower discount rate.

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78	VS / SEIA	4-4	**Social Cost of Carbon.** The SCT adopted in D. 19-05-019 also includes the social cost of carbon to measure the avoided damages from mitigating carbon emissions and the associated climate change. Societal benefits should include a recent estimate of the amount by which the social cost of carbon exceeds the carbon compliance costs included in the 2020 Avoided Cost Calculator (2020 ACC). A recent estimate of the social cost of carbon is the median estimate of $417 per metric tonne from an academic review of a range of SCC values published in *Nature Climate Change.* See Ricke *et al., "*Country-level social cost of carbon," *Nature Climate Change* (October 2018). Available at: https://www.nature.com/articles/s41558-018-0282-y.epdf.	While we appreciate your comments, the Societal Cost Test (SCT) is not approved for use in the NEM Lookback Study. This analysis will maintain what we are calling the Societal Total Resource Cost (sTRC) test, which only differs from the TRC in the lower discount rate.
79	VS / SEIA	4-4	**Out-of-state Methane Leakage.** The 2020 Avoided Cost Calculator includes a direct avoided cost for avoided in-state methane leakage upstream of gas-fired power plants. This leakage can be avoided when gas use for electric generation is reduced. Displacing gas use for electric generation also reduces out-of-state methane leakage, because 92% of California's gas supplies are imported from outside the state. These reductions in methane leaks are a societal benefit (and thus are not incuded in the ACC) because, unlike in-state leaks, out-of-state leakage is not in the CARB's official GHG inventory for California. This benefit is 11.5 times (11.5 = 92% out-of-state gas / 8% in-state gas) larger than the methane leakage component of the ACC.	While we appreciate your comments, the Societal Cost Test (SCT) is not approved for use in the NEM Lookback Study. This Analysis will maintain what we are calling the Societal Total Resource Cost (sTRC) test, which only differs from the TRC in the lower discount rate.
80	VS / SEIA	4-4	**Land Use Benefits.** Distributed generation makes use of the built environment in the load center – typically roofs and parking lots – without disturbing the existing use for the property. In contrast, central station solar plants require larger single parcels of land, and are more remotely located where the land has other uses for agriculture or grazing. Today, the land must be removed from this prior use when it becomes a solar farm. Central-station solar photovoltaic plants with fixed arrays or single-axis tracking typically require 7.5 to 9.0 acres per MW-AC, or 3.3 to	While we appreciate your comments, the CPUC has provided guidance that the Societal Cost Test (SCT) is not approved for use in the NEM Lookback Study. This analysis will maintain what we are calling the Societal Total Resource Cost (sTRC) test, which only differs from the TRC in the lower discount rate.

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			4.4 acres per GWh per year. The lost value of the land depends on the alternative use to which it could be put. The U.S. Department of Agriculture has reported the average value of farm and ranch land in California in 2019 as $10,000 per acre. See https://downloads.usda.library.cornell.edu/usda-esmis/files/pn89d6567/g732dn07g/9306t9701/land0819.pdf. Assuming 3.5 acres per GWh per year, a $10,000 per acre value of land, and a 25-year loan at an interest rate of 4% per year to finance the land purchase, DG provides the benefit of avoiding a lost land use value of $2.20 per MWh.	
81	VS / SEIA	4-4	**Reliability and Resiliency.** Solar plus storage sysems can provide an assured back-up supply of electricity, improving the reliability and resiliency of the electric system. This could be considered a direct benefit to ratepayers, but assuredly it is a societal benefit. The literature distinguishes reliability from resiliency: reliability focuses on minimizing the normal, shorter-duration outages caused by weather or equipment failures; resiliency is the ability to maintain service during less-frequent, higher-consequence "black sky" events of longer duration and larger extent. See Converge Strategies for NARUC, *The Value of Resilience for Distributed Energy Resources: An Overview of Current Analytical Practices* (April 2019), at p. 8. Available at https://pubs.naruc.org/pub/531AD059-9CC0-BAF6-127B-99BCB5F02198. Storage-based DERs can improve both reliability and resiliency, and both benefits can be quantified. The value of reliability -- about $300 per year per customer – is based on the reliability metrics that the IOUs file with this Commission and on value of service studies widely used by the IOUs. Vote Solar and SEIA have calculated a value of resiliency from the costs of fossil-fuel-based backup power systems that can provide a basic level of electric service during a prolonged interruption; this resiliency value is $104 per kW-year for residential customers and $106 per kW-year for non-residential. See	While we appreciate your comments, the CPUC has provided guidance that the Societal Cost Test (SCT) is not approved for use in the NEM Lookback Study. This analysis will maintain what we are calling The Societal Total Resource Cost (sTRC) test, which only differs from the TRC in the lower discount rate.

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			Prepared Direct Testimony of R. Thomas Beach on behalf of SEIA and Vote Solar, served October 7, 2019 in CPUC Docket No. R. 14-10-003, at pages 65-70. This testimony is **attached**. The residential resiliency value was revised to $104 per kW-year during the hearings in R. 14-10-003 to include greater required fuel storage costs.	
82	VS / SEIA	1-8 to 1-10	In describing the Cost of Service analysis, the draft states: "We used information from the utilities' General Rate Case (GRC) Phase 2 filings, regulatory costs, and NEM customer incremental costs to develop estimates of the cost of service for NEM 2.0 customers." The draft study appears to use marginal cost information from the IOUs' GRC filings. As VS/SEIA discussed in our comments on the study's scope, IOU GRC Phase 2 cases typically are resolved through "black box" settlements that do not specify the marginal costs on which rates are based. The marginal costs used to set rates -- as well as the methods used to allocate these avoided costs across the hours of the year -- are the products of negotiations among the range of marginal costs proposed by parties, and often can differ significantly from the IOUs' marginal costs filings at the outset of cases. Simply assuming that rates are based on filed IOU marginal costs is thus inaccurate and gives no weight to the expert testimony of other parties in IOU GRC Phase 2 cases that propose marginal costs that often impact the adopted rates. In some cases, the CPUC orders or adopted settlements resolving GRC Phase 2 cases do adopt specific marginal costs; where available, these values should be used. Some marginal costs in the IOU filings are uncontested; these values also can be used. Finally, reasonable values can be derived from the mid-points of the range of positions that parties took in the record of the Phase 2 cases that are resolved by "black box" settlements. SEIA and Vote Solar have prepared the **attached Tables VS-SEIA-1 and VS-SEIA-2** with recommendations for selecting such middle-ground values from the records in recent IOU GRC Phase 2 cases that were resolved by settlement. Our comments on the	We appreciate your comment and the willingness to work with the evaluation team and the IOUs to develop alternatives to the GRC values used in the draft report. Unfortunately, it was considered out of scope to develop alternatives to the GRC values for this analysis.

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			scope for this study also expressed a willingness to work cooperatively with the utilities, Itron, and staff to develop a set of agreed-upon cost-of-service parameters that reflect the currently-adopted rates used by most NEM 2.0 customers and that respect the settlements in recent Phase 2 cases, but such a collaborative effort has not been pursued.	
83	VS / SEIA	4-8	The Study's cost-of-service analysis assumes that FERC-regulated transmission costs are a pass-through on a $ per kWh basis for residential customers. This effectively assumes that the transmission cost of service is the same in every hour. However, transmission costs are driven by peak transmission system loads, which occur in the mid-to-late afternoon when there is significant solar output. Recognizing this, in Resolution E-5077, at pp. 23-24, the Commission adopted transmission PCAFs to allocate avoided transmission costs in the 2020 ACC. Thus, the cost-of-service for transmission costs should be focused on the afternoon hours with peak transmission loads, and the Study's cost-of-service analysis over-allocates transmission costs to customers post-solar.	Thank you for the suggestion. Our intent was to be consistent with the IOU GRC filings in the Cost of Service analysis. While we recognize that there may be opportunities to improve that portion of the analysis, they are not in our scope here.
84	VS / SEIA	4-18	The study uses all elements of the 2020 ACC. However, the GHG Rebalancing component (a subtracter from the overall GHG value) should be excluded, because existing NEM systems are already built and their impact is already included in existing loads. Thus, unlike new resources that will be developed in the future, they will not cause a future change in loads that triggers a need to rebalance the resource portfolio.	It is true that existing loads reflect the impact of existing NEM systems. The comment, however, mistakenly assumes that there is no marginal cost impact of existing systems, and further seems to pick and choose which marginal cost impacts it can ignore. The comment states that the existing solar will not cause a change in loads and therefore will not cause a need to rebalance the portfolio. This perspective takes the existing system as the base case and only looks to value changes from the

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				base case. However, if one were to take this "no change" perspective, then there would not only be zero rebalancing impact, but zero impact at all. In other words, in order to justify not incorporating the rebalancing effect one would need to assume that existing solar has no impact on the base case, and therefore has no avoided cost value (energy, or capacity or emissions). This study is looking at the value provided by all solar, whether existing or incremental. The study therefore uses the same marginal cost values for both existing and incremental solar. The study approach recognizes that the marginal value of adding an incremental kW is identical to the marginal value of maintaining (i.e., not removing) a kW of existing BTM resources included in the baseline.
85	VS / SEIA	1-7 to 1-8	Please explain the need for and relevance of modeling NEM 2.0 without the ITC. This is a lookback study, and all NEM 2.0 projects to date have received the full ITC. Vote Solar and SEIA are not aware of any NEM 2.0 customers who will not receive the ITC. If this comparison is intended to have some prospective relevance, bacuse the ITC may sunset prospectively, the study should explain the purpose and relevance of this no-ITC sensitivity to this lookback study. Also, under current law the ITC will remain at 10% for commercial customers going foward; it will only sunset to zero for residential customers.	The intent of the sensitivity was to consider the influence of the Federal ITC on the PCT and TRC tests. This analysis was conducted at the request of the CPUC. We are not making any forward looking statements by analyzing results without the ITC.

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86	VS / SEIA	1-2	The Draft states: "The program provides customer generators full retail rate credits for energy exported to the grid and requires them to pay charges intended to align NEM customer costs more closely with non-NEM customer costs." This is not accurate, because NEM 2.0 does not provide "full" retail rate credits (which suggests 100% retail rate credits). Export rates under NEM 2.0 are reduced by non-byassable charges, so NEM 2.0 customers do not receive a "full" retail rate credit. It is unclear what aspect of NEM 2.0 is meant by "charges intended to align NEM customer costs more closely with non-NEM customer costs." NEM 2.0 customers take service under the same TOU rates as non-NEM customers who elect TOU. Further, NEM 2.0 customers have been required to take service on TOU rates, which are more accurate and cost-based than the tiered rates still available to non-NEM customers.	This language is taken directly from the CPUC NEM website in the "NEM Overview" section. https://www.cpuc.ca.gov/general.aspx?id=3800 However we value your feedback and will make the clarifying changes.
87	VS / SEIA	1-4	The summary paragraph for the section on cost-effectiveness states that "Overall, our results show that the NEM 2.0 tariff is cost-effective to participants and cost-effective from a combined participant/utility perspective. However, NEM 2.0 projects overall are not cost-effective from the perspective of ratepayers." **Ratepayers** as a group include both ratepayers who install solar (participants) and ratepayers who do not (non-participants). Since NEM 2.0 is cost-effective for the subset of participating ratepayers, the final sentence should be modified to read "However, NEM 2.0 projects overall are not cost-effective from the perspective of **non-participating** ratepayers."	The text will be updated to indicate that the systems are not cost effective under the RIM test and would lead to increases in rates for all customers.
88	VS / SEIA	NEM 2.0 Model	The monthly minimum delivery charge of $10 per month used in the NEM 2.0 model does not appear to escalate with inflation, as is allowed by D. 15-07-001, at the table on p. 227 and Conclusion of Law 24.	We agree and have updated this portion of the analysis.

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89	VS / SEIA	NEM 2.0 Model	The model includes taxes on utility bills. The tax impacts of distributed generation are more complicated than presented in the Study. The analysis does not include the offsetting sales, employment, property, and other taxes that resulted from the distributed generation projects developed under NEM 2.0. For example, portions of the equipment purchased for NEM 2.0 systems were subject to state sales taxes; the workers hired to install the systems paid an array of employment-related taxes; and, although solar systems are exempt from direct property taxes in California, solar energy systems increase property values which are reflected in increased property transfer taxes and increased property taxes when a residence is sold. In essence, the NEM 2.0 program represents a substitution of capital for ongoing purchases of electricity from the utilities; this is what happens whenever a utility customer makes a capital investment to upgrade its equipment to reduce its consumption of power from the grid. The net impact of such transactions on tax revenues is a complex mixture of changes to local franchise fees and utility user taxes (a reduction), sales taxes (both increases and decreases), property taxes (an increase), and employment-related taxes (an increase). This complicated calculation is not provided in the NEM 2.0 Study. Moreover, if the net result of such a transaction is a reduction in tax revenues (which is not necessarily the case), the remedy lies with the power of the California Legislature and other governmental entities to set tax rates, not with the CPUC. Tax effects should not be included in the NEM 2.0 model.	We appreciate these comments. We understand that the model is not designed to capture all or perhaps even most of the complicated taxes paid by residential or non-residential customers and believe it merits further examination. We have included the tax on the energy bill to ensure we are representing customer bills as closely as possible.
90	VS / SEIA	NEM 2.0 Model	The model includes the fixed California climate credit as a credit both before and after a customer installs solar. Since this is a per-customer credit that does not vary with usage, it should not be included in the analysis, as it is not a cost or credit that changes due to a customer adopting solar. Including the credit makes the customer's post-solar bill appear artificially low.	We believe that including the credit makes the bills representative of actual customer payments, which would include the credit. The bills are not artificially low if they include the climate credit.

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91	VS / SEIA	NEM 2.0 Model	The model makes certain seemingly arbitrary assumptions about what the customer's pre-solar tariff would have been over time without solar. For example, the model assumes that customers would have stayed on E-1 or E-1 CARE for three years after installing solar, even if a TOU rate were more economic -- and the customer had signaled its willingness to move to TOU by electing solar. A better assumption for those cases would be to use the customer's chosen TOU rate as both the pre-solar and post-solar rate.	The study generally uses their post-solar rate to represent their post-solar rate and make adjustments to the pre-solar rate to mimic likely time trajectories associated with the utility's transition to TOU rates.
92	VS / SEIA	NEM 2.0 Model	The model appears to analyze NEM 2.0 systems assuming that they all come on-line in 2020, at 2020 rate levels, and then continue in operation for 25 years. In reality, NEM 2.0 began in 2016, and on the order of 400,000 NEM 2.0 systems began operating prior to 2020. As a result, the bill savings/lost revenues from these NEM 2.0 customers are overstated by assuming that they do not begin operation until 2020 when rates are higher. Further, the NEM 2.0 structure will be in place only for 20 years from each customer's PTO date (see D. 16-01-044, at pp. 100-101). The Study should show how the results change with different possible compensation structures for years 21-25, such as various percentage reductions in NEM 2.0 export compensation.	Regarding the first point, we understand the comment and consider this a simplifying assumption. Regarding compensation beyond 20 years, we understand that the NEM 1.0 grandfathering period set certain precedents, but we find that changing the compensation mechanism in years 21-25 would add additional complexity to the interpretation of the results.

End of Attachment A